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EXECUTIVE SUMMARY

In its 74th session, the Texas Legislature directed the Public Utility Commission of Texas (the Commission) to prepare a report on stranded investment in the electric industry in Texas:

> *The commission shall submit a report to the 75th Legislature on methods or procedures for quantifying the magnitude of stranded investment, procedures for allocating costs, and the acceptable methods of recovering stranded costs.*[1]

As used in the on-going national debate on the future of the electric industry, the term "stranded investment" can be interpreted differently by differing parties. In this report, stranded investment is defined as *the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market.* Throughout this volume, the phrase "potentially strandable investment" often is used in place of the phrase "stranded investment." Referring to potentially strandable investment is a way of emphasizing that these historic costs are not yet stranded, but may become stranded at some point in the future. The degree to which investments are ultimately stranded will depend upon changes in the market price of electricity, the speed with which markets become effectively competitive, tax implications of potential restructuring options, mitigation efforts by the utilities, and the actions of utilities, the Legislature, and the Commission regarding electric industry restructuring. Until such time as historical investments actually become stranded, these potentially strandable investments remain a component of the rates that utilities currently charge their customers.

The prospect of potentially strandable investment arises because utilities that have long been regulated entities face the prospect of competition, which may reduce the market value of utility assets below book value (leaving those assets "stranded" and potentially unrecoverable). The issue has risen to prominence in response to fundamental changes

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[ES-1] Public Utility Regulatory Act of 1995, Tex. Rev. Civ. Stat. Ann. art. 1446c-0 §2.057(e) (Vernon Supp. 1996) (PURA95).

now occurring in the electric industry. Some changes are specific to the electric market in Texas, while others are taking place on a national scale. The 74th Legislature acknowledged the increasing competitiveness of certain segments of the electric industry in Senate Bill 373, noting that:

> *. . . the wholesale electric industry . . . is becoming a more competitive industry which does not lend itself to traditional electric utility regulatory rules, policies, and principles and that, therefore, the public interest requires that new rules, policies, and principles be formulated and applied to protect the public interest in a more competitive marketplace.*[2]

In S.B. 373, the Legislature took a number of additional steps that are expanding competitive opportunities in the electric industry in Texas.

In preparing its investigation, the Commission recognized its opportunity to conduct a more broad-based investigation into the structure of the electric industry, the prospects for regulatory restructuring, and the magnitude of potentially strandable investments. The Commission established three projects that have become the platforms for investigating competition, restructuring, and strandable investment:

1. *Project No. 15000:* An investigation into issues related to the electric utility industry and regulatory restructuring;
2. *Project No. 15001:* An investigation into potentially stranded investment in the electric utility industry in Texas, conducted in accordance with §2.057(e) of PURA95; and
3. *Project No. 15002:* An investigation into the scope of competition in the electric utility industry in Texas, conducted in accordance with §2.003 of PURA95.

The Commission determined that it could make a valuable contribution to the debate on electric industry competition and restructuring by providing estimates of the magnitude of potentially strandable investment in Texas. The Commission initiated an investigation of the excess costs over market value (ECOM) of utility assets in Texas. ECOM—as defined in this report—is a *measure* of potentially strandable investment in Texas. The Commission believes that an estimate of ECOM, while not necessarily

[ES-2] PURA95 §2.001(a).

required to discuss procedures and methods for allocating and recovering stranded investments, can help guide policy decisions in the State and give utilities the opportunity to develop strategies for the future.

The Commission's report to the Legislature is presented in three volumes. Volume I is the Commission's report to the Legislature on the Scope of Competition and Potentially Strandable Investment (ECOM), pursuant to PURA95 §§ 2.003 and 2.057(e). Volume II is the Commission's detailed analysis of the scope of competition in the electric industry in Texas.[3] Volume III (this volume) is the Commission's detailed report to the Legislature on stranded investment.

A. Sources of Stranded Investment

Utility investments in plant and equipment are currently recovered in the utility's regulated rates. In a competitive market, the prevailing price of electricity is likely to be below the present regulated price. Thus, under competitive conditions, a utility may collect less revenue for every unit of electricity sold than it would have collected under regulation. Because the market value of an asset (e.g., a power plant or a transmission line) is determined by the expected revenue from that asset, lower expected revenue will lower the value of the asset.

Figure ES–1 presents a simplified illustration of the source of stranded investment. The height of the first vertical bar in the figure represents the *regulated* price of electricity, in cents per kWh sold by Utility A to a large consumer. That price is composed of fixed costs, the embedded costs of providing utility plant and equipment, and variable costs, operating costs—including fuel—that depend upon the amount of power provided. For the customer historically buying power from Utility A, a new source of supply is now available from Alternative B—represented by the second bar—which may be a co-generator or power marketer, for example. Alternative B is able to supply electricity at the competitive market price, which is lower than the regulated price

[ES-3] Public Utility Commission of Texas, *Report to the 75th Texas Legislature Volume II The Scope of Competition in the Electric Industry in Texas: A Detailed Analysis*, Austin, Texas (January 1997), hereafter, the "Scope of Competition" Report.

offered by Utility A. The customer will choose to switch to the less expensive source of supply offered by Alternative B.

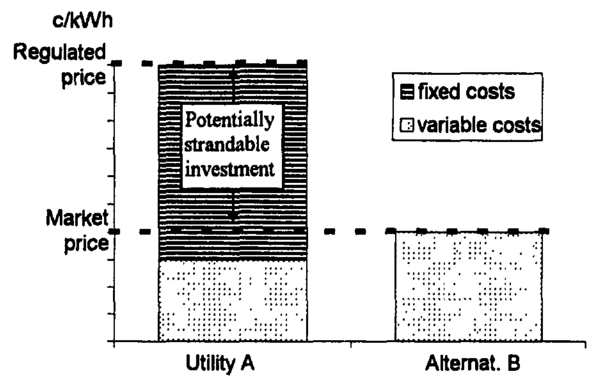


Figure ES–1: Simplified Depiction of the Source of Stranded Investment

In Figure ES–1, a portion of the utility's fixed costs are above the dotted line representing the competitive market price. These fixed costs are historic costs of supplying power to that customer. Because a portion of the historic fixed costs are above the competitive market price, that portion of the fixed costs will be unrecoverable in the competitive market. The portion of fixed costs above the market price is the stranded investment the utility will incur if the customer leaves.

In the example, costs become stranded because the customer switches from Utility A to Alternative B, but it is important to note that the investment that is *potentially strandable* is not dependent upon the customer's behavior. Rather, the quantity of potentially strandable investment arises from conditions in the market. As long as the utility's regulated price is above the market price, investment is potentially strandable.

As long as the customer buys service from Utility A at the regulated price, the customer continues to pay the utility the value of its potentially strandable investment. The investments will not become *stranded* unless and until the customer actually switches to a market-based source of supply. Thus, assets becomes "stranded," or unrecoverable from the original customer when the customer switches to Alternative B. Assets may also become stranded if Utility A lowers its price to the market price, in an effort to stave off the competition. In so doing, Utility A may keep the original customer but no longer recovers its fixed costs above the market price.

B. WHOLESALE AND RETAIL STRANDED INVESTMENT

Electricity sales can be divided into wholesale and retail functions depending upon the final disposition of the power.[4] Stranded investment may arise in both wholesale and retail markets. Retail electricity markets are those in which electricity services are delivered to end users. Retail public utilities include IOUs, distribution cooperatives, and municipally owned utilities, all of which may be subject to alternative forms of rate regulation under the provisions of PURA95. Wholesale transactions involve sales for resale. The wholesale market is primarily a long-term contracts market in which utilities enter into contracts for "firm" power. Among Texas utilities, the wholesale market represents a small portion of total Texas utility generation. Of retail sales in the State in 1995, 12.6 percent were sold by a utility through an intermediate wholesale transaction.

Stranded investments associated with wholesale contracts arise through a different mechanism than the stranded investments attributable to retail service. Retail stranded investment arises when a customer switches from its traditional supply at regulated rates to electric supply at the competitive market price. Wholesale stranded investment arises when a contract expires or is otherwise terminated. The size of wholesale stranded investment will depend upon the contract terms, whether the contract remains in effect through its term, and the obligations of the contract signatories for stranded investment following expiration of the contract.

Current and proposed examples of market transactions with the potential to create wholesale stranded investment include the following:

- *Wholesale contract replacements:* Since the Commission adopted rules requiring comparable transmission access, several parties have entered into contracts with non-utility providers, replacing prior contracts held with

[ES-4] A more detailed discussion of the structure of the electric market in Texas and the distinctions between wholesale and retail markets can be found in Chapter V of the Scope of Competition Report.

utilities. For example, Granbury Municipal Electric Department will buy 16 MW of load from LG&E Power Marketing, replacing Brazos Electric Cooperative. Rayburn Country Electric Cooperative also selected LG&E Power Marketing to supply more than 300 MW of load currently served by Texas Utilities Electric Company.

- *Co-generation:* Co-generation facilities are typically industrial concerns that own and/or operate generating facilities, but are not primarily engaged in the generation or sale of electric power. These facilities produce electric energy, steam used in manufacturing, and thermal energy used for industrial and commercial heating/cooling. If a utility customer chooses instead to co-generate, utility investments may become stranded. Although data are incomplete, in 1995, non-utilities (mostly co-generators) sold at least 21.3 million MWh to utilities and used at least 20.3 million MWh for their own consumption.
- *Municipalization:* Most cities receive electric service under franchise agreements. Upon the expiration of a franchise agreement, cities have the opportunity to form municipal utilities, which would allow the municipalities to shop for electricity in the wholesale market.

These examples demonstrate that utility investments that are providing service in the wholesale market can and are becoming stranded today. In particular, new wholesale supply contracts that have replaced utility power with non-utility power may cause the original utility's investments to become stranded.

C. METHODS FOR QUANTIFYING STRANDED INVESTMENT

The two main methods of estimating the magnitude of strandable investments are market valuation and administrative valuation. The Commission's detailed analysis of potentially strandable investment reviews each approach and presents the results of several administrative studies performed for the U.S. electric market. If the valuation is conducted in a market, the asset value is determined by the interaction between buyers and sellers in the marketplace, and stranded investment is the difference between the value of the asset on the utility's books and the market value. In contrast, administrative valuation methods simulate market outcomes using financial and accounting models. Various analytical approaches can be applied to both administrative and market valuation methods. Table ES–1 summarizes some of the different approaches used to estimate the value of potentially strandable investment.

Table ES–1: Methods and Approaches for Valuing Potentially Strandable Investment

	Administrative Method		Market Method	
	EX ANTE	*EX POST*	*EX ANTE*	*EX POST*
	Assumed Market Conditions	New Market Conditions Established	Assumed Market Conditions	New Market Conditions Established
BOTTOM-UP	Assets and liabilities valued individually	Assets and liabilities valued individually	Market transaction values individual assets	After-the-fact purchase price adjustment
TOP-DOWN	Total generation resources valued	Total generation resources valued	Market transaction values total generation resources	After-the-fact transaction adjustment

Source: Based on Baxter, Lester and Eric Hirst, *Estimating Potential Stranded Commitments for US Investor-Owned Electric Utilities,* U.S. Department of Energy, Oak Ridge National Laboratory at 7 (January 1995).

Valuation can occur before, *ex ante,* or after, *ex post,* market restructuring is complete, and may use a bottom-up or top-down approach. A bottom-up approach uses asset-specific data to calculate potentially strandable investments for each generating unit or other asset a utility owns. A top-down approach uses aggregated utility or regional-level data, and requires fewer assumptions to calculate potentially strandable investments for a portfolio of assets. Because it is a more general approach than a bottom-up analysis, top-down analysis tends to be easier to understand, but may provide fewer detailed insights into specific assets, liabilities, and costs.[5]

Market valuation methods are undertaken by market participants, buyers and sellers of utility assets. Examples of market valuation methods include: a spin-off of generation assets to unregulated affiliates or to third parties; open auctions; and all-source solicitations. The main advantage of market valuation methods is that market methods can produce asset values grounded in markets rather than based on the judgments of

ES–5 The ECOM Model developed by the Commission Staff to assess potentially strandable investment in Texas can be classified as an *ex ante* administrative approach that blends aspects of the top-down and bottom-up methods. The ECOM Model analyzes potentially strandable investment by resource type—a blend of the two methods—rather than valuing assets and liabilities individually (bottom-up) or by the total generation function as an undivided whole (top-down).

financial analysts. Market methods also can reduce the market power of dominant utilities and ease entry barriers for competitors. The principle potential disadvantage of market valuation methods lies in the market itself; accurate valuation relies on a well-functioning market for generation assets. Market values could be inaccurate—after the fact—if transactions for generation assets are completed before the new market structure is firmly established.

Administrative methods rely on financial and accounting models that can be used as substitutes for market transactions. Administrative methods are especially helpful when estimating potentially strandable investments for assets that may not have viable markets, such as nuclear plants. Administrative methods can also be used to value potential wholesale strandable investment, which can be distinguished from potential retail strandable investment.

The greatest disadvantage of administrative valuation is that values are based on estimates, not observations in working markets. Administrative methods do not address marketplace issues like market power. At their worst, administrative methods serve as another form of regulation that attempts to mimic an unregulated market. If performed *ex ante*, administrative methods require projecting a utility's generation costs and revenues, and making assumptions about industry structure and market prices. If the valuation is performed *ex post*, the new marketplace will be functioning, and utilities' actual operating financial information can be used to quantify stranded investment.

The Commission's report on stranded investment also describes some of the financial considerations associated with electric industry restructuring and deregulation. Each utility has a unique debt and equity structure that may influence its response to changing market and regulatory conditions. The value and stability of utility stocks and bonds may be affected by deregulation and industry restructure. The strength of each utility's securities is dependent on its market position relative to its competitors.

Through competition and deregulation, many utility stocks are likely to lose their previous status as "quasi fixed-income" securities because the companies will have the potential for additional growth and the risk of declining sales. If deregulation progresses, investors will adjust their expectations, and stock prices will move accordingly. If a utility is in a strong position relative to other generators in the market, and has low operating costs, then its stock prices may not be harmed by a single event. If, however, the utility is in a weak position relative to other generators in the market, and has high operating costs, its higher-risk profile should be reflected in lower stock prices.

Electric utility bonds are true fixed-income securities that have historically been considered very safe investments. An indenture is a type of contract through which utilities issue secured bonds. Utilities often use secured bonds to finance construction and other projects. Typically, indentures contain provisions about the form of the bond, amount of the issue, property pledged, protective covenants, working capital, current ratio, and redemption rights or call privileges. Some utilities may be able to raise enough money through asset sales to retire secured bonds. Other possible solutions for a utility with insufficient cash to retire bonds are to reorganize its debt structure with the cooperation of the bondholders' trustee, to substitute or swap bonded property with unbonded property, or to retain the debt associated with the generation assets.

If industry restructuring were to take the form of divestiture or asset sales, the federal income taxes of both the utilities and their shareholders could be affected. The type of market transaction will dictate the federal income tax effect. Local tax revenue may also be affected by market prices of electricity or changing values of generation assets.

D. THE COMMISSION'S INVESTIGATION OF EXCESS COSTS OVER MARKET

In April of 1996, the Commission ordered Texas investor-owned utilities, cooperatives, and river authorities (and requested municipally owned utilities) that own generation assets to estimate the ECOM of their assets using an administrative model developed by the Commission Staff following workshops with interested parties in Texas. In June of 1996, utilities filed their ECOM estimates using the Staff model. The purpose of quantifying the potential effect of deregulation *is not* to provide a final determination of the magnitude of stranded costs to be used in setting utility rates. Rather, the objective is to provide information that will be beneficial to decision-makers in the analysis of electric industry restructuring alternatives. Although the Staff reviewed the utilities' filings extensively, the filings have not been audited by the Commission, nor have interested parties reviewed the filings due to confidentiality concerns.

The ECOM model is an electronic workbook in Microsoft Excel 5.0 software. The model provides an estimate of the after-tax net present value of the change in generation-related revenues that a utility may experience as a result of selling electricity at market-based prices rather than at regulated prices. In the model, ECOM is defined as the present value of the difference between a utility's existing fixed costs—including related obligations—and projected contributions to capital of utility sales under competitive conditions (i.e., revenues in excess of ongoing operating costs). ECOM is estimated for both Texas retail and wholesale jurisdictions.

Texas utilities that own generation plants were required to provide data on the capital and production costs associated with generation resources. In the ECOM Model, reporting utilities allocate these costs by resource type (gas, coal/lignite, nuclear, or other) and by customer class (Texas retail industrial, commercial, residential; and Texas jurisdictional wholesale) for each year for the projected life of the plants. The utilities also provided projections of their sales (in MWh) allocated by resource type and by customer class. Using these utility cost and sales projections, the model calculates the regulated price of electricity for each customer class under continued cost of service regulation. Based upon a range of projected competitive market prices developed by Staff (low, base, and high), the model calculates a corresponding range of competitive market-based revenues for each utility by customer class. ECOM is then calculated as the present value of the difference between the regulated and the market-based revenue streams.

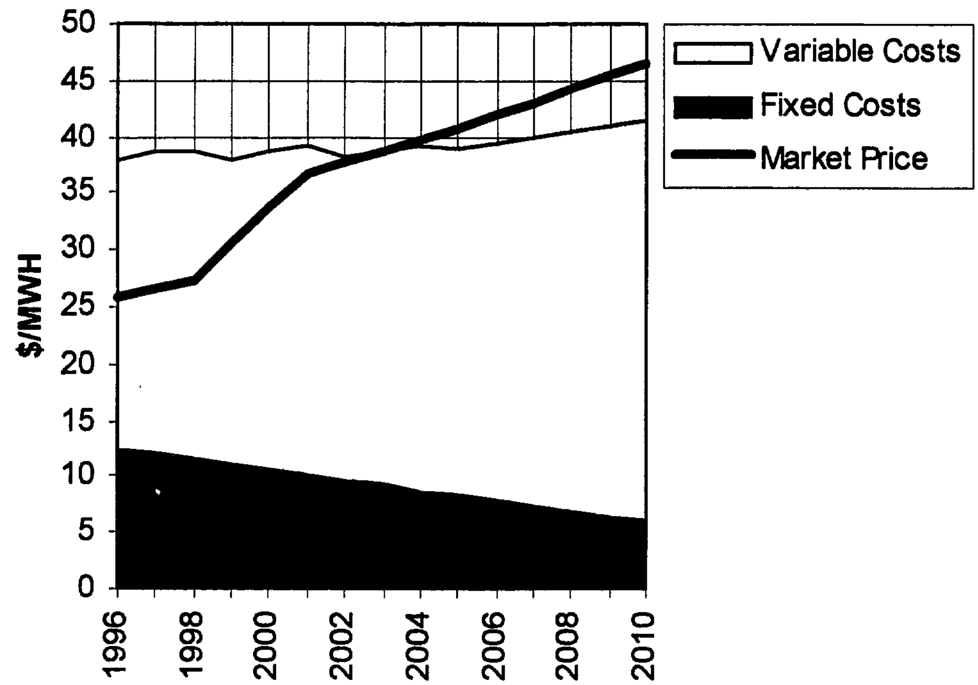


Figure ES–2: Illustration of the ECOM Methodology (1)

Figure ES–2 and Figure ES–3 provide an illustration of the ECOM Model methodology. In Figure ES–2, the utility generation cost-of-service is represented by the sum of the variable costs and the fixed costs. In the illustration, the utility's generation cost-of-service is greater than the projected market price of electricity for the years 1996 to 2004. In contrast, for the years 2005 to 2010, the projected market price exceeds the projected generation cost-of-service. Figure ES–3 demonstrates the ECOM calculation. ECOM is calculated as the difference between the generation cost-of-service and the projected market price. From 1996 to 2004, ECOM is equal to the vertically shaded area representing the difference between the market price and cost-of-service. For the years 2005 to 2010, the cost-of-service is less than the market price. As indicated in Figure ES–3, this area represents a reduction to ECOM. It is important to note in this example that, even if these two areas were of identical size, ECOM would not net to zero. ECOM is computed as a present value over time; thus, the ECOM that results in the near years will have a greater present value than the reduction to ECOM that results in the later years.

It is also important to note that the relationship between market price and utility cost-of-service depicted in the figure applies to existing utility generation assets that are currently being depreciated on the companies' books. If a utility were to add new generation, the new generation would be provided at the market price.

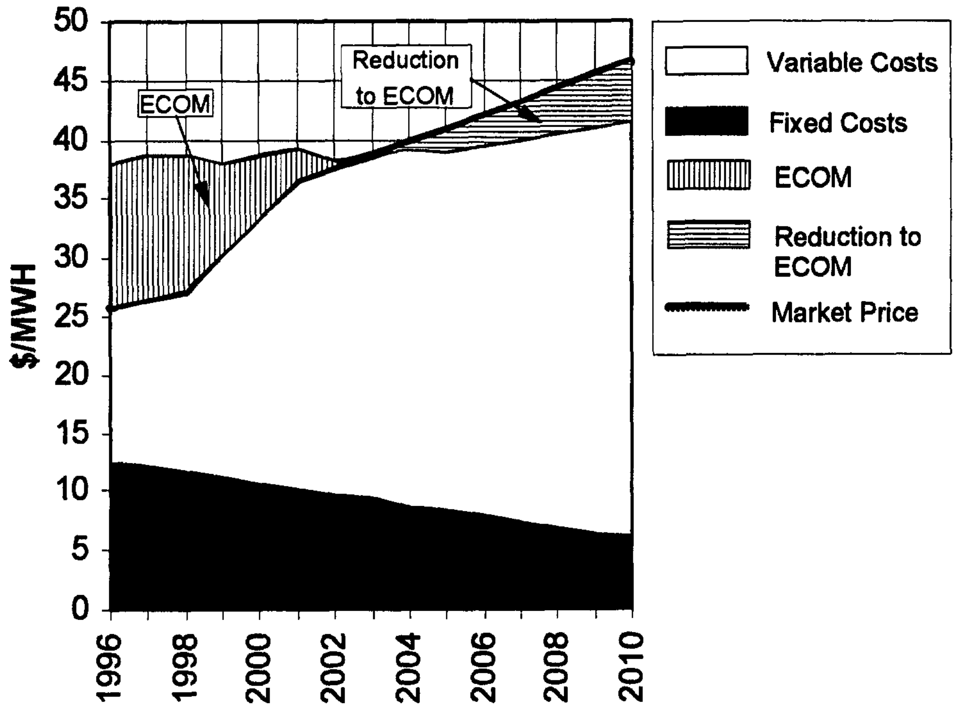


Figure ES–3: Illustration of the ECOM Methodology (2)

In the model, ECOM can never be greater than the discounted present value of the utility's *fixed* costs. If the model predicts that a plant will cease to operate because it becomes uneconomic to operate in a competitive environment, ECOM will be *equal* to the discounted present value of only the fixed costs. If the model predicts that a plant will continue to operate, then ECOM will be *less* than the discounted present value of fixed costs because the firm will collect revenues greater than its operating expenses, which will offset the total amount of fixed costs.

E. SUMMARY OF WHOLESALE ECOM ESTIMATES IN TEXAS

The Commission Staff calculated wholesale ECOM estimates for Texas jurisdictional utilities using the data provided by utilities in the ECOM Model. Estimates of potential wholesale stranded investment are presented under two scenarios:

1. *Contract expiration scenario:* assumes that a utility's current wholesale contracts will be renegotiated at the market price of power upon the contract expiration date; and
2. *Contract abrogation scenario:* assumes all wholesale contracts conform to the market price immediately in 1998.

In the Texas wholesale ECOM analysis, *positive ECOM values* indicate that, on a net present value basis, the utility's allocated Texas wholesale generation cost-of-service is greater than the revenues the utility may receive in a competitive market. In contrast, *negative ECOM values* indicate that the utility's Texas wholesale allocated generation cost-of-service is less than the revenues the utility may receive in a competitive market (on a net present value basis).

Table ES–2: Total Texas Wholesale ECOM Model Results ($1996 millions)

	Extreme High	5th percentile	Expected Value	95th percentile	Extreme Low
Contract Expiration Scenario	$ 115	$ 5	$ (57)	$ (115)	$ (258)
1998 Contract Abrogation Scenario	279	(558)	(1,007)	(1,457)	(2,325)

Note: Results presented assume a 10 percent reduction in the O&M expense values projected by the utilities due to efficiency gains. See Appendix B for individual utility ECOM Model results.

Table ES–2 summarizes the range of potentially stranded wholesale costs in ERCOT as calculated using the ECOM Model. The expected value in the *contract expiration* scenario shows a net present value ERCOT-wide *benefit* of reselling power at the market price subsequent to wholesale contract expiration of $57 million for ERCOT investor-owned utilities. This net benefit is largely driven by West Texas Utilities

Company's (WTU's) low-cost wholesale power producing a benefit of $96 million, with Texas Utilities Electric Company (TU Electric) and Houston Lighting & Power Company (HL&P) offsetting the benefit with a net stranded cost of $25 and $19 million, respectively. Central Power and Light Company (CPL) has an expected value of ECOM near zero under the *contract expiration* scenario. Brazos Electric Power Cooperative (BEPC), the Lower Colorado River Authority (LCRA), and South Texas Electric Cooperative (STEC) are not at risk in the *contract expiration* scenario because of their long-term contracts with their wholesale customers.

In the *contract abrogation* scenario, the total expected value of Texas wholesale ECOM is *negative* $1,007 million, consisting of $1,148 million in potential benefits to LCRA, BEPC, STEC and WTU combined with $141 million in potentially stranded costs for TU Electric, CPL and HL&P. As in the *contract expiration* scenario, TU Electric has the largest share of potentially strandable wholesale costs at approximately $87 million for the *contract abrogation* scenario, with HL&P and CPL having expected values for ECOM of $31 and $23 million, respectively. WTU, LCRA, Brazos, and STEC indicate *negative* expected net present values (or net benefits) for ECOM of $87, $849, $195, and $17 million, respectively, under the *contract abrogation* scenario.

Negative wholesale ECOM values mean that if those companies were able to abrogate their long-term contracts and sell at the market price, the companies would increase their earnings. While negative ECOM appears to be a benefit to consumers, it must be remembered that if these low-cost utilities were able to abrogate their long-term contracts and sell at the market price, the current customers could experience price increases unless the benefits of negative ECOM were passed along to customers in lower prices.

F. SUMMARY OF RETAIL ECOM ESTIMATES IN TEXAS

Texas retail ECOM estimates were calculated for each utility for six different competitive scenarios, using varying combinations of three market price assumptions and two operations and maintenance efficiency improvement factors (0 and 10 percent) for each scenario, for a total of 36 competitive scenarios for each utility. The broad competitive scenarios are described in Table ES–3.

Table ES–3: Competitive Retail Scenarios Modeled

Scenario Name	Scenario Description	Residential Access Year(s)	Commercial Access Year(s)	Industrial Access Year(s)
1998Full	1998 Full Access	1998	1998	1998
2000Full	2000 Full Access	2000	2000	2000
I98/C00/R02	Industrial 1998 Commercial 2000 Residential 2002	2002	2000	1998
I98/C02/R06	Industrial 1998 Commercial 2002 Residential 2006	2006	2002	1998
I98/C00/R02 Phase-in	50/50 Class Phase-in: Industrial 1998/1999 Commercial 2000/2001 Residential 2002/2003	50% in 2002 50% in 2003	50% in 2000 50% in 2001	50% in 1998 50% in 1999
R98/C00/I00	Residential 1998 Commercial 2000 Industrial 2000	1998	2000	2000

Note: The ECOM Model can accommodate additional competitive access scenarios with varying customer class access percentages.

In the Texas retail ECOM analysis, positive ECOM values indicate that, on a net present value basis, the utility's allocated Texas retail generation cost-of-service is greater than the revenues the utility may receive in a competitive market. In contrast, negative ECOM values indicate that the utility's Texas retail allocated generation cost-of-service is less than the revenues the utility may receive in a competitive market (on a net present value basis).

Table ES–4 and Figure ES–4 summarize the range of estimated ECOM for the Texas retail jurisdiction, excluding the estimated Texas wholesale ECOM. In the *1998Full* scenario, the expected value of total Texas retail ECOM is estimated at approximately \$12.8 billion, with the 90 percent confidence interval of ECOM outcomes ranging from approximately \$9.2 to \$16.4 billion. In the *2000Full* scenario, the estimate of the

Table ES–4: Total Texas Retail ECOM Model Results ($1996 millions)

Scenario Name	Extreme High	95th percentile	Expected Value	5th percentile	Extreme Low
1998Full	$ 21,126	$ 16,396	$ 12,816	$ 9,188	$ 3,475
2000Full	14,628	9,945	7,243	4,487	(832)
I98/C00/R02	13,959	9,172	6,661	4,120	(1,327)
I98/C02/R06	10,088	6,411	4,065	1,715	(2,635)
I98/C00/R02 Phase-in	12,840	8,400	5,862	3,293	(1,800)
R98/C00/I00	17,767	12,961	9,913	6,834	1,368

Note: Results assume a 10 percent reduction in the O&M expense values projected by the utilities due to efficiency gains. In addition to asset net book values, fixed costs include projected federal income tax and property tax payments in the ECOM model. Thus, net ECOM for specific assets may exceed asset book values by the net present value of federal income tax and property tax payments in the projected generation cost-of-service.

expected value of total Texas retail ECOM is reduced to approximately $7.2 billion, with the 90 percent confidence interval of ECOM outcomes ranging from approximately $4.5 to $9.9 billion.

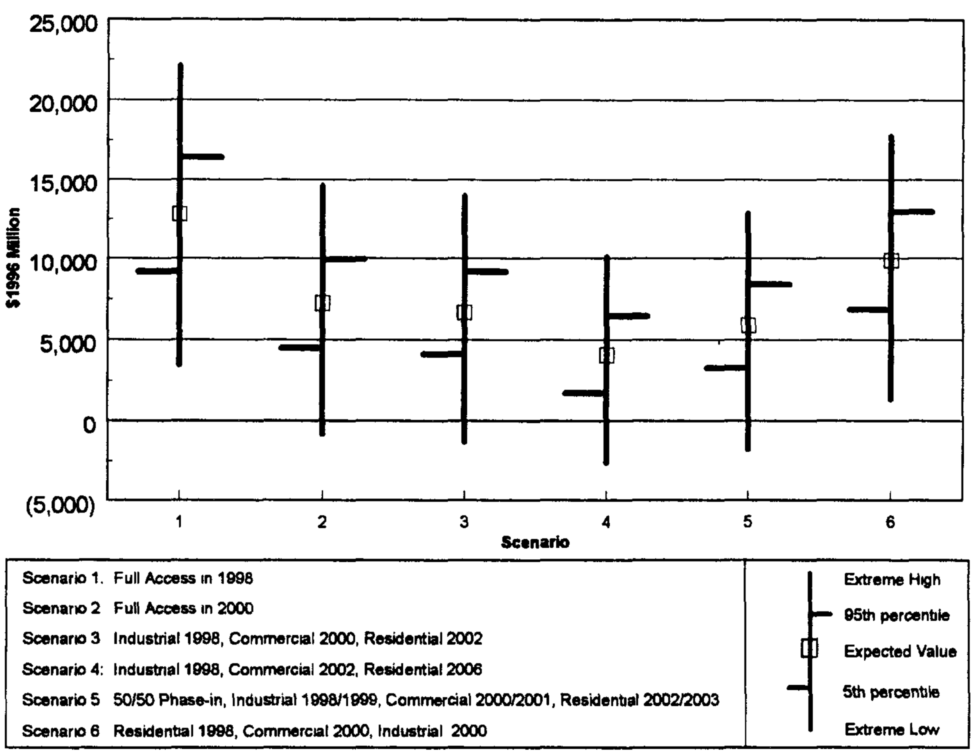


Figure ES–4: Total Texas Retail ECOM Model Results ($1996 Million)

To put the ECOM estimates in perspective, it is useful to use a base for comparison. For the utilities that filed ECOM reports, annual Texas retail cost-of-service generation-related revenues are approximately $10.5 billion dollars per year. Thus, the $12.8 billion expected value for ECOM in the *1998Full* scenario is more than $2 billion greater than the annual generation-related revenues currently collected by utilities. In the *2000Full* scenario, the $7 billion expected value for ECOM is approximately $3.8 billion dollars less than the annual generation-related revenues currently collected by utilities in their regulated rates.

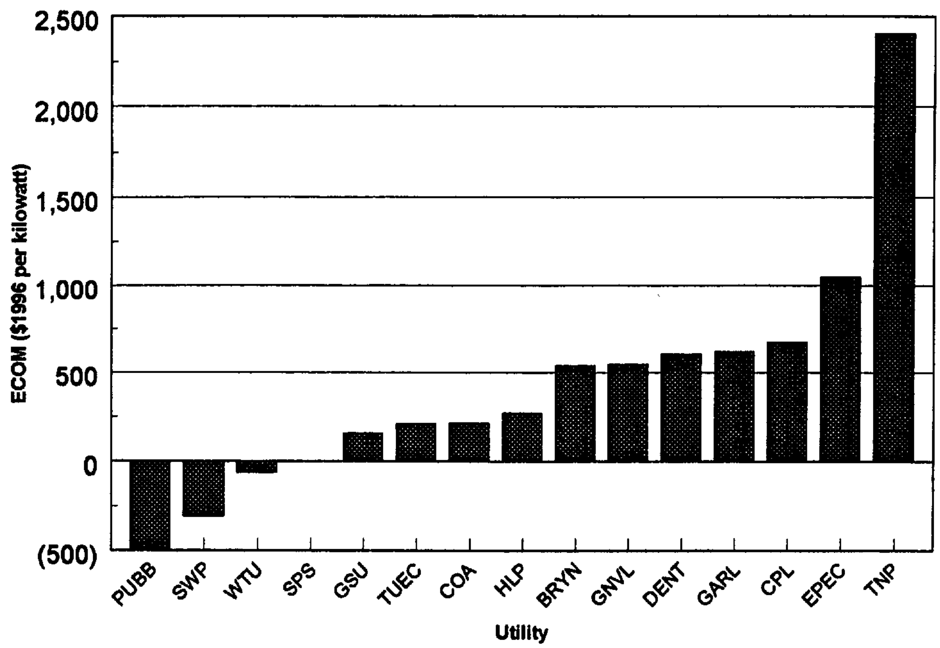
Comparing the estimated ECOM results with total fixed costs is another measure that is helpful to put the ECOM estimates in perspective. Utilities in Texas have a combined net present value of fixed costs[6] of approximately $32 billion. Thus, the $12.8 billion expected value for ECOM in the *1998Full* scenario is approximately 40 percent of the total fixed costs in the utilities' generation costs-of-service.

In comparing ECOM results for utilities of differing sizes and structures, the relative exposure to potentially strandable costs can be examined by *normalizing* the ECOM results, that is, transforming the absolute dollar amount of estimated ECOM to a unit of standard measure. Normalizing the estimates recognizes that the utilities with the largest ECOM may not necessarily be at risk from their potentially strandable investments. Though a large utility may have the largest ECOM, it will also have larger sales and more customers. Thus the *per customer* ECOM burden of a large utility may be much less than that of a smaller utility.

Normalizing the estimates can be achieved in a number of ways. For the purpose of comparison in this report, each utility's estimated dollar amount of ECOM is divided by the utility's installed generating capacity to arrive at a normalized ECOM value in terms of dollars per kilowatt. Figure ES–5 depicts the normalized utility ECOM results for the *1998Full* scenario in terms of ECOM dollars per kilowatt of installed generating

[ES–6] As described in Chapter VI, the fixed generation costs in this analysis include depreciation and return on current investment, federal income taxes, property taxes, nuclear decommissioning costs, and existing purchased power contract costs. The total fixed costs of approximately $32 billion ($1996) is the sum of the net present value of the fixed costs in each utility's ECOM filing.

capacity. As shown, while TU Electric has the greatest amount of ECOM in terms of absolute dollars, the utility ranks in the lower half of the group on a dollars per kilowatt basis. The graph also illustrates the high exposure to potentially strandable costs faced by the municipalities that comprise the Texas Municipal Power Authority, with these four cities showing relatively high normalized ECOM estimates.[7]



Notes:
1) ECOM expected value as measured in the in the *1998Full* scenario.
2) ECOMper kW measured in $1996 per installed kilowatt of Texas retail capacity.
3) ECOM results include existing purchased power contracts.

Figure ES–5: Normalized Texas Retail ECOM Model Results for the *1998Full* Scenario

Table ES–5 examines total Texas retail ECOM for the *1998Full* scenario by resource type (natural gas, coal/lignite, nuclear, and other). Nuclear assets comprise a large majority of potentially strandable costs, with an expected value of nuclear-related ECOM in excess of $15 billion. Excluding nuclear assets, the expected value of total Texas retail ECOM in the *1998Full* scenario is reduced to *negative* $2.3 billion.

[ES-7] The Texas Municipal Power Authority is comprised of the Cities of Bryan, Denton, Garland, and Greenville.

Table ES–5: Total Texas Retail ECOM Summary by Resource Type (*1998Full* scenario)

Generation Resource Type	Expected Value of Texas Retail ECOM ($1996 million)
Natural Gas	$ 2,020
Coal/Lignite	(4,630)
Nuclear	15,085
Purchased Power/Other	341
Total	**12,816**
Total Excluding Nuclear	(2,269)

Note: See Appendix B for individual utility ECOM results.

In aggregate, the non-nuclear assets of Texas utilities are expected to generate power at average costs that are below the projected market price of electricity, primarily because the original capital investment in these non-nuclear assets is less than the nuclear investment, and the older non-nuclear assets have had time to become more fully depreciated. In addition, the operating costs of most of the non-nuclear assets are low relative to the projected market prices, thus providing a sizable margin in a competitive market that will serve to offset the remaining fixed costs of the non-nuclear generation assets.

The Commission's report on stranded investment presents a number of observations arising from its ECOM estimates:

- *Sensitivity to timing of retail access:* The timing of the implementation of retail access is key to determining the magnitude of ECOM, regardless of the other assumptions incorporated into the analysis.
- *Sensitivity to the market price:* Generally, for every one percent deviation from the projected base case market price, the estimated total Texas retail ECOM results will change by approximately $450 million on a net present value basis.
- *Rate of return:* In the ECOM Model, the rate of return for investor-owned utilities is specified at 10 percent.[8] The 10 percent rate of return is reflective of the various risks to which a utility is currently exposed, and is not reflective of the risk associated with *guaranteed* recovery of investments.

[ES-8] The rate of return for municipals, river authorities and cooperatives was specified at 7.5 percent; however, these entities were allowed to adjust this number to reflect their individual debt service requirements in each year of the forecast period.

- *Utility generation cost projections:* As described in Chapter VI, utilities were required to provide projections of their generation costs and sales for the life of the longest-lived plant in the utility's rate base. While these projections were examined for general consistency, a rigorous analysis of specific aspects of the generation costs was not performed. With the exception of the 10 percent O&M efficiency improvement adjustment, this analysis has not attempted to examine the impact of options that would allow utilities to reduce or mitigate their stranded cost exposure.

G. Rights and Expectations For ECOM Allocation

The Commission's report on stranded investment includes a substantive analysis of the rights and expectations for ECOM allocation. Allocation is the process of assigning all or a portion of ECOM to or among classes of parties, such as firm or interruptible ratepayers, shareholders, and service providers. The allocation issue is highly contentious, and as such, should be considered in careful detail. Some of the key arguments are described below.

1. Wholesale Contracts

One argument maintains that Texas utilities are not subject to a statutory obligation to serve wholesale customers. In wholesale transactions, there is no unwritten or "implied" contract that, in conjunction with the express written wholesale power sales contract, determines the legal rights and expectations of the parties. Because the wholesale transaction is governed by a written agreement, the utility:

1. Does not have a definitive legal right, based on contract law, to demand continued purchases after the lawful termination of the wholesale contract; and
2. Cannot reasonably claim that it must stand ready to serve a wholesale customer that lawfully terminated (or never commenced) service in accordance with its wholesale service contract.

If the contract is silent as to ECOM or continuing cost allocation and recovery issues, and is otherwise unambiguous, the wholesaler arguably does not have a valid legal right or expectation to ECOM recovery from the purchaser beyond the term of the contract. This conclusion is based on the well-settled "parol evidence" rule, which:

> *renders inadmissible any testimony to vary the legal effect of a writing in the absence of any ambiguity, accident, mistake, or fraud shown in connection with the contract.*

Alternatively, one may adopt the "rebuttable presumption" course taken by the FERC in its Order No. 888. If this rebuttable presumption approach is adopted, a party to a wholesale contract would be permitted to rely on parol evidence in an attempt to prove that an apparently clear and unambiguous wholesale contract does not absolutely reflect the parties' expectations.

2. Retail Transactions.

Unlike the written contracts in wholesale transactions, the State (through the Commission) regulates public utility *retail* (or final use) rates and services. Except for a few large customers, there are no written contracts between utilities and their retail customers. Instead, the current arrangement in Texas between consumers and their municipality, cooperative, river authority, or IOU suppliers is predicated on a form of unwritten "implied contract" that requires the consumer to pay for service taken from the utility at the rate established in the ordinance then in effect. In addition to an implied contract to pay for power actually taken, a *regulatory compact* arguably exists between the State and utility. This regulatory compact requires the utility to provide adequate and reliable service at fair rates to all consumers within the utility's certificated service area. In return for this *public* service, the State, through the Commission (or municipal authority), agrees to set rates that provide a reasonable opportunity to earn a reasonable return on its invested capital as well as reasonable and necessary operating expenses. Because the implied contract and the regulatory compact are not bilateral written agreements, it is more difficult to determine the legal rights and expectations arising from retail transactions, as compared to wholesale transactions.

In addition, ECOM allocation issues that apply to IOUs do not necessarily pertain to cooperatives, river authorities, and municipal utilities. A cooperative's or municipal utility's owners, "shareholders," ratepayers, and customers are generally one-and-the-same. Accordingly, cooperatives and municipalities argue that, regardless of the allocation, the members/citizens, as also the "shareholders"/owners, must foot the entire bill.

3. Summary of Allocation Conclusions

Regardless of the allocation method adopted, ECOM should be allocated and recovered in a way that places the lowest possible cost burden on the parties. To reach this goal, the public interest would appear to require an allocation method that:

1. Does not inhibit the transition to competition;
2. Provides benefits if possible (such as providing incentives to shut down inefficient generation facilities that may otherwise continue to operate in a regulated market);
3. Allocates only verifiable, non-mitigatable ECOM; and
4. Provides incentives to ensure that the utilities' ECOM is reduced to the lowest amount possible.

The Legislature may also consider whether utility divestiture of generation plant will further the public interest and enhance competition. If so, an allocation method could be adopted that provides a utility and its shareholders with significant ECOM recovery if it agrees to divest its generation plant. This approach has the added benefit of clearly defining that utility's ECOM—the difference between the present book value of the plant, and the purchase price paid by the entity that acquires the divested plant.

An allocation method may also best serve the public interest, both equitably and legally, if it ensures that ECOM is allocated to the broadest possible base. For example, if ECOM is allocated to all constituencies, it should be allocated in an appropriate manner to: (1) all ratepayers, regardless of whether they are firm or interruptible, high or low load factor, industrial, commercial, or residential ratepayers; and (2) the utilities. If ECOM is allocated only to ratepayers, it should be allocated in an appropriate manner to all ratepayers regardless of class. If ECOM is to be allocated solely to the utilities, the utilities can be left with the discretion to determine how to deal with the allocation internally, subject to the caveat that the utilities cannot shift any ECOM allocated to them back to the ratepayers.

On one end of the spectrum, the utility parties would prefer full ECOM recovery while, on the other end, the ratepayer parties would prefer full ECOM absorption by the utilities' shareholders. Numerous alternatives lie between the two ends, including adjustments to rates of return, adjustments to expenses, adjustments to generation plant depreciation rates, as well as a more general sharing of ECOM among all constituencies. Given the differences between the parties, it is likely that any ECOM allocation method adopted will face a court challenge. For this reason, ECOM allocation (and recovery) is an issue that lends itself to resolution as one part of a multi-issue, multi-party negotiation in which all transition and restructuring issues are on the table. Recent experience in other states has shown that it is possible to reach such a settlement and thereby move those state more swiftly to a market-based regulatory regime.

H. Options for ECOM Recovery

If ratepayers are deemed responsible for some portion of ECOM, the ensuing question is how should their allocated ECOM be recovered by the utility? Five criteria should be considered when selecting ECOM recovery mechanisms:

1. Impact on rates;
2. Incentives of firms to reduce costs;
3. Impact on the competitive market;
4. The time horizon over which ECOM will be recovered; and
5. Ease of administration of the recovery mechanism.

Table ES–6 presents a summary of the approaches to ECOM recovery, along with a brief discussion of the advantages and disadvantages of each. A single recovery mechanism or a combination of methods could be selected. The actual design of access charges, exit fees, or other mechanisms would occur in a manner similar to the rate design portion of a utility rate case. Likewise, the revaluation of assets and/or

Table ES–6: Summary of ECOM Recovery Mechanisms

Recovery Mechanisms	Definition	Advantages	Disadvantages
Access charges	Charges imposed on customers that are tied to continued transmission and distribution service.	Nonbypassable charge is competitively neutral.	Must design the access charge in a manner that will not distort customer behavior (e.g., encourage self-generation).
Exit fees	Fees charged to departing customers that are scaled to recover specific costs attributable to that customer.	Clearly identifies customers' ECOM responsibility and allows customers to structure their own payment plan.	Assignment to departing customer may imply a penalty for leaving incumbent (even though the value should be equivalent to the remaining customers' access charge).
Revaluing assets	Writing down the book value of generation assets while writing up the book value of transmission and distribution assets.	Does not require identification of specific charges.	Transmission and distribution are not competitive, will continue to be regulated, and should not be valued at market.
Adjusting depreciation	Accelerating the depreciation of generation assets while decelerating the depreciation of transmission and distribution.	Does not require identification of specific charges.	May not comply with generally accepted accounting principles.
Rate freeze	Rates are frozen at current levels and additional earnings from efficiency gains and decreases in fuel prices are applied against ECOM.	Does not require identification of specific charges.	Primarily used to pay off ECOM *in advance* of competition.

adjustment of depreciation could require a contested proceeding before the Commission.

Once an allocation of ECOM responsibility has been made, the real difficulties of quantification and recovery become apparent. Any *one-time* ECOM quantification method is subject to a significant estimation risk. Underestimating market price will result in a fixed ECOM payment larger than it should be, and will allow incumbents to earn excess profits while customers' rates remain higher than is appropriate. Overestimating market price will result in a fixed ECOM payment smaller than it should be, causing shareholders to bear more of the transition costs than policy makers intend. True-up mechanisms may reduce the effects of estimation error by tracking market prices over time, adjusting the quantification of *realized* ECOM and reconciling and adjusting the ECOM payment.

One type of ECOM recovery mechanism that provides an incentive for firms to reduce costs and confers benefits to ratepayers would be a mechanism that links ECOM recovery to performance (i.e., performance-based ECOM or PB ECOM). More so than any other recovery mechanism, PB ECOM is consistent with the concept of allowing utilities a reasonable *opportunity* to recover an allocated amount of ECOM. Just like any other performance-based ratemaking methodology, PB ECOM would require firms to achieve specified levels of operating performance.

I. INTRODUCTION

In its 74th session, the Texas Legislature directed the Public Utility Commission of Texas (the Commission) to prepare a report on stranded investment in the electric industry in Texas:

> *The commission shall submit a report to the 75th Legislature on methods or procedures for quantifying the magnitude of stranded investment, procedures for allocating costs, and the acceptable methods of recovering stranded costs.*[1]

As used in the on-going national debate on the future of the electric industry, the term "stranded investment" can be interpreted differently by differing parties. In this report, stranded investment is defined as *the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market.* Throughout the report, the phrase "potentially strandable investment" often is used in place of the phrase "stranded investment." Referring to potentially strandable investment is a way of emphasizing that these historic costs are not yet stranded, but may become stranded at some point in the future. The degree to which investments are ultimately stranded will depend upon changes in the market price of electricity, the speed with which markets become effectively competitive, tax implications of potential restructuring options, mitigation efforts by the utilities, and the actions of utilities, the Legislature, and the Commission regarding electric industry restructuring. Until such time as costs do become stranded, these potentially strandable investments remain a component of the rates that utilities currently charge their customers.

The prospect of potentially strandable investment arises because utilities that have long been regulated entities may now face the prospect of competition, which may reduce the market value of utility assets below book value (leaving those assets "stranded" and potentially unrecoverable). Historically, utilities were required by their regulators to offer electric services to any and all retail residential, commercial, and industrial

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[1] Public Utility Regulatory Act of 1995, Tex. Rev. Civ. Stat. Ann. art. 1446c-0 §2.057(e) (Vernon Supp. 1996) (PURA95).

customers located in their service territories. In fulfilling this regulatory commitment, utilities invested in generation plant and facilities deemed necessary to serve their customers. Under regulation, utilities were given a reasonable opportunity to earn a reasonable return on those investments found prudent by regulators.

The market value of the assets owned by a utility is based on the anticipated return over the life of the assets. In a competitive electric market, suppliers would receive market-based prices rather than their regulated rates. If the resulting market price is below a utility's regulated rate, the value of its assets could be reduced. The reduction in value represents the degree to which the assets are stranded.

The issue of potentially stranded investments has risen to prominence in response to fundamental changes now occurring in the electric industry. Some changes are specific to the electric market in Texas, while others are taking place on a national scale. The 74th Legislature acknowledged the increasing competitiveness of certain segments of the electric industry in Senate Bill 373, noting that:

> *. . . the wholesale electric industry . . . is becoming a more competitive industry which does not lend itself to traditional electric utility regulatory rules, policies, and principles and that, therefore, the public interest requires that new rules, policies, and principles be formulated and applied to protect the public interest in a more competitive marketplace.*[2]

In S.B. 373, the Legislature took a number of additional steps that will extend competition in the electric industry in Texas. These steps include:

- Creating provisions requiring competitive acquisition of new resources (PURA95 §2.051);
- Allowing wholesale and retail providers to offer certain discounted rates at less than rates approved by the Commission but above marginal costs (PURA95 §2.052 and §2.001(b));
- Creating new categories of wholesale electricity providers—exempt wholesale generators (EWGs) and power marketers—allowed to operate in Texas (PURA95 §2.053);

[2] PURA95 §2.001(a).

- Allowing EWGs and power marketers to become affiliates of public utilities (PURA95 §2.054);
- Requiring utilities and municipalities to provide transmission service at wholesale to any other utility, qualifying facility, EWG, or power marketer (PURA95 §2.056);
- Guaranteeing comparable access to wholesale transmission services (PURA95 §2.057); and
- Allowing cooperatives to opt out of Commission rate regulation (PURA95 §2.2011(a)).

Each of these measures promotes a competitive electric market in Texas. As that market becomes increasingly competitive, greater concerns are being raised over potentially stranded investments. Indeed, every advance toward a more competitive market accelerates the need to address and account for potentially strandable investment.

In a companion to this volume,[3] the Commission describes in detail both the historic regulatory context in which utilities have operated and the changes that the industry is undergoing. Those changes are, in part, due to:

- Legislative and regulatory changes at the State and federal levels;[4]
- Technological innovations in the generation of electricity that allow smaller gas-fired plants to compete with larger, older nuclear, coal- and lignite-fired plants;
- Changes in the relative prices of fuels favoring consumption of natural gas; and
- Existing excess electricity generation capacity.

These changes have put downward pressure on the price of electricity leading many observers to speculate that in a fully competitive market, some existing generation plants could not recover their costs at competitive prices. Today, however, these

[3] Public Utility Commission of Texas, *Report to the 75th Texas Legislature Volume II The Scope of Competition in the Electric Industry in Texas: A Detailed Analysis,* Austin, TX (January 1997), hereafter, the "Scope of Competition" Report.

[4] As discussed in the Scope of Competition Report, relevant federal legislation included the Public Utility Regulatory Policy Act of 1978, the Energy Policy Act of 1992, and Federal Energy Regulatory Commission Order No. 888.

plants are protected from the competitive market by utility rate regulation, which allows utilities to recover costs of even the most costly plants in regulated (and perhaps elevated) prices. With continued legislative and regulatory changes, it is unclear whether utilities will be able to recover the full costs of their historic investments; in other words, utilities face potentially strandable investments.

A. Overview of the Commission Investigation

In preparing this report, in conjunction with its report to the Legislature on the Scope of Competition in the Electric Industry in Texas, the Commission recognized that these reports provide an opportunity for a broad investigation into the structure of the electric industry, the options for regulatory restructuring, and the magnitude of potentially strandable investments. The Commission established three projects as its platforms for investigating competition, restructuring, and strandable investment:

1. *Project No. 15000:* An investigation into issues related to the electric utility industry and regulatory restructuring;
2. *Project No. 15001:* An investigation into potentially stranded investment in the electric utility industry in Texas, conducted in accordance with §2.057(e) of PURA95; and
3. *Project No. 15002:* An investigation into the scope of competition in the electric utility industry in Texas, conducted in accordance with §2.003 of PURA95.

In its deliberations on the scope of this report, the Commission determined that it could make a valuable contribution to the debate on electric industry competition and restructuring by providing estimates of the magnitude of potentially strandable investment in Texas. The Commission initiated an investigation of the excess costs over market value (ECOM) of utility assets in Texas. ECOM—as defined in this report—is *a measure of potentially strandable investment* in Texas. "ECOM" is the difference between the full embedded costs of a utility's electric generation and the price that customers are willing to pay for electricity in a fully competitive market. Because regulated cost-of-service electric rates are higher (in some cases) than expected market prices, some Texas utilities will have positive ECOM (i.e., above-market generation). Thus, discussions about ECOM levels and recovery should recognize that ECOM already exists and is already fully recovered in existing utility rates. The Commission believes that an estimate of ECOM, while not necessarily required to discuss procedures and methods for allocating and recovering stranded investments, can help guide policy decisions in the State and give utilities the opportunity to develop strategies for the future.

The Commission cautions reviewers of this report that estimates of potentially strandable investments presented here should not be interpreted as determining policy with regard to the measurement, allocation, or recovery of strandable investments. The Commission has not made any ruling regarding what, if any, portion of potentially strandable investments an incumbent utility should be allowed to recover, nor recommended or imposed an ECOM recovery mechanism. At present, the costs of potentially strandable investments are being recovered from utility customers in regulated electric rates. The estimates presented in this report will help legislators, regulators, and members of the public at large understand the magnitude of potentially strandable investments. In the event that the Legislature and/or the Commission eventually takes action toward more competitive markets that could cause utility investments to become stranded, and authorizes allocation and recovery of stranded investments, further investigation would be required to make utility-specific determinations of the magnitude of stranded investments.

B. The Commission's Investigation of ECOM

At its November 21, 1995 Open Meeting, the Commission directed Staff to begin preparation of an order directing utilities to estimate ECOM. The commissioners' discussion at this and prior meetings gave Staff a general set of guidelines to follow in the determination of ECOM:[5]

- ECOM should be estimated on a systemwide basis for each utility.

[5] See Walsh, Judy, *Memorandum: Goals and Scope of Project 15000*, Project No. 15000 (November 3, 1995). At a subsequent Open Meeting, on December 1, 1996, Commissioner Gee recommended incorporating a scenarios-based approach in which competition is phased in to subsets of customers over time and the resulting ECOM measured as competition is phased in.

- The generation cost of service should be broken down into a component representing the market cost of generation and a component representing excess cost over market.
- Determination of ECOM should be based on financial methodologies and modeling.
- The Commission should work in partnership with the investor-owned utilities and other interested parties in determining an appropriate methodology for valuing ECOM.
- ECOM should be measured in a manner that is independent of the eventual market structure.

These principles helped guide Staff in its ECOM investigation. In particular, Staff labored to develop a method that is independent of the *structure* of the electric market. Being independent of the market structure means that the value of ECOM does not depend on the means or method by which competition is introduced in the electric industry in Texas. If competition is introduced, ECOM can be estimated whether competition is introduced through full retail access, a statewide pool, or some other scheme. However, ECOM is not independent of the *timing* by which competition is introduced because investments in plant and equipment depreciate over time and because the firm continues to pay off its debt. The magnitude of ECOM resulting from the introduction of competition in 1998 will be different from the magnitude of ECOM if competition is introduced in the year 2000, as two additional years will have passed allowing for additional depreciation and cost recovery through the rates paid by utility customers.

In its initial investigation of ECOM, the Commission invited comments and participation from interested parties in Texas. The Commission invited parties to workshops on December 1, 1995, January 17, 1996, and January 30, 1996, to participate in the design and scope of Project No. 15001 and to design a financial model to estimate ECOM. These workshops were attended by many members of the utility industry, including investor-owned utilities, cooperatives, and municipalities, as well as business and industry groups, citizens and environmental groups, and individual interested citizens.

On February 26, 1996, Staff released a draft of the order requiring utilities in Texas to estimate ECOM under a variety of scenarios.[6] The Commission requested comments from interested parties on the draft order, and on March 4, 1996, Staff held a technical session at which interested parties provided oral comments on the draft order.

On April 24, 1996, the Commission issued its ECOM Order,[7] requiring that all investor-owned utilities, generating cooperatives, generating river authorities, and requesting that all municipally owned generating utilities, estimate the magnitude of their potentially strandable investments using a copyrighted financial model developed by Staff. The Order directed utilities to estimate ECOM under 54 scenarios reflecting the timing of a competitive market, the market price of natural gas, and generation operating efficiency improvements in a competitive market. The Commission also released a Staff paper that discussed the Order and provided an overview of the ECOM model.[8] On June 24, 1996, utilities filed their ECOM estimates using the Commission model.[9] On October 29, 1996, the Staff released the Staff Draft report to interested parties for comment and review. On November 8, 1996, the Staff held a Technical Session at which interested parties and members of the public offered comments on the report. The final report reflects many of the comments received from interested parties and the public.

C. OVERVIEW OF THE ECOM MODEL

The ECOM model is an electronic workbook in Microsoft Excel 5.0 software, containing a number of different worksheets. The model estimates the after-tax net present value of the change in revenues that a utility would experience as a result of selling electricity at market prices rather than at regulated prices. The model defines

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[6] Public Utility Commission of Texas, *Order Initiating Investigation: Stranded Investment Report (Draft)* (February 26, 1996).

[7] Public Utility Commission of Texas, *Order Initiating Investigation*, Project No. 15001: Stranded Cost Report, Estimation of ECOM for Generating Utilities in Texas (April 24, 1996).

[8] Public Utility Commission of Texas, Office of Policy Development, *Staff Discussion of the Order: Estimation of ECOM for Generating Utilities in Texas*, Project No. 15001 (April 24, 1996).

[9] Although an analysis of the ECOM filings is presented in this report, Staff has not audited the utility filings, nor were the data made available to all parties for review.

ECOM as the discounted present value of the difference between sunk costs and the contributions to capital of utility sales under competitive conditions.

The model's users input capital and production cost data associated with generation resources, and allocate those costs by generation resource type (e.g., nuclear, coal, and natural gas) and by customer class (e.g., residential, commercial, industrial, and other). Users also allocate projected sales by resource type and by customer class. Using these cost and revenue projections, the model calculates utility revenues under continued cost of service regulation. The model incorporates a range of future market prices, which are used in the calculation of market-based revenues under alternative competitive scenarios. The model calculates ECOM based on the difference between revenues under cost of service regulation and the market-based revenues under competitive scenarios.

As released by the Commission, the model calculates an estimated value of a utility's Texas *retail* ECOM once the necessary input data are incorporated in the model. The model is also used to collect data required to calculate an estimated value of a utility's Texas jurisdictional *wholesale* ECOM. Wholesale ECOM raises a number of unique issues because the relationship between utilities and their wholesale customers is contractual and therefore different from the relationship between utilities and their retail customers. Calculation of wholesale ECOM depends upon the contract terms, whether the contract remains in effect in a competitive market, and the obligations of parties for ECOM following the expiration of a contract. The Commission collected information from utilities on their wholesale power contracts, and used the submitted wholesale data to estimate the potentially strandable costs that could arise from wholesale power obligations. Those estimates are presented in this report along with the estimates of retail ECOM.

D. Overview of the Report

This report is presented in ten chapters. Following this introduction, Chapter II provides an overview of potentially strandable investments and the means by which stranded investments are created in the marketplace. Chapter III discusses methods and procedures for quantifying the magnitude of potentially strandable investments, followed by a review of relevant studies in Chapter IV. Chapter V discusses financial and tax complications associated with strandable investments. Chapter VI presents the Commission's ECOM model, followed by analyses of wholesale and retail ECOM estimates submitted by the electric utilities in Texas in Chapters VII and VIII, respectively. Chapter VI also includes a review and comparison of the approach for the treatment of stranded investments included in Order No. 888 issued by the Federal Energy Regulatory Commission (FERC) for public utilities subject to FERC jurisdiction under the Federal Power Act. Chapter IX discusses the rights, obligations, and expectations affecting the allocation of potentially strandable investments in Texas, and Chapter X discusses various methods of recovering stranded costs.

The remainder of this introduction presents a more detailed summary of each chapter of the report.

Chapter II: Sources of Stranded Investment. This chapter defines stranded investment and explains how stranded investment is created. A simple illustration is used to show that competitive electricity supply alternatives that are offered at market prices can lead buyers to shift from their traditional utility suppliers. The utility's costs above the market price are the potentially strandable investment. Stranded investment is created somewhat differently in wholesale and retail markets. Wholesale stranded investment arises when a contract expires or is broken. Retail stranded investment arises when a customer leaves its traditional utility supplier to a market-priced alternative. The chapter presents a summary of wholesale and retail transactions, already occurring in electric markets, or likely to arise in the near future, that could lead to stranded investment.

Chapter III: Methods for Quantifying Stranded Investment. This chapter discusses methods and procedures for estimating the magnitude of potentially strandable investments associated with electric utility generation assets. The two main methods of estimating the magnitude of strandable assets are market valuation and administrative valuation. The estimation can occur before or after market restructuring is complete. Market valuation is the outcome of market-based transactions by the buyers and sellers of utility assets. Administrative valuation methods are financial models intended to simulate market results.

Chapter IV: Examples of Administrative Studies. This chapter reviews administrative studies that estimate utility generation costs and the effects of market-based pricing on the value of generation assets. Although the studies have different approaches and use various assumptions, the results are fairly consistent for Texas investor-owned utilities.

Chapter V: Financial Considerations. This chapter describes some of the financial considerations associated with electric industry restructure and deregulation. Each utility has a unique debt and equity structure that may influence its response to changing market and regulatory conditions. The value and stability of utility stocks and bonds will be affected by deregulation and industry restructure. The strength of each utility's securities is dependent on its market position relative to its competitors. If industry restructuring takes the form of market transactions, the federal income taxes of both the utilities and their shareholders may be affected. Local taxes may also be affected by the changing utility environment.

Chapter VI: The ECOM Estimation Methodology. This chapter provides a description of the design and operation of the ECOM Model used to estimate the magnitude of each utility's potentially strandable investments. The ECOM Model provides a measure of the magnitude of excess generation-related cost-of-service revenues relative to market-based revenues that a utility may experience under various market access, or deregulation, scenarios. This analysis is performed for both the Texas retail and wholesale jurisdictions. The purpose of quantifying the potential effect of deregulation *is not* to provide a final determination of the magnitude of stranded costs to be used in setting utility rates. Rather, the objective is to provide information that will be beneficial to decision-makers in the analysis of electric industry restructuring alternatives.

Chapter VII: Wholesale Competition in Texas: ECOM Results. This chapter presents ECOM Model results for the Texas wholesale jurisdiction. The chapter begins with an overview of the Federal Energy Regulatory Commission's (FERC) Order No. 888 as it pertains to stranded costs. The FERC's adopted methodologies for justifying stranded cost claims, calculating stranded cost amounts, and recovering such amounts are analyzed and critiqued. Finally, ECOM Model results are presented for utilities in the Texas wholesale jurisdiction.

Chapter VIII: Retail Competition in Texas: ECOM Results. This chapter presents ECOM Model results for the Texas retail jurisdiction. A description of the various competitive retail access scenarios is provided along with an overview of Texas retail ECOM Model results on an aggregate basis for each scenario. Texas retail ECOM Model results are also presented by generation resource type (i.e., coal/lignite, natural gas, nuclear, etc.) for the scenario in which retail access is assumed to occur for all customer classes in 1998. Various trends and observations of the ECOM Model results are described. The chapter concludes with a presentation of utility-by-utility Texas retail ECOM Model results.

Chapter IX: Rights and Expectations for ECOM Allocation. This chapter discusses the legal and equitable considerations that bear on the ECOM allocation issue. The chapter discusses both wholesale-related and retail-related issues. Wholesale-related issues are straightforward because the rights and expectations of the affected parties are governed by written wholesale electric power sales contracts. Retail-related transactions, however, typically are not governed by written contracts. Instead, retail transactions are governed by generally applicable tariffs, the Public Utility Regulatory Act of 1995 (PURA95), and the unwritten "regulatory compact" between the State and the utility. This compact, as reflected in large part in PURA95, requires the utility to provide reliable and adequate retail electric service to all parties in its service territory at reasonable rates. In return, the State agrees to provide the utility with a reasonable opportunity to earn a reasonable return on its invested capital. The utilities argue that the State must allow them to recover all of their ECOM because, to do otherwise, would deny them the statutory and "compact" opportunity to earn a reasonable return on their investment. On the other hand, parties who want the utilities to absorb at least some ECOM argue that the utility (and its shareholders) made the choice of investing in facilities that now cost more than the current market alternatives. These parties assert that the utility's risk-assuming shareholders must absorb at least some of the ECOM. This chapter discusses the arguments for and against full ECOM allocation to either the ratepayers or the utility shareholders. The chapter then addresses other options, including allocations that share ECOM between ratepayers and shareholders (collectively "stakeholders"). This chapter does not recommend the percentages of ECOM that should be allocated to each class of stakeholder.

Chapter X: ECOM Recovery. This chapter of the report discusses the various methods available to recover any ECOM that has been allocated to ratepayers. The chapter begins with a presentation of the general criteria that should be considered when selecting ECOM recovery mechanisms. Various types of alternative ECOM recovery mechanisms are presented and discussed, followed by a discussion of true-up mechanisms. Some form of a true-up may be necessary if ECOM is quantified in an administrative manner. Performance-based ECOM recovery mechanisms are also presented and discussed.

II. SOURCES OF STRANDED INVESTMENT

As it is discussed in the national debate over restructuring the electric industry, the concept of stranded investment has at times become confusing because a number of different definitions and interpretations have been applied to it. This report refers to "potentially strandable investment" because no investment is stranded until a customer leaves a regulated utility for some other supplier.[10] What portion of that potentially strandable investment ultimately becomes stranded is unknown.

The purpose of this chapter is to offer a simple explanation of stranded investment so that policy makers in Texas can speak with a common language and understanding. Section A presents a simplified illustration of stranded investment. Section B makes the idea of stranded investment more concrete by looking at changes already taking place in the Texas electric market. Each example represents a means by which *potentially* strandable investment can become stranded in the market.

A. AN ILLUSTRATION OF STRANDED INVESTMENT

Utility investments in plant and equipment are currently recovered in the utility's regulated rates. In a competitive market, the prevailing price of electricity is likely to be below the present regulated price. Thus, under competitive conditions, a utility may collect less revenue for every unit of electricity sold than it would have collected under regulation. Because the market value of an asset (e.g., a power plant or a transmission line) is determined by the expected revenue from that asset, lower expected revenue will lower the value of the asset.

In this report, stranded investment is defined as *the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market.* In the past, utility investments, i.e., "financial obligations," have been made in the *regulated* market, the market in which utilities "historically" operated. In that market, utilities anticipated that investment expenses would be recovered in rates

[10]It should be noted that the alternative supply source may be a nonregulated supplier or the customer's existing utility supplier offering a market-based price.

charged to their customers. These obligations may become "unrecoverable in a competitive market" because prices in competitive markets are uncertain and may fall below regulated prices. If a utility cannot charge as much in a competitive market as it would have charged in a regulated market, a portion of the asset becomes "unrecoverable" or "stranded." Thus, the change from a regulated to a competitive market can create stranded investment.

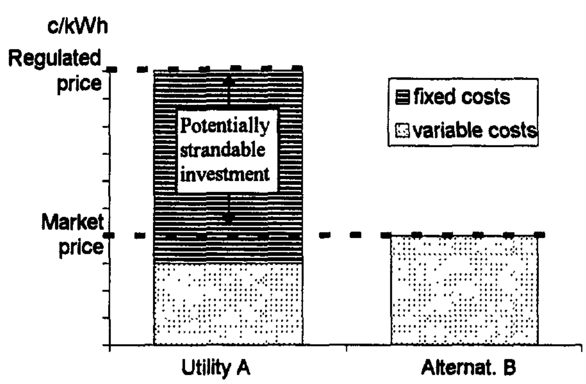


Figure II-1: Simplified Depiction of the Source of Stranded Investment

Figure II-1 presents a simplified illustration of the source of stranded investment. The height of the first vertical bar in the figure represents the *regulated* price of electricity, in cents per kWh sold by Utility A to a large consumer. That price is composed of fixed costs, i.e., the embedded costs of providing utility plant and equipment, and variable costs, operating costs—including fuel—that depend upon the amount of power provided. For the customer historically buying power from Utility A, supply is also available from Alternative B—represented by the second bar. Alternative B may be an EWG, a co-generator, or power marketer, for example. Alternative B can sell electricity at the competitive market price, which is lower than the regulated price offered by Utility A.[11] The customer will choose to switch to the cheaper source of supply offered by Alternative B.

[11] In the figure, Alternative B's costs are depicted as entirely variable costs, which may be an accurate assumption in the short-run. Nevertheless, the implication of the example is unchanged if Alternative B's costs are a mix of variable and fixed costs.

In Figure II-1, a portion of the utility's fixed costs are above the dotted line representing the competitive market price. These fixed costs are historic costs of supplying that customer. Because a portion of the historic fixed costs are above the competitive market price, that portion of the fixed costs will be unrecoverable in the competitive market. The portion of fixed costs above the market price is the stranded investment the utility will incur if the customer leaves.[12] In the example, costs become stranded because the customer switches from Utility A to Alternative B, but it is important to note that the investment that is *potentially strandable* is not dependent upon the customer's behavior. Rather, the quantity of potentially strandable investment arises from conditions in the market. Even if the customer continues to buy from Utility A, as happens under the current regulatory regime, the utility's regulated price is still above the market price. In that case, the difference between the regulated price and the market price reflects the *potentially strandable investment.*

The excess embedded costs over the market value of the asset (i.e., the ECOM) is a *measure* of this potentially strandable investment. As long as the customer buys service from Utility A, as happens under the current regulatory regime, the customer continues to pay the utility the value of its ECOM as part of the utility's regulated rate. The investments will not become *stranded* unless and until the customer actually switches to a market-based source of supply. Thus, ECOM becomes "stranded," or unrecoverable from the original customer only when the customer switches to Alternative B.

The extent to which a potentially strandable investment actually becomes stranded will be dependent upon legislative and regulatory outcomes, as well as the interactions of buyers and sellers in the marketplace. If, for example, new electricity sellers enter the Texas market and capture more customers from existing utilities, the quantity of potentially strandable investment that becomes stranded could increase. Legislative and/or regulatory actions that speed (or slow) the pace at which lower-cost generation enters the market could raise (or lower) the magnitude of stranded investment.

[12]In the figure, the difference between the regulated price and the market price is the stranded investment for a single kWh of electricity. The total stranded investment associated with the asset would be the value for a single kWh multiplied by the total kWh sold each year, discounted to the present over the life of the asset.

It is important to note that the quantity of potentially strandable investment does not depend upon the *structure* of the electric market. At any point in time, the amount of potentially strandable investment is fixed by the book value of regulated assets relative to the competitive market price of those assets. But the amount of the potentially strandable investment that becomes stranded depends upon both the future structure of the market and actions of participants in the market.

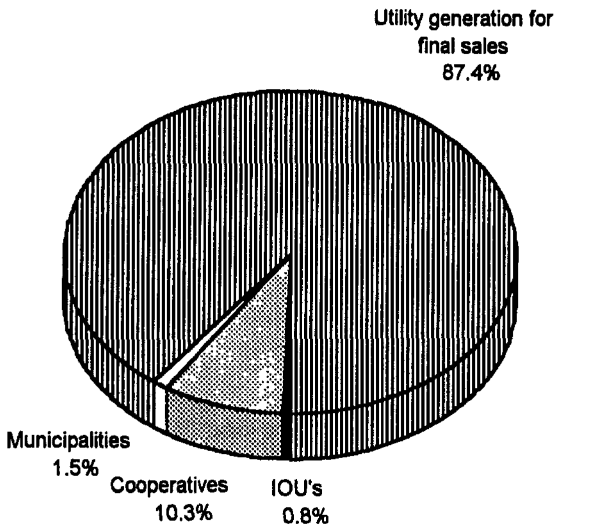
B. Wholesale and Retail Stranded Investment

Electricity sales can be divided into wholesale and retail functions depending upon the final disposition of the power.[13] Stranded investment may arise in both wholesale and retail markets. Wholesale transactions involve sales for resale. Wholesale sellers may be either utilities or non-utilities (such as co-generators, power marketers, or EWGs). Although utilities often make short-term wholesale sales of excess power—called "economy energy" sales—most wholesale transactions occur under long-term contracts. Some utilities, including river authorities and generation and transmission (G&T) cooperatives, sell only at wholesale. Distribution cooperatives and municipally owned utilities that do not own generation resources are the primary buyers of wholesale power. Investor-owned utilities (IOUs) will also buy at wholesale on a short-term basis.

Retail electricity markets are those in which electricity services are delivered to end users. Retail sales are sales from utilities or energy services providers to end-users in the residential, commercial, industrial, and "other" classes.[14] Retail public utilities include IOUs, distribution cooperatives, and municipally owned utilities, all of which may be subject to alternative forms of rate regulation under the provisions of PURA95.

[13] A more detailed discussion of the structure of the electric market in Texas and the distinctions between wholesale and retail markets can be found in Chapter V of the Scope of Competition Report.

[14] Other retail sales include, but are not limited to, energy delivered to street lighting, pumping, cotton gins, and government customers.



Source: Commission Staff computations based on responses to the Commission's Data Request under Project No. 15002 issued April 11, 1996.

Figure II-2: Texas Utilities' Wholesale Purchases as a Share of Total Retail Sales (1995 MWh)

The wholesale market among Texas utilities represents a small portion of total Texas utility generation. Figure II-2 shows the relative size of the Texas wholesale market by type of wholesale buyer. Total system retail sales in Texas equaled 265.2 million megawatt-hours (MWh) in 1995 (the size of the entire pie). Of total retail sales, 87.4 percent was sold by the generator directly to the end user. The remaining 12.6 percent was first sold in the wholesale market before being resold to the retail consumer. Figure II-2 shows the relative sizes of wholesale purchases of IOUs, municipally owned utilities, and cooperatives.

The wholesale market is primarily a long-term contracts market in which utilities enter into contracts for "firm" power. Table II–1 presents a summary of the purchases under wholesale contracts. Almost two-thirds of the 166 contracts are to supply power to distribution cooperatives. Municipally owned utilities hold about one-third of the contracts. IOUs hold only five contracts.

Table II–1: Allocation of Wholesale Contracts Among Final Purchasers

Utility Type	Number of Contracts	Capacity in All Contracts (in MW)	Sales under Contract (1995; thousands MWh)
IOUs	5	587	1,970
Cooperatives	106	5,627	24,895
Municipally owned utilities	54	850	3,696
All utilities	166	7,064	30,566

Sources: Commission Staff computations based on responses to the Commission's Data Request, Project 15002, Scope of Competition Report, issued April 11, 1996, and follow up communications with representatives of reporting utilities.

As will be explained in Chapters VII and VIII of this report, stranded investments associated with wholesale contracts arise through a different mechanism than the stranded investments attributable to retail service. Retail stranded investment arises when a customer switches from its traditional supply at regulated rates to electric supply at the competitive market price. Wholesale stranded investment arises when a contract expires or is otherwise terminated. The size of wholesale stranded investment will depend upon the contract terms, whether the contract remains in effect through its term, and the obligations of the contract signatories for stranded investment following expiration of the contract.

1. Examples of Wholesale Stranded Investment

Recent legislative and regulatory changes have introduced a variety of competitive opportunities in the wholesale electric market in Texas.[15] Under recent federal and State laws,[16] new types of generators have been allowed to operate in the electric market, as have the power marketers. The requirements under PURA95 for open access and comparability of service—and comparable requirements from the FERC in its Order No. 888—now guarantee alternative suppliers access to the electric transmission system. Competitive conditions are now in place allowing wholesale

[15] For a detailed discussion of the emergence of the competitive wholesale electric market in Texas, see Chapter V of the Scope of Competition Report.

[16] Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in various sections of 16 U.S.C); Energy Policy Act of 1992, 42 U.S.C.A. §§ 6349, 6350, 8262g, 13369, 13474 (West Supp. 1996); and PURA95.

customers opportunities for competitive supply, conditions that could lead to the creation of stranded investment in Texas.[17] These examples are not speculative or related to some uncertain future; rather, the examples show that the market is already operating in a manner that can create stranded investments. Current and proposed examples of market transactions with the potential to create wholesale stranded investment include the following:

- *Wholesale contract replacements:* Since the Commission adopted rules requiring comparable transmission access, several parties have entered into contracts with non-utility providers, replacing prior contracts held with utilities. Granbury Municipal Electric Department will buy 16 MW of load from LG&E Power Marketing, replacing Brazos Electric Cooperative.[18] Rayburn Country Electric Cooperative also selected LG&E Power Marketing to supply more than 300 MW of load currently served by TU Electric.[19]
- *Co-generation:* Co-generation facilities are typically industrial concerns that own and/or operate generating facilities, but are not primarily engaged in the generation or sale of electric power. These facilities produce electric energy, steam used in manufacturing, and thermal energy used for industrial and commercial heating/cooling. If a utility customer chooses instead to co-generate, utility investments may become stranded. Although the data are incomplete, in 1995, non-utilities (mostly co-generators) sold at least 21.3 million MWh to utilities and used at least 20.3 million MWh for their own consumption.
- *Municipalization:* Most cities receive electric service under franchise agreements. Upon the expiration of a franchise agreement, cities have the opportunity to form municipal utilities, which allow the municipalities to shop for electricity in the wholesale market.

These examples demonstrate that utility investments providing service in the wholesale market can and are becoming stranded today. In particular, new wholesale power supply contracts that have replaced utility providers with non-utility power may cause the original providers' investments to become stranded. As non-utility generation

[17] It should be noted that there has not been an obligation by utilities to sell wholesale power in Texas. The implications of this are discussed in Chapter IX(B) in this report.

[18] "Marketer Replaces Brazos Co-op as Supplier of 16 MW to Texas Muni," *Electric Utility Week*, at 7 (May 13, 1996).

[19] "Rayburn G&T Co-op Will Buy 300 MW in Deal with LG&E Power Marketing," *Electric Utility Week*, at 7 (July 1, 1996).

capacity increases, the likelihood of non-utility providers substituting for existing utility providers will increase. Municipalization is another mechanism that can lead to stranded utility investments without requiring any further regulatory changes.

2. Example of Creation of Retail Stranded Investment

The retail electric market in Texas offers fewer competitive opportunities than the wholesale market; thus there are fewer current avenues for creation of stranded investment. Nevertheless, stranded investment can be created in the retail market in a number of ways.

- *Self-generation:* A company may choose to generate its own power. This option has long been available to the largest manufacturing interests, but with reductions in the cost of generation, self-generation is becoming a more viable option for smaller power users. In one notable example of self-generation intended to bypass the traditional utility provider (Docket No. 13943, later withdrawn), Gulf Coast Power Connect, Inc. proposed to build a transmission line to provide transmission from a self-generation plant to a facility owned by the same end user.
- *Multiple certification:* Approximately 20 percent of the State operates under limited retail competition because more than one utility is certificated in those areas. Multiple certification creates a limited competitive market by allowing consumers to choose electric suppliers. Stranded investments (including investments in transmission and distribution plant) may be created if a customer switches from one certificated provider to another.
- *Discounted retail rates:* Under PURA95 § 2.214, utilities may offer rate discounts to retail customers to prevent those customers from choosing an alternative source of supply. A number of Texas utilities offer retail discounts, particularly to the largest industrial and commercial customers.
- *Potential retail bypass:* In a case considered by the Commission in the Fall of 1996 (Docket No. 16147), Power Clearinghouse, Inc. (PCI), a power marketer, proposed to bypass the City of Austin's retail electric service by selling electricity to an apartment complex currently serviced by the City utility.[20] Master-metered apartment buildings are currently considered to be retail customers. PCI's proposal would have the Commission define such customers as wholesale customers, increasing the

[20] On a two to one vote, the Commission granted a motion filed by the City to dismiss PCI's complaint to compel the City to provide wholesale transmission service from the Lower Colorado River Authority to the apartment building.

size of the wholesale market and raising the possibility of greater wholesale competition and stranded investment.

Although the retail market offers fewer competitive opportunities than the wholesale electric market, some opportunities do exist that can lead to retail stranded investment under the current regulatory structure. If changes to the market such as that posed in the PCI case are adopted, the pace at which assets become stranded could be accelerated.

III. METHODS FOR QUANTIFYING STRANDED INVESTMENT

This chapter discusses methods and procedures for estimating the magnitude of potentially strandable investments associated with electric utility generation assets.[21] Quantification methods are used to measure the effect of market competition on the value of generation assets. Market competition refers to market-based pricing of electricity instead of traditional regulated cost-of-service pricing. Chapter II of the Scope of Competition Report discusses the evolution of electric utility regulation in Texas, and Chapter IV of that report includes a basic description of the operation of efficient competitive markets.

Section A of this chapter begins with an overview of stranded investment estimation, paying particular attention to some of the complexities and uncertainties that any estimation methodology must address. Section B provides an overview of two categories of approaches for estimating the magnitude of potentially strandable investments: market valuation methods and administrative valuation methods. Section C describes market valuation methods in greater detail, and Section D describes administrative valuation methods.

A. OVERVIEW OF STRANDABLE INVESTMENT ESTIMATION

Estimation of a utility's potentially strandable investments is a complex undertaking, subject to many uncertainties. The financial and accounting methods and structures developed for regulated utilities are highly detailed; application of those methods to the estimation of potentially strandable investments is equally detailed and complex. Estimation requires a careful review and understanding of utility costs and balance sheets. In some cases, the meaning of specific details may be subject to interpretation by the analyst conducting the estimate. This section presents an overview of some of the complications and uncertainties associated with estimating strandable investment. *Because these uncertainties are so broad, any current estimate of potentially*

[21] As competition expands in the electricity market, other categories of utility assets may also have the potential to become stranded, including transmission and distribution plant, regulatory assets and liabilities, and costs for demand side management programs.

strandable investment is at best an informed estimate of future conditions in the electric industry.

An estimate of a utility's potentially strandable investment may be divided into three distinct cost categories: sunk costs; prospective costs; and contractual obligations. The first category, sunk or previously committed costs, consists of dollars that the utility has already spent and expects to recover through regulated electric rates. These costs are unavoidable, and already appear on the company's balance sheets. The book values of nuclear, coal, gas, or lignite power plants are examples of sunk costs.

The second category, prospective costs, represents future costs that a utility may or may not be able to control. Prospective costs that a utility cannot avoid may be classified as strandable investment. Examples of unavoidable current and on-going costs may include nuclear decommissioning costs, capitalized demand-side management expenses, and capitalized costs for low-income assistance programs. Prospective costs that a utility can avoid, e.g. operations and maintenance expenses, are not considered in strandable investment estimates. The values of prospective costs are estimated through the determination of the rate base in the current regulatory system, and therefore are much more difficult to estimate in an unregulated environment because of the uncertainties involved.

The third category includes costs for on-going contractual agreements that can be detrimental or beneficial to a utility's cost position relative to the market, depending on the stability and level of fuel and electricity prices. Contractual agreements can involve long-term fuel purchases, power sales, or power purchases of varying lengths, terms, and conditions. Utility generators make fuel purchase agreements for supplies of coal, lignite, natural gas, or uranium at a stated price for a specified period of time. Power sales contracts provide the utility with guaranteed customers for a specific period of time. Power purchase contracts can obligate a utility to purchase electricity from another generator.

The magnitude of potentially strandable investments is difficult to estimate, in part because of the uncertainty associated with the future of the electricity industry. To ease the estimation process, it is helpful to separate the uncertainty of the future into three areas: the regulatory environment; consumer responses to changes in the marketplace; and the relationship between the market price of electricity and the operating costs of individual utilities. These three areas are interdependent; actions in one will create reactions in the others that may affect the size of potentially strandable investments.

1. The Regulatory Environment

The environment in which electric utilities operate is a creation of State and federal legislators and regulators.[22] State and federal laws and regulatory activities will determine the timing and nature of any industry restructuring. In addition, the speed at which competition is introduced will have an impact on the magnitude of investments that are ultimately stranded. If regulators restrain or phase in further competition, utilities can continue to recover costs through the rates paid by utility customers and take other actions to mitigate the magnitude of stranded investments.

Legislative and regulatory decisions could affect the very structure of the electric industry. Changes in federal and State laws, beginning with the federal Public Utility Regulatory Policies Act (PURPA) in 1978, have led to the emergence of an increasingly competitive generation market. More recent changes include the federal Energy Policy Act of 1992 (EPAct) and Texas' Public Utility Regulatory Act of 1995 (PURA95). PURPA requires utilities to purchase power from qualifying non-utility facilities, certain co-generators and small power producers. The EPAct encourages competition in the wholesale electric generation market by requiring greater access to utility transmission facilities and the creation of a new class of generating entities called exempt wholesale generators (EWGs). PURA95 contains provisions that conform State law with the EPAct by introducing wholesale competition to the Texas power

[22] For a more complete discussion of the origin of the regulatory environment, see Chapter II of The Scope of Competition Report.

industry. PURA95 also allows for partial deregulation of cooperatives, wholesale sales from EWGs and power marketers, comparable transmission service for all generators and power suppliers, and integrated resource planning. By increasing the number of electric suppliers and easing bulk power transactions, these policies have created downward pressure on the wholesale price of electricity.[23]

2. Consumer Responses to Marketplace Changes

The uncertainty concerning consumer activity in an unregulated environment centers around how consumers might change their consumption habits in response to changes in electricity prices. It is also uncertain whether consumers would change their generation provider if broader service and rate options were available from their current suppliers. If competition in the generation sector results in lower prices, consumer demand for electricity will increase, which could offset at least a portion of utilities' investments that ultimately become stranded.

3. Industry Prices and Utility Costs

The third critical uncertainty involves factors that establish the relationship between the future market price of electricity and the operating costs of individual utilities. Marketplace conditions, such as the relative prices of fuels, will influence the market price of electricity. The relationship between the utility's historic costs and the emerging market price is a critical determinant of the magnitude of potentially strandable investments. Any remaining barriers to competition may prevent prevailing prices from reaching the truly competitive level. If (partially) competitive prices are kept above the competitive market price, utilities will continue to recover some of their strandable investment in their rates.

Perhaps the most fundamental determinant of market price is the degree of competition within the market. A number of conditions determine the degree of competitiveness of a market, including the existence of many buyers and sellers, a homogeneous product,

[23] The Public Utility Regulatory Policies Act, 16 USC §8241-3. Energy Policy Act, Pub. L. 102-486, 106 Stat. 2776 (1992). S.B. 373, 74th Leg., R.S., Chi. 765, 1995 Tex. Sess. Law. Serv. 3972 (Vernon) (Codified at Tex. Rev. Civ. Stat. Ann. art. 1446c-o). See The Scope of Competition Report for further discussion.

perfect information, ease of entry and exit, and freedom from economies of scale. In a truly competitive market for electricity, the short-term market price of power largely consists of fuel and operations and maintenance costs (i.e., variable costs). In the long-run, the market price includes the cost of acquiring additional capacity. If a market is less than fully competitive, one or several firms could influence the market price, holding it higher than a fully competitive price.[24] When a firm cannot control the market price of electricity, it must adjust its own operating behavior to maximize profits and minimize the size of its stranded investments. For example, a utility could market to high-volume customers, design value-added services for the residential customer, or develop rate structures that are consistent with daily variations in its cost of service.

The estimation of industry prices and utility costs of operation involves the use of many different assumptions. The assumptions include traditional financial indicators such as inflation, escalation rates, the cost of capital, and fuel costs. Some assumptions are very technical in nature, such as predictions about load growth, supply reliability, transmission constraints, fuel use, and technology improvements. In some cases, assumptions are tied to a specific vision of the structure and operation of the future electric industry. Structural and operating assumptions involve anticipating the market entry of competitors, existence of a spot market for electricity, the development of regional marketplaces, and competitive access to wholesale and retail consumers. This list is just a selection of the general set of assumptions contributing to the large uncertainties that will influence both the market price and utility costs.

B. Methods and Approaches for Estimating the Magnitude of Potentially Strandable Investments

There are two basic methods for valuing potentially strandable investments: market and administrative methods. If the valuation is conducted in a market, the interaction between buyers and sellers in the market determines the asset value. Using this

[24] Chapter IV of The Scope of Competition Report discusses of the efficiency of competitive markets and the determination of market power.

method, strandable investment is the difference between book value and market value. In contrast, administrative valuation methods simulate market outcomes; regulators, financial analysts, utilities, and other interested parties estimate asset value. Various analytical approaches can be applied to both administrative and market valuation methods. Table III-1 summarizes some of the different approaches used to estimate the value of potentially strandable investment.

Table III-1: Methods and Approaches for Valuing Potentially Strandable Investment

	Administrative Method		Market Method	
	EX ANTE	*EX POST*	*EX ANTE*	*EX POST*
	Assumed Market Conditions	New Market Conditions Established	Assumed Market Conditions	New Market Conditions Established
BOTTOM-UP	Assets and liabilities valued individually	Assets and liabilities valued individually	Market transaction values individual assets	After-the-fact purchase price adjustment
TOP-DOWN	Total generation function valued	Total generation function valued	Market transaction values generation function	After-the-fact transaction adjustment

Source: Based on Baxter, Lester and Eric Hirst, *Estimating Potential Stranded Commitments for US Investor-Owned Electric Utilities*, U.S. Department of Energy, Oak Ridge National Laboratory at 7 (January 1995).

A bottom-up approach uses asset-specific data to calculate potentially strandable investments for each generating unit a utility owns.[25] A bottom-up approach involves a data-intensive and complex analysis that requires numerous assumptions about the costs associated with running individual plants to determine the profitability of each plant. A top-down approach uses utility or regional-level data, and requires fewer assumptions to calculate potentially strandable investments for a portfolio of assets. Because it is a more general approach than a bottom-up analysis, a top-down analysis

[25] Although this discussion focuses on generation stranded investment, transmission and distribution assets may become stranded as well. If transmission and distribution functions remain regulated in the future, they are unlikely to become stranded.

tends to be easier to understand, but may provide fewer detailed insights into specific assets, liabilities, and costs.

Valuations can be performed *ex ante*, before any structural change takes place, or *ex post*, following structural changes. *Ex ante* valuations provide prospective estimates of potentially strandable investments. Results of *ex ante* valuations can be a valuable planning tool and can limit the range of uncertainty. Utilities can interpret the results as signals on how to behave in the new market, but must not completely rely on the estimate. If assumptions used to develop *ex ante* estimates prove to be incorrect over time, the estimate can be corrected through "true-up" mechanisms. A true-up mechanism is an administrative measure that calculates the difference between estimated and actual values that could be used to ensure that a utility does not over- or under-recover its stranded investment.

Ex post valuations are conducted after the new industry structure is in place and actual transition costs can be used to calculate stranded investment. Through *ex post* valuations, both costs and benefits of industry transition can be incorporated into the stranded investment calculation.

C. MARKET VALUATION METHODS

Market methods may be preferred over administrative methods for valuing assets because "markets are more efficient than individuals in determining the value of goods and services."[26] The main advantage of market valuation methods is that market methods can produce asset values grounded in markets rather than based on the judgments of financial analysts. In that sense, market methods may be considered more "accurate." Added benefits to market valuation methods could be "price signals to customers, more upside potential for stockholders, better incentive to utility

[26] Lessor, Jonathan and Malcolm Ainspan, "Using Markets to Value Stranded Costs", *The Electricity Journal* at 68 (October 1996). Some utilities are already considering market valuation of strandable investment through generation asset sales. Pacific Gas & Electric Company (PG&E) of California recently announced plans to sell four of its natural gas plants. The sale is in compliance with a California Public Utilities Commission order that required California IOUs to divest 50 percent of their fossil fuel plant capacity.

management than cost-based regulation, and utilities may be able to take advantage of financial leverage currently enjoyed by independent power production firms."[27]

Market valuation will play a role in utility restructuring in California. In December of 1995, the California Public Utility directed the State's two largest utilities, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), to divest voluntarily up to 50 percent of their fossil generation resources as a curb on market power in a restructured electric market. PG&E recently announced plans to auction four gas-fired power plants by the end of 1997, and SCE announced plans to sell all of its in-state fossil generation plants.[28] The market values derived in the sales will be used in the computation of transition (i.e., stranded investment) charges.

Market valuation of generation assets relies on transactions between buyers and sellers. All market transactions incorporate the buyers' and sellers' projections of revenues and costs for the assets, based in part on their expected market prices for electricity. The comparison can lead to an accurate determination of the value of utility assets only if a workable marketplace for those assets exists, in other words, a marketplace that consists of many viable buyers and sellers. Viable buyers are those with sufficient capital and human resources to maintain the assets. For market methods to provide viable valuation for a utility asset, the market participants as a whole must have confidence that the buyers can manage utility assets as well as incumbent firms while maintaining system reliability.

Market transactions can involve individual generation plants or a utility's entire generation portfolio.[29] Breaking up large generating utilities so that transactions involve only one or two plants at a time can address market power concerns by creating smaller, competing generation companies. The sale of the assets as a group can

[27] Southwestern Public Service Company, *Excess Cost Over Market (ECOM) Supplemental Request for Comments* at 2 (May 20, 1996).

[28] "PG&E Files its Plan to Shed 3,000 MW with PUC; Says Hearings not Needed" and "Socal Edison Sets Plan to Sell Off All 12 Oil and Natural Gas Plants," *Electric Utility Week*, at 5, 1 (November 25, 1996).

[29] Since many utilities co-own generation facilities, it is likely that generation capacity could be sold in increments smaller than whole plants.

be a mechanism to alleviate the risk associated with nuclear plants by selling them in conjunction with lower risk fossil fuel plants. There is considerable doubt about the existence of a market for Texas nuclear plants because of high decommissioning costs and Nuclear Regulatory Commission (NRC) licensing requirements.[30] The NRC recently released a draft policy statement "regarding its expectations for, and intended approach to, its power reactor licensees as the electric utility industry moves from an environment of rate regulation toward greater competition."[31] In the draft policy statement, the NRC indicates that its "concerns with deregulation and restructuring lie primarily in the area of adequacy of decommissioning funds, although it is also concerned with the potential effect that economic deregulation may have on operational safety."[32] The NRC also indicates that it is within its purview to require notification and prior approval in the event of mergers, the formation of holding companies, or sales of nuclear facilities.

Valuing *wholesale* assets using market methods poses particular difficulties because of the current integrated nature of the industry. Utilities rarely dedicate entire power plants exclusively to the production of power at wholesale. More commonly, a plant produces power sold at wholesale and retail. Estimating the potential for wholesale stranded investment separate from retail would require allocating the costs incurred jointly between wholesale and retail sales. If the share of output sold at wholesale is known for a specific plant, joint costs can be allocated administratively.

The principal potential disadvantage of market valuation methods lies in the market itself. Accurate valuation relies on a well-functioning market for generation assets. In Commission workshops and comments submitted under Commission Project Nos. 15000 and 15001, the parties' most common objection to market valuation concerned

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[30] Houston Lighting & Power Company, *Response to Supplemental Questions Regarding Allocation and Recovery of ECOM* at 2 (May 20, 1996). Central and South West Corporation, *Central and South West's Comments to Supplemental Allocation and Recovery of ECOM Questions* at 2 (May 20, 1996).

[31] Nuclear Regulatory Commission, *10 CFR Part 50, Draft Policy Statement on the Restructuring and Economic Deregulation of the Electric Utility Industry*, Federal Register, Vol. 61, No. 185, Proposed Rules at 49,711 (September 23, 1996).

[32] *Id.* at 49,712.

the likelihood of inaccurate prices resulting from transactions for generation assets. Parties also expressed concern that market valuation methods would result in a "fire sale" if all plants are put up for sale at the same time.[33] Another disadvantage voiced by commentors is that without a secure market, asset prices would reflect the systemic risk of an unstable market structure rather than the risk inherent in each asset.[34] Systemic risk refers to the amount of risk that exists for all goods and services in a specific market. If that "background risk" is too great, it can overshadow and depress the value of any one good or service in the market. A similar argument is that transactions completed *ex ante* would be based on current market perceptions and could lead to substantial undervaluation of generation assets.[35]

Concern about "fire sale" prices for generation assets are not groundless. There could be downward pressure on asset prices if the number of buyers is small relative to the number of plants for sale, especially if the buyers are financially constrained. Prices for goods and services typically fall dramatically when supply outstrips demand.[36] The market methods discussed in this section do not involve any changes in the quantity of electricity demand or supply. The only change proposed is the *ownership* of supply. Changes in the *value* of generation assets should reflect the change to a non-regulated pricing environment.

Concerns about an unstable market structure may be exaggerated. The FCC auction of radio frequency spectrum rights illustrates that market prices can be valid even in emerging industries with unknown technologies.[37] The electricity market has been

[33] Environmental Defense Fund and Public Citizen of Texas, *Responses to Supplemental Questions Relating to Allocation and Recovery of ECOM* at 1-3 (May 20, 1996); Nucor Steel, *Comments in Response to Supplemental Questions on the Allocation and Recovery of ECOM* at 2 (May 20, 1996); Texas Industrial Energy Consumers, *Response to Supplemental Questions Relating to allocations and Recovery of ECOM* at 4 (May 20, 1996); South Texas Electric Cooperative, *Comments Concerning Appropriate Allocation and Recovery of Excess Cost Over Market*, at 22 (May 20, 1996); and Texas Utilities Electric Company, *Comments of Texas Utilities Electric Company Concerning Supplemental Questions on Allocation and Recovery of ECOM* at 5 (May 20, 1996).

[34] Houston Lighting & Power Company, *supra* at 2.

[35] Nucor Steel, *supra* at 4.

[36] Lesser, Jonathan, and Malcolm Ainspan, "Using Markets to Value Stranded Costs," *The Electricity Journal* at 72 (October 1996).

[37] Lesser, *supra* at 69.

operating for many years, and industry participants should have the expertise to value generation assets accurately. Apprehension about market perceptions and changing prices are perhaps appropriate, since fluctuating prices are a normal function of a competitive market. A requirement for sellers to provide all financial and operations records to potential buyers would minimize the information advantage enjoyed by incumbent firms. Despite potential obstacles, market methods provide quicker entry for new competitors than building new capacity.

In market valuation methods, mechanisms such as spin-down, spin-off, or auction determine the value of a utility's generation assets. The open solicitation for purchased power is another market valuation method.[38] The following sections discuss the mechanisms and describe possible market structure outcomes associated with each.

1. Spin-down of Generation Assets to An Unregulated Affiliate

In a spin-down, the utility separates its generation assets into an unregulated affiliate, and distributes new shares of stock in the unregulated affiliate to existing shareholders. The utility's management determines the price of the generation assets through the book value assigned to the new shares. The vertically integrated utility would remain whole, but would operate its generation assets independently of its other functions. This process is sometimes known as "functional unbundling" of a company's assets.

One criticism of this method is that a true *initial* market valuation would not occur since utility management does not create a separate publicly traded security or offer shares to third parties.[39] Thus, this "insider's" valuation of the assets would not necessarily yield a *market* estimate for stranded investment. However, after some time has passed and the new shares are traded on stock markets along with other energy shares, a true market valuation of the assets would be established. A true-up

[38] Pat Wood, III, Chairman of the Public Utility Commission of Texas, introduced these market valuation options in his *Proposal for Achieving Transmission Access and Full Wholesale Competition*, Project No. 14045 (September 6, 1995).

[39] Central and South West Corporation, *supra* at 4.

mechanism that examined share prices at different times could reduce any measurement distortion that resulted from the timing of the spin-down.

Another potential disadvantage of the spin-down method is that the on-going affiliation between the utility divisions could perpetuate self-dealing, market power, and/or lead to additional distortions of the magnitude of strandable investment. Because the utility maintains ownership control of the generation assets, the company may be able to exert vertical market power, taking advantage of its continued integration. The persistence of the incumbent's market power could effectively block market entry and impair competition. The potential for self-dealing or abuse of market power could necessitate continued monitoring by regulatory authorities.[40]

According to Destec Energy, Inc., one advantage to a spin-down estimation is the avoidance of an asset "fire sale" because the utility would retain ownership its generation assets.[41] Additionally, sales of disaggregated competitive generation stocks would better align investors according to their risk tolerance levels.[42] Risk-averse investors could retain transmission and distribution stock while risk-tolerant investors could purchase generation-only stocks.

2. Spin-off Generation Assets to a Third Party

In a spin-off, the utility sells its generation assets—either as an operating unit or in separate pieces—to an independent third party (or parties). The sale price of the transaction establishes the market value of the assets. Full separation of generation assets from other utility operations would accomplish industry restructuring. This process is often referred to as "divestiture" or "structural unbundling."

Control of the generation assets by unrelated entities eliminates the potential problems associated with self-dealing. Spin-off will eliminate vertical market power arising from

[40] Enron Capital & Trade Resources, *Response of Enron Capital & Trade Resources to Supplemental Questions to Relating to the Allocation and Recovery of ECOM* at 1 (May 20, 1996).

[41] Destec Energy, Inc., *Responses to Supplemental Questions to the April 16, 1996 Request for Comments Relating to the Allocation and Recovery of ECOM (Excess Costs Over Market)* at 3 (May 20, 1996).

[42] *Id.* at 3.

joint ownership of generation as well as transmission and distribution assets. Horizontal market power may or may not be reduced depending on the concentration of assets after divestiture. Spin-offs could increase the number of generation firms in the market by providing a vehicle for quick entry of competitors. Sale of individual generation plants could also decrease entry costs and encourage competition.

3. Open Auction of Generation Assets

In an open auction, the utility sells its generation assets individually or in groups. Depending upon the auction design, the utility could have the option to retain each asset by matching the winning bid and exercising a right of first refusal. The winning bid would determine the asset value, and would be used to calculate strandable investment. An open auction would create a visible and widely recognized value for each asset. However, if the utility is allowed to match the winning bid and retain ownership of the asset, fewer buyers may participate or may reduce their bids for the assets. In addition, the seller would have an information advantage over any other bidders. It could choose to compete for the best performing, low-cost assets, leaving the high-cost, poor performers for other bidders.

An auction designed without right of first refusal by the utility would be more likely to yield an accurate asset price. If the incumbent were on an equal footing with all other bidders, the bidders would have more confidence in the possibility of purchasing the utility's assets. Other bidders could glean more reliable information about the actual performance of specific assets from the utility's bidding behavior, leading to a valid market price.

With an auction, the generation-owning utility would have the choice of remaining in the generation business or not. Problems associated with market power could linger if the utility were able to "buy back" a substantial amount of its generation assets. A utility with a lot of cash on hand could block competition by bidding-up its assets and making market entry expensive. However, such a strategy would reduce the estimated value of the utility's strandable investment.

4. Open All-Source Solicitation for all Power Requirements

Using this market valuation method, a utility would solicit bids from other generators to supply all its power requirements. A utility could state its requirements in terms of base load or peaking capacity, by time-of-day, time-of-year, generation fuel, demand-side management (DSM) services, customer class, or another appropriate definition. The utility would also determine the contract life of the solicitation, and would have the right to match the best purchased power bids received. The winning bid would determine the market price of electricity. If the utility could meet the market price, it would opt to supply its own power. When the utility supplies its own power, the calculation of strandable investment would be based on the difference between its regulated price and the market price. If the utility cannot meet the market price, the strandable investment calculation would be based on the difference between its regulated price and the market price of electricity plus the costs of mothballing or shutting down the higher-cost plant.

A solicitation method may be less complex to implement than other market methods because the utility's structure remains unchanged. This method could mitigate utility excess capacity if utilities with over-capacity bid to sell power to capacity-constrained utilities located in the same region. Mitigation is not possible if the entire region has too much generation capacity.

One criticism of the solicitation process is that it could incorrectly estimate strandable investment; the contract price might reflect only a short-term valuation of the electricity needed, not the value of an asset with a 30-year life.[43] Knowledgeable bidders would be able to value each solicitation offer correctly. Contract prices, like market prices, vary depending on the length, quantity, and quality of power rendered. The utility could use its information advantage and the right of first refusal to send false signals to the other bidders and distort the value of its strandable investment. As discussed

[43] Enron Capital & Trade Resources, *Responses to Supplemental Questions Regarding Allocation and Recovery of ECOM* at 2 (May 20, 1996).

above, instituting an open records requirement could minimize the utility's information advantage.

All-source solicitation could encourage competition because the existence of a power purchase contract represents a guaranteed customer base. The contractual agreement could aid new entrants in securing the funding needed to build new generation facilities. The need for new construction, however, could slow market entry of new competitors. All-source solicitation would not address market power issues if utilities had the right of first refusal and could maintain ownership of generation assets.

D. Administrative Valuation Methods

In administrative valuation methods, financial models or other analytical techniques are used to calculate asset values by attempting to simulate market results. If performed *ex ante*, administrative methods require projecting a utility's generation costs and revenues, and making assumptions about market prices. If the valuation is performed *ex post*, the new marketplace will be functioning, and utilities' actual operating financial information can be used to quantify stranded investment.

Administrative valuation methods are a powerful analytical tool that can be used as a substitute for market transactions. Administrative methods are especially helpful when estimating potentially strandable investments for assets that may not have viable markets, such as nuclear plants. These methods can also be used to value potential wholesale strandable investment, which can be distinguished from potential retail strandable investment using standard accounting practices.

The greatest disadvantage of administrative valuation is that values are based on estimates, not observations of working markets. An administrative method does not, in itself, effect any structural changes to the industry, mitigate market power, or ease the difficulties faced by new competitors. At their worst, administrative methods serve as another form of regulation that attempts to mimic an unregulated market. If market power exists and a utility (or utilities) is able to maintain higher prices, an administrative estimate based on the market price would overstate the magnitude of potentially strandable investments. Barriers to entry could also lead to a prevailing price above the market price and thus an overestimation of potentially strandable investment.

Administrative methods incorporate many assumptions, and each assumption introduces an opportunity for error. If utilities use the results from an administrative estimation as benchmarks for stranded investment, a true-up mechanism could reconcile assumed prices with market reality after the market matures.

IV. EXAMPLES OF ADMINISTRATIVE VALUATION STUDIES

This chapter discusses recent *ex ante* administrative studies that attempt to quantify the effect of competition on America's utility generators. The analytical models used in administrative studies are limited only by the imagination of the analyst designing them. Two common types of administrative models are lost revenue and asset-by-asset. A lost revenue model views the effects of competition in terms of the revenues that a utility could lose under market pricing. Lost revenue models use a top-down approach and provide results on a utility or regional basis. Asset-by-asset models estimate revenue and cost streams for individual utility generating plants, and calculate the profitability of assets under market pricing. As a bottom-up approach, asset-by-asset modeling requires the highest level of detail. Asset-by-asset models require analysts to make many assumptions and use proxies because utilities often do not maintain accounting records at the individual plant level. As a result, asset-by-asset models are open to more opportunities for forecast error than other methods, but provide insight into profitability of individual plants.

Four of the studies discussed in this chapter were conducted on a nationwide basis: Moody's Investment Service (Moody's); DRI/McGraw-Hill (DRI); Standard & Poor's (S&P); and The Fitch Report (Fitch). The fifth study, conducted by Resource Insight, Inc. (RII) estimates stranded investment for individual utilities operating in the State of Massachusetts. Moody's, S&P, and Fitch used publicly available data that FERC requires major electric utilities to file every year.[44]

[44] Pursuant to Sections 3, 4 (a), 304, and 309 of the Federal Power Act and 18 CFR 141.1. *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others*, Instructions for Filing at I. FERC defines major utilities to be those that have had, in each of the three previous calendar years, sales or transmission service that exceed one of the following: one million megawatt hours (MWh) of total annual sales; 100 MWh of annual sales for resale; 500 MWh of annual power exchanges delivered; or 500 MWh of annual wheeling for others (deliveries plus losses).

Table IV-1: The North American Electric Reliability Council

	Region Name	Geographic Area
ECAR	East Central Area Reliability Coordination Agreement	Indiana, Kentucky, Michigan, Ohio, and Pennsylvania
ERCOT	Electric Reliability Council of Texas	Texas
MAAC	Mid-Atlantic Area Council	Delaware, Maryland, New Jersey, Pennsylvania, and Virginia
MAIN	Mid-America Interconnected Network	Illinois, Missouri, and Wisconsin
MAPP	Mid-Continent Area Power Pool	Iowa, Minnesota, North Dakota, South Dakota, and Manitoba, and Saskatchewan Canada
NPCC	Northeast Power Coordinating Council	Connecticut, Maine, Massachusetts, New York, New Hampshire, Rhode Island, Vermont, and New Brunswick, Ontario, and Quebec, Canada
SERC	Southeastern Electric Reliability Council	Alabama, Florida, Georgia, Mississippi, North Carolina, and South Carolina
SPP	Southwest Power Pool	Arkansas, Kansas, Louisiana, Mississippi, Missouri, Oklahoma, and Texas
WSCC	Western Systems Coordinating Council	Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah, Washington, Wyoming, British Columbia and Alberta, Canada, and Baja California Norte, Mexico.

Source: North American Electric Reliability Council (September 23, 1996).

Moody's, S&P, and Fitch aggregate data according to the regional boundaries of the nine North American Electric Reliability Council (NERC) regions.[45] The nine NERC regions interconnect all the electric utility systems in the United States, Canada and Baja California Norte, Mexico as a means of augmenting the reliability and adequacy of bulk power supply in the electric utility systems of North America.[46] The NERC regions create a natural aggregation for generation data because the utilities within each are integrally connected via transmission lines, and may eventually compete for the same customers.

In a fully competitive market, each region may become a functioning marketplace for electricity. Table IV-1 shows each NERC region and the geographic territories it

[45] The Florida Reliability Coordinating Council (FRCC) became the tenth NERC region on September 18, 1996. FRCC became operational on October 1, 1996.

[46] *10th Annual review of Overall Reliability and Adequacy of the North American Bulk Power Systems*, Princeton, NJ: National Electric Reliability Council at 2 (1980).

encompasses. Table IV-2 identifies Texas investor-owned utilities by NERC region. Figure IV-1 is a map of the State of Texas that shows the boundaries of the Electric Reliability Council of Texas, the Southwest Power Pool and the Western Systems Coordinating Council.

Table IV-2: Texas Investor Owned Utilities

Utility Name	Acronym	NERC Region
Central Power and Light Co.	CPL	ERCOT
El Paso Electric Company	EPE	WSCC
Gulf States Utilities	GSU	SPP
Houston Lighting and Power Co.	HL&P	ERCOT
Southwestern Electric Power Company	SWEPCO	SPP
Southwestern Public Service Company	SPS	SPP
Texas Utilities Electric Co.	TUEC	ERCOT
Texas-New Mexico Power Co.	TNP	ERCOT
West Texas Utilities	WTU	ERCOT

Source: Office of Regulatory Affairs, *1996 Statewide Electrical Energy Plan for Texas,* Austin, TX: Public Utility Commission of Texas (June 1996).

The remainder of this chapter is organized as follows: Section A discusses Moody's stranded cost study; Section B explains S&P's lost revenue approach; Section C describes DRI's estimated stranded investment results; Section D discusses Fitch's utility generation costs; Section E compares the different results estimated for Texas; and Section F describes RII's asset-by-asset stranded investment study of Massachusetts utilities.

A. MOODY'S ESTIMATE OF STRANDED COST

Moody's Investors Service published a study estimating stranded costs for U.S. investor-owned utilities in August 1995. Moody's top-down analysis begins with the determination of a utility's break-even price.[47]

[47] Fremont, Paul B., Rogihn K. Hornstra, Susan D. Abbott, and M. Douglas Watson, Jr., *Stranded Costs Will Threaten Credit Quality of US Electrics*, New York, NY: Moody's Investors Service, Special Comment (August 1995).

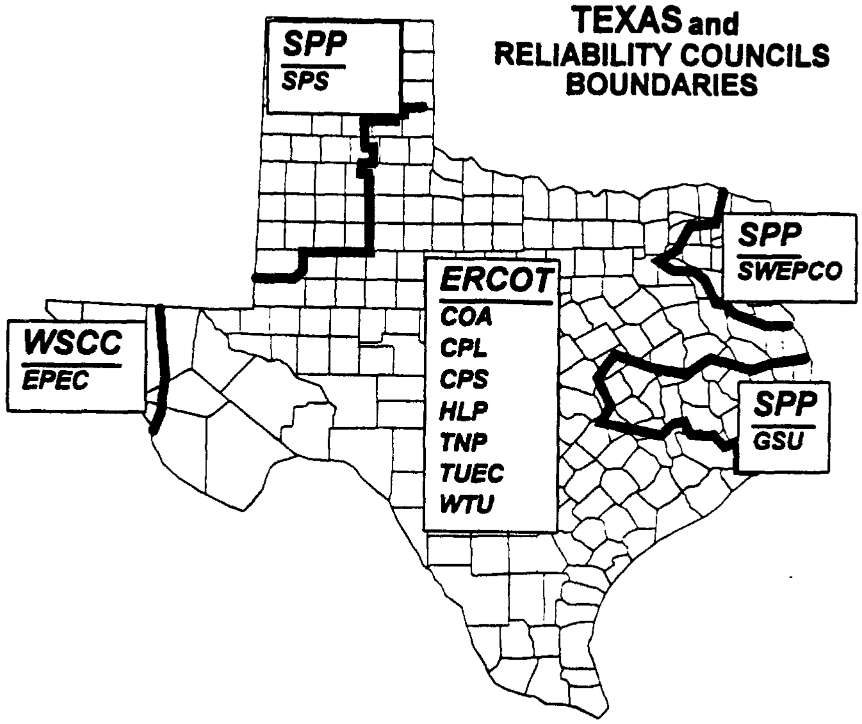

Figure IV-1: Utilities in Texas with NERC Region Boundaries

Moody's defines the break-even price as the minimum price at which a company must sell electric capacity, both owned and purchased, to recover all of its fixed production costs. Moody's argues that if a company's margin from selling electric energy does not cover all fixed costs, it must make up the difference by charging customers for electric capacity. The size of the gap between total fixed costs and the amount recovered by margins determines the amount of revenue a company must generate from capacity sales in order to break-even or cover its total generating costs.[48] The total amount of potentially stranded costs for any electric utility is equal to the difference between its break-even price and the market price for capacity, times the amount of the company's capacity.[49]

[48] Moody's defines fixed costs to include current cash expenditures such as non-fuel operating and maintenance expenses, fixed payments under long-term power contracts, interest, property taxes, and depreciation. Adjusted break-even prices and equity for each company were calculated using 1993 FERC Form 1 reports.

[49] Fremont, *supra* at 1 - 6.

Table IV-3: Moody's Market Price Assumptions

NERC Region	Energy (cents/kWh)	Capacity ($/kW)
ECAR	1.7	$ 40
ERCOT	1.8	30
MAAC	1.9	45
MAIN	1.7	40
MAPP	1.3	45
NPCC	2.0	45
SERC	2.0	30
SPP	1.7	20
WSCC	2.4	35

Source: *Stranded Costs Will Threaten Credit Quality of US Electrics*, Moody's Investors Services, Special Comment at 10 - 18 (August 1995).

Table IV-3 shows Moody's energy and capacity pricing assumptions for each NERC region. Under Moody's pricing assumptions, ERCOT is almost exactly at the median price for both energy and capacity. ERCOT's energy prices reflect the region's diverse fuel mix. The lower capacity prices reflect the fact that there are only four operating nuclear plants in ERCOT. Nuclear plants tend to have higher costs than other types of plants because of the high capital costs associated with them. Moody's asserts that the "forces of supply and demand" determine the value of capacity. Moody's contends that in a surplus situation, capacity has little or no value; when capacity is in short supply, the value is determined by the cost of a new plant. Moody's believes that there will be surplus capacity in every region of the country and that utilities will close plants with higher operating costs if they are not needed to satisfy demand.[50]

Moody's analysis uses a 10-year transition period to competition beginning in 1996. Moody's assumes that companies would be able to fully write-off plant values and deferred assets over the 10 years. Each year that the break-even price for a company is above the regional market price for capacity, the company incurs stranded costs. The losses during the 10-year period are discounted using present value calculations and a 9 percent discount rate.[51]

Moody's estimates that stranded costs in the United States will total about $135 billion with losses concentrated in the northeastern and western United States. Moody's

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[50] *Id.* at 1 - 6.

[51] *Id.* at 1 - 6.

results rest on the current and previously incurred fixed costs associated with production such as purchase power contracts and nuclear power plants. Moody's concludes that the NERC regions with exposure to stranded costs are those whose utilities have high break-even prices for owned and purchased generation, large amounts of deferred assets, and low market prices for capacity. ERCOT is in a good position to incorporate market-based pricing of electricity relative to other NERC regions. Table IV-4 shows Moody's stranded cost estimates for each NERC region.

Table IV-4: Moody's Estimated Stranded Costs in NERC Regions

NERC Region	Estimated Capacity (kW)	Equity ($ millions)	Stranded Costs ($ millions)	Stranded Costs/ Equity
ECAR	92,516,139	$ 22,330	$ 20,164	90 %
ERCOT	42,485,969	11,638	10,307	89
MAAC	52,105,651	19,838	13,303	67
MAIN	47,666,966	12,351	5,984	48
MAPP	19,245,520	4,515	632	14
NPCC	57,242,833	18,124	29,544	163
SERC	100,183,491	26,066	11,261	43
SPP	50,124,441	12,159	14,384	118
WSCC	79,224,938	26,501	28,863	109
TOT/AVG	540,795,948	153,522	134,442	88

Source: *Stranded Costs Will Threaten Credit Quality of US Electrics*, Moody's Investors Services, Special Comment at 10 - 18 (August 1995).

Moody's estimates stranded costs for Texas to total about $12 billion. Table IV-5 summarizes the results of Moody's stranded cost study of Texas IOUs. TUEC has the highest estimated stranded costs, about $5 billion. TNP has the highest break-even price ($136/kW) and the highest stranded cost relative to equity (337 percent) of all the Texas utilities included in the study. SWEPCO has the lowest break-even price, and has the second lowest estimated stranded cost. WTU is in the best position; it faces no stranded costs, and has a break-even price that is lower than the calculated ERCOT market price for capacity.

Moody's indicates that the $135 billion estimate for stranded costs is probably understated because current fixed payments made under long-term fuel contracts were not included in the calculations. In addition, the estimated average market price for

Table IV-5: Moody's Estimated Stranded Costs for Texas IOUs

Company	Break-Even ($/kW)	Estimated Capacity (kW)	Equity ($ millions)	Stranded Costs ($ millions)	Stranded Costs/ Equity
CPL	$ 67	4,206,869	$ 1,424	$ 999	70 %
EPE	109	1,043,559	(239)	497	N/A
GSU	94	2,760,673	851	1,320	155
HL&P	71	14,279,796	3,705	3,737	101
SWEPCO	22	1,532,076	220	21	9
SPS	26	2,210,248	377	88	23
TNP	136	1,065,667	214	722	337
TUEC	65	21,568,573	6,029	4,849	80
WTU	25	1,365,064	266	0	0
TOT/AVG		50,032,525	12,847	12,233	95

Note: The break-even price includes an adjustment for deferred assets. Texas jurisdiction of capacity, equity, and stranded costs calculated by Commission Staff based on a generation demand allocator of 67 percent for EPE, 44 percent for GSU, 54 percent for SPS, and 34 percent for SWEPCO.

Source: *Stranded Costs Will Threaten Credit Quality of US Electrics*, Moody's Investors Services, Special Comment at 10 - 18 (August 1995).

capacity may be higher than what could actually result because there is currently excess generation capacity. Finally, the utilities may be forced to write-off plant values and deferred assets immediately. According to the study, if regulators do not allow incremental write-off over the full 10-year period, stranded costs will increase due to the time value of money.[52]

B. STANDARD & POOR'S ESTIMATED LOST REVENUES

S&P published an administrative study estimating lost revenues for US utilities in November 1995. S&P used a top-down approach to measure the annual revenues that electric utilities would lose if retail markets were opened to direct access. Under direct access, wholesale and retail customers would be able to choose their power generator, and electricity prices would be determined by the market.

[52] *Id.* at 1-6.

Table IV-6: S&P Estimated Production Costs for Texas IOUs (cents/kWh)

Utility	Generation Costs				Purchased-Power Costs	Total Generation & Purchased Power Costs
	Residential	Commercial	Industrial	Total		
CPL	6.94	7.10	3.55	5.55	1.78	5.14
EPE	9.18	8.09	4.89	6.37	2.66	5.79
GSU	7.25	6.43	3.95	5.26	2.84	4.81
HL&P	6.97	5.72	3.27	4.85	4.30	4.88
SWEPCO	5.14	4.15	3.14	3.42	.70	3.17
SPS	4.68	4.19	2.75	3.13	1.76	3.12
TUEC	6.38	5.33	3.41	5.15	4.33	5.13
TNP	10.78	10.15	5.54	8.45	4.31	5.55
WTU	5.32	3.98	2.93	3.47	1.76	3.40

Source: Bilardello, John, and Michael Cole, Standard & Poor's, Utilities and Perspectives, Special Edition, *Direct Access Threatens Electric Utility Revenues*, Vol. 2, No. 48 at 4 - 5 (November 27, 1995).

S&P derived generation costs by multiplying the total net income contribution from owned generation by the portion of total assets dedicated to generation. Production costs were segmented by customer type based on the relationship between actual residential, commercial, and industrial rates to average rates. Table IV-6 summarizes S&P's estimation of production costs for major Texas IOUs.

S&P based the lost revenues estimate on assumptions about unregulated electricity prices and load factors shown in Table IV-7. A load factor compares average demand to peak demand, and is always shown as a percentage. Industrial customers typically have a high load factor, indicating that they use more electricity relative to their expected peak use than other customers. "Higher load factors tend to reduce average power costs because the investment costs for equipment are spread over more energy consumption."[53] S&P's higher price for residential customers reflects their lower load factor. The prices in Table IV-7 do not include any services associated with transmission and distribution, which S&P estimates to add about 1.5 cents per kWh to

[53] Fink, Donald G., and H. Wayne Beaty, *Standard Handbook for Electrical Engineers*, Eleventh Edition, New York, NY: McGraw-Hill Book Company at 12 - 17 (1978).

rates for all customer segments. The prices used in the model are for illustrative purposes only. S&P was not trying to predict market prices.[54]

Table IV-7: S&P's Lost Revenue Assumptions

Customer Class	cents/kWh	Load Factor
Industrial Rate	2.50	80 %
Commercial Rate	3.75	60
Residential Rate	5.00	40

Source: Bilardello, John and Michael Cole, Standard & Poor's Utility Perspectives, Special Edition, *Direct Access Threatens Electric Utility Revenues* at 3 (November 27, 1995).

The difference between the assumed market rates for generation and each utility's production costs was multiplied by the three-year average sales volume for each utility to arrive at an estimate of potential lost revenues. The S&P study calculated lost revenues for two scenarios: a Reasonable Case and a Severe Case. The Reasonable Case Scenario assumes that competition will not occur in residential markets for several years, and contains estimates of potential lost revenues from the commercial and industrial sectors only. The Reasonable Case also assumes recovery of 50 percent of lost revenues. The Severe Case Scenario estimates potential lost revenues occurring if all three customer segments were opened to competition at the same time. This study determined that lost revenues would range from $10 billion to $26 billion per year for the entire country. The result translates into 6 to 16 percent of annual utility revenues. S&P identifies utilities with high generation costs and a heavy industrial customer base to be most at risk.

S&P estimates that Texas utilities could lose $700 million to $2 billion in revenues because of competition. Table IV-8 shows S&P's result for Texas' nine major IOUs. Under the Reasonable Case Scenario, TUEC could lose $266 million in revenues, suffering the most from competition in commercial and industrial customer classes. WTU could be much better off, losing only $3 million. A comparison of lost revenues to total revenues shows that GSU and TNP tie for the worst position, with 8.2 percent of total revenues lost to competition.

[54] Bilardello, John, and Michael Cole, *Direct Access Threatens Electric Utility Revenues*, Standard & Poor's at 1 - 8 (November 27, 1995)

Table IV-8: S&P Lost Revenues for Texas IOUs

Utility	Severe Case: Total Lost Revenues ($ millions)	Severe Case: Total Lost Revenue as Percent of Total Revenues	Reasonable Case: Total Lost Revenues ($ millions)	Reasonable Case: Total Lost Revenue as Percent of Total Revenues
CPL	242.51	20.8	83.04	7.1
EPE	85.74	23.4	26.38	7.2
GSU	174.61	23.0	62.14	8.2
HL&P	761.87	19.6	226.91	5.8
SWEPCO	5.29	2.0	4.45	1.6
SPS	10.32	2.4	7.59	1.8
TUEC	894.11	16.9	266.13	5.0
TNP	117.11	25.7	37.44	8.2
WTU	8.85	2.7	3.01	0.9
TOTAL	2,300.41		717.09	

Note: Total lost revenues include purchased power. Texas jurisdiction of potential lost revenues calculated by Commission Staff based on a generation demand allocator of 67 percent for EPE, 44 percent for GSU, 54 percent for SPS, and 34 percent for SWEPCO.

Source: Bilardello, John, and Michael Cole, *Direct Access Threatens Electric Utility Revenues* at 6 - 7 (November 27, 1995).

S&P also estimated lost revenues by customer segment. Table IV-9 shows the figures for Texas IOUs. The largest estimated loss is by TUEC in the residential sector, close to $350 million. In contrast, S&P estimates that SPS will have a negative loss, or a gain of $4.4 million from its residential customers.

C. DRI/McGraw-Hill Stranded Costs

DRI published its *Electricity Outlook for Spring-Summer 1996* incorporating an estimation of stranded investments.[55] DRI uses a top-down approach with very general assumptions in its methodology.

DRI assumes that electricity prices would decline between the years 1995 and 2020 due to declining coal prices and improvements in generating plant heat rates. DRI also expects increased competition to lead to decreases in industry reserve margins, peak

[55] Yanchar, Joyce, and Michael Mendelsohn, *Electricity Outlook*, DRI/McGraw-Hill World Energy Service U.S. Outlook, (Spring-Summer 1996).

Table IV-9: S&P Lost Revenues from Generation for Major Texas IOUs by Customer Segment ($ millions)

Utility	Residential	Commercial	Industrial	Total
CPL	$ 96.08	$ 126.68	$ 58.29	$ 281.04
EPE	34.57	40.61	13.14	88.32
GSU	56.93	54.84	75.38	187.14
HL&P	272.59	211.24	190.43	674.27
SWEPCO	1.76	3.99	11.98	17.73
SPS	(4.40)	6.09	9.90	11.58
TUEC	347.16	325.42	171.28	843.87
TNP	35.06	29.90	23.46	88.42
WTU	4.34	2.44	5.02	11.80
TOTAL	386.56	801.21	558.88	2,204.17

Note: Total does not include purchased power. Texas jurisdiction of potential lost revenues calculated by Commission Staff based on a generation demand allocator of 67 percent for EPE, 44 percent for GSU, 54 percent for SPS, and 34 percent for SWEPCO.

Source: Bilardello, John, and Michael Cole, *Direct Access Threatens Electric Utility Revenues* at 6 - 7 (November 27, 1995).

demands, administrative and operating costs, and write-offs of uneconomic assets. The DRI model anticipates that all states will allow utilities to recover 80 percent of their stranded costs. DRI based its stranded cost on the difference between the region's industrial electricity price (less transmission and distribution costs) and the long-run marginal generation cost in the base-load generation, multiplied by the volume of electricity demand expected to be at risk in the region. The long-run marginal cost is the weighted average of the levelized costs associated with new coal or gas generation units. The price of natural gas or coal and the technology available in each region accounts for the variation in costs between regions. Average electricity prices are assumed to be 5 to 6 cents per kWh above long-run marginal costs in the highest-price regions, and 2 to 4 cents per kWh above the long-run marginal costs in most other regions. Table IV-10 shows DRI's forecast for long-run marginal costs and average electricity prices for the West South Central Region that consists of Texas, Oklahoma, Louisiana, and Arkansas.[56]

[56] Yanchar *supra* at 49-51.

Table IV-10: DRI Generating Costs and Price of Electricity for the West South Central Region of the United States

	Long-Run Marginal Cost (cents/kWh)			Average Electricity Price
Year	Base	Peak	Average	(cents/kWh)
1995	4.9	9.3	5.6	6.0
2005	6.4	11.3	7.1	7.1
2020	10.7	18.1	11.8	11.3

Source: Yancher, Joyce and Michael Mendlesohn, *Electricity Outlook,* DRI/McGraw-Hill World Energy Service U.S. Outlook (Spring-Summer 1996).

DRI estimates that stranded costs for the United States will total about $87 billion. The model assumes functional but not structural unbundling of generation from transmission and distribution activities.[57] The results from the Reference Case analysis are shown in Table IV-11. DRI's calculation was performed on a regional level and its results do not indicate which individual utilities would have stranded costs. The results indicate that the coastal regions of New England and Pacific II (California and Hawaii) are at risk for more than one-third of their rate base. The study indicates that the West South Central region, which includes Texas, will have no stranded costs.

D. FITCH REPORT

The Fitch Report is a top-down administrative study that measures companies' fixed and variable costs. While this study does not estimate stranded investment, it provides insight into the relative cost positions of IOUs in the United States. The authors chose to use FERC data because reporting is conducted at the individual operating utility level, has a high degree of compliance,[58] and cost information could be identified by cost elements and business sectors.

[57] DRI/McGraw-Hill, *The Future of the Electric Power Industry Around the World, Volume IV, North America* at 20.

[58] Only three utilities did not file in 1995: Central Hudson Gas & Electric Corp., Consolidated Edison Co. of New York, Inc., and San Diego Gas & Electric Co. The utilities argued that filing would expose competitive data, placing them at a disadvantage in the marketplace.

Table IV-11: DRI Estimated Stranded Costs

Region	Stranded Costs ($ billions)	Present Value of Stranded Costs ($ billions)	Present Value as Share of Current Rate Base (%)
New England	$16.6	$12.7	59 %
Middle Atlantic	21.5	16.5	13
South Atlantic	12.2	9.3	13
East North Central	0.0	0.0	0
West North Central	2.7	2.0	0
East South Central	7.5	5.8	36
West South Central	0.0	0.0	0
Mountain 1	0.0	0.0	0
Mountain 2	3.4	2.6	18
Pacific 1	0.0	0.0	0
Pacific 2	24.0	18.4	54
U.S.	87.9	67.3	17

Note: DRI's present value calculation assumes assets are stranded in equal portions between 1997 and 2002.

Source: Yancher, Joyce and Michael Mendlesohn, *Electricity Outlook*, DRI/McGraw-Hill World Energy Service U.S. Outlook (Spring-Summer 1996).

Fitch used an embedded cost model because of the belief that investment in fixed assets valued at historical cost drives the electric utilities' existing cost structures.[59] The model estimates a utility's current fixed and variable costs associated with power supply, transmission and distribution functions. Fitch's model estimates a company's underlying cost structure; it is not a detailed utility-specific cost study. Fitch uses the following simplifying assumptions:

1. Utility plant assets are valued at historical cost less depreciation;
2. Return of capital and return on capital invested in utility plant are based on embedded costs;
3. Each utility is entitled to earn a return on all net electric plant equal to the return authorized in the utility's last electric rate case; and
4. Recovery of regulatory assets and deferred assets are not included as a cost.[60]

[59] Lapson, Ellen, and Edward J. King, *Electric Utility Competitive Operating Statistics*, Fitch Research at 2 (October 30, 1995).

[60] *Id.* at 3.

Table IV-12: Fitch Estimated Embedded Cost of Electric Service for NERC Regions (cents/kWh)

NERC Region	Power Supply	Transmission	Distribution	General and Administrative	Total Embedded Cost
ECAR	3.74	0.30	0.90	0.54	5.48
ERCOT	4.41	0.32	1.02	0.66	6.42
MAAC	4.92	0.38	1.54	0.84	7.68
MAIN	3.56	0.24	1.08	0.60	5.49
MAPP	3.19	0.48	1.01	0.57	5.25
NPCC	5.56	0.52	1.89	0.88	8.79
SERC	3.87	0.30	1.12	0.71	6.53
SPP	3.52	0.32	0.92	0.57	5.32
WSCC	4.04	0.46	1.21	0.73	6.44

Note: Estimate is for year ended 12/31/95.

Source: Lapson, Ellen, and Edward J. King, *Electric Utility Competitive Operating Statistics,* Fitch Investors Service, LP, Special Report at 10 - 13 (October 30, 1995).

Fitch's results indicate that power supply costs make up the majority of the utilities' embedded costs, followed by distribution, then general and administrative costs, with transmission costs being the smallest part. Table IV-12 shows that ERCOT's embedded costs are about average when compared to the other NERC regions. General and administrative costs for ERCOT are lower than in other regions but power supply and transmission costs are slightly above average. Table IV-13 contains Fitch's embedded cost results for Texas IOUs. At 8.09 cents per kWh, TNP has the highest total embedded cost, while SPS enjoys the lowest at 4.07 cents per kWh.

E. Comparison of Texas Results in National Studies

The studies discussed in the previous sections used different approaches to arrive at an estimate of the effect of competition. To the extent that these studies are all measuring the end result of a transition to a competitive electric generation market, a broad comparison of the final numbers can be made. Because of the very different assumptions and methodologies used in each study, a more detailed comparison is not appropriate. Further caution is necessary when comparing the results from the studies because Moody's estimates are stated in terms of net present value, while S&P's and DRI's estimates are stated in terms of nominal values.

Table IV-13: Fitch Estimated Embedded Cost of Electric Services for Major Texas IOUs (cents/kWh)

Utility	Power Supply	Transmission	Distribution	General and Administrative	Total Embedded Cost
CPL	4.37	0.33	0.85	0.70	6.25
EPE	5.28	0.47	0.72	1.01	7.48
GSU	4.06	0.29	0.60	0.87	5.82
HL&P	4.01	0.19	0.90	0.85	5.95
SWEPCO	2.76	0.28	0.71	0.39	4.13
SPS	2.90	0.32	0.51	0.35	4.07
TUEC	4.96	0.24	0.92	0.43	6.55
TNP	5.54	0.43	1.46	0.65	8.09
WTU	3.17	0.43	0.99	0.67	5.26

Note: Estimate is for year ended 1995.

Source: Lapson, Ellen, and Edward J. King, *Electric Utility Competitive Operating Statistics*, Fitch Investors Service, LP, Special Report at 10 - 13 (October 30, 1995).

Table IV-14 summarizes the estimates from Moody's, S&P, and DRI studies. These very different estimates of the effects of competition illustrate the level of uncertainty that *ex ante* administrative studies are attempting to quantify. The large variance of the results also points to the potential error involved in this type of analysis.

Table IV-14: Estimated Effects of Competition on Texas, ERCOT and United States ($ millions)

Study	ERCOT	Texas	U.S.
Moody's Stranded Costs Estimate	$ 10,307	$ 12,233	$ 134,442
S&P's Lost Revenue Estimate (Reasonable Case Scenario)	616	717	10,000
DRI's Stranded Costs Estimate (Reference Case Scenario)	Not Available	Not Available	87,800

Note: DRI estimates $0 stranded costs for the West South Central Region, which includes Texas, Oklahoma, Louisiana, and Arkansas. The West South Central Region is the smallest regional breakdown that includes Texas provided in DRI's study.

Despite the large variance in the absolute losses estimated by the administrative studies, the *relative* positions of Texas utilities are fairly constant: Texas' higher cost utilities will probably have the highest amounts of potentially strandable assets. Table IV-15 displays the relative ranking of each Texas IOU; a ranking of 1 indicates least losses/least cost and a ranking of 9 indicates the most losses/highest cost. The rankings were determined by normalizing Moody's and S&P's results in order to compare them with Fitch's embedded cost of service estimates. Normalization was achieved by dividing the study results by 1995 sales as reported to the Commission.

The uniformity of the normalized results between Moody's, S&P and Fitch studies may serve as a general indicator of which Texas utilities may have the largest quantities of potentially strandable investment. The fifth column in Table IV-15 lists the utilities' reported 1995 sales in the state of Texas and indicates that utility size does not appear to be a determinant for relative success in a competitive market. EPE, GSU, TNP and TUEC share the 7, 8, and 9 ranking, indicating that they may have higher relative strandable investment than the other Texas utilities. The rankings for EPE, GSU and TUEC reflect large investments in nuclear plants. The high costs of a fluidized-bed generation plant may be the primary cause of TNP's low rank.

WTU, SWEPCO, and SPS consistently rank 1, 2, or 3, indicating that these three utilities could have an easier transition to a market pricing environment. This situation is probably due to the fact that SPS, SWEPCO, and WTU generate electricity by burning coal and natural gas only; they have no nuclear capital or decommissioning costs. Section C of Chapter VII contains additional information about each utility.

Table IV-15: Relative Position of Texas IOUs

Utility	Moody's Stranded Investment	S&P Lost Revenue (Reasonable Case)	Fitch Embedded Cost of Service	1995 Sales (MWh)
CPL	4	6	6	19,592,050
EPE	8	8	8	4,348,559
GSU	7	7	4	13,679,884
HL&P	6	5	5	60,384,443
SPS	3	3	1	13,786,346
SWEPCO	2	1	2	9,805,580
TNP	9	9	9	5,082,191
TUEC	5	4	7	89,062,760
WTU	1	2	3	6,400,437

Note: 1995 sales are as reported for the Texas jurisdiction only.

Source: Office of Regulatory Affairs, *1996 Statewide Electrical Energy Plan for Texas*, Austin, Texas: Public Utility Commission of Texas (June 1996).

F. MASSACHUSETTS STUDY

Resource Insight, Inc. (RII), published the results of a study prepared for the Massachusetts Attorney General that estimated potentially strandable investment for five major Massachusetts utilities in April 1996. The five utilities studied were: Boston Edison (BECo); Cambridge Electric; Commonwealth Electric (ComElectric); the portion of New England Electric System's (NEES) attributable to Massachusetts; and Western Massachusetts Electric Company (WMECo). This study is a bottom-up analysis that attempts to quantify the sale price of individual utility assets. The stated objective of the study is to "estimate the price that would be paid by the high bidder for each generation asset in a competitive market."[61]

RII defines stranded investment as the difference between net plant and the present value of future operating profits, as of January 1, 1998. RII used data from the utilities' 1994 FERC Form 1 to estimate net plant. Operating profits were calculated as the present value of the market value of energy and capacity, less annual expenditures for fuel, operations and maintenance expenses, and nuclear capital additions (including taxes). The *New England Power Pool's 1995 Capacity, Energy, Load and Transmission Report*, which predicts a capacity deficiency by the year 2003, was used to develop forecasts of market prices of capacity and energy.[62] Because the Massachusetts study was based on the analysis of individual generating plants, RII made many assumptions regarding plant operations. The assumptions are necessary because the utilities in the study do not maintain plant level data of the type necessary for a bottom-up stranded investment study. Table IV-16 summarizes the assumptions RII used in its base case scenario.

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[61] Chernick, Paul, Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster, ***Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities,*** Resource Insight, Inc. at 1 - 12 (April 17, 1996).

[62] Chernick, ***supra*** at 6.

Table IV-16: The Massachusetts Study, Base-Case Assumptions & Inputs

Global Assumptions	
General and Administrative Expenses	Non-fuel operations and maintenance expenses adjusted upwards by 20 percent
Discount Rate	10 percent - similar to utility embedded and marginal costs of capital
Bidders' Beliefs that Underlie their Behavior	• Plant performance and costs can continue at historical levels as they did under incumbent management • Market values of capacity and energy will bear the same relationship to the plants' operating costs as described above • Bidders can finance the plants at costs similar to utility costs of capital
Nuclear Inputs	
Capacity Factors	65 to 85 percent
Capital Additions	Set at average of recent costs for each unit and continued at that rate through the plants' scheduled operating life
Non-fuel Operations and Maintenance Expenses	Increase annually at 1 percent in real terms
Nuclear Fuel Costs	Held constant at 6 mills/kWh in 1996 dollars
Operating Life	Operate until the end of its license
Non-Nuclear Inputs	
Fossil Fuel Prices	• Interruptible gas will reach $2.98/MMBtu and #2 oil will reach $4.60/MMBtu by 2003 (in 1996 dollars) • For dual-fuel plants, assumed average fuel price would be 90 percent of the price of residual oil
Capital Additions	Not considered significant for non-nuclear plants, therefore assumed to be zero
Operating Life	• 18 years for fossil units • 38 years for hydroelectric units
Peaking Capacity	Fossil peakers are treated as having no fuel costs and no energy benefits
Capacity Factor	• 50 percent for oil and dual-fuel steam plants, except Canal 1 (60 percent) and West Springfield 3 (20 percent) • 80 percent for coal plants • 50 percent for firm gas plants • 40 percent for NEES and 60 percent for WMECo conventional hydroelectric plants • 8 percent for pumped-storage hydroelectric
Market Prices	
Capacity	Trending upwards from $10.56 in 1996 to $51.75/kW in 2003.
Energy	Trending upwards starting from $25/MWh in 1995 to $42.75/MWh (the cost of a new gas combined-cycle plant) in 2003.

Source: Chernick, Paul, et al., *Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities*, Resource Insight, Inc. (April 17, 1996).

Under the base case scenario, all the generation assets studied produced positive present values of operating profits except Millstone 1 & 2 and Pilgrim.[63] The two plants were considered uneconomical to operate, and RII stated that they should be retired regardless of whether the electric industry is restructured. In the base case, the two plants have no value to any potential bidder. For the remaining plants, the present value of the operating profit represented the market value of the utility's plant investment.

The RII study predicted stranded investment for the Millstone 3 unit and the shares of the Seabrook nuclear plant owned by Cambridge and ComElectric. The study predicted that the Maine and Vermont Yankee nuclear plants, NEES's share of Seabrook and each utility's groups of fossil steam plants, combustion turbines and hydroelectric plant would produce a restructuring gain.[64] RII expects net profit from selling generation at market prices to be $250 to $500 million for each Massachusetts utility, except NEES, which will be about $2.7 billion. According to RII, NEES's restructuring gain is higher because it owns more generation assets, will receive a small net gain from its nuclear assets, and has large hydroelectric resources which are very valuable.[65]

To test the robustness of the study, RII ran four alternative scenarios: improved nuclear performance; increased discount rate; lower fuel prices; and extremely low market price. The results from the base case scenario were maintained for all of the alternative scenarios except the extremely low market price. Under the extremely low market price scenario the long-term market price for electricity is approximately $32/MWh.

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[63] The Millstone plant consists of three units located in New London County, Connecticut. Millstone is owned by the Northeast Nuclear Energy Company. Millstone 1 began operation in 1970 and has a nameplate capacity of 661.5 mw. Millstone 2 began operation in 1975 and has a nameplate capacity of 909.9 mw. Millstone 3 began operation in 1986 and has a nameplate capacity of 1,253.1 mw. Pilgrim is a Boston Edison Company nuclear power plant located in Plymouth County Massachusetts. Pilgrim began operation in 1972 and has a nameplate capacity of 678 mw.

[64] More recently, Northeast Utilities (NU) announced the closure of its Connecticut Yankee nuclear power station. The president of NU's nuclear division stated, "It's all about economics . . . We looked at the value of the plant to our customers over its remaining lifetime and concluded that the right economic choice was to leave the unit shut down." Reukin, Andrew C., "Connecticut Reactor to Close, A Victim of Economic Change," *New York Times*, at 18 (December 5, 1996).

[65] Chernick, *supra* at 12.

With such a price, which RII claims is very unlikely, most of New England's nuclear generation would be retired, as well as many older fossil fuel plants.[66]

RII acknowledges that its results are "strikingly different" from those filed by the major Massachusetts electric utilities in February 1996. The utilities all attested that their generation assets would have zero market value in a restructured industry, and requested stranded investment charges to fully recover the net plant investment. RII states that "large levels of stranded investment are the result of poor plant performance or low market prices, either of which would also result in retirement of large amounts of capacity, regardless of industry structure."[67] RII concludes that the market valuation of most utilities' generation assets will exceed their net investment, resulting in large restructuring gains. RII also states that divestiture appears to be the most promising method for determining potentially stranded investment.

[66] *Id.* at 17.

[67] *Id.* at 2.

V. Financial Considerations

Each utility has a unique debt and equity structure that may influence its response to changing market and regulatory conditions. This chapter provides an overview of some of the complications associated with potentially strandable investment that are related to utility financial structure. Section A discusses changes that have already been observed in utility stock prices. Section B explains some of the complications associated with utility bonds. Section C describes some of the standard financial reporting requirements that utilities must follow. Section D illustrates the difficulties of evaluating the impact of industry restructuring on federal income taxes. Section E explores local tax repercussions associated with utility asset sales.

A. Utility Stocks

Historically, investors coveted the stocks of vertically integrated utilities because monopoly status and regulation practically guaranteed comfortable rates of return. Through competition and deregulation, utility stocks will lose their previous status as "quasi fixed-income" securities because they will have the potential for additional growth and the risk of declining sales.[68] Investors are aware of the risks inherent in the purchase of other types of industrial stocks, and will become more sophisticated regarding the new risks connected to utility stocks. Table V-1 shows year-end stock prices for Texas IOUs and holding companies with utilities operating in Texas. Between 1986 and 1995, the stock prices of these Texas companies have been flat relative to the Dow Jones Industrial Average. As deregulation progresses, however, investors will adjust their expectations and stock prices will move accordingly. The effects of market-based pricing on utility stocks depend on the market position of the utility. If a utility is in a strong position relative to other utilities in the market, and has low operating costs, then its stock price may not be harmed by a single event, since there are many factors that influence a utility's stock price. If, however, the utility is in

[68] Rose, Kenneth, *An Economic and Legal Perspective on Electric Utility Transition Costs*, Columbus, Ohio: National Regulatory Research Institute at 80 (July 1996).

a weak position relative to others in the market and has high operating costs, its higher-risk profile will be reflected in a lower stock price.

Table V-1: Year End Stock Prices for Texas IOUs

Utility	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
CSW	17.13	14.75	16.00	20.06	22.00	27.00	29.13	30.25	22.63	27.88
EPE	18.75	14.13	14.63	8.50	4.00	3.50	2.38	2.69	0.81	0.38
GSU	7.38	4.75	7.88	11.88	11.00	10.25	16.25	*	*	*
HI	17.13	15.00	14.00	17.50	18.38	22.13	22.94	23.82	17.82	24.25
SPS	31.00	23.63	26.38	30.50	28.50	31.38	32.63	30.50	26.75	30.00
TNP	22.12	18.50	19.63	21.25	19.63	19.25	19.00	16.50	14.88	18.75
TU	31.50	27.00	28.13	35.13	36.63	41.75	42.50	43.25	32.00	41.00
Dow Jones Industrial Avg.	1,896	1,939	2,169	2,753	2,634	3,169	3,301	3,754	3,834	5,117

Note: Central and South West Corporation (CSW) is the parent company of SWEPCO, CPL, and WTU. Stock prices for CSW from 1986 to 1990 have been restated to reflect stock splits. Houston Industries, Inc. (HI) is the parent company of HL&P. Texas-New Mexico Enterprises, Inc. is the parent company of TNP. Texas Utilities, Inc. (TU) is the parent company of TUEC. GSU became a subsidiary of Entergy in 1993.

Sources: Office of Regulatory Affairs, *Texas Electric Utility Company Profiles Reports* (1987-1995). Moody's Handbook of Common Stocks, Winter (1995-1996).

B. UTILITY BONDS

Bonds are an "IOU" between the utility and the bondholder that convey no corporate ownership privileges. Unlike utility stocks, electric utility bonds are true fixed-income securities that have historically been considered very safe investments. Secured bonds are "backed by collateral which may be sold by the bondholder to satisfy a claim if the bond's issuer fails to pay interest and principal when they are due."[69] Utilities often use secured bonds to finance construction and other projects. An indenture is a type of contract through which secured bonds can be issued.

Indentures are complex contracts governed by The Trust Indenture Act.[70] The Trust Indenture Act provides for a trustee, to whom the indenture is made out. The trustee must be free of conflicts of interest and "acts in a fiduciary capacity for investors who

[69] Downes, John and Goodman, Jordan Elliot, *Dictionary of Finance and Investment Terms*, Barron's Financial Guides at 38.

[70] *See* The Trust Indenture Act of 1939, 15 USCA §77aaa *et. seq.*

own a bond issue."[71] Indentures must have, under the Trust Indenture Act, provisions that define the rights and obligations of the lender and the issuer of the bond. In general, indentures contain provisions about the form of the bond, amount of the issue, property pledged, protective covenants, working capital (cash, accounts receivable, inventory, and other current assets), current ratio (current assets divided by current liabilities), and redemption rights or call privileges.[72] If a utility undertakes a sale or transfer of a bonded generation asset, the utility must not violate the covenants of its indentures. Individual covenants vary, but utility management must have approval from the bond trustee before undertaking any actions that may put the bondholders' investment at risk. Texas utilities have expressed concern that asset sales or transfers could result in violations of debt covenants.[73]

In March 1996, Moody's Investors Service published a report discussing the effects of electric utility disaggregation on bondholder security.[74] Moody's report examines options a utility may exercise if it decides to disaggregate its generation assets. Some utilities may be able to raise enough money through asset sales to retire secured bonds under indenture. A possible solution for a utility with insufficient cash to retire bonds under indenture is to reorganize its debt structure, with the cooperation of the trustee. Debt restructuring or repayment may not be a practical solution for most utilities and could result in substantial transaction costs.[75]

Another possible solution is to substitute or swap bonded property with unbonded property. If a utility successfully completes a property swap, it would not have to relinquish its low-cost debt. There are two possible complications associated with property swaps. The first complication is that the utility's unbonded property, which

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[71] Fabozzi, Frank J. and Irving M. Pollack, *The Handbook of Fixed Income Securities*, Second Edition, Dow Jones-Irwin, Homewood, IL at 230 (1987).

[72] Downes, *supra* at 178.

[73] Central and South West Corporation *supra*, at 3. Southwestern Public Service Company *supra*, at 4. Texas Utilities Electric Company, *supra* at 8.

[74] Abbot, Susan, D., *Legal Disaggregation Threatens Bondholder Security*, Moody's Investment Service, Special Comment (March 1996).

[75] El Paso Electric Company, *supra* at 3.

tends to consist of transmission and distribution assets, may not be of comparable value to the bonded generation assets, proving to be a meager substitute.[76] The second complication is that the quality of the revenue stream of unbonded transmission and distribution property may be lower than that of generation facilities and would decrease bondholders' security. The foundation of bondholders' security is the value of the underlying assets and the utility's ability to make bond payments.

A third option for utilities with insufficient cash to retire secured bonds is to retain the debt with the generation assets. Maintenance of the bonds with generation assets may result in a downgrading of the bonds, reflecting the higher risk associated with generation assets in an unregulated market. At the same time, the bondholder's security could be lowered, and the utility's debt rating downgraded, if the generation assets have a less predictable cash flow.

Table V-2 summarizes the results of Moody's study of secured debt. Moody's analysis shows that EPE is the most inflexible Texas utility with a ratio of 66 percent of gross

Table V-2: Texas IOUs, Ratio of Senior Secured Debt to Gross Plant, 1994

Utility	Senior Secured Debt Outstanding ($ millions)	Gross Plant ($ millions)	Secured Debt/ Gross Plant (%)
CPL	$ 1,761	$ 4,870	36 %
EPE	1,200	1,831	66
GSU	2,369	7,224	33
HL&P	2,607	12,494	21
SWEPCO	411	2,883	14
SPS	477	2,328	20
TUEC	7,221	21,755	33
TNP	686	1,196	57
WTU	210	1,028	20

Source: Abbot, Susan, D., *Legal Disaggregation Threatens Bondholder Security*, Moody's Investment Service, Special Comment at 5 (March 1996).

[76] Moody's indicates that for CPL, EPE, GSU, TUEC, and TNP the amount of total secured debt outstanding exceeds the value of gas and electric non-production assets. Abbot, *supra* at 8.

plant already bonded. SWEPCO has the most flexibility with only 14 percent of gross plant already bonded.

C. FINANCIAL REPORTING IN A CHANGING UTILITY ENVIRONMENT

Corporations use general purpose financial statements to report financial information to investors. In the United States, general purpose financial statements are usually prepared according to Generally Accepted Accounting Principles (GAAP). Companies must comply with GAAP "in order to obtain a 'clean' opinion from independent auditors."[77] The Securities and Exchange Commission (SEC), through authority granted by the U.S. Congress, has the ultimate responsibility for establishing GAAP for companies whose stock is held by the general investing public. An independent private-sector organization, the Financial Accounting Standards Board (FASB), has heavily influenced GAAP over the years. The Federal Power Act (1935) and the Natural Gas Act (1938) give the Federal Energy Regulatory Commission (FERC) jurisdiction over accounting principles and procedures used by electric and gas companies. FERC accounting requirements are set forth in its Uniform System of Accounts (USOA). In general, USOA and GAAP are comparable. Differences that exist are due to the "economic effects of the process of ratemaking, something not present in unregulated firms . . . FERC adopts FASB statements to the extent they do not conflict with sound principles of ratemaking."[78] FASB has issued specific pronouncements, referred to as Statements of Financial Accounting Standards (SFAS), relevant to capturing issues related to regulation. Through SFAS Nos. 71, 101, and 121, electric utilities inform investors of financial conditions specific to regulated industries.[79]

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[77] Debelstein, Carl W., CPA, *Generally Accepted Accounting Principles for Utilities*, NARUC Annual Regulatory Studies Program, Michigan State University, East Lansing, MI at 2 (August 1996).

[78] *Id.* at 5.

[79] Financial Accounting Standards Board, *SFAS No. 71, Accounting for the Effects of Certain Types of Regulation* (December 1982). Financial Accounting Standards Board, *SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71* (December 1988). Financial Accounting Standards Board, *SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of* (March 1995).

The determination to apply SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* is made individually by each company and the standard may be applied to the entire company or to a separable portion of its operations. SFAS No. 71 is applied to the financial statements of an enterprise that has regulated operations that meet all of the following criteria:

> *a. The enterprise's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.*
>
> *b. The regulated rates are designed to recover the specific enterprise's costs of providing the regulated services or products.*
>
> *c. In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs.*[80]

SFAS No. 71 was intended to uniformly capture the effects on a company's balance sheet due to items that non-regulated enterprises would not record:

> *Specifically, FASB noted that a regulator's actions can require a regulated enterprise to capitalize certain costs that [other] enterprises would expense . . . the costs capitalized for regulatory purposes must be capitalized in the regulated enterprise's general-purpose external financial statements. Paragraph 9 [of SFAS No. 71] requires that the enterprise reach a conclusion that it is probable that the specific costs capitalized will be included in future rates and result in revenue at least equal to the amount of the capitalized costs. Costs capitalized pursuant to Paragraph 9 are commonly referred to as 'deferred debits' or 'regulatory assets'.*[81]

There are two additional FASB pronouncements that are specific to regulated enterprises. SFAS No. 90, *Regulated Enterprises - Accounting for Abandonments and Disallowance of Plant Costs* (1986), applies to recorded costs of assets previously abandoned, or which will probably be abandoned in the future, previously disallowed plant costs, and probable future disallowances of plant costs. SFAS No. 92, *Regulated Enterprises - Accounting for Phase-In Plans* (1987), allows for capitalization for financial reporting purposes of deferred costs associated with recently completed plants.

[80] Financial Accounting Standards Bosard, *Statement of Financial Accounting Standards No. 71* at 2 (December 1982).

[81] Coopers & Lybrand L.L.P., *Going Off 71* at 2 (September 1995).

SFAS No. 101, *Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71,* is applied when the operations of an enterprise cease to qualify for treatment under SFAS No. 71. As with SFAS No. 71, the utility can apply SFAS No. 101 to its entire operations or to separable portions. SFAS No. 101 provides the following examples of situations in which SFAS No. 71 no longer applies:

> *a. Deregulation.*
>
> *b. A change in the regulator's approach to setting rates from cost-based rate making to another form of regulation.*
>
> *c. Increasing competition that limits the enterprise's ability to sell utility services or products at rates that will recover costs.*
>
> *d. Regulatory actions resulting from resistance to rate increases that limit the enterprise's ability to sell utility services or products at rates that will recover costs if the enterprise is unable to obtain (or chooses not to seek) relief from prior regulatory actions through appeals to the regulator or the courts.*[82]

SFAS No. 121, *Accounting for the Impairment of Long-Lived and for Long-Lived Assets to be Disposed Of,* provides a vehicle for reporting impairment losses. An impairment loss occurs when a company determines that an asset has been impaired and has been written-down to a new carrying amount that is less than the remaining book cost of the asset. Paragraph 5 of SFAS No. 121 lists examples of events or changes in circumstances that indicate that the recoverability of the carrying amount of an asset should be assessed:

> *a. A significant decrease in the market value of an asset.*
>
> *b. A significant change in the extent or manner in which an asset is used or a significant physical change in an asset.*
>
> *c. A significant adverse change in legal factors or in the business climate that could affect the value of an asset or an adverse action or assessment by a regulator.*
>
> *d. An accumulation of costs significantly in excess of the amount originally expected to acquire or construct an asset.*

[82] Financial Accounting Standards Board, *Statement of Financial Accounting Standards No. 101,* at 2 (December 1988).

> *e. A current period operating or cash flow loss combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with an asset used for the purpose of producing revenue.*

SFAS No. 121 amended Paragraph 9 of SFAS No. 71 to require that there be a continuous probability of recovery, or else amounts previously capitalized (deferred debits or regulatory assets) are to be charged to earnings. SFAS No. 121 also amended Paragraph 10 of SFAS No. 71 to require write-off of regulatory assets when disallowed by a regulator, but allows reinstatement of previously recorded impairments of regulatory or plant assets if the regulator subsequently allows the costs to be recovered.

FASB is contemplating a new pronouncement, *Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets,* to become effective in 1997. The new statement addresses concerns that traditional financial statement reporting understates decommissioning costs for nuclear plants. Decommissioning is the process undertaken by utilities to protect the public from contamination by radioactive materials and equipment at the nuclear power plant site. The costs for decommissioning are substantial. The original scope of the statement has been expanded to include all major obligations incurred upon the closure or removal of long-lived assets when current operations cease: dismantlement, removal, site reclamation, and decontamination.[83]

It is clear from GAAP standards that both the SEC and FASB recognize that the emergence of competition and increased deregulation have significant implications for the financial reporting standards of public utilities. SFAS Nos. 101 and 121 specifically allow for the accounting treatment of events related to stranded investments. SFAS No. 101 provides for the accounting treatment of assets that are no longer subject to regulation by state or federal agencies. Utilities may be able to use SFAS No. 121 for reporting changes in asset value due to deregulation. The new statement addressing decommissioning concerns will further increase the ability of both utilities and investors to gauge the impact of industry changes on their investments.

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[83] Debelstein, *supra* at 27.

D. FEDERAL INCOME TAXES

There are many different ways that the restructuring of the United States electric industry can take place. Examples include functional unbundling, spin-offs, and mergers. Each variation in how the transition to competitive markets could occur has implications for the treatment of the federal income tax liabilities of the utility and its shareholders; however, the Internal Revenue Code (IRC) has not yet been changed to address tax issues related to industry restructuring and stranded investment. While each utility's restructuring should be analyzed independently, there are several generic issues that can be discussed: temporary differences; accumulated deferred income taxes; taxable transactions; and non-taxable transactions.

1. Temporary Differences—Normalization

Temporary differences refer to "revenue and expense items which enter into the determination of [both] taxable income and pretax book income but enter into such determination in different accounting periods."[84] Tax effects are reported for book purposes according to GAAP and USOA, and according to the IRC for federal income tax returns. Depreciation method, depreciation life, and investment tax credits (ITC) are the items that create most of the temporary differences that may have an impact on the magnitude of a utility's strandable investment. Accelerated depreciation and ITCs are mechanisms that encourage capital investments by lowering current tax expenses.

Normalization "is the recognition of the tax effects of certain transactions in the same period the related transactions are recognized *rather than* when the tax effects are reported on the tax return. . . when normalization is used in a ratemaking context, the tax effects of income and expenses are reflected in rates *at the same time* the related income and expenses are included in rates."[85] Normalization also equalizes the tax burden between current and future ratepayers. Without normalization, current

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[84] Keglevic, Paul, *Introduction to Accounting for Utility Income Taxes*, Arthur Andersen at IG UIT-5 (March 1996).

[85] Electric Division Accounting Section, *An Overview of Federal Income Taxes*, The Public Utility Commission of Texas, Austin, Texas at 15 (February 1993). Emphasis added. IRC provisions require that these differences be normalized if a utility is to enjoy the benefits of accelerated depreciation and ITC.

ratepayers would benefit (at the expense of future ratepayers) from the lower current tax expense the utility enjoys in the early years of a plant's life because of accelerated depreciation and investment tax credits. For these reasons, most utilities normalize for all or a majority of timing differences.

Under IRC rules, normalization applies only to regulated utilities, or regulated segments of a utility's operations. If the generation assets of an integrated utility become deregulated, they would be excluded from the calculation of cost of service for ratemaking. As a result, the tax benefits of the generation asset could no longer be used to reduce the tax expense component of the cost of service for the transmission and distribution operations.[86]

2. Accumulated Deferred Federal Income Taxes

Utilities use the accumulated deferred federal income tax account (ADFIT) to report the tax benefits associated with accelerated depreciation and investment tax credits to shareholders, until the benefits are flowed-through to customers in the form of reduced rates. The IRC has provisions that control the amortization of ADFIT and the rate at which it can be reflected in rates. ADFIT is a non-cash credit balance payable in the future to the United States government. Over time, the dollar amount is amortized until it reaches zero, when plant life is fully depreciated for financial reporting and ratemaking purposes.

However, if the assets are passed from one regulated entity to another, it may be possible for the deferred tax benefits to be transferred intact to the new entity. This type of transfer is likely only if the form of the transfer is a non-taxable event such as a tax-free disaggregation or incorporation.[87]

[86] Deloitte & Touche L.L.P., *Federal, State and Local Tax Implications of Electric Utility Industry Restructuring*, The National Council on Competition and the Electric Industry at 31 (October 1996).

[87] Warren, James, I., and Timothy S. Wright, *Federal Tax Consequences of Utility Restructuring*, Reid & Priest, L.L.P. at 1 - 7.

3. Taxable Transactions

A utility asset sale through auction or divestiture could lead to events recognized as taxable by the IRS. A utility would report a taxable gain from such sales if the proceeds were higher than the tax basis of the asset. A utility would report a loss for tax purposes if the proceeds from such sales were lower than the tax basis of the asset. The tax basis of the asset is the original cost less tax depreciation. EPE, CSW, and Entergy have expressed concern over the potential size of the taxable gain from profitable asset sales due to the use of accelerated depreciation. HL&P anticipates a 100 percent taxable gain from the sale of generation assets that, due to accelerated depreciation, will be fully depreciated for tax purposes by the end of 1998.[88] However, the calculation of the tax expense due to the sale of an asset is not complete until *all* related tax accounts are included. The following example explains one result:

> *. . . in a sale of assets, the seller recognizes gain or loss for federal income tax purposes. Recognition of gain increases the seller's tax payable to the federal government. Thus, ADFIT related to the assets sold is no longer "deferred" and must be paid to the government. If the tax payable on the sale exceeds the amount of ADFIT recorded for the property, then both the deferred taxes and the additional taxes due must be paid by the company. In the event that the tax payable on the gain is less than the amount of ADFIT recorded for the property, then the excess deferred taxes, in effect, would increase the book gain (or decrease the book loss) on the sale.*[89]

The treatment of spin-downs by the IRS is subject to a very complex set of rules. Unless the transaction follows these rules, the IRS treats the distribution of new shares as a dividend, and shareholders would have to report the entire value of the new shares as taxable income.[90]

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[88] El Paso Electric Company *supra,* at 4; Houston Lighting & Power, *supra* at 4; Central & South West Corporation, *supra* at 7; Entergy, *supra* at 5.

[89] Deloitte & Touche, *supra* at 39.

[90] *Id.* at 38.

4. Non-Taxable Transactions

The deregulation of an asset that does not involve a change in ownership may require a write-off on the utility's balance sheet, but triggers no federal income tax consequence.[91] Similarly, in some circumstances functional unbundling could take the form of a distribution to shareholders but still be considered a non-taxable event by the IRC. Congress created a special provision (Section 355) which can result in a distribution of appreciated stock or securities without tax imposed either on the distributing corporation or to the shareholders. Receipt of Section 355 provision is complicated and involves passing many requirements. The most elemental requirement is that there be a "real and substantial non-tax business purpose underlying the transaction." The qualification of a transaction under Section 355 can only be provided by the receipt of a private letter ruling from the IRS.[92] If, in a spin-down, the corporation does not recognize a gain or loss for federal income tax purposes, it would continue to be liable for the ADFIT associated with the assets.[93]

E. Local Taxes

It is possible that competition in the electricity industry may result in significantly lower revenues for states and local municipalities that depend on utility taxes. Taxes that are based on a percentage of electricity price, such as gross receipts taxes or franchise fees, are particularly vulnerable because market prices should be lower than regulated prices. Electricity price is not the only factor that will change tax revenues. The increase in electricity sales for non-utility, non-regulated businesses could also result in lower tax revenues. Jurisdictions generally tax IOUs (e.g., gross receipts tax) differently than other businesses (e.g., net income). In the event that IOUs lose market share, and non-utility generators gain market share, jurisdictions will suffer with lower tax revenues. When a customer purchases electricity from a utility, the gross receipts tax is applicable to the entire sales price. If, however, the customer switches to a non-utility generator

[91] Houston Lighting & Power, *supra* at 3.

[92] Warren, *supra* at 5.

[93] Deloitte & Touche, *supra* at 39.

for supply, the gross receipts tax would be applied only to the transmission portion of the price.[94] Another possible revenue loser for local jurisdictions is property taxes. Currently, Texas IOUs generate in excess of $250 million per year in property taxes.[95] Lower market valuations due to competition and closings of uneconomic plants would have immediate impact on local jurisdictions.

[94] *Id.* at 23.

[95] Staff estimate based on ECOM filings from Texas utilities in Project No. 15001.

VI. THE ECOM ESTIMATION METHODOLOGY

On April 24, 1996, the Commission issued an Order Initiating Investigation in Project No. 15001.[96] The Order required investor-owned electric generating utilities (IOUs), electric generating river authorities, and cooperatively owned electric generating utilities to file a special report (ECOM report) with the Commission and the Office of Public Utility Counsel (OPC). Municipally owned electric generating utilities in Texas were not required to file the report but were encouraged to do so.

Each utility was required to file a completed spreadsheet model, documentation of input data and assumptions used to complete the model, and printed results of the output data from each competitive access scenario. Table VI–1 presents the entities filing reports with the Commission pursuant to the ECOM Order.

Table VI–1: Utilities Filing ECOM Results with the Commission

Number	Investor-Owned Utilities	Municipally Owned Utilities	Cooperatively Owned Utilities	River Authorities
1	Central Power & Light Company (CPL)	City of Austin (COA)	Brazos Electric Power Cooperative (BEPC) (2)	Brazos River Authority (BRA) (1)
2	El Paso Electric Company (EPE)	Public Utility Board - Brownsville (PUBB)	Medina Electric Cooperative (MEC) (1)	Lower Colorado River Authority (LCRA)
3	Gulf States Utilities Company (GSU)	City of Bryan (BRYN)	South Texas Electric Cooperative (STEC) (2)	Sabine River Authority (SRA) (1)
4	Houston Lighting & Power Company (HL&P)	City of Denton (DENT)	San Miguel Electric Cooperative (SMEC) (2)	
5	Southwestern Electric Power Company (SWP)	City of Garland (GARL)	Northeast Texas Electric Cooperative (NTEC) (3)	
6	Southwestern Public Service Company (SPS)	City of Greenville (GNVL)	Sam Rayburn G&T Cooperative (SRG&T) (3)	
7	Texas Utilities Electric Company (TUEC)			
8	Texas-New Mexico Power Company (TNP)			
9	West Texas Utilities Company (WTU)			

Note: (1) MEC, BRA, and SRA filed ECOM reports; however, because each has minimal generating capacity, all of which has been in service in excess of 35 years, ECOM is a non-issue for these entities. (2) Power from the SMEC lignite plant is sold under a wholesale contract to BEPC and STEC. Therefore, ECOM is not estimated for SMEC directly; rather, it is reflected in the ECOM estimates for BEPC and STEC. (3) Data is still being analyzed by Staff as these utilities did not file until September 6, 1996.

[96] *Stranded Cost Report: Estimation of ECOM for Generating Utilities in Texas*, Project No. 15001, Order Initiating Investigation (April 24, 1996). See also *Staff Discussion of the Order: Estimation of ECOM for Generating Utilities in Texas*, Project No. 15001 (April 24, 1996).

A. Objective of the ECOM Model

As noted in Chapter I, ECOM is a measure of the magnitude of a utility's potentially strandable investments. These investments are properly described as "potentially strandable" for two reasons. First, no investment is stranded so long as it is still subject to regulated cost-based rates. Second, stranded investment is a consequence of market prices being lower than regulated cost-based rates, and with no competitive market from which to base a comparison, estimates of competitive market prices must be used to gauge the magnitude of excess costs over market.

The ECOM Model estimates the magnitude of *excess* generation-related cost-of-service revenues relative to the market-based revenues that a utility may experience under various market access, or deregulation, scenarios.[97] This analysis is performed for both the Texas retail and wholesale jurisdictions. All ECOM estimates presented in this report are calculated under varying assumptions regarding (1) the timing of the introduction of competition in Texas, and (2) the market price that may prevail in the competitive market.

The purpose of quantifying the potential effect of deregulation is *not* to provide a conclusive determination or point-estimate of the magnitude of stranded costs to be used in setting utility rates.[98] Rather, the objective is to provide a range of information that will be beneficial to decision makers in the analysis of electric industry restructuring alternatives. The ECOM Model is an administrative method of determining the magnitude of potentially strandable investments. Alternative measurement methods are discussed in Chapter III of this report.

B. Overview of the ECOM Model

The ECOM model is an electronic workbook in Microsoft Excel 5.0 software. The model estimates the after-tax net present value of the change in generation-related

[97] ECOM estimates are calculated on a net present value basis.

[98] In the event retail markets are eventually opened to competition and a method is selected to quantify the financial impact of such competition on utilities, evidentiary hearings would likely be required on a utility-by-utility basis.

revenues that a utility may experience as a result of selling electricity at market-based prices rather than at regulated prices. In the model, ECOM is defined as the present value of the difference between a utility's fixed costs and the contributions to capital of utility sales under competitive conditions (i.e., revenues in excess of ongoing operating costs). The model, as distributed to the utilities, was developed to provide estimates of Texas retail ECOM. However, generation cost and sales data were also collected in the utilities' filings, enabling the Commission Staff to develop estimates of Texas jurisdictional wholesale ECOM.

Texas utilities that own generation plants were required to provide forecasted data on capital and production costs associated with generation resources. In the ECOM Model, reporting utilities allocate these costs by resource type (gas, coal/lignite, nuclear, or other) and by customer class (industrial, commercial, residential on the retail side; and Texas jurisdictional wholesale) for each year for the projected life of the plants. The utilities also provided projections of their sales (in MWh) allocated by resource type and by customer class.[99] Using these utility cost and sales projections, the ECOM Model calculates the regulated price of electricity for each customer class under continued cost of service regulation. Based upon a range of projected competitive market prices developed by Staff (low, base, and high),[100] the model calculates a corresponding range of competitive market-based revenues for each utility by customer class. ECOM is then calculated as the present value of the difference between the regulated and the market-based revenue streams.[101]

As stated previously, ECOM is defined as the present value of the difference between fixed costs and the contributions to fixed costs of utility sales under competitive conditions. Utilities recover a contribution to fixed costs by selling electricity at a

---

[99] All generation cost and sales data were projected and provided by the utilities pursuant to the Order Initiating Investigation in Project No. 15001 for the forecast period of 1996 to 2035. Commission Staff has reviewed the filings for accuracy and general consistency, however Staff has not audited the utility filings nor were the data made available to all interested parties for review because of confidentiality concerns.

[100] A table containing the ECOM Model market prices is contained in Appendix A. The competitive market price of electricity is discussed further in Section B(1) of this chapter.

[101] Some minor modifications to the ECOM Model were performed by Staff subsequent to the filing date of June 24, 1996. See Appendix C for a discussion of these changes.

competitive price that exceeds the variable cost of operation. In the ECOM Model, fixed costs consist of the following:

1. Return on existing generation-related invested capital (net of deferred taxes and other rate base deductions);[102]
2. Depreciation of existing generation assets;
3. Nuclear decommissioning expense;
4. Property tax payments;[103]
5. Existing purchased power contracts; and
6. Generation-related federal income tax (FIT) payments.

Operating costs (or variable costs) in the ECOM Model consist of the following:

1. Return on incremental generation-related investment (net of deferred taxes and other rate base deductions);
2. Depreciation of incremental generation investment;
3. Operations and maintenance expense;
4. Fuel expense;
5. Taxes other than FIT; and
6. Miscellaneous expense.

Combining fixed costs, operating costs and competitive operating revenues, ECOM can be represented by the following equation:

$$\text{ECOM} = \sum pv\{\text{FC} + \text{OC} - \text{R}\}, \text{ where}$$

pv = present value;

FC = Fixed costs in the regulated cost-of-service;

OC = Operating costs;

---

[102] The return and FIT components of the cost-of-service are treated as fixed costs in the ECOM Model. If a different rate of return were specified for ECOM recovery, the return and FIT components would become variable costs. See discussion in Chapter VIII, Section B.3.

[103] Property tax payments are treated as fixed costs in the ECOM Model. In the event the market value of generation is less than current book values, the ECOM portion of the current book value would have to be taxable by the various property taxing districts for this assumption to hold. Data contained in the utilities' ECOM filings indicate that approximately $275 million in property taxes were levied upon investor-owned utility generation assets in 1995. Using the base case *1998Full* scenario as an example, the ECOM portion of the $275 million would be approximately $100 million. Thus, given the assumptions of this example and all other variables held constant, if the ECOM portion were not taxable, property tax receipts from utilities would decrease by approximately $100 million per year on a Statewide basis.

R = Revenues from electricity sales at the market price.; and

Σ = Sum from the first year of retail access through 2035.

As stated previously, the difference between the market price of electricity (R) and a firm's average variable cost of electricity production (OC) is the firm's contribution to capital. When the market price is greater than variable costs, the firm will collect revenues that at least partially offset fixed costs. This revenue offset of fixed costs is reflected in the calculation of ECOM. If projections of variable costs are greater than the expected market revenues over the life of a plant, then the firm will not operate the plant (except perhaps in the very short-run). Once that plant is shut down, no further contribution to capital is received, and ECOM is equal to the fixed costs remaining at the time the plant ceases operation.[104]

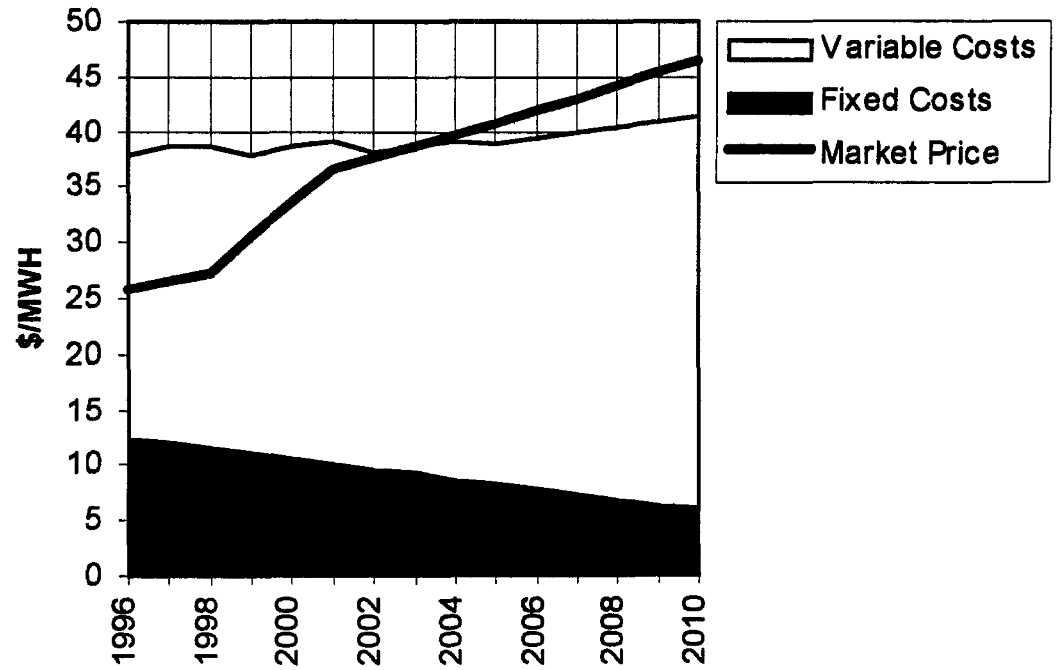

Figure VI–1: Illustration of the ECOM Methodology (1)

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[104] The ECOM Model can be classified as an *ex ante* administrative approach that is a blend of the top-down and bottom-up methods. The ECOM Model does not value assets and liabilities individually (bottom-up) nor is the total generation function valued as an undivided whole (top-down). Rather, the ECOM Model analyzes potentially strandable investment by resource type, and is therefore a blend of the two methods. See Chapter

Figure VI–1 and I–2 illustrate the ECOM Model methodology. In Figure VI–1, the utility generation cost-of-service is represented by the sum of the variable costs and the fixed costs. In the illustration, the utility's generation cost-of-service is greater than the projected market price of electricity for the years 1996 to 2004. From 1996 to 2004, ECOM is equal to the vertically hatched area representing the difference between the market price and the generation cost-of-service. For the years 2005 to 2010, the generation cost-of-service is less than the market price and therefore results in a reduction to ECOM. It is important to note in this example that, even if the positive and negative ECOM areas were of identical size, ECOM would not net to zero as the ECOM that results in the near years will have a greater present value than the reduction to ECOM that may occur in later years.

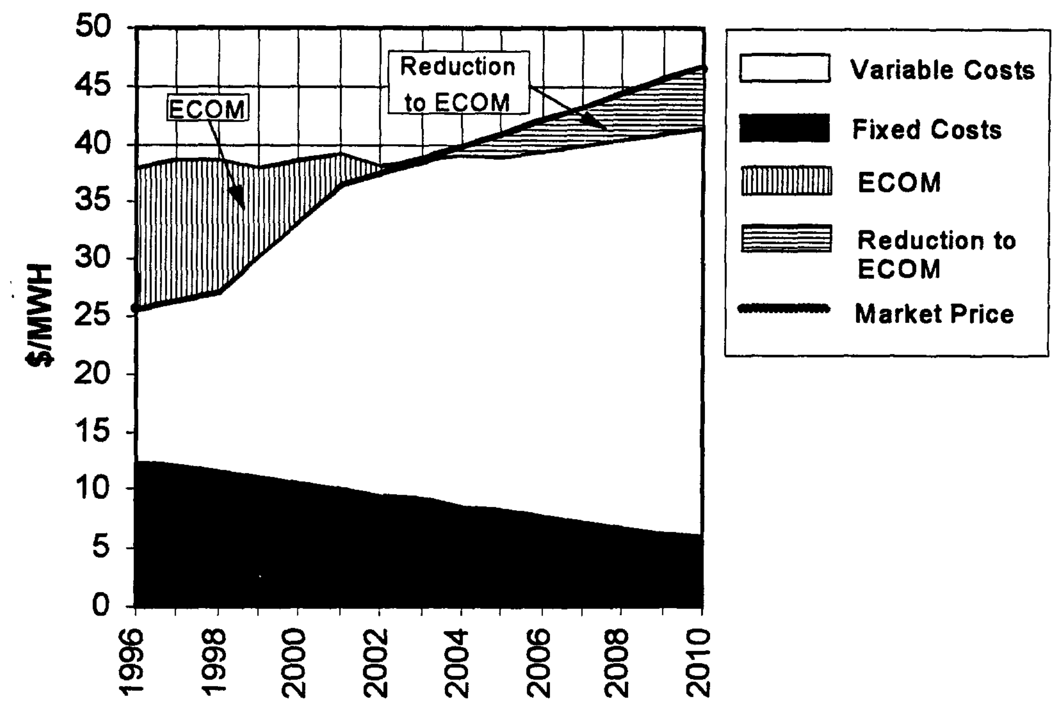

Figure VI–2: Illustration of the ECOM Methodology (2)

III(B) for a discussion of methods and approaches for estimating the magnitude of potentially strandable investments.

Worth noting is the effect of using a *present value* in presenting ECOM results as opposed to nominal year-by-year ECOM results. As shown in Figure VI–1 and Figure VI–2, ECOM levels will vary from year to year as the market price and the components of the regulated generation revenue requirement change. For example, in Figure VI–1, the generation revenue requirement exceeds the projected market revenues in the early years, producing positive ECOM values. However, in the later years, the generation revenue requirement is less than projected market revenues, producing *negative* ECOM values. By using a present value, the ECOM values (positive or negative) calculated for the nearest years are weighted more heavily than the ECOM values calculated for later years. Thus, in this example, the positive ECOM values in the early years have a greater effect on the total ECOM result than do the *negative* ECOM values in the later years.

Additionally, inspection of Figure VI–1 reveals that the market price is greater than the variable cost in each year. This indicates that, from an economic standpoint, the plant should continue to operate. Even though the total cost is not recovered in the early years, the plant should continue to operate from an economic perspective because the revenue obtained by selling power at the market price is greater than the variable cost of operation, thus creating a positive operating margin.[105] In this example, although the firm is unable to recover its total cost in the early years, it is able to offset at least a portion of its fixed costs with the positive operating margin.

Inspection of the ECOM Model equation reveals that ECOM equals total costs—composed of fixed costs and variable costs in the regulated generation cost-of-service—net of total revenues received under market-based rates. In the model, ECOM can never be greater than the present value of the utility's fixed costs as defined in the Model. If a plant ceases to operate because it is uneconomic to operate in a competitive environment, ECOM will equal the present value of only the fixed costs. If it is economic to continue operating a plant, then ECOM will be *less* than the present

[105] Over the long-run, a firm generally cannot continue to operate in a condition in which it does not recover its average total cost of production.

value of fixed costs because the firm will collect revenues greater than its operating expenses which will offset the total amount of fixed costs.

1. The Competitive Market Price of Electricity

A critical variable in any analysis of potentially strandable investment is the projected future market price of electricity. The ECOM Model includes a range of annual average market price estimates—low, base, and high.[106] In projecting the market price of electricity, the goal was to calculate a reasonable range for the annual average equilibrium price that would exist in a truly competitive generation market, i.e., a market in which no company possesses market power. If one or more companies were able to exercise market power in a deregulated market, the prevailing price of electricity would be higher than the price that would prevail in a truly competitive market. In that case, higher market prices would yield reduced utility ECOM levels relative to that of a truly competitive generation market.[107]

a) Short- and Long-run Marginal Cost

The development of market prices for electricity is based upon the premise that the market price in a competitive market will be determined by the cost marginal unit neçessary to satisfy market demand. The determination of which costs to include as costs associated with the production of the marginal unit (the marginal costs) depends on the time-frame of the analysis, i.e., either the short-run or long-run. In this analysis, the short-run is the period in which existing capacity is sufficient to meet market demand. The long-run is the time period in which capacity additions are required to satisfy market demand.

Over the short-run, the marginal cost of operating a generating unit consists primarily of fuel and variable O&M costs. Therefore, the short-run market price is determined

[106] In an effort to reduce the number of variables in the estimation of ECOM, the market price used in the ECOM Model is based upon the assumption of a single market price for the Texas market.

[107] A quantitative analysis of the effect of market power is not provided in this report. However, an analysis of the effect of market power on Texas ECOM results is provided by J. Kennedy and Associates, Inc. in *Electric Utility Restructuring Issues For ERCOT: Prices, Market Power and Market Structure*, prepared on behalf of the Office of Public Utility Counsel of Texas (October 1996). This document is referenced solely as an additional resource, as the Commission has not engaged in a critical analysis of the study.

by summing the fuel and variable O&M costs of the most costly generating unit operating in a particular market at a particular time (the short-run marginal cost, SRMC). Under this pricing structure, all units in operation, except the marginal unit, are guaranteed at least some contribution to fixed costs. For the Texas market, the marginal unit at any point in time is likely to be either a natural gas steam or combustion turbine unit; thus, the short-run market price will be highly sensitive to the price of natural gas.

In the long-run, *all* of the costs of a new unit in the market comprise the relevant marginal costs. That is, all fixed and all variable costs attributable to an incremental unit sum to equal the long-run marginal cost (LRMC) or the long-run market price. Projection of the total cost of future generating technologies is vital to the calculation of LRMC. Analysis of current capital, O&M, and fuel projections indicate that combined-cycle combustion turbine (CCCT) technology is and will continue to be the most economic new generation resource in the Texas market for the foreseeable future.

Modeling the transition from SRMC to LRMC market prices requires an assessment of the timing of future capacity additions and a judgment as to when the costs of such additions will be fully reflected in the market price. It is reasonable to expect a period of transition in which the market price is reflective of a blend of SRMC and LRMC. Without any capacity additions, the reserve margin from existing units in ERCOT is projected to fall below 15 percent in the year 1999 or 2000 due to the projected growth in demand for energy across the State. By using the projected date of reserve margin requirements as a decision point in the transition of market price from short-run to long-run, reserve margins can be implicitly accounted for in the market price calculation. The Commission developed market price estimates based upon SRMC for the years 1996 through 1999, with a linear transition to full LRMC in the year 2001 and thereafter.

b) Natural Gas Prices

A key input variable in the projection of market prices is the future price of natural gas. Because of the high degree of uncertainty associated with future natural gas prices, inputs to the ECOM Model use a range of projected natural gas prices to account for the uncertainty associated with this variable. Following the deregulation of the natural gas market at the wellhead and the development of a spot market for natural gas in the mid-1980s, annual average spot market natural gas prices as delivered to utilities on the Texas Gulf Coast averaged $2.11 per MMBtu and ranged from a low of $1.77 to a high of $2.46 per MMBtu ($1996).[108] The 1996 base case natural gas price is set at the $2.11 per MMBtu historical average. The high and low cases were calculated by adding/subtracting two standard deviations (i.e., 2.0 times $0.21 = $0.42) from the base case. Thus, the high and low natural gas price estimates in 1996 were $2.53 and $1.69 per MMBtu, respectively. This range establishes a 95 percent confidence interval for prices in 1996. The base, high and low cases are each escalated each year at the assumed inflation rate of 3 percent (i.e., a zero percent real growth rate). Historical and projected natural gas prices for the years 1986 to 2010 are presented in Figure VI–3.[109]

[108] MMBtu stands for Million British thermal units. Historical natural gas price data as reported in *Natural Gas Week* for the years 1986 to 1995.

[109] Historical price data from 1986 to 1995, projected thereafter (nominal dollars per MMBtu).

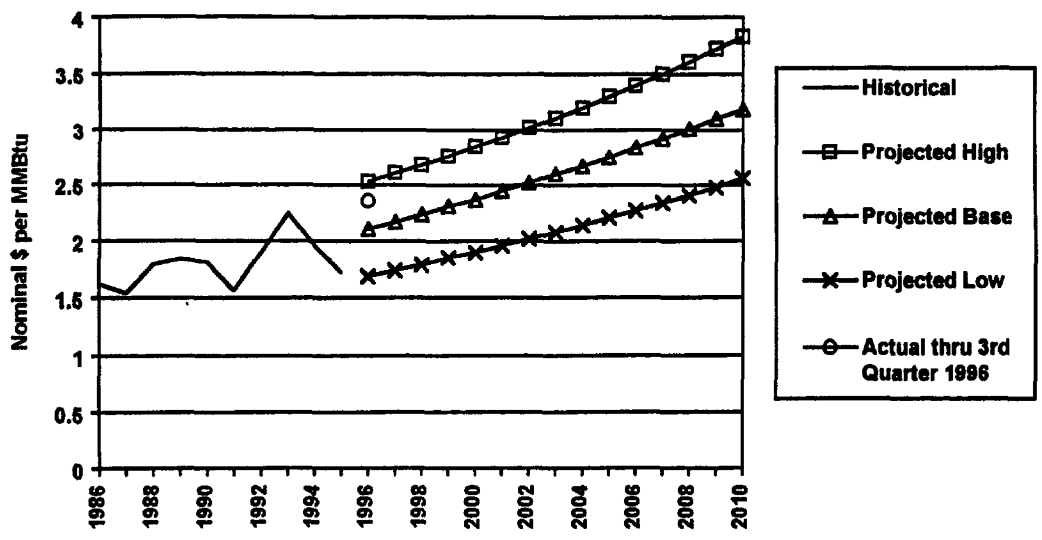

Figure VI–3: Historical and Projected Natural Gas Prices

The base case natural gas price projection is conservative compared to other published forecasts of natural gas prices because it incorporates a relatively lower growth rate. The base case forecast for natural gas prices is escalated at the general rate of inflation, incorporating 0 percent real growth over the forecast horizon. Among other published forecasts, the only forecast with a comparable growth rate is that of the Gas Research Institute (GRI), which projects a 0 percent real growth rate for the period 2000 to 2015. The remaining natural gas price forecasts contain positive real growth projections over the same period ranging from approximately 1 to 3 percent.[110] All else equal in the ECOM analysis, *higher* natural gas prices have the effect of *decreasing* the estimated level of ECOM; and likewise, *lower* natural gas prices *increase* the estimated level of ECOM.

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[110] Published forecasts are from the *DOE/EIA Annual Energy Outlook 1996*, Appendix F, and include: Energy Information Administration; The WEFA Group, *Natural Gas Service Long Term Forecast, Spring 1995*; Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, (August 1995)*; DRI/McGraw Hill, *World Energy Service U.S. Outlook (Spring-Summer 1995)*; and American Gas Association; *1995 AGA-TERA Base Case (January 1995).*

c) Market Price by Customer Class

Electricity market prices have also been projected by customer class. Over the forecast period, industrial customers are projected to continue receiving a lower price than commercial customers; and commercial customers are projected to receive a lower price than residential customers. This price disparity is based on the higher average load factor of large customers relative to small customers.[111] Not only is a high load factor a desirable characteristic from the viewpoint of an electricity supplier, but in a competitive market, larger customers will likely have the ability to consume a higher percentage of energy during off-peak hours. In contrast, smaller customers, while consuming a share of energy during off-peak hours, will likely consume a significant portion of their overall requirements during the higher-priced on-peak hours. Still, in a competitive generation market, the price differential among customer classes is projected to be relatively modest. In the short-run, the industrial and residential classes are projected to be 96 and 104 percent, respectively, of the commercial class price. In the long-run, the differential is projected to increase slightly to 93 and 107 percent, respectively, of the commercial class price.[112]

Market prices as projected for the commercial class for the years 1996 through 2020 are contained in Figure VI–4. A tabular representation of the market price projections for all customer classes from 1996 though 2035 is contained in Appendix A.

[111] Load factor for a customer is the ratio of the average customer load to the peak customer load over a specified period of time. Generally, a higher load factor requires less "excess" capacity be reserved to serve the peak load.

[112] The projected competitive price differentials are based upon annual average projections for ***generation only***. The prices do not include transmission losses, transmission costs, or distribution costs. The increase in the price differential over the long-run is due to a projected increase in the difference in the average efficiency of the marginal on-peak unit and the average efficiency of the marginal-off peak unit.

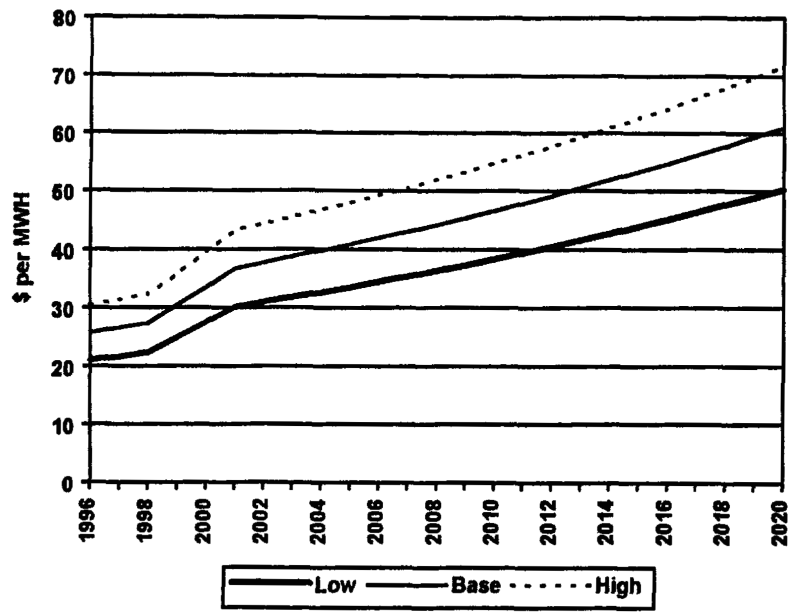

Figure VI-4: Market Prices for Electricity Used in the ECOM Model (Commercial Class)

2. Probabilistic ECOM Analysis

Although the price range incorporated in the ECOM Model captures a wide range of potential market prices, the range does not adequately reflect the probability of incurring the low or high market price in consecutive years. While it is possible that the high (or low) market price will occur in consecutive years, it is highly unlikely that these extreme values will continue to occur repeatedly. As a simple illustration, consider the toss of a coin. For any fair coin, there is a 50 percent chance of landing heads and likewise for tails. Assume you toss the coin 50 times, choosing either heads or tails on each toss.

Obviously, the number of tosses for which you will choose correctly is between zero and 50, including these two extreme values. However, the likelihood of choosing either always correctly or always incorrectly is extremely remote. In fact, your odds are better at correctly picking all six winning numbers in the Texas Lottery on two separate attempts! Statistically, you are most likely to select 25 tosses correctly, and you should be more than 90 percent confident that you will select between 19 and 31 tosses correctly (inclusive). An analogous probabilistic approach has been implemented in the ECOM Model.

In the ECOM Model, the extreme high and low ECOM estimates are calculated by using the projected low and high market prices, respectively, for consecutive years throughout the forecast period, even though a stream of consecutive years of extreme market prices is statistically unlikely. To more properly reflect the probability of occurrence of the projected market prices, a simulation has been incorporated into the ECOM Model using @RISK risk analysis software.[113] @RISK is used to determine the relative likelihood of each possible ECOM outcome. From a public policy perspective, knowledge of the relative likelihood of outcomes provides more useful information upon which to base decisions. Note, however, that probabilities *are not* certainties, and there is always a chance, albeit small, of ending up at either of the extremes.[114]

Performing a probabilistic ECOM analysis requires assigning a probability distribution to the projected market price of electricity. Because the market prices for electricity in Texas are largely a function of natural gas prices and the capital cost of new electric generating units, a probability distribution for future market prices is used that accounts

[113]@RISK, copyright 1996 by Palisade Corporation, is an add-in program to Microsoft Excel that uses simulation, sometimes called Monte Carlo, to perform risk analyses. See Appendix C for further discussion of the capabilities of the @RISK software.

[114] Probabilistic analyses require the specification of probability distributions for outcomes that are subject to uncertainty, e.g., future natural gas prices. Unlike in the coin toss and lottery examples in which the distribution of outcomes is known (binomial and hypergeometric, respectively), the distributions of variables such as natural gas prices must be estimated. This analysis incorporates reasonable assumptions regarding the various probability distributions; however, to the extent actual future outcomes vary from the assumed distributions, the actual ECOM levels will vary as well and may well fall outside the bounds of the specified confidence intervals.

The Office of Public Utility Counsel comments that "[t]he accuracy of the probabilistic percentiles associated with specific ECOM values is dependent upon the validity of the base case market price forecast and the assumptions which underlie that forecast. For example, assumptions regarding the exercise of market power by dominant suppliers or the potential for real gas price increases would result in higher probability estimates for the occurrence of lower ECOM values." Staff notes that it is not the *potential* for real gas price increases that would result in higher probability estimates for the occurrence of lower ECOM values, as the *potential* for real gas price increases is captured in the range of market prices used in the ECOM Model. Rather, it is an *expectation* of real gas price increases that would shift the probability distribution for natural gas prices, thus resulting in higher probability estimates for the occurrence of lower ECOM values.

for uncertainty in both of these inputs.[115] In addition, the cost of natural gas in each utility's embedded generation cost projection was varied in the same manner as the natural gas price used in the market price estimate.

The results of the probabilistic ECOM analysis are similar to the results in the coin toss example. While the basic ECOM Model provides the expected value, the extreme low, and the extreme high estimates of ECOM, the probabilistic ECOM analysis reveals the range of most likely ECOM outcomes for a particular scenario.

Table VI–2: Example of the Effect of Probabilistic Analysis on the Range of ECOM Outcomes ($1996 millions)

	Extreme High	95th Percentile	Expected Value	5th Percentile	Extreme Low
TUEC ECOM	$ 7,181	$ 5,600	$ 4,090	$ 2,580	$ 195

Note: See Chapter VII for complete Texas retail ECOM results.

As an illustration of the effect of the probabilistic ECOM approach on the range of outcomes, consider the case of the Texas Utilities Electric Company (TUEC). In the analysis of the effect of full retail access in the year 1998, the ECOM Model produces the results shown in Table VI–2 for TUEC. Examining only the extreme cases, TUEC's ECOM could vary by $7 billion. However, using a probabilistic approach that identifies a range of likely outcomes, the extreme range is reduced by more than 55 percent to approximately $3 billion.[116] The probability-based ranges presented in this report are representative of the 90 percent confidence interval of ECOM outcomes. Note that the outcomes labeled as *extreme high* and *extreme low* are well outside the 90 percent confidence band, and therefore can be considered to have an extremely low

[115] Probabilistic natural gas prices are modeled assuming a truncated normal distribution with zero as a lower limit. The historical mean of $2.11 per MMBtu on a delivered to utility basis in 1996 is incorporated with a growth rate equal to the projected inflation rate of 3 percent. The natural gas price standard deviation is assumed to be 10 percent of the mean, consistent with historical data. This natural gas standard deviation percentage is adjusted in future years by multiplying by $(T - 1996)^{1/2}$, where T is equal to the year, to account for forecast uncertainty. In the development of the ECOM Model market price, capital costs for combined-cycle combustion turbine units range from $400 to $600 per kilowatt for a turn-key project ($1996). In the probabilistic market price, capital cost was assigned a uniform distribution ranging from $400 to $600 per kilowatt ($1996).

[116] $7 billion is equal to the extreme high case minus the extreme low case. $3 billion is equal to the 5th percentile value minus the 95th percentile value.

probability of occurrence. A similar relationship holds for all of the ECOM scenarios presented in this report.

The high, base, low and probabilistic market prices used in the ECOM Model produce the following five ECOM outputs for each scenario:[117]

1. **Extreme High ECOM Estimate** - The extreme high ECOM estimate is obtained by using the low market price in every year of the forecast period. The low market price incorporates the low projected natural gas price for every year and the low projected capital cost for new combined-cycle generating units. The extreme high ECOM estimate has a very low probability of occurrence.
2. **95th Percentile ECOM Estimate** - The 95th percentile ECOM estimate is less than the extreme high ECOM estimate and greater than the expected value ECOM estimate. The 95th percentile ECOM estimate is obtained by using a probability-weighted market price distribution to calculate a probability distribution of ECOM results for each competitive scenario. The probabilistic ECOM analysis indicates with 95 percent confidence that the actual ECOM level will be less than the 95th percentile ECOM estimate.
3. **Expected Value ECOM Estimate** - The expected value ECOM estimate is obtained by using the base market price in each year of the forecast period. The base market price incorporates the base projected natural gas price for each year and the base projected capital cost for new combined-cycle generating units. The expected value ECOM estimate is the most likely or best estimate of the actual ECOM level in each competitive access scenario.
4. **5th Percentile ECOM Estimate** - The 5th percentile ECOM estimate is greater than the extreme low ECOM estimate and less than the expected value ECOM estimate. The 5th percentile ECOM estimate is obtained by using a probability-weighted market price distribution to calculate a probability distribution of ECOM results for each competitive scenario. The probabilistic ECOM analysis indicates with 95 percent confidence that the actual ECOM level will be greater than the 5th percentile ECOM estimate.
5. **Extreme Low ECOM Estimate** - The extreme low ECOM estimate is obtained by using the high market price in every year of the forecast period. The high market price incorporates the high projected natural gas

[117] The low, base, and high capital cost estimates for a new CCCT are $400, $500 and $600 per kilowatt ($1996), respectively, escalated annually at the projected inflation rate of 3 percent. The low, base and high delivered to utility natural gas price estimates are $1.69, $2.11 and $2.53 per MMBtu, respectively, escalated annually at the projected inflation rate of 3 percent.

price for every year and the high projected capital cost for new combined-cycle generating units. The extreme low ECOM estimate has a very low probability of occurrence.

As described previously, these five outputs effectively band the range of ECOM outcomes. Furthermore, the probabilistic ECOM analysis establishes a 90 percent confidence interval representing the range of the most likely ECOM outcomes for each utility under each competitive scenario.

3. Market Price Indicators as Projected by Utilities

With the wholesale market in its competitive beginnings, very little pricing data is available from market-based transactions. In fact, most such transactions are subject to strict confidentiality because of their competitive nature. However, some proceedings have been conducted at the Commission that provide some insight into the expected future cost of generating electricity.

a) Competitive Pricing Proceedings

Figure VI–5 displays pricing data submitted in three separate competitive pricing-related proceedings at the Commission. The utility-filed data consist of actual competitive wholesale transaction prices, utility projections of marginal cost, and the projected cost

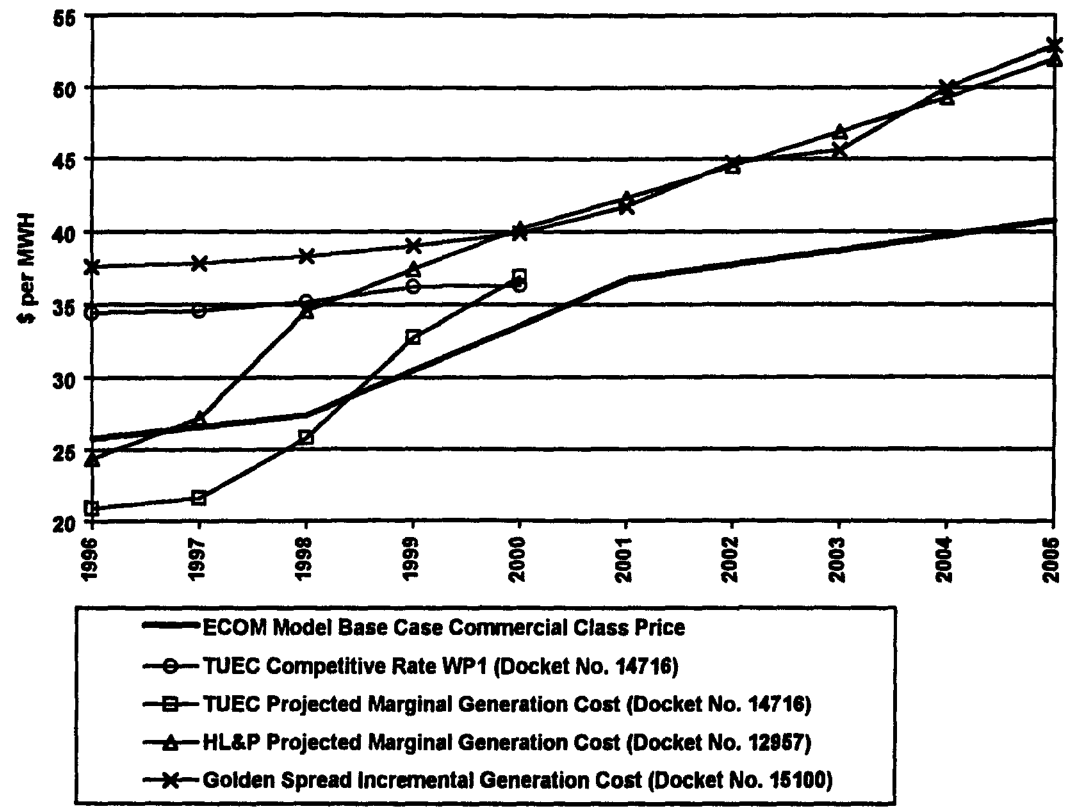

Figure VI–5: The ECOM Market Price as Compared to Utility Market Price Indicators[118]

of power from new generation resources.[119] While the available data are limited, Figure VI–5 shows the utility projections to be, on average, higher than price projected in the commercial class base case (the "Base Price"), especially after 1998 (the first year in which retail access is assumed in the ECOM Model scenarios).

[118] *Application of Texas Utilities Electric Company for Authority to Implement Rate WP1 to Lyntegar Electric Cooperative, Inc. and Taylor Electric Cooperative, Inc.*, Docket No. 14716 (Mar. 21, 1996)(not yet reported). Testimony of Stephen Houle, Exhibits SJH-4, 5, 6, and 7 (Rate WP1 adjusted to remove transmission costs). *HLP Tariff, Sheet No. D6.5*, approved Aug. 30, 1995. (HLP projects energy cost in dollars per MWh and capacity costs in dollars per kW. To convert to dollars per MWh for comparison, a conservative estimate of the capacity factor of 100 percent was assumed in converting the capacity costs). *Request of Golden Spread for Determinations Required by Section 32(K) of the Public Utility Holding Company Act and for Certification of Contract,*, Docket No. 15100, Rebuttal testimony, Exhibit AGH-4, Schedule AB-01.1, at 2.

[119] By law, the utility's negotiated competitive rate must be greater than or equal to the utility's marginal cost. See PURA95 §§ 2.001(b), 2.052(b), and 2.2011(p).

b) Utility Avoided Cost Filings

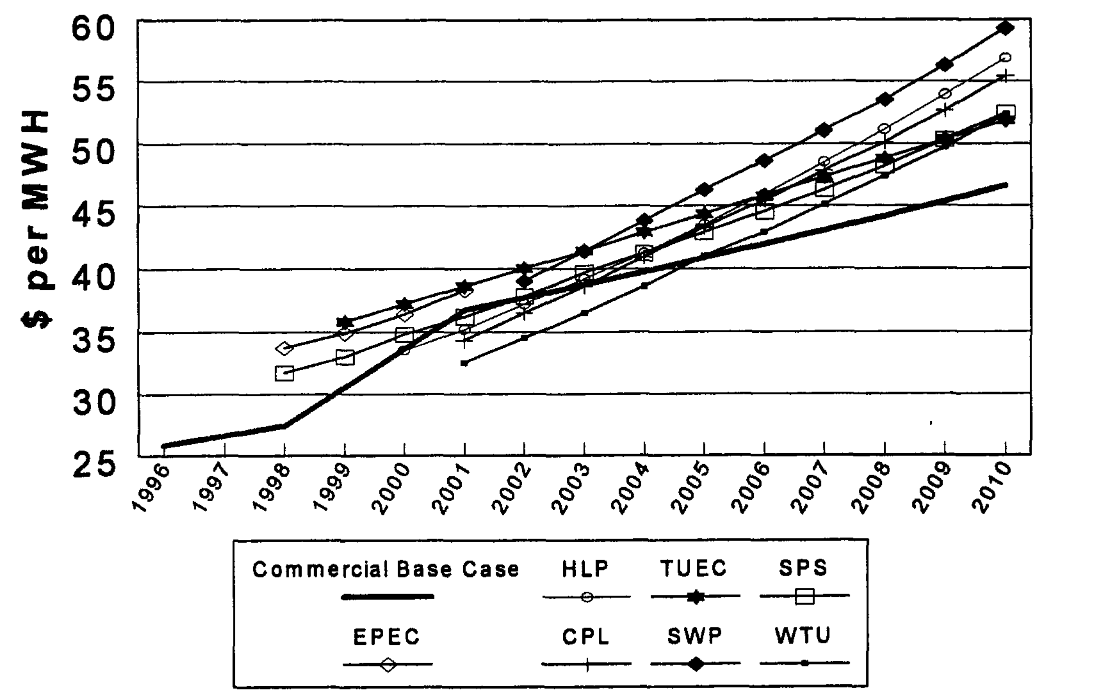

Figure VI-6: Utility Projected Avoided Cost Payments as filed at the Commission

In accordance with P.U.C. SUBST. R. 23.66(h), utilities in Texas are required to submit a biannual filing detailing projected capacity and energy payments that each utility projects to incur as the result of adding new generation resources over the coming 5 to 15 years. These data are used as a basis for calculating the price a utility should pay to a qualifying facility as a result of deferring generation requirements and planned capacity additions. The most recent avoided cost filing was in December 1994. Figure VI-6 shows the avoided cost projections of several utilities along with the Base Price used in the ECOM Model.[120] As indicated in Figure VI-6, the utility avoided cost projections compare favorably with the Base Price through the year 2004, after which the avoided cost projections exceed the Base Price.

[120] Capacity payments projected by the utilities were reported in dollars per kW and were converted to dollars per MWh by assuming a 100 percent capacity factor. A 100 percent capacity factor is a conservative capacity factor that results in a lower cost per MWh than if a capacity factor less than 100 percent were used.

VII. WHOLESALE COMPETITION IN TEXAS: ECOM RESULTS

As discussed in Chapter VI, the Commission uses the ECOM Model methodology to calculate a range of potentially strandable costs in both the Texas wholesale and retail jurisdictions; the estimates obtained for the Texas wholesale jurisdiction are presented in this chapter. Section A of this chapter includes an overview of portions of the Federal Energy Regulatory Commission's (FERC's) recent Order No. 888 on open access and stranded costs, comparing FERC's stranded cost provisions to the ECOM Model approach to calculate potentially strandable costs in the Texas wholesale jurisdiction. Section B includes the wholesale ECOM estimates for Texas jurisdictional utilities using the data provided by utilities in the ECOM Model.

A. FERC ORDER 888: STRANDED COSTS

On April 24, 1996, the FERC issued its final open access and stranded cost rules together in Order No. 888.[121] Among other provisions, Order No. 888 provides guidelines for the full recovery of legitimate, prudent, and verifiable stranded costs associated with existing wholesale requirements contracts.[122] The FERC asserts jurisdiction over wholesale stranded costs in a manner that could be construed as extending to ERCOT utilities, based on the theory that Order No. 888 opened all wholesale markets and thereby caused the stranded costs. The Texas Commission has requested rehearing of that order, arguing, among other things, that FERC's causation rationale would not pertain to Texas wholesale costs. As of the date of this report, the motion for rehearing is still pending. The Commission believes that Texas has the flexibility to create its own approach for addressing wholesale stranded investment claims. However, primarily because the mechanics of the FERC's methodology are

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[121] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities,* Docket No. RM95-8-000, *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Docket No. RM94-7-001, Order No. 888, Final Rule (April 24, 1996) (Page numbers refer to the widely circulated manuscript version of the Order). Coincidentally, the FERC's Order No. 888 was issued the same day that the Commission issued its Order Initiating Investigation in Project No. 15001, *Stranded Cost Report: Estimation of ECOM for Generating Utilities in Texas.*

[122] *Id.* at 329. Existing wholesale requirements contracts are defined as contracts executed on or before July 11, 1994.

sound, and also to maintain consistency among the jurisdictions, the FERC methodology in Order No. 888, with some minor modifications, is a reasonable method by which to address wholesale stranded cost claims in the Texas jurisdiction.

1. The FERC Stranded Cost Calculation

If a utility wishes to recover costs left stranded by a wholesale customer's departure, the utility must petition FERC for approval. In its petition, the utility must demonstrate that it had a reasonable expectation of continuing to serve the customer.[123] To meet the reasonable expectation standard, a utility must effectively overcome the "rebuttable presumption" that the existence of a notice provision in a wholesale contract left the utility with no reasonable expectation of serving the customer beyond the period provided for in the notice provision.[124] In other words, unless a utility can prove otherwise in an evidentiary hearing, the FERC presumes that a wholesale contract with a notice provision leaves the utility with no stranded cost claim. If the FERC determines that a utility is entitled to recovery of stranded costs, the departing generation customer's stranded cost obligation (SCO) can be calculated.

2. Calculation of Recoverable Stranded Costs

Order No. 888 adopts the "revenues lost" approach to determine recoverable stranded costs. The revenues lost approach measures stranded costs by subtracting the competitive market value of the power the customer would have purchased from the revenues that the customer would have paid had it stayed on the utility's generation system.[125] A customer's SCO is calculated according to the following formula and conditions, as outlined in Order No. 888:[126]

$$SCO = (RSE - CMVE) \times L$$

[123] Such determinations will be conducted on a case-by-case basis.

[124] FERC Order No. 888 at 374. The reasonable expectation standard is also applicable in those cases where a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory, and in order to make such a sale possible, transmission service has been rendered by an intervening utility.

[125] *Id.* at 375.

[126] *Id.* at 390 - 395.

where:

RSE = Revenue Stream Estimate — average annual revenues from the departing generation customer over the three years prior to the customer's departure (with the variable cost component of the revenues clearly identified), less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same three years under its new wholesale transmission tariff.

CMVE = Competitive Market Value Estimate — determined in one of two ways, *at the customers option*: Option (1) - the utility's estimate of the average annual revenues (over the reasonable expectation period "L" discussed below) that it can receive by selling the released capacity and associated energy, based on a market analysis performed by the utility; or Option (2) - the average annual cost to the customer of replacement capacity and associated energy, based on the customer's contractual commitment with its new supplier(s).

L = Length of Obligation (reasonable expectation period) — refers to the period of time the utility could have reasonably expected to continue to serve the departing generation customer.

Thus, the calculation of a departing customer's SCO is a function of the existing contract-based revenues, the projected market-based revenues associated with the capacity released by the customer, and the length of time that the utility could have expected to serve the customer.

In addition, application of the stranded cost formula and collection of the resulting stranded costs are subject to the following conditions:

1. **Cap on SCO**. The quantity (RSE - CMVE) can be no greater than the average annual contribution to fixed power supply costs (defined as RSE less variable costs) that would have been made by the departing generation customer had it remained a customer.
2. **Changes in Customer Revenues**. If the customer's rates (or contract demand amounts, if relevant) changed during the three-year period prior to the termination of its existing requirements contract, then the RSE should be calculated using the customer's most recent 12 months of revenue.
3. **CMVE Option 2 Conditions**. Option 2 (a CMVE equal to the average cost to the customer of replacement capacity and associated energy) would be available to a customer whose alternative purchase(s) runs concurrent with L, or, if longer than L, contains rates that do not fluctuate

over the duration of the contract. The customer would be required to demonstrate (at the time it chooses this option) that the replacement capacity contract(s) is for service equivalent to the released capacity (that is, firm power for a period at least equal to L), and must also clearly identify the rates to be paid for the replacement service.

4. **Payment Options**. The method and term of payment should be negotiated, but is ultimately left to the customer's discretion. Possible payment options include a lump-sum payment, amortization of a lump-sum payment over a reasonable period of time, or a surcharge on the customer's transmission rate.

5. **Applicability**. The formula is designed for determining stranded costs associated with departing wholesale generation customers and for retail-turned-wholesale customers.

6. **Marketing/Brokering Option**. The FERC will allow the customer, at the customer's sole discretion, a choice to market the released capacity and associated energy (or to contract with a marketer for such service). Alternatively, the customer may choose to broker the released capacity and associated energy (or to contract with a broker).

7. **Released Capacity and Associated Energy**. A utility requesting stranded cost recovery must indicate the amount of system capacity and the amount of associated energy released by the departing generation customer and used in the revenues lost calculation. This will allow the departing generation customer to fairly consider exercising a choice to market or broker the released capacity and associated energy.

While the Commission generally supports the method adopted by the FERC for calculating recoverable wholesale stranded costs, the Commission believes that the approach has two shortcomings:

1. The calculation of the revenue stream estimate (RSE) is based upon the revenues paid by the departing customer during the last three years of its contract (or retail in the case of retail-turned-wholesale) service rather than a projection of future revenues. In choosing to use "present" revenues in the calculation of RSE, the FERC stated that using present revenues has several advantages, including the elimination of dispute over estimates of future revenues (thereby adding certainty to the calculation), and the elimination of the need for a detailed listing of includable costs (relying instead on the assumption that present rates include all of the utility's costs of providing service). The Commission believes the use of a projected revenue stream may be more appropriate, especially given the fact that most, if not all Texas utilities are facing declining fixed costs in the generation-related revenue requirement as current assets are

depreciated, retired, and replaced with new and lower cost resources.[127] Relying on the historic revenue figures under these circumstances is likely to overstate the true value of RSE in future years and, thus, overstate the level of SCO.

2. The calculation of the RSE implicitly assumes that all of a utility's current generation plant will continue to operate economically for the duration of the calculation period (L). This may not be a valid assumption in an increasingly competitive environment where generation assets may become operationally uneconomic, i.e., operating costs exceed market revenues.[128] If this situation occurs, the plant will be shut down, and neither operating costs nor associated revenues will be incurred. Because RSE is based upon historic costs, SCO will be overstated by an amount equal to the net present value of the annual operating costs less the market revenues.

Because both of these shortcomings to the FERC methodology are likely to produce an overstated estimate of SCO, the Commission would modify the FERC's method for use in Texas to recognize and account for the change in future utility revenue requirements as well as generation assets that may not be economic to operate in a competitive generation market.

3. FERC Recovery Method

In Order No. 888, the FERC concluded that the SCO should be determined in a one-time (or snapshot) calculation and that the SCO should be recovered via an exit fee assigned directly to the departing customer. The exit fee can be in the form of a lump-

[127] Fixed costs are the relevant costs as these are the only type of costs that can be "stranded." In fact, in setting the cap on the SCO, the FERC states that "[t]he quantity (RSE - CMVE) can be no greater than the average annual contribution to fixed power supply costs (defined as RSE less variable costs) that would have been made by the departing generation customer had it remained a customer." By using a historical RSE, the FERC's methodology is not able to achieve its goal because the fixed costs of existing assets are declining over time and utilities are facing declining marginal capacity costs. For this reason, the FERC's cap on SCO will be set at the annual contribution to fixed power supply costs that the customer ***did make while it was a customer*** rather than at the annual contribution to fixed power supply costs that *would have been made* by the departing generation customer. The effect of using this historical RSE will be to overstate the SCO for a departing generation customer.

[128] Operating costs, in this instance, refer to long-run variable costs, i.e., all costs other than fixed costs and obligations. Over the short-run, a plant may continue to operate while receiving revenues that are less than its average variable costs; however, the ability to continue operations under these circumstances is limited. Over the long-run, a firm must recover not only its average variable costs but its total cost, i.e., fixed and variable costs, to remain in business.

sum payment, an amortization of a lump-sum payment over a reasonable period of time, or another method of payment at the discretion of the customer.[129]

4. Consistency with the ECOM Model

To quantify wholesale stranded costs, the FERC adopted the revenues lost approach, limiting stranded cost recovery to the departing customer's contribution to fixed costs that the utility would no longer recover because of the customer's departure.[130] This approach is entirely consistent with the methodology incorporated into the ECOM Model, in that the ECOM estimate can never be greater than the fixed cost contribution that would have been made by the departing generation customer had it remained a customer. Both methods employ the comparison of regulated revenue streams to market-based revenue streams as the basis for analysis.

The three notable differences between the FERC and the Commission's ECOM Model for quantifying wholesale stranded costs are:

- While the FERC method is designed to be applied on a case-by-case basis to determine the SCO for a specific wholesale customer, the ECOM Model is designed to provide a range of aggregate estimates of the potentially strandable costs, or excess costs over market. Any actual quantification of wholesale stranded costs should be performed on a case-by-case basis.
- The ECOM Model differs from the FERC revenues lost approach in that the ECOM Model uses *projected* revenue requirements and analyzes the economics of continued plant operation in future years.
- The ECOM Model uses a range of market prices rather than the FERC's point estimate of market value, thus generating a range of estimates of potentially strandable wholesale costs as opposed to a point estimate.

Overall, the assumptions and methodology incorporated into the ECOM Model are comparable with the assumptions of the FERC's revenues lost approach.

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[129] *Id.* at 391.

[130] *Id.* at 403.

5. Potential for Cost-shifting Under the FERC Order No. 888

In Order No. 888, the FERC did not offer a remedy regarding the treatment of stranded costs caused by a departing generation customer in the event the FERC determined that the utility had no reasonable expectation of continuing to serve that customer. Specifically, the FERC stated:

> *We further note that we are not addressing in this Rule who will bear the stranded costs caused by a departing generation customer if the Commission finds that the utility had no reasonable expectation of continuing to serve that customer. . . .we anticipate that, in such a case, a public utility will seek in subsequent requirements rate cases to have the costs reallocated among the remaining customers on its system. However, we will not prejudge that issue here.*[131]

The failure to decide who will bear the stranded costs caused by a departing generation customer in the event the FERC denies recovery from the customer leaves the issue of cost-shifting unsettled, even though a primary purpose in addressing the stranded cost issue at the outset was to prevent such costs from being "unfairly shifted to other (remaining) customers."[132] In fact, the FERC is not likely to have a chance to judge the issue of stranded cost reallocation to retail customers as the forum for such deliberations will be state commissions rather than at the FERC.

Within Texas, if a utility seeks stranded cost recovery from a departing wholesale customer, it will have deemed such costs to be allocable to that wholesale customer. If the wholesale recovery effort proves unsuccessful, any further attempt to allocate and recover the same costs from the utility's remaining customers would be an attempt to take a "second bite at the apple." Nonetheless, a utility may believe that previously allocated wholesale costs that become stranded are properly reallocated to the retail class upon the departure of the wholesale customer. To justify such a finding, a utility should be subject to, at a minimum, the following thresholds prior to the reallocation of costs:

[131] *Id.* at 377.

[132] *Id.* at 298.

1. The utility should petition the Commission or the FERC for stranded cost recovery from the departing wholesale customer.
2. If denied recovery from the departing wholesale customer, the utility must carry the burden of proof in an evidentiary hearing that the previously allocable wholesale costs are properly allocable to the retail class.[133]

B. ECOM Model Texas Wholesale Results

The Commission Staff calculated wholesale ECOM estimates for Texas jurisdictional utilities using the data provided by utilities in their ECOM filings. Estimates of potential wholesale stranded costs are presented under two scenarios:

1. *Contract expiration scenario:* assumes that a utility's current wholesale contracts will be renegotiated at the market price of power upon the contract expiration date; and
2. *Contract abrogation scenario:* assumes all wholesale contracts conform to the market price immediately in 1998.

To calculate wholesale ECOM estimates, it is necessary to establish a baseline for the percentage of a utility's costs and sales allocable to the wholesale customer class. For the purpose of this analysis, the wholesale allocation provided in the utilities' filings for 1996 was assumed for the remainder of the forecast horizon.[134] For example, if a utility has 5 percent of its costs and 5 percent of its sales allocated to the Texas wholesale jurisdiction in 1996, then these allocation percentages are held constant in each year through the year 2035.[135] Thus, in this example, the Texas retail classes are allocated 95 percent of costs and 95 percent of sales in each year of the forecast period.

[133] The Commission would likely place a heavy burden of proof upon the utility in justifying such a claim.

[134] In an actual wholesale stranded cost determination, the utility's allocation of costs between retail and wholesale classes should be examined as of a specific date, such as the utility's most recent rate case or July 11, 1994, the date decided upon in FERC Order No. 888 as the dividing point for new and existing wholesale contracts.

[135] In this example, the wholesale class is allocated an identical share of costs and sales (both 5 percent). However, these percentages will typically vary, depending primarily upon the load characteristics of the wholesale customer.

There are only seven utilities filing ECOM reports that sell a significant amount of electricity at wholesale in the Electric Reliability Council of Texas (ERCOT).[136] Of these seven, the Lower Colorado River Authority (LCRA) is exempt from the Commission's wholesale rate jurisdiction, leaving six utilities within the rate jurisdiction of the Commission.[137] As shown in Table VII-1, 20,054 gigawatt-hours (GWh) of electricity were sold at wholesale in ERCOT out of a total of 194,970 GWh of ERCOT sales in 1995 by ERCOT utilities with wholesale contracts. Thus, utility wholesale transactions comprise approximately 10 percent of total sales for these utilities.[138] Of the 20,054 GWh in wholesale transactions by ERCOT utilities, 8,859 GWh were sold by the LCRA. Thus, only 11,195 GWh of the 194,970 GWh in total sales by these ERCOT utilities, or 5.8 percent of the total ERCOT sales, were wholesale sales under the rate jurisdiction of the Commission.

Table VII–1: 1995 ERCOT Wholesale Contract Transactions

	Wholesale Sales (GWh)	Total ERCOT Sales (GWh)	Wholesale % of Total Sales
West Texas Utilities	1,976	6,400	30.9 %
Texas Utilities Electric	2,637	89,063	3.0
Central Power & Light	999	19,592	5.1
Houston Lighting & Power	170	60,384	0.3
Brazos Electric Power	4,417	4,417	100.0
Lower Colorado River Auth.	8,859	9,036	98.0
South Texas Elec. Coop.	996	996	100.0
	20,054	194,970	10.3
Total Wholesale - IOUs	5,782	175,439	3.3
Total Wholesale - Non-IOUs	14,272	14,449	98.8

Source: Office of Regulatory Affairs, *1996 Statewide Electrical Energy* Plan, Austin, TX: Public Utility Commission of Texas, at Appendix I (June 1996), except for South Texas Electric Cooperative for which generation level data were extracted from the ECOM Model filing and adjusted for losses.

[136] West Texas Utilities Company, Texas Utilities Electric Company, Houston Lighting and Power Company, Central Power and Light Company, the Lower Colorado River Authority, Brazos Electric Power Cooperative, and South Texas Electric Cooperative.

[137] PURA95 §2.0012 exempts the LCRA from Commission regulation of LCRA's wholesale rates.

Under the *contract expiration* scenario, the only wholesale sales at risk in the near term are those of investor-owned utilities. This is because the LCRA, Brazos Electric Power Cooperative (Brazos), and South Texas Electric Cooperative (STEC) have long-term contracts with their wholesale customers that do not expire until the year 2016 or later. In contrast, most of the current wholesale contracts of the ERCOT IOUs will expire by the year 2001.

1. Interpretation of Wholesale ECOM Results

Table VII–2 and Figure VII–1 present ECOM results for the Texas wholesale jurisdiction assuming that utilities are able to achieve a 10 percent improvement in O&M efficiency.[139] Table VII–3 presents wholesale ECOM results assuming no efficiency improvements. In the Texas wholesale ECOM analysis, *positive ECOM values* indicate that, on a net present value basis, the utility's allocated Texas wholesale generation cost-of-service is greater than the revenues the utility may receive in a competitive market. In contrast, *negative ECOM values* indicate that the utility's Texas wholesale allocated generation cost-of-service is less than the revenues the utility may receive in a competitive market (on a net present value basis); in other words, over the analysis period, the book value of the utility's assets is less than the value of the generation assets in a competitive market, thus the utility may make greater profits under competition than under existing cost-based wholesale rates.

This section graphically portrays the Texas Jurisdictional wholesale ECOM Model results for the *contract expiration* and the *contract abrogation* scenarios. The graphical representation of each scenario can be interpreted as follows:[140]

- **Extreme High ECOM Estimate** - Represented by the top of the vertical line.

[138] Statewide, the wholesale market is 12.6 percent of utility sales.

[139] The 10 percent O&M efficiency improvement factor incorporates a 10 percent reduction in base O&M expenditures in the initial year in which competition is introduced in the ECOM Model, with no further reductions thereafter.

[140] For a more detailed discussion regarding the interpretation of the ECOM presentation figures, see Chapter VI.B.2.

Table VII–2: Total Texas Wholesale ECOM Model Results ($1996 millions, 10 percent O&M efficiency improvement)

	Extreme High	5th percentile	Expected Value	95th percentile	Extreme Low
Contract Expiration Scenario	$ 115	$ 5	$ (57)	$ (115)	$ (258)
1998 Contract Abrogation Scenario	279	(558)	(1,007)	(1,457)	(2,325)

Note: See Appendix B for individual utility ECOM Model results.

- **95th Percentile ECOM Estimate** - Represented by the right tick mark on the vertical line.
- **Expected Value ECOM Estimate** - Represented by the square in the middle of the vertical line.
- **5th Percentile ECOM Estimate** - Represented by the left tick mark on the vertical line.
- **Extreme Low ECOM Estimate** - Represented by the bottom of the vertical line.

As indicated in Table VII–2 and Figure VII–1, the expected value in the *contract expiration* scenario indicates a net present value ERCOT-wide *benefit* of reselling power at the market price subsequent to wholesale contract expiration of $57 million ($1996) for ERCOT IOUs. (If utilities are unable to achieve efficiency improvements, ECOM estimates are some what higher.) This net benefit is largely driven by WTU's low-cost wholesale power producing a benefit of $96 million, with TUEC and HL&P offsetting the benefit with a net stranded cost of $25 and $19 million, respectively. CPL has an expected value of ECOM near zero under the *contract expiration* scenario. As stated previously, Brazos, the LCRA, and STEC are not at risk in the *contract expiration* scenario because of their long-term contracts with their wholesale customers.[141]

[141] See Appendix B for individual utility ECOM Model results.

Table VII-3: Total Texas Wholesale ECOM Model Results ($1996 millions, 0 percent O&M efficiency improvement)

	Extreme High	5th percentile	Expected Value	95th percentile	Extreme Low
Contract Expiration Scenario	$ 138	$ 28	$ (29)	$ (87)	$ (230)
1998 Contract Abrogation Scenario	376	(461)	(908)	(1,335)	(2,223)

Note: See Appendix B for individual utility ECOM Model results.

Under the *contract abrogation* scenario, all current utility wholesale contracts are eliminated and the corresponding wholesale load is subjected to market-based prices. In this scenario, each IOU's ECOM level increases relative to the *contract expiration* scenario because market-based prices are introduced earlier than the contract expiration dates. However, because the LCRA, Brazos, and STEC have embedded cost wholesale rates that are generally lower than anticipated market prices, the abrogation of contracts actually produces *negative* ECOM values for these three utilities, especially for the LCRA and Brazos. Thus, the customers of LCRA and Brazos are likely to be better off purchasing power under cost-of-service based wholesale rates under their existing contracts rather than at the future market price of electricity. STEC's expected value for ECOM in the *contract abrogation* scenario is slightly less than zero, indicating a net present value benefit to the utility of $17 million.[142]

[142] The situation of embedded costs that are less than the projected market price exists in Texas at the retail level as well, e.g., West Texas Utilities and Southwestern Electric Power have embedded generation costs that are projected to be lower than future market prices (see Chapter VIII). On the national level, there are some states that currently oppose retail access for this very reason. For example, the Idaho Public Utilities Commission has issued a policy statement opposing retail access because it has determined that competitive market prices will likely be greater than the embedded generation costs of the State's low-cost utilities, therefore causing rates to increase for Idaho residents.

In the *contract abrogation* scenario, the total expected value of Texas wholesale ECOM is *negative* $1,007 million, consisting of $1,148 million in potential benefits to LCRA, Brazos, STEC, and WTU combined with $141 million in potentially stranded costs for TUEC, CPL, and HL&P. As in the *contract expiration* scenario, TUEC has the largest share of potentially stranded wholesale costs at approximately $87 million for the *contract abrogation* scenario, with HL&P and CPL having expected values for ECOM of $31 and $23 million, respectively. WTU, LCRA, Brazos, and STEC would realize *negative* expected net present values (or net benefits) for ECOM of $87, $849, $195, and $17 million, respectively, under the *contract abrogation* scenario.

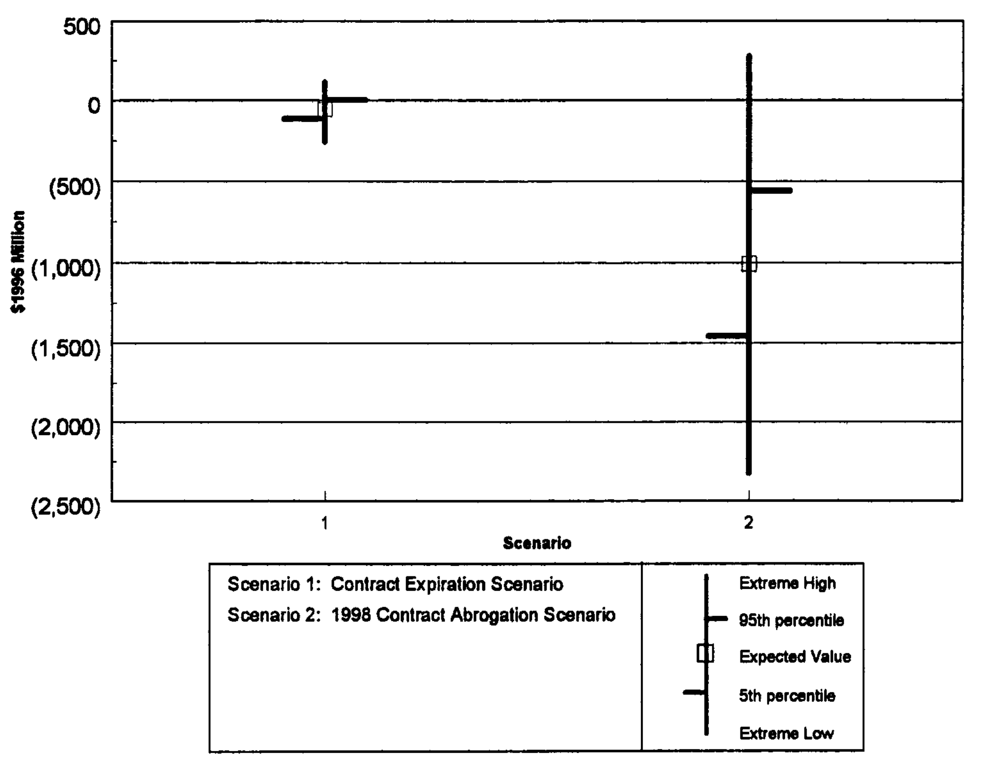

Figure VII–1: Total Texas Jurisdiction Wholesale ECOM Model Results

It is important to note that, while the model results indicate that certain utilities are expected to receive net benefits or *negative* wholesale stranded costs, this does not mean that the windfall occurs instantly, nor that that utilities should be able to retain all of these profits. In real time, the utilities with net negative ECOM may have several early years in which the cost of their generating assets will exceed the projected market price. But in later years, the cost-based rates may fall below the market price, and the windfall of negative ECOM (or positive profits) would begin. It is at this point that the customers who previously bore the costs of paying for above-market assets should now reap the benefits from their new profitability.[143]

[143] For the wholesale case, the analysis period may be dependent upon the duration of the wholesale contract or, as the FERC has set forth, the period of time the utility could have reasonably expected to continue to serve the departing wholesale customer. For the retail case, as discussed in Chapter VIII, to the extent utilities with positive ECOM are granted recovery of such costs from ratepayers or otherwise, utilities with negative ECOM should be required to pass through the benefits of their low cost generation resources over the remaining life of those generation resources.

2. Individual Utility Texas Wholesale ECOM Results

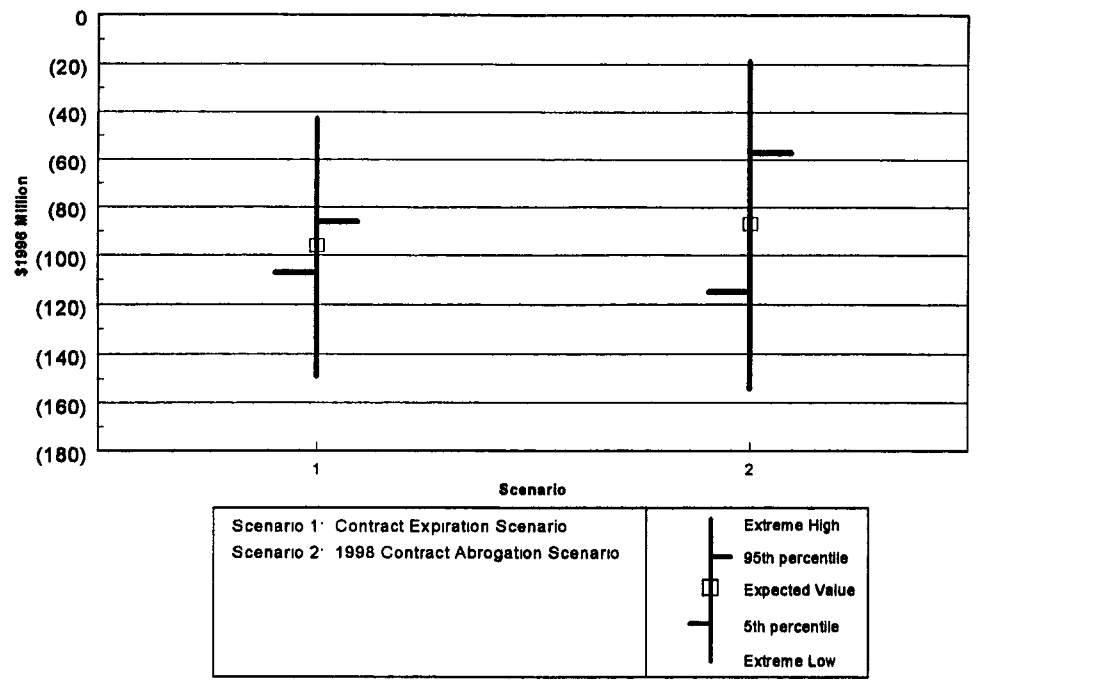

Figure VII–2: WTU Texas Wholesale ECOM Model Results

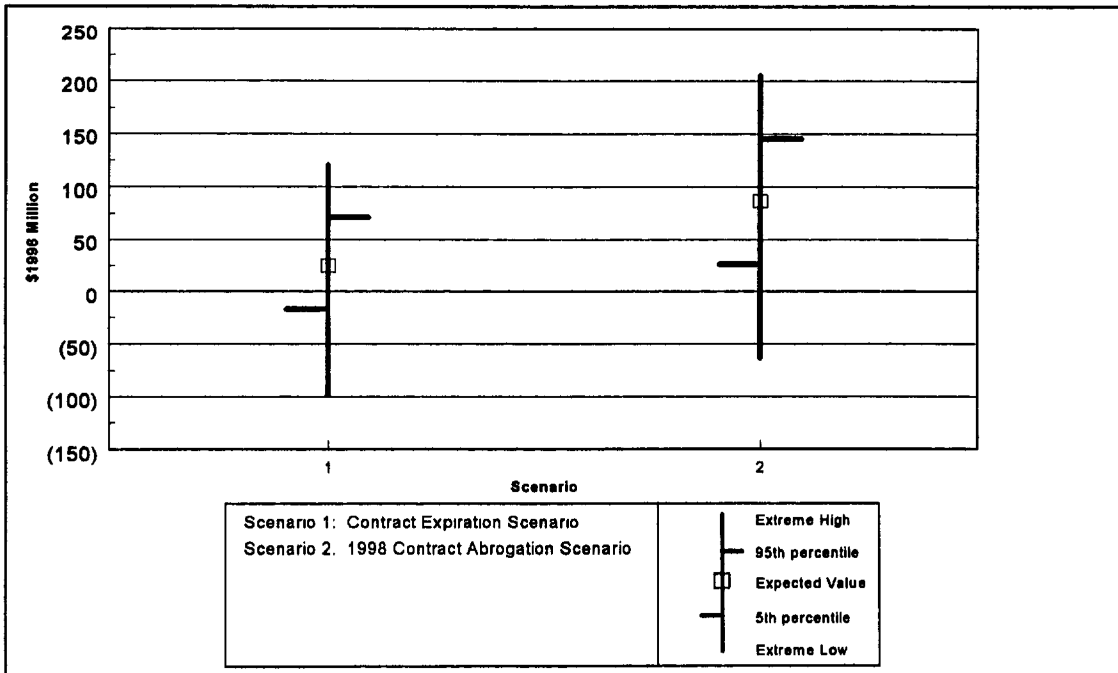

Figure VII–3: TUEC Texas Wholesale ECOM Model Results

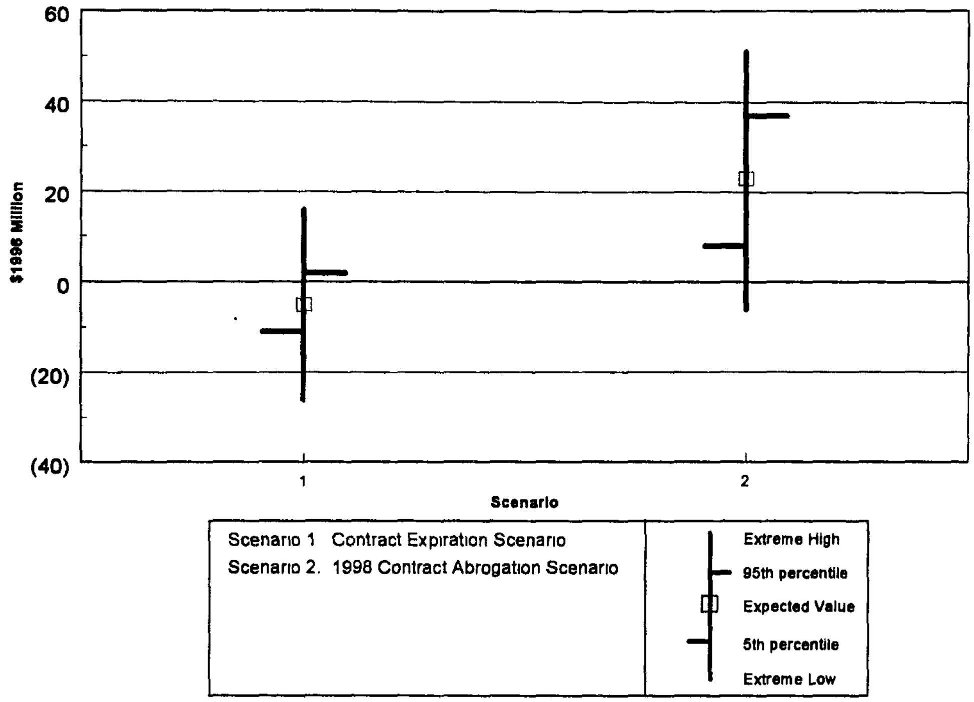

Figure VII–4: CPL Texas Wholesale ECOM Model Results

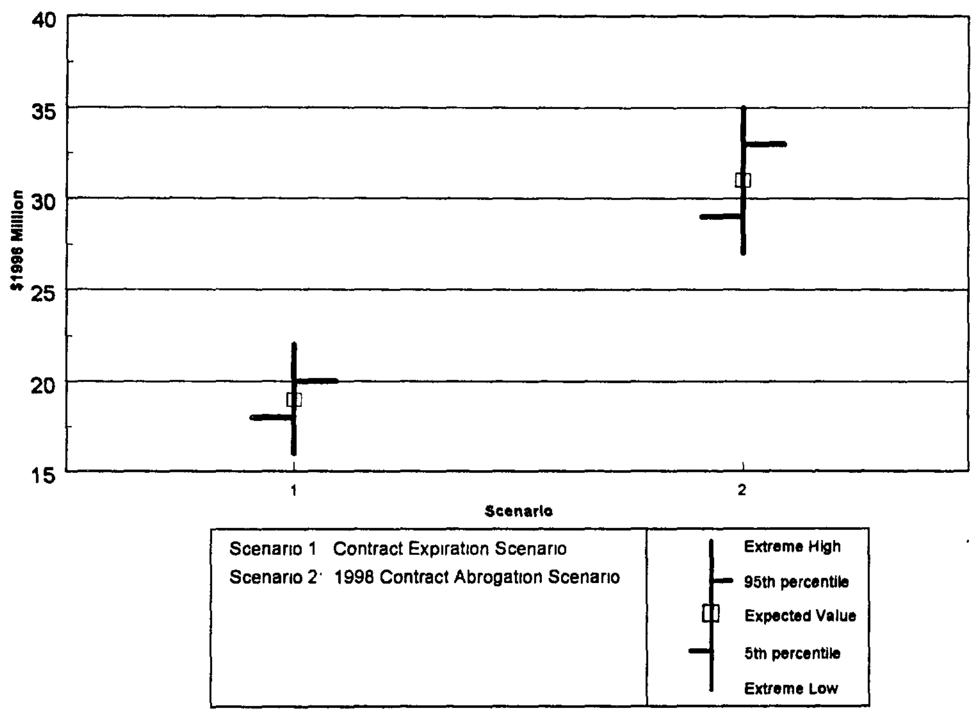

Figure VII–5: HL&P Texas Wholesale ECOM Model Results

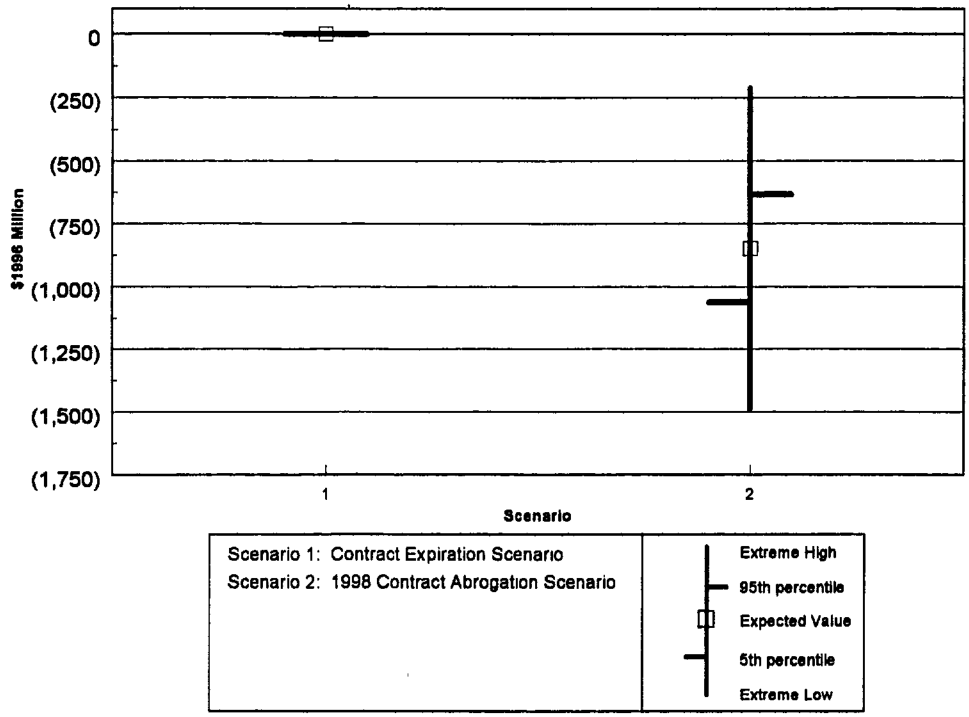

Figure VII–6: LCRA Texas Wholesale ECOM Model Results

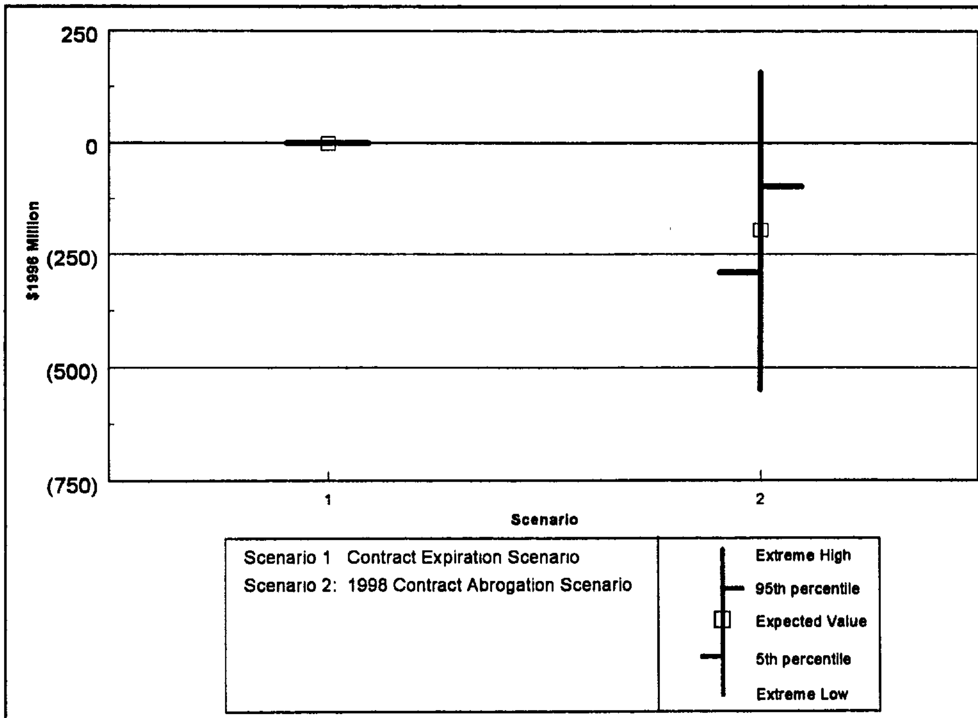

Figure VII–7: BEPC Texas Wholesale ECOM Model Results

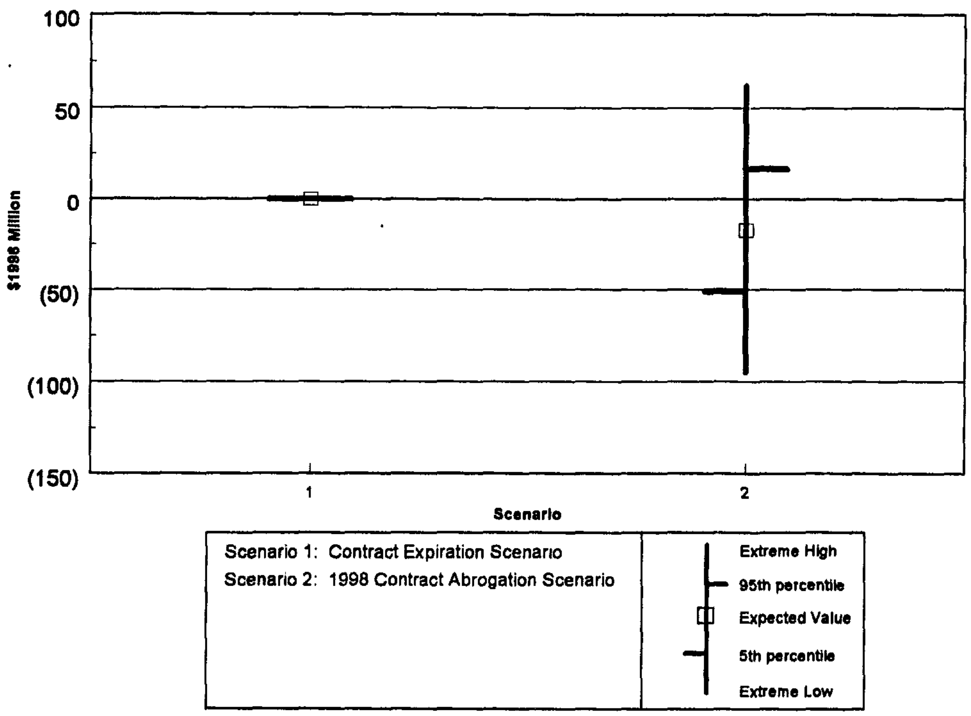

Figure VII–8: STEC Texas Wholesale ECOM Model Results

VIII. Retail Competition in Texas: ECOM Results

Texas retail ECOM estimates were calculated for each utility for six different competitive scenarios, using varying combinations of three market price assumptions and two operations and maintenance efficiency (O&M) improvement factors (0 and 10 percent) for each scenario, for a total of 36 competitive scenarios for each utility.[144] In addition, corresponding probabilistic ECOM results are provided for each scenario. The broad competitive scenarios are described below and in Table VIII–1.

Scenarios ***1998Full*** and ***2000Full*** assume that all Texas retail electric customers receive the market price beginning in 1998 and 2000, respectively. The ***1998Full*** scenario includes the fastest transition to full competition; thus, the ***1998Full*** scenario

Table VIII–1: Competitive Retail Scenarios Modeled

Scenario Name	Scenario Description	Residential Access Year(s)	Commercial Access Year(s)	Industrial Access Year(s)
1998Full	1998 Full Access	1998	1998	1998
2000Full	2000 Full Access	2000	2000	2000
I98/C00/R02	Industrial 1998 Commercial 2000 Residential 2002	2002	2000	1998
I98/C02/R06	Industrial 1998 Commercial 2002 Residential 2006	2006	2002	1998
I98/C00/R02 Phase-in	50/50 Class Phase-in: Industrial 1998/1999 Commercial 2000/2001 Residential 2002/2003	50% in 2002 50% in 2003	50% in 2000 50% in 2001	50% in 1998 50% in 1999
R98/C00/I00	Residential 1998 Commercial 2000 Industrial 2000	1998	2000	2000

Note: The ECOM Model can accommodate additional competitive access scenarios with varying customer class access percentages.

[144] Utilities were required to calculate ECOM with three operations and maintenance efficiency assumptions—0, 5, and 10 percent. Only the 0 and 10 percent efficiency scenarios are contained in this report. A 10 percent O&M efficiency improvement is presented in the text of the report as the base case. Individual utility 0 percent results are presented in Appendix B.

will produce the highest ECOM estimates because it allows relatively little time for the utilities to mitigate stranded costs through continued depreciation and rate recovery or more aggressive structured mitigation measures.

The four remaining scenarios incorporate both an inter- and intra-class phase-in to competition. In these scenarios, a share of customers receive the market price while other customers continue to purchase power at regulated rates. In the scenario names, the letters indicate customer classes and the digits indicate the year each customer class receives competitive retail access to electric services. ***I***, ***C***, and ***R*** stand for industrial, commercial, and residential classes, respectively. ***98*** indicates that a customer class receives competitive retail access in 1998, with ***00*** representing access in the year 2000, and so on.

Scenario ***I98/C00/R02*** represents a phased introduction of competition by customer class where all industrial customers receive the market price in 1998, all commercial customers receive the market price in 2000, and all residential customers receive the market price in 2002.

Scenario ***I98/C02/R06*** represents a phased introduction of competition by customer class in which all industrial customers receive the market price in 1998, all commercial customers receive the market price in 2002, and all residential customers receive the market price in 2006.

Scenario ***I98/C00/R02 Phase-in*** represents a phased introduction of competition by partial shares of each customer class. One-half of industrial customers receive the market price in 1998, followed by the remaining one-half in 1999. One-half of commercial customers receive the market price in 2000, followed by the remaining commercial customers in 2001. One-half of residential customers receive the market price in 2002, followed by the remaining residential customers in 2003.

Scenario ***R98/C00/I00*** represents a phased introduction of competition by customer class with residential preference—all residential customers receive the market price in 1998, followed by all commercial and industrial customers in 2000.

All the scenarios presented here involve retail access to competition grouped by customer class. However, it is also possible to use the ECOM Model to estimate the impact for scenarios involving narrower customer subsets, such as military installations, state government accounts, and educational institutions. The Commission asked utilities to provide cost data for select customer subsets, but many utilities stated an inability to develop and forecast such data. The Commission has not attempted to calculate such alternative retail access scenarios to date, but could perform such analyses if the proper data were available.

The ECOM Model also has the capability to estimate the rate impact on remaining captive customers under the various competitive phase-in scenarios. Rate impacts are only applicable in a phased-access scenario when some customers are able to leave the system without paying an exit- or access-fee, thus escaping their share of formerly allocated generation cost. In this situation, the *stranded* fixed costs may be reallocated to remaining customers or borne by the utility shareholders. Reallocation of such costs to captive customers will result in upward pressure on their rates.

Rate impact statistics were not calculated for this report because to do so would require speculation regarding the method and timing of ECOM allocation and recovery. ECOM is calculated on a net present value basis, and it is unclear what methodology or time period would be appropriate to recover ECOM. Furthermore, the methodology underlying the ECOM Model assumes that costs *stranded* by customers receiving access to the market price are not shifted to other customer classes. If such cost-shifting is assumed, then the result is a *shifting of ECOM* to the regulated rates of captive customers, and therefore a reduction to the utilities' potentially strandable costs.

A. ECOM Model Texas Retail Results

Texas retail ECOM represents the degree to which the costs of a utility's generation resources exceed the revenues that the utility will receive from selling electricity in a competitive retail market. In the ECOM Model analysis, Texas retail consists of all generation and existing purchased power obligations allocable to the Texas retail jurisdiction.[145] The values presented in this report are estimates only, and should *not* be considered as conclusive determinations of ECOM for any given utility. As discussed in Chapter VI, the ECOM estimates are sensitive to a number of variables, with the market price of electricity producing the most variation in the estimation of ECOM. The sensitivity of the ECOM results to the uncertainty associated with future market prices is captured in the range of ECOM estimates presented in each competitive access scenario.[146]

Estimates of the magnitude of potentially strandable costs are important because the size of ECOM may affect how policy makers choose to structure ECOM allocation and recovery methodologies. Also, the magnitude of ECOM may play a role in decisions regarding the timing of competitive access in the Texas retail electric market.

In the Texas retail ECOM analysis, *positive ECOM values* indicate that, on a net present value basis, the utility's allocated Texas retail generation cost-of-service is greater than the revenues the utility may receive in a competitive market; in other words, the book value of the utility's generation assets is greater than the value of the generation assets in a competitive market. In contrast, *negative ECOM values* indicate that the utility's Texas retail allocated generation cost-of-service is less than the revenues the utility may receive in a competitive market (on a net present value basis).

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[145] Texas retail costs both inside and outside of ERCOT are included in the ECOM analysis. Utility generation and purchased power costs that are allocable to other state jurisdictions, the federal wholesale jurisdiction, and the Texas wholesale jurisdiction *are not* included in the Texas retail analysis.

[146] As discussed in Chapter VI, the ECOM results are presented for each scenario as an expected value with a 90 percent confidence interval. This range of the 90 percent confidence interval is representative of the range of most likely outcomes for ECOM for each utility in each scenario. An even wider range of ECOM outcomes is established by the *extreme high* and *extreme low* ECOM outcomes, which carry a relatively low probability of occurrence. Section B.2. of this Chapter presents an analysis of the sensitivity of the Texas retail ECOM estimates to the future market price of electricity.

In the transition to a competitive retail electricity market, to the extent utilities with *positive ECOM* are granted recovery of such costs from ratepayers or otherwise, utilities with *negative ECOM* should likewise be required to pass through to ratepayers the benefits of their low cost generation resources.

1. Overview of Texas Retail ECOM Model Results

Table VIII–2: Total Texas Retail ECOM Model Results ($1996 millions, 10 percent O&M efficiency improvement)

Scenario Name	Extreme High	95th percentile	Expected Value	5th percentile	Extreme Low
1998Full	$ 21,126	$ 16,396	$ 12,816	$ 9,188	$ 3,475
2000Full	14,628	9,945	7,243	4,487	(832)
I98/C00/R02	13,959	9,172	6,661	4,120	(1,327)
I98/C02/R06	10,088	6,411	4,065	1,715	(2,635)
I98/C00/R02 Phase-in	12,840	8,400	5,862	3,293	(1,800)
R98/C00/I00	17,767	12,961	9,913	6,834	1,368

Note: In addition to asset net book values, fixed costs include projected federal income tax and property tax payments in the ECOM model. Thus, net ECOM for specific assets may exceed asset book values by the net present value of federal income tax and property tax payments in the projected generation cost-of-service.

Table VIII–2 and Figure VIII–1 summarize the range of estimated ECOM for the Texas retail jurisdiction, including ERCOT and non-ERCOT service areas within the State of Texas, assuming the utilities are able to achieve a 10 percent improvement in O&M efficiency.[147] Table VIII–3 presents ECOM results assuming no efficiency improvements. The Texas retail results exclude the Texas wholesale ECOM estimated in Chapter VII. In the *1998Full* scenario, the expected value of total Texas retail ECOM is approximately $12.8 billion, with the 90 percent confidence interval ranging from approximately $9.2 to $16.4 billion. In the *2000Full* scenario, the expected value of total Texas retail ECOM is lower, at approximately $7.2 billion, with the 90 percent confidence interval ranging from approximately $4.5 to $9.9 billion.

[147] The 10 percent O&M efficiency improvement factor incorporates a 10 percent reduction in base O&M expenditures in the initial year in which competition is introduced in the ECOM Model, with no further reductions thereafter.

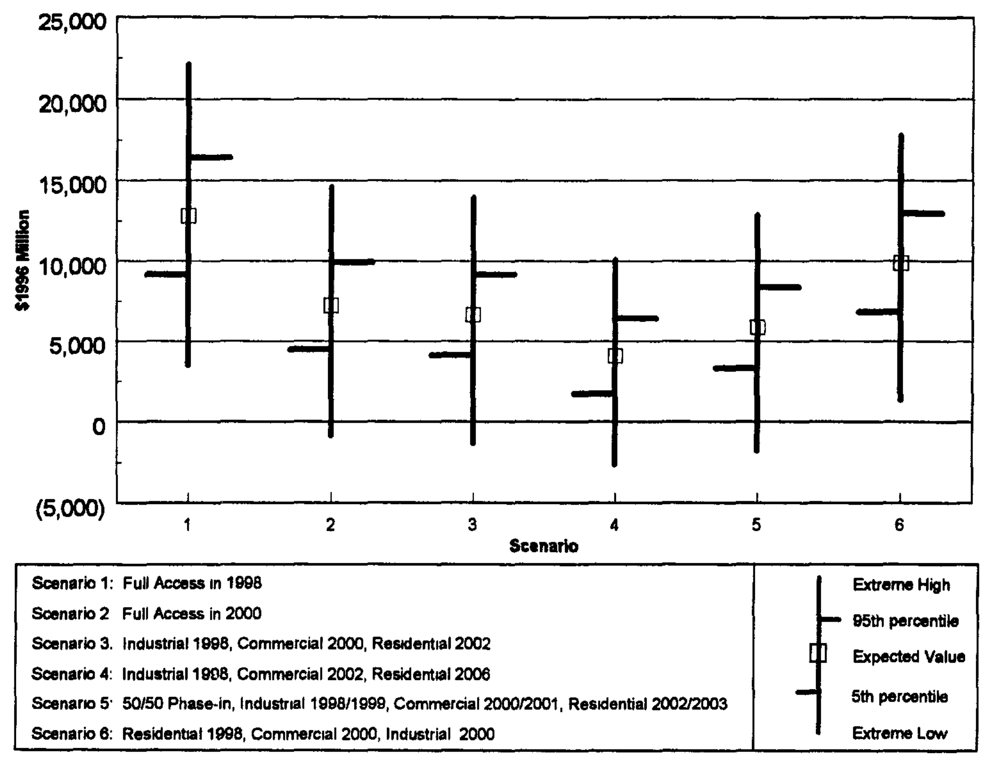


Figure VIII–1: Total Texas Retail ECOM Model Results ($1996 Million)

Comparing the estimated ECOM results with annual utility sales and asset values is helpful to put the ECOM estimates in perspective. For the utilities that filed ECOM reports, annual Texas retail cost-of-service generation-related revenues are approximately $10.5 billion dollars per year. Thus, the total net present value of ECOM over the life of existing generation assets[148]—equal to $12.8 billion ($1996) in the *1998Full* scenario—is more than $2 billion greater than the annual generation-related revenues currently collected by utilities. Similarly, in the *2000Full* scenario, the $7.2 billion ($1996) expected value for ECOM is approximately $3.3 billion dollars less than the annual generation-related revenues currently collected by utilities in their regulated rates.

Comparing the estimated ECOM results with total fixed costs is another measure that is helpful to put the ECOM estimates in perspective. Combined, utilities in Texas have

[148] Including related fixed cost commitments as defined in Chapter VI.

fixed generation costs[149] equal to approximately $32 billion on a net present value basis ($1996). Thus, the $12.8 billion expected value for ECOM in the *1998Full* scenario is approximately 40 percent of the total fixed costs in the utilities' generation costs-of-service.

Table VIII–3: Total Texas Retail ECOM Model Results ($1996 millions, 0 percent O&M efficiency improvement)

Scenario Name	Extreme High	95th percentile	Expected Value	5th percentile	Extreme Low
1998Full	$ 22,245	$ 17,806	$ 14,188	$ 10,560	$ 4,847
2000Full	15,593	11,126	8,393	5,637	337
I98/C00/R02	14,938	10,317	7,777	5,235	(191)
I98/C02/R06	10,884	7,316	4,970	2,618	(1,708)
I98/C00/R02 Phase-in	13,772	9,503	6,935	4,365	(709)
R98/C00/I00	18,832	14,243	11,165	8,086	2,643

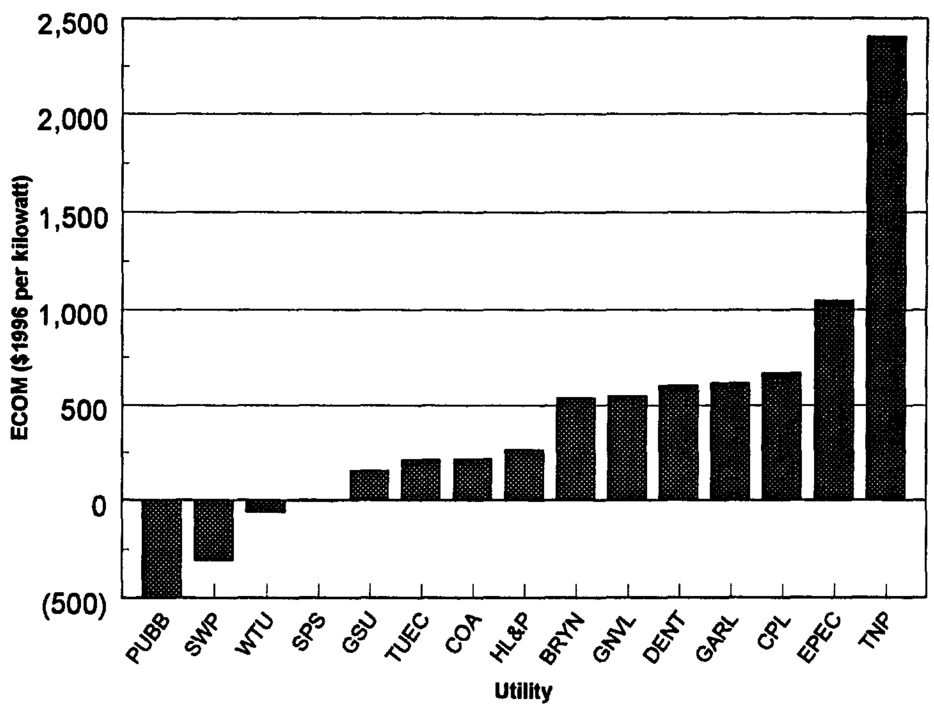
Note: In addition to asset net book values, fixed costs include projected federal income tax and property tax payments in the ECOM model. Thus, net ECOM for specific assets may exceed asset book values by the net present value of federal income tax and property tax payments in the projected generation cost-of-service.

2. Normalized Levels of ECOM

In comparing ECOM results for utilities of differing size and structure, the relative exposure to potentially strandable investments can be examined by *normalizing* the ECOM results, that is, transforming the absolute dollar amount of estimated ECOM to a unit of standard measure. This can be achieved in a number of ways; however, for the purpose of comparison in this report, each utility's estimated dollar amount of ECOM is divided by the utility's installed generating capacity to arrive at a normalized ECOM value, in dollars per kilowatt ($/kW). Figure VIII–2 depicts the normalized utility ECOM results for the *1998Full* scenario. As shown, TNP has the largest ECOM on a $/kW basis, more than double that of EPEC. CPL has the third largest ECOM burden on a normalized basis; however, CPL affiliates WTU and SWP are among the lowest. While TUEC has the greatest amount of ECOM in absolute dollars, the utility ranks in the lower half of the group on a dollars per kilowatt basis. The

[149] As described in Chapter VI, the fixed generation costs in this analysis include depreciation and return on current investment, federal income taxes, property taxes, nuclear decommissioning costs, and existing purchased

figure also illustrates the high exposure to potentially strandable costs faced by the municipalities that comprise the Texas Municipal Power Authority, with these four cities showing relatively high normalized ECOM estimates.[150] Because of the unique financing and governing structures of municipalities and cooperatively owned utilities, the assessment of the magnitude and treatment of potentially strandable costs in the transition to a competitive retail electric market will require paying close attention to the particular circumstances of these entities. As such, the manner in which the issue of potentially strandable costs is ultimately resolved may differ for municipalities and cooperatives as compared to IOUs.



Notes: Based upon the ECOM expected value as measured in the *1998Full* scenario. ECOM per kW is measured in $1996 per installed kW of Texas retail capacity. ECOM results include existing purchased power contracts.

Figure VIII–2: Normalized Texas Retail ECOM Model Results for the *1998Full* Scenario

power contract costs. The total fixed costs of approximately $32 billion ($1996) is the sum of the net present value of the fixed costs in each utility's ECOM filing.

[150] The Texas Municipal Power Authority is comprised of the Cities of Bryan, Denton, Garland, and Greenville.

3. Texas Retail ECOM by Resource Type

Table VIII–4 examines total Texas retail ECOM for the *1998Full* scenario by resource type (natural gas, coal/lignite, nuclear, and other). As noted previously, the *1998Full* scenario is the quickest transition to a competitive retail market and produces the highest estimates of Texas retail ECOM. As shown in Table VIII–4, nuclear assets comprise the lion's share of potentially strandable costs, with an expected value of nuclear-related ECOM in excess of $15 billion. Excluding nuclear assets, the expected value of total Texas retail ECOM in the *1998Full* scenario is reduced to *negative* $2.3 billion. Thus, in the aggregate, the non-nuclear assets of Texas utilities are expected to generate power at average costs that are below the projected market price of electricity. The original capital investment in these non-nuclear assets is less than the nuclear investment, and the older non-nuclear assets have had time to become more fully depreciated. Both of these factors result in lower remaining book costs for non-nuclear generating assets. In addition, the operating costs of most of the non-nuclear assets are low relative to the projected market prices, thus providing for a sizable margin in a competitive market that will offset the remaining fixed costs of the non-nuclear generation assets.

Table VIII–4: Total Texas Retail ECOM Summary by Resource Type (*1998Full* scenario)

Generation Resource Type	Expected Value of Texas Retail ECOM ($1996 million)
Natural Gas	$ 2,020
Coal/Lignite	(4,630)
Nuclear	15,085
Purchased Power/Other	341
Total	**12,816**
Total Excluding Nuclear	**(2,269)**

Note: See Appendix B for individual utility ECOM results.

B. Retail ECOM Trends and Observations

A detailed review of the ECOM filings of the utilities in Texas reveals a number of interesting observations. Among these are the sensitivity of the ECOM estimate to the timing of retail access; the sensitivity of the ECOM estimate to the future market price of electricity; and the effect of including a risk-adjusted versus a risk-free rate of return in the ECOM calculation.

1. Sensitivity of ECOM to the Timing of Retail Access

The timing of the implementation of retail access is key in determining the magnitude of ECOM, regardless of the other assumptions incorporated into the analysis. Obviously, if retail access is never implemented, a utility will have no stranded costs as the utility will continue to collect revenues from ratepayers at cost-based rates.

However, as explained in Chapters I and II, ECOM can be identified even without retail access because the utilities' book costs differ from a competitive market value. As time passes, depreciation and retirement of generation assets cause the magnitude of ECOM to decrease as the utility's generation cost-of-service declines. This discussion will focus on the magnitude of ECOM as it changes over time, regardless of the retail market structure.

For utilities whose production costs exceed projected market prices, time alone is the single greatest factor affecting the level of retail ECOM. For every year that a utility can continue collecting cost-of-service based rates, it can further depreciate its over-market assets with the regulated revenue stream, thus reducing the level of generation investment remaining at risk in a competitive retail market. For the Texas retail market, the expected value of ECOM for the *1998Full* scenario is approximately $12.8 billion ($1996); but, with retail access delayed only two years, the expected value of ECOM for the *2000Full* scenario falls to approximately $7.2 billion ($1996). Thus, in just two years of continued utility collection of traditional cost-based rates, utility fixed costs (and ECOM) are reduced by $5.6 billion ($1996), or 44 percent, for the total Texas retail market. By delaying retail access an additional two years to the year 2002, the expected value of total Texas retail ECOM is reduced by an additional 36 percent to approximately $4.6 billion ($1996).[151] Thus, on a total Texas retail basis, delayed retail access has the effect of reducing ECOM by about 20 percent per year.

An important observation in the above analysis is that the estimates are all presented in $1996. Thus, the analysis implicitly assumes that ECOM is "settled"[152] in 1996, and that regulated rates continue to the year of deregulation. For example, the Statewide Texas retail ECOM estimate for the *1998Full* scenario of $12.8 billion ($1996) assumes that ECOM is "settled" in 1996, and that regulated rates continue until retail access is implemented beginning in 1998. Likewise, the Statewide Texas retail ECOM estimate of $7.2 billion ($1996) for the *2000Full* scenario assumes that ECOM is "settled" in 1996, and that regulated rates continue until retail access is implemented beginning in the year 2000.

If ECOM levels are "settled" in years other than 1996, the dollar amounts will change due to the time value of money. For example, it may be more appropriate to assume that ECOM is "settled" in the year in which retail access is implemented rather than in 1996. If the estimate of Statewide Texas Retail ECOM for the *1998Full* scenario of $12.8 billion ($1996) is "settled" in 1998 rather than in 1996, the value in $1998 increases to $15.1 billion solely because of the time value of money.[153] Likewise, if the estimate of Statewide Texas Retail ECOM for the *2000Full* scenario of $7.2 billion ($1996) is "settled" in the year 2000 rather than in 1996, the value increases to $10.0 billion ($2000). Table VIII–5 contains a matrix of ECOM estimates for the *1998Full* and *2000Full* scenarios with varying ECOM "settlement" dates.

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[151] Delayed retail access is actually detrimental to low-cost producers (or the current customers of the low-cost producers in the instance that *negative* ECOM is flowed-through to the utility's customers) in that such utilities may actually sell power at cost-based rates that are *lower* than what they might otherwise receive in a competitive market.

[152] The term "settled" refers to the date at which the level of ECOM is determined and a mechanism is implemented for the recovery of the percentage of ECOM that is appropriately allocated to the customers of a utility.

[153] In this case, a growth rate of 8.5 percent (the generic after-tax weighted average cost of capital used in the ECOM Model) is applied for two years to transform $12.8 billion in $1996 to $15.1 billion in $1998.

Table VIII–5: Statewide Texas Retail ECOM Estimates with Varying ECOM "Settlement" Dates (billions)

	$1996	$1997	$1998	$1999	$2000
Statewide Texas Retail ECOM Estimate for the *1998Full* Scenario	$ 12.8	$ 13.9	$ 15.1	n/a	n/a
Statewide Texas Retail ECOM Estimate for the *2000Full* Scenario	7.2	7.8	8.5	$ 9.2	$ 10.0

Note: Results table incorporate a 10 percent O&M efficiency improvement.

2. Sensitivity of ECOM Estimates to the Market Price

As noted previously, the estimation of ECOM is also very sensitive to the projection of the future market price of electricity. In the ECOM Model, the sensitivity of the results to the market price is effectively captured through the presentation of a range of ECOM values as discussed in Chapter VI.

Roughly speaking, for every 1 percent deviation from the projected base case market price, the estimated total Texas retail ECOM results will change by approximately $450 million on a net present value basis. Thus, if the base case annual average market price were increased by 1 percent *in each year of the forecast period*, the resulting total Texas retail ECOM estimate would be reduced by approximately $450 million. Likewise, if the base case annual average market prices were reduced by 1 percent *in each year of the forecast period*, the resulting total Texas ECOM estimate would be increased by approximately $450 million.

As an illustration of this effect, assume that the actual annual average market price were 5 percent *higher* than the base case annual average market price in each year of the forecast period. Applying this assumption to the *1998Full* scenario results in a reduction in the estimated total Texas retail ECOM of approximately $2.3 billion, from $12.8 billion to $10.5 billion. Likewise, if the annual average market price were 5 percent *lower* than the base case annual average market price in each year of the forecast period, the total Texas retail ECOM estimated in the *1998Full* scenario would be increased by approximately $2.3 billion, from $12.8 billion to $15.1 billion.

It is important to emphasize that the sensitivities discussed above are premised upon a reduction/increase in the market price *in each year of the forecast period.* If actual market prices were higher than the projected market price in some years and less than the projected market price in other years, the effect of such variations would likely net out to produce a level of ECOM comparable to the base case result. Furthermore, the presentation of a range of ECOM values in each scenario is intended to incorporate and account for the uncertainty associated with the future market price of electricity.[154]

3. Rate of Return on Equity

Utility generation cost-of-service ratemaking allows the opportunity to recover a return on utility investment. In the ECOM Model, the rate of return for IOUs is specified at 10 percent.[155] The 10 percent rate of return reflects the various risks to which a utility is currently exposed, not the risk associated with *guaranteed* recovery of investments. Some methods of ECOM recovery have been proposed that would guarantee a utility recovery of a percentage of its measured stranded costs through some type of non-bypassable charge. If such a guaranteed recovery mechanism were implemented, it may be appropriate to reduce the utility's rate of return on equity (and, thus, the overall rate of return) in accordance with its reduced risk profile.[156] Lowering the return component of the cost-of-service will reduce the utility's total generation cost-of-

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[154] The development of the market price of electricity is based upon an economic analysis in which the future market prices were "constructed" using various cost components such as fuel and capital costs. In addition, the market price projections include a 5 percent adder resulting from the value that fuel diversity may add to a competitive market price. The exclusion of the fuel diversity portion of the market price would have the effect of reducing the market price, and therefore increasing ECOM estimates. The quantitative effect of removing the fuel diversity component of the projected market price would be comparable to the 5 percent reduction in market price discussed above on a Statewide Texas retail basis. Noteworthy, however, is that actual data and utility projections indicate market prices that are ***higher*** than the prices projected in the ECOM Model, including the fuel diversity component (see discussion at Chapter VI(B)(3) of this report).

[155] The rate of return on equity is a component of the overall utility rate of return. The rate of return for municipal utilities, river authorities, and cooperatives was specified at 7.5 percent; however, procedures were adopted to allow these entities to adjust this number to reflect their individual debt service requirements in each year of the forecast period.

[156] It has also been suggested in comments on the draft report that risk premia that previously have been collected by utilities in rates charged customers "could be considered to represent an excess recovery. This amount could be applied to mitigate the impact of any 'stranding' by consumers . . . A true-up of these amounts would be possible at the time of an IOU's final recovery of stranded costs." See comments of Marta Greytok on behalf of the Aluminum Company of America (ALCOA), "A Practical Solution to the 'Stranded Cost' Dilemma," Project No. 15001, at 5 (November 25, 1996).

service, and thus the level of ECOM. Quantification of the magnitude of a reduction in the rate of return is beyond the scope of this analysis, but could be estimated using the ECOM Model.[157]

4. Utility Generation Cost Projections

As described in Chapter VI, utilities were required to provide projections of their generation costs and sales for the life of the longest-lived plant in the utility's rate base. While these projections were examined for general consistency, a rigorous analysis of specific aspects of the generation costs was not performed. With the exception of the 10 percent O&M efficiency improvement adjustment, this analysis has not attempted to examine the impact of options that would allow utilities to reduce or mitigate their stranded cost exposure, such as aggressive cost-cutting measures, economic capital additions to enhance plant performance, and economic extension of plant lives, among others. Such measures would either reduce a utility's cost relative to market prices or provide increased revenues and contributions to fixed costs, thereby reducing the magnitude of assets at risk of under-recovery in a competitive market.

C. Individual Utility Retail ECOM Model Results

This section graphically portrays the Texas Retail ECOM Model results for each of the six competitive retail access scenarios. The graphical representation of each scenario can be interpreted as follows:[158]

- **Extreme High ECOM Estimate** - Represented by the top of the vertical line.
- **95th Percentile ECOM Estimate** - Represented by the right tick mark on the vertical line.
- **Expected Value ECOM Estimate** - Represented by the square in the middle of the vertical line.

[157] Federal income tax (FIT) payments are a function of the return component in the cost-of-service. Therefore, a reduction in the return will result in a reduction in the projected FIT payments as well, although the reduction in FIT will not be directly proportional to the reduction in the return. Analysis of the effect of a reduction in the return on the projected FIT payments would require an extensive analysis conducted on a utility-by-utility basis.

[158] For a more detailed discussion regarding the interpretation of the ECOM presentation figures, see Chapter VI(B)(2).

- **5th Percentile ECOM Estimate** - Represented by the left tick mark on the vertical line.
- **Extreme Low ECOM Estimate** - Represented by the bottom of the vertical line.

Table VIII–6 summarizes utility-by-utility results for the *1998Full* and *2000Full* scenarios. Detailed results for individual utilities are contained in Appendix B.

Table VIII–6: Individual Utility Texas Retail ECOM Model Results for Scenarios *1998Full* and *2000Full*

Utility	*1998Full* Expected Value of ECOM ($1996 million)	*2000Full* Expected Value of ECOM ($1996 million)	*1998Full* Expected Value of ECOM per kW	*2000Full* Expected Value of ECOM per kW	Utility Sales as a Percent of Texas Retail MWh Sales
Total Texas Retail	$ 12,816	$ 6,985	$ 253	$ 141	100.0
WTU	(63)	(122)	(63)	(123)	1.7
TUEC	4,090	1,913	211	99	32.8
CPL	2,251	1,611	568	406	7.5
HL&P	3,587	2,084	263	153	24.2
EPEC	1,051	778	1,048	776	1.7
GSU	426	181	156	66	5.2
SWP	(470)	(457)	(311)	(302)	3.0
SPS	(8)	(145)	(4)	(67)	4.2
TNP	707	518	2,406	1,760	2.1
COA	519	305	213	125	2.9
PUBB	(100)	(107)	(496)	(528)	0.3
BRYN	178	147	536	443	0.3
DENT	171	147	601	516	0.3
GARL	401	322	616	513	0.6
GNVL	82	68	545	456	0.2

Note: Individual utility percentage of Texas retail sales do not add to 100 percent because certain municipalities that did not file ECOM reports are not included in the list. Utility generation capacity is measured as the current installed Texas retail generation capacity in kilowatts.

1. West Texas Utilities Company (WTU) Texas Retail ECOM Highlights

- WTU has a *negative* expected value for ECOM for all six competitive retail access scenarios.
- WTU owns only coal- and gas-fired generation, thus avoiding the nuclear cost burden.
- Among the nine Texas IOUs, WTU has the second lowest ECOM on a per kW of installed capacity basis.
- WTU's Texas retail sales represent approximately 1.7 percent of the total Texas retail market.

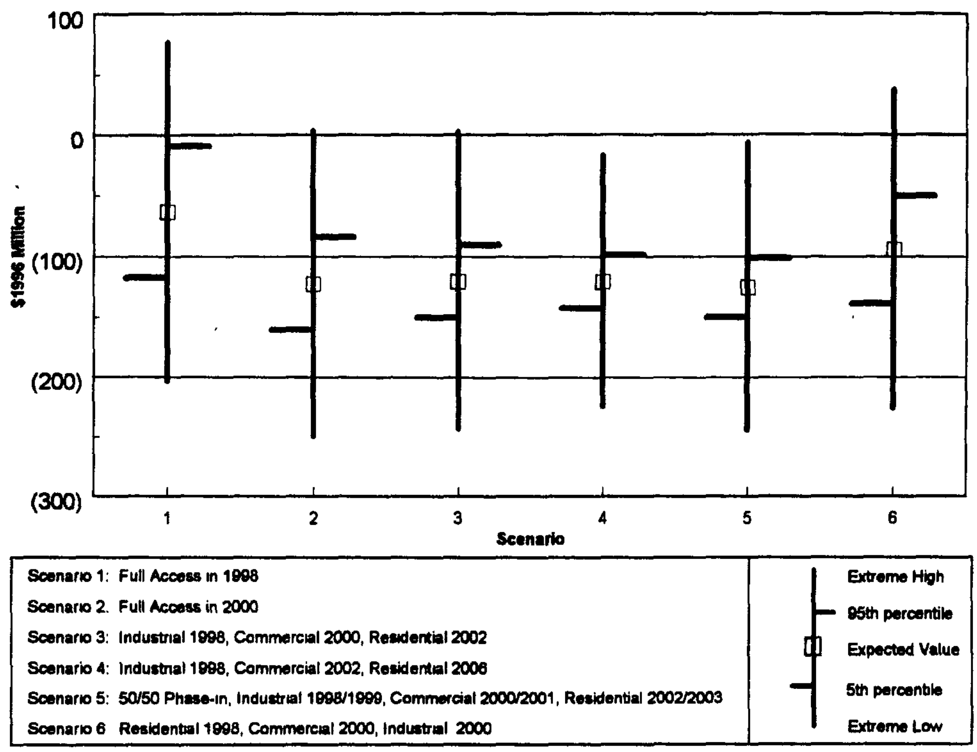

Figure VIII–3: West Texas Utilities Company Texas Retail ECOM Model Results ($1996 million)

2. Texas Utilities Electric Company (TUEC) Texas Retail ECOM Highlights

- TUEC's ECOM is largely a function of its investment in the Comanche Peak nuciear plant.
- TUEC's lignite plants appear to be very competitive and serve to offset a portion of the ECOM associated with Comanche Peak.
- Excluding Comanche Peak from TUEC's ECOM calculation results in *negative* ECOM for TUEC.
- Among the nine Texas IOUs, TUEC has the fifth lowest ECOM on a per kW of installed capacity basis.
- TUEC's Texas retail sales represent approximately 32.8 percent of the total Texas retail market.

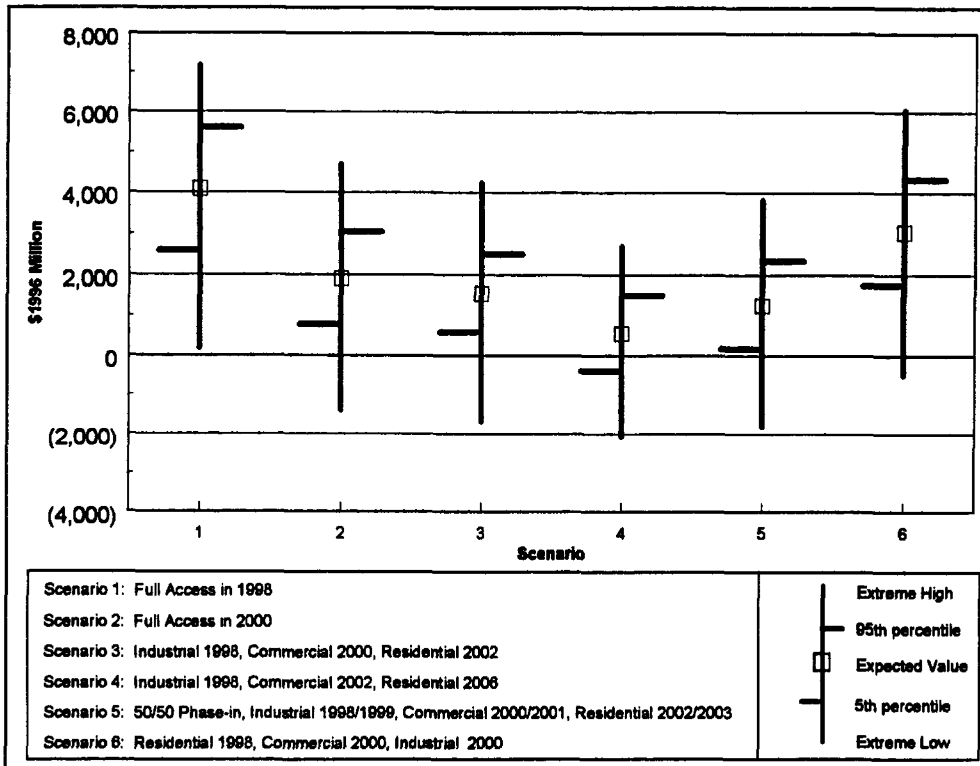

Figure VIII–4: Texas Utilities Electric Company Texas Retail ECOM Model Results ($1996 million)

3. Central Power and Light Company (CPL) Texas Retail ECOM Highlights

- CPL's ECOM is largely a function of its investment in the South Texas Nuclear Project.
- Excluding the South Texas Project from CPL's ECOM calculation results in *negative* ECOM for CPL.
- Among the nine Texas IOUs, CPL has the third highest ECOM on a per kW of installed capacity basis.
- CPL's Texas retail sales represent approximately 7.5 percent of the total Texas retail market.

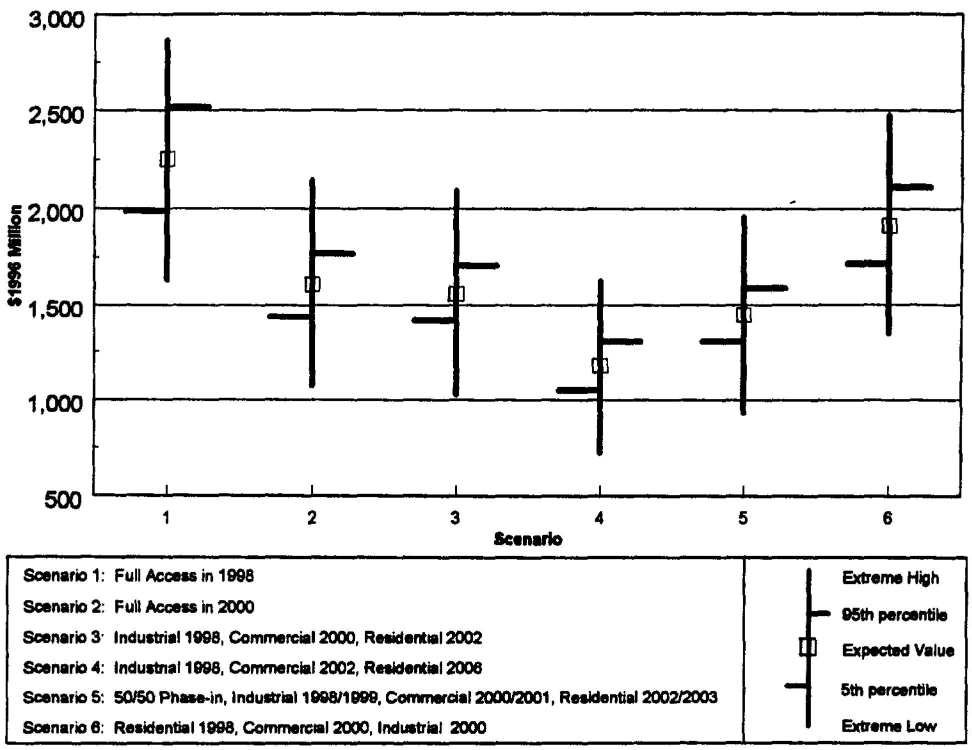

Figure VIII–5: Central Power & Light Company Texas Retail ECOM Model Results ($1996 million)

4. Houston Lighting and Power Company (HL&P) Texas Retail ECOM Highlights

- HL&P's ECOM is largely a function of its investment in the South Texas Nuclear Project.
- A significant portion of HL&P's ECOM is comprised of costs allocated to natural gas-fired generation.[159]
- Excluding the South Texas Project from HL&P's ECOM calculation reduces HL&P's ECOM by approximately 80 percent.
- Among the nine Texas IOUs, HL&P has the fourth highest ECOM on a per kW of installed capacity basis.
- HLP's Texas retail sales represent approximately 24.2 percent of the total Texas retail market.

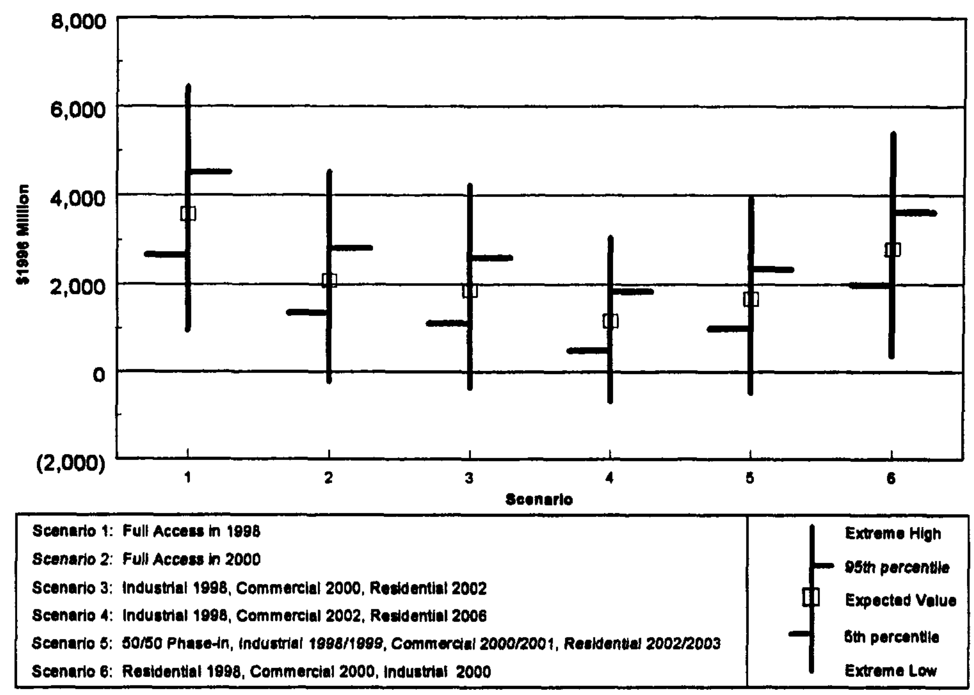

Figure VIII–6: Houston Lighting & Power Company Texas Retail ECOM Model Results ($1996 million)

[159] HL&P has an unusually high level of ECOM associated with its natural gas-fired plants. Appendix B indicates that HL&P's estimated natural gas related ECOM in the *1998Full* scenario comprises approximately 55 percent of the Statewide total of estimated ECOM for natural gas-fired generation resources. Inspection of HL&P's natural gas related generation costs reveals that the company's O&M costs (excluding fuel) are high relative to other IOUs. The high O&M costs result in a reduced operating margins, therefore causing higher levels of ECOM for HL&P's natural gas plants relative to other Texas IOUs. Should an administrative method of quantifying stranded costs be ultimately adopted, this issue should be examined in further detail.

5. El Paso Electric Company (EPEC) Texas Retail ECOM Highlights

- EPEC's ECOM is largely a function of its investment in the Palo Verde Nuclear Plant.
- Excluding the Palo Verde Nuclear Plant from EPEC's ECOM calculation results in near zero ECOM for EPEC.
- Among the nine Texas IOUs, EPEC has the second highest ECOM on a per kW of installed capacity basis.
- EPEC's Texas retail sales represent approximately 1.7 percent of the total Texas retail market.

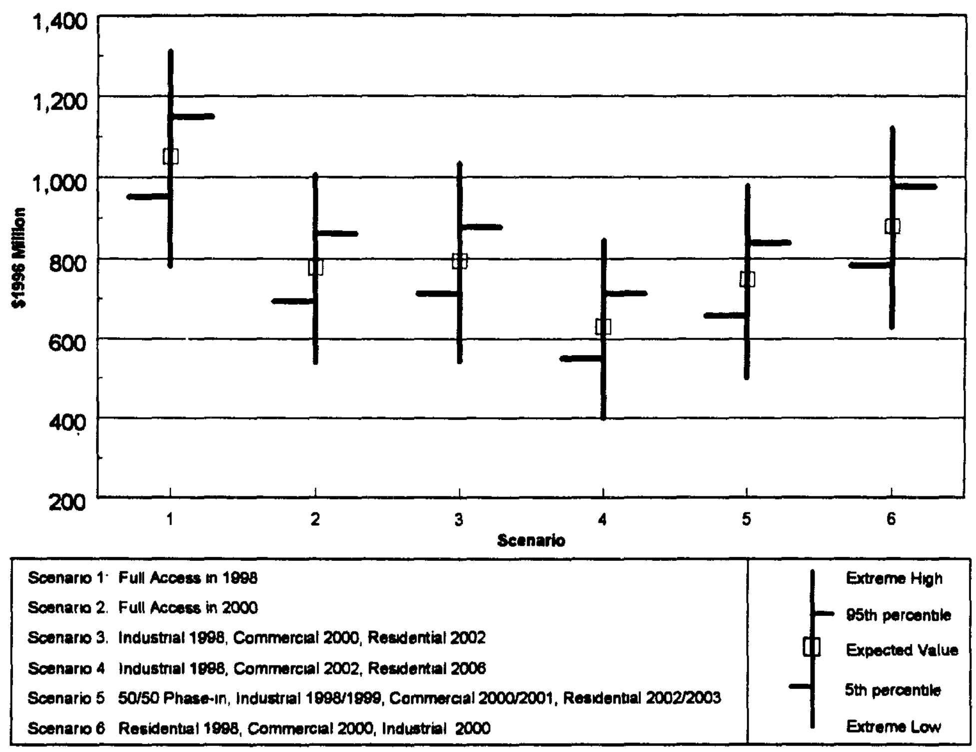

Figure VIII–7: El Paso Electric Company Texas Retail ECOM Model Results ($1996 million)

6. Gulf States Utilities Company/Entergy (GSU) Texas Retail ECOM Highlights

- GSU's ECOM is largely a function of its investment in the River Bend Nuclear Plant.
- Excluding the River Bend Nuclear Plant from GSU's ECOM calculation results in *negative* ECOM for GSU.
- Among the nine Texas IOUs, GSU has the fourth lowest ECOM on a per kW of installed capacity basis.
- GSU's Texas retail sales represent approximately 5.2 percent of the total Texas retail market.

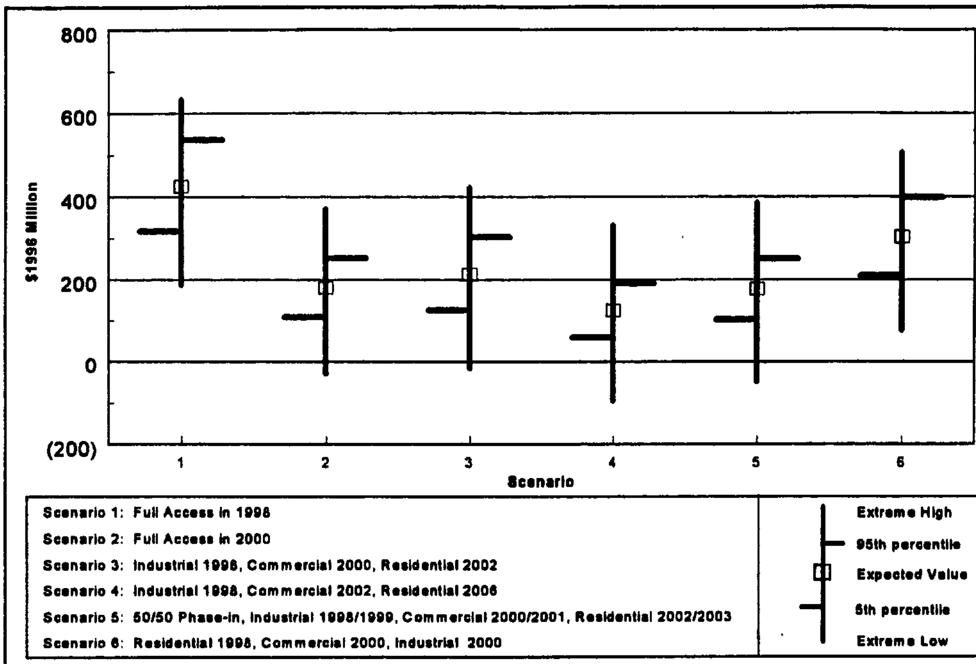

Figure VIII–8: Gulf States Utilities Company Texas Retail ECOM Model Results ($1996 million)

7. Southwestern Electric Power Company (SWP) Texas Retail ECOM Highlights

- SWP has a *negative* expected value for ECOM for all six competitive retail access scenarios.
- Among the nine Texas IOUs, SWP has *the lowest* ECOM on a per kW of installed capacity basis.
- SWP's Texas retail sales represent approximately 3.0 percent of the total Texas retail market.

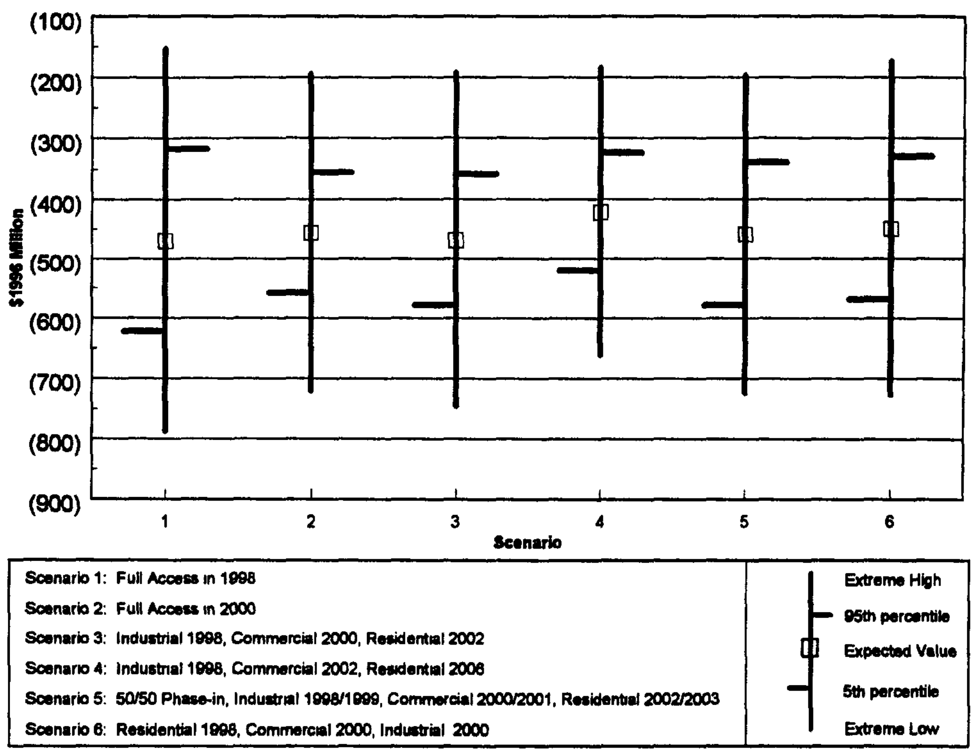

Figure VIII–9: Southwestern Electric Power Company Texas Retail ECOM Model Results ($1996 million)

8. Southwestern Public Service Company (SPS) Texas Retail ECOM Highlights

- SPS has a *negative* expected value for ECOM for all six of the competitive retail access scenarios.
- Among the nine Texas IOUs, SPS has the third lowest ECOM on a per kW of installed capacity basis.
- SPS's Texas retail sales represent approximately 4.2 percent of the total Texas retail market.

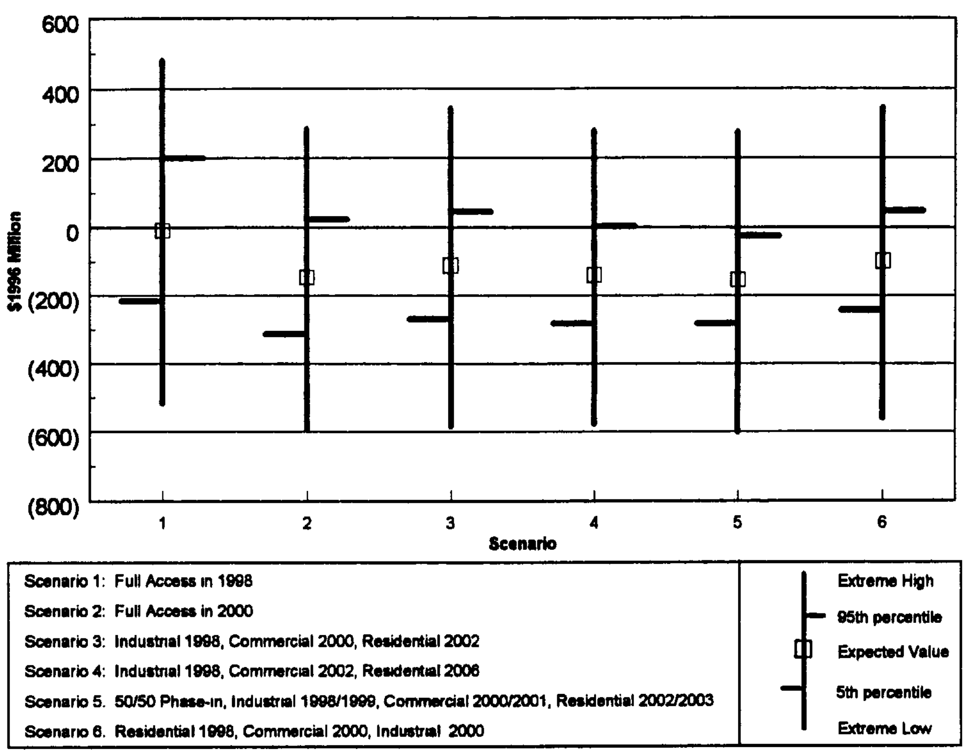

Figure VIII–10: Southwestern Public Service Company Texas Retail ECOM Model Results ($1996 million)

9. Texas-New Mexico Power Company (TNP) Texas Retail ECOM Highlights

- TNP's ECOM is a function of costs related to its sole generation facility, TNP ONE, and costs related to existing purchased power commitments.
- Among the nine Texas IOUs, TNP has *the highest* ECOM on a per kW of installed capacity basis.
- TNP's Texas retail sales represent approximately 2.1 percent of the total Texas retail market.

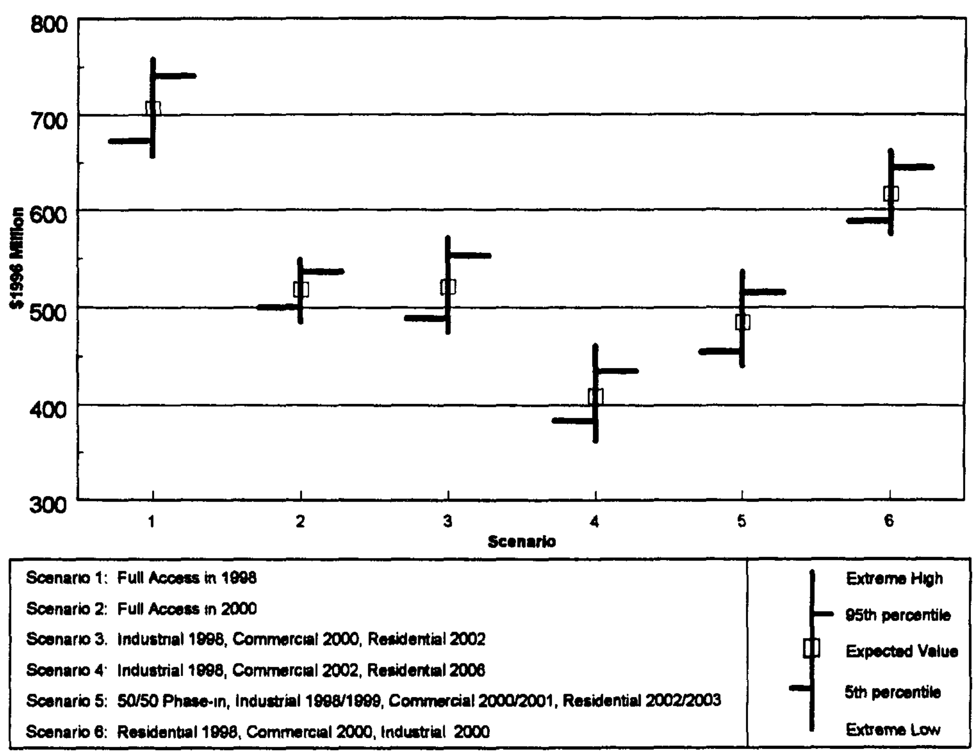

Figure VIII–11: Texas-New Mexico Power Company Texas Retail ECOM Model Results ($1996 million)

10. City of Austin (COA) Texas Retail ECOM Highlights

- Austin's ECOM is largely a function of its investment in the South Texas Nuclear Project.
- Excluding the South Texas Project from Austin's ECOM calculation results in *negative* ECOM for Austin.
- Austin's Texas retail sales represent approximately 2.9 percent of the total Texas retail market.

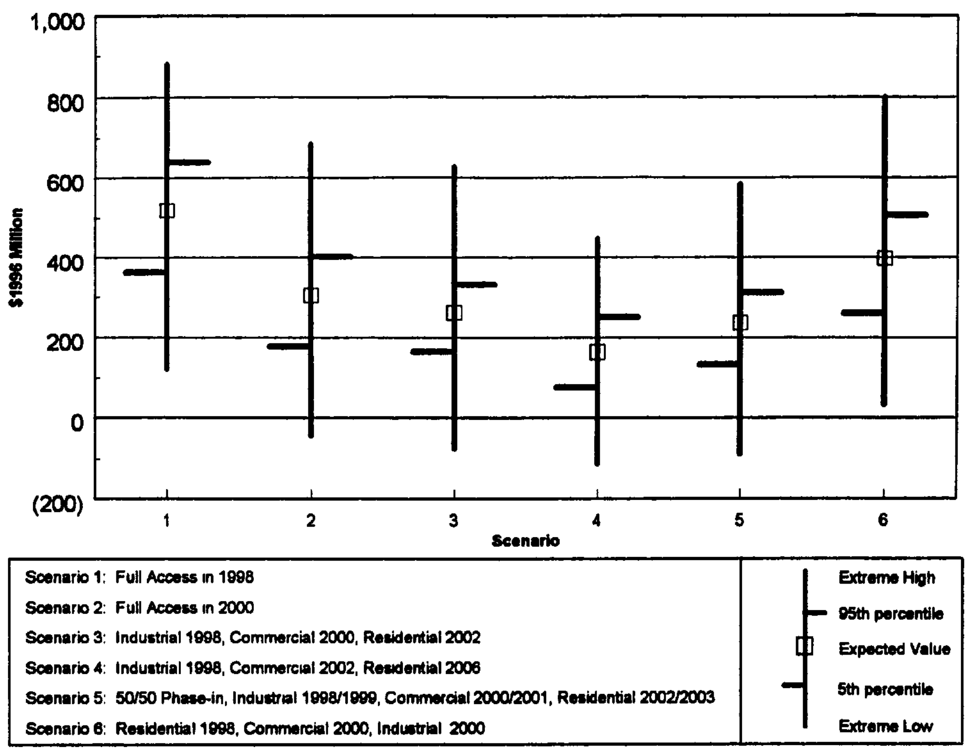

Figure VIII–12: City of Austin Texas Retail ECOM Model Results ($1996 million)

11. Public Utility Board of Brownsville (PUBB) Texas Retail ECOM Highlights

- Brownsville appears to be extremely well-positioned for competition with the lowest projected cost of generation among all Texas utilities.
- Brownsville's Texas retail sales represent approximately 0.3 percent of the total Texas retail market.

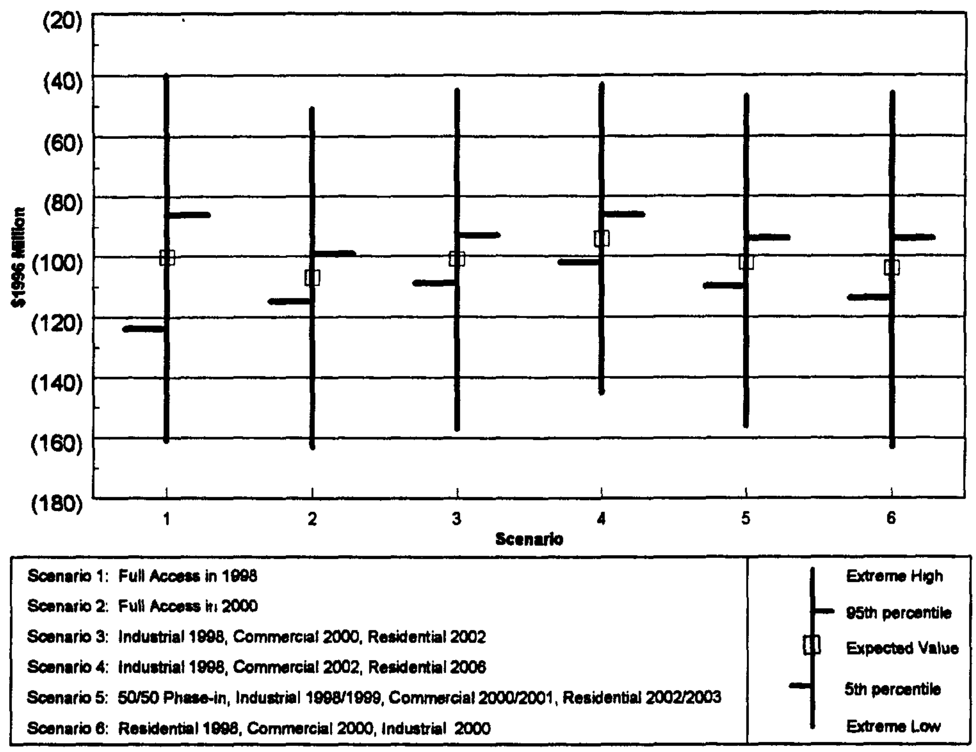

Figure VIII–13: City of Brownsville Texas Retail ECOM Model Results ($1996 million)

12. City of Bryan (BRYN) Texas Retail ECOM Highlights

- Bryan is a member of the Texas Municipal Power Agency, which operates the 452 MW Gibbons Creek Power Plant. Bryan owns approximately 21.7 percent of the Gibbons Creek Power Plant, which is the prime contributor to Bryan's relatively high ECOM.
- Excluding the Gibbons Creek Power Plant, Bryan's ECOM is reduced to near zero.
- Bryan's Texas retail sales represent approximately 0.3 percent of the total Texas retail market.

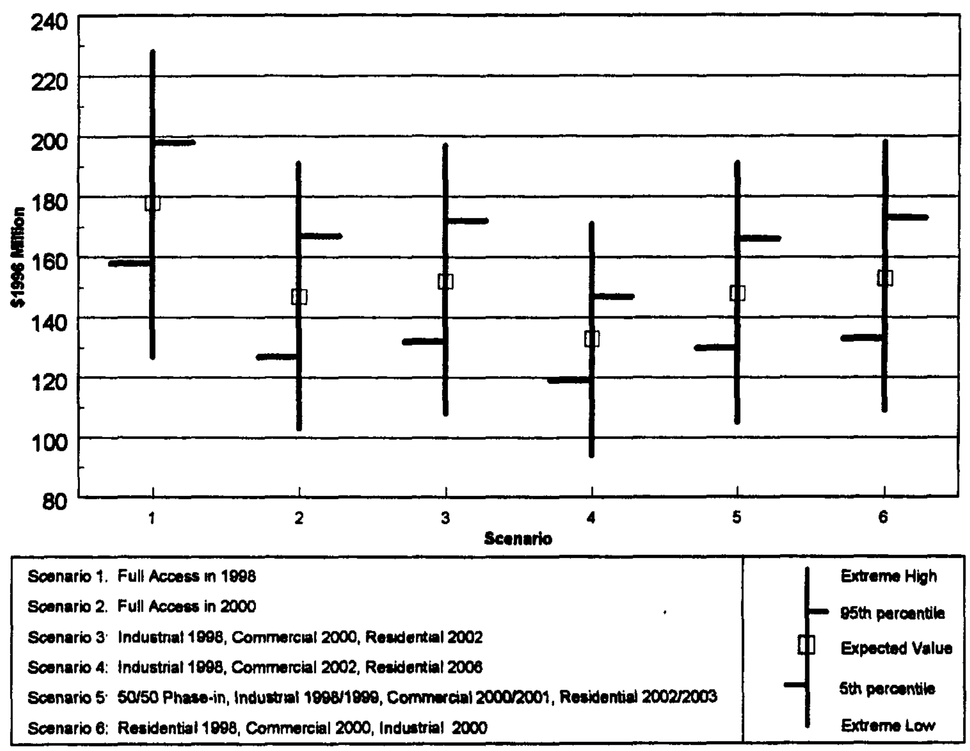

Figure VIII–14: City of Bryan Texas Retail ECOM Model Results ($1996 million)

13. City of Denton (DENT) Texas Retail ECOM Highlights

- Denton is a member of the Texas Municipal Power Agency, which operates the 452 MW Gibbons Creek Power Plant. Denton owns approximately 21.3 percent of the Gibbons Creek Power Plant, which is the prime contributor to Denton's relatively high ECOM.
- Excluding the Gibbons Creek Power Plant, Denton's ECOM is reduced to near zero.
- Denton's Texas retail sales represent approximately 0.3 percent of the total Texas retail market.

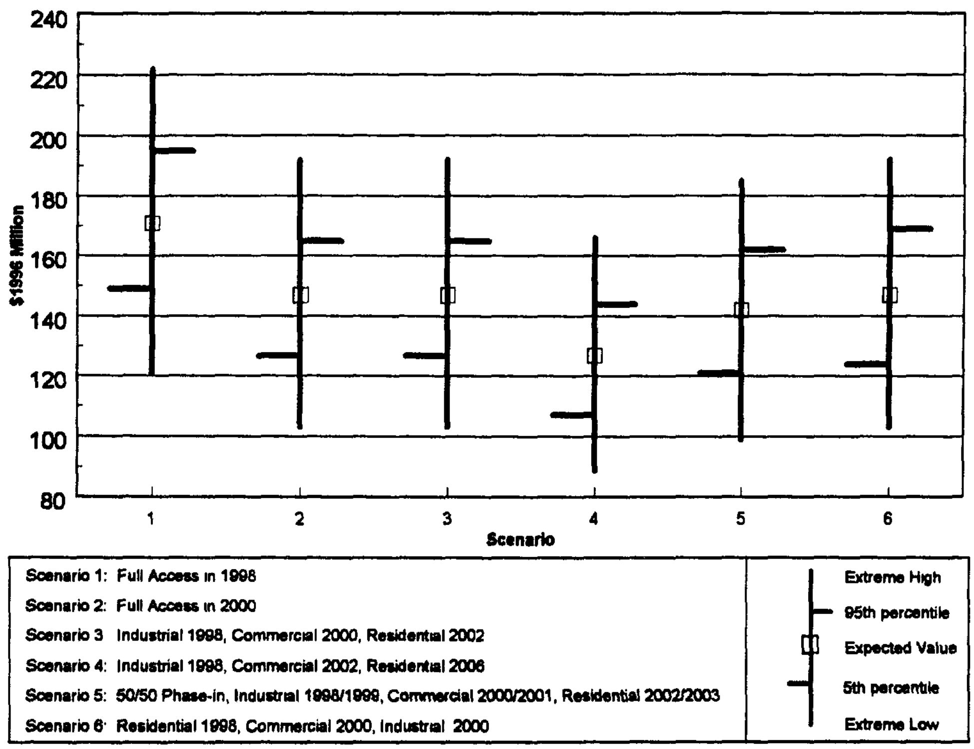

Figure VIII–15: City of Denton Texas Retail ECOM Model Results ($1996 million)

14. City of Garland (GARL) Texas Retail ECOM Highlights

- Garland is a member of the Texas Municipal Power Agency, which operates the 452 MW Gibbons Creek Power Plant. Garland owns approximately 47 percent of the Gibbons Creek Power Plant, which is the prime contributor to Garland's relatively high ECOM.
- Excluding the Gibbons Creek Power Plant, Garland's ECOM is reduced to near zero.
- Garland's Texas retail sales represent approximately 0.6 percent of the total Texas retail market.

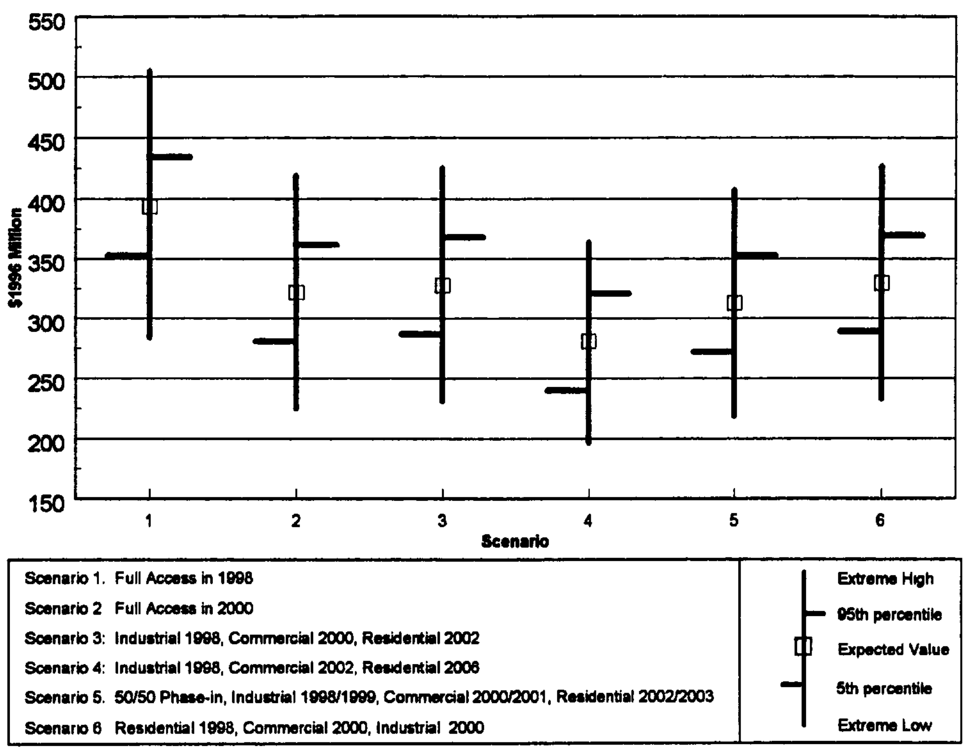

Figure VIII–16: City of Garland Texas Retail ECOM Model Results ($1996 million)

15. City of Greenville (GNVL) Texas Retail ECOM Highlights

- Greenville is a member of the Texas Municipal Power Agency, which operates the 452 MW Gibbons Creek Power Plant. Greenville owns approximately 10 percent of the Gibbons Creek Power Plant, which is the prime contributor to Greenville's relatively high ECOM.
- Excluding the Gibbons Creek Power Plant, Greenville's ECOM is reduced to near zero.
- Greenville's Texas retail sales represent approximately 0.2 percent of the total Texas retail market.

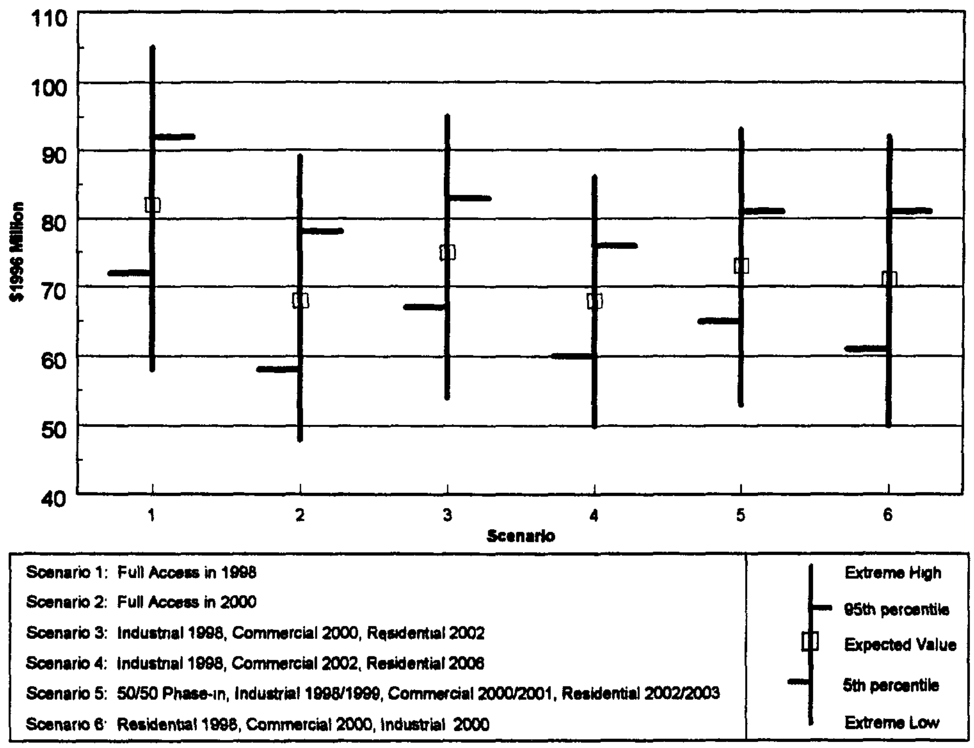

Figure VIII–17: City of Greenville Texas Retail ECOM Model Results ($1996 million)

16. Sam Rayburn G&T Cooperative (SRG&T)

SRG&T filed a late ECOM report on September 6, 1996. Because of the late filing, Staff was unable to incorporate SRG&T's data into this report. SRG&T owns 55 megawatts of coal-fired capacity.

17. Northeast Texas Electric Cooperative (NTEC)

NTEC filed a late ECOM report on September 6, 1996. Because of the late filing date, Staff was unable to incorporate NTEC's data into this report. NTEC owns 114 megawatts of lignite-fired capacity.

18. Sam Rayburn Municipal Power Agency (SRMPA)

SRMPA, consisting of the cities of Livingston, Jasper, and Liberty, has not yet filed an ECOM report but has stated its intention to do so. SRMPA owns 110 megawatts of coal-fired capacity.

19. City Public Service of San Antonio (CPS)

CPS did not file an ECOM report. CPS owns 1,340, 2,385, and 700 megawatts of coal-fired, natural gas-fired, and nuclear capacity, respectively.

20. Lubbock Power and Light (LPL)

LPL did not file an ECOM report. LPL owns 221 megawatts of natural gas-fired capacity.

IX. RIGHTS AND EXPECTATIONS FOR ECOM ALLOCATION

This chapter addresses the legal rights and expectations of regulated utilities and consumers with respect to the allocation of ECOM. Allocation is the process of assigning all or a portion of ECOM to or among classes of parties, such as firm or interruptible ratepayers, shareholders, and service providers. Allocation addresses the questions of *who* should bear ECOM; currently, customers bear ECOM through utility rates. The question of *how* to recover ECOM is closely related to allocation issues. ECOM recovery, while tangentially addressed in this chapter, is addressed in detail in the following chapter.

A. INTRODUCTION

This chapter is divided into two principal sections: (1) wholesale power sales contracts and (2) retail power sales transactions. ECOM allocation arises in the context of both wholesale and retail electric power markets. The Commission, however, does not have jurisdiction over all electric power sales within the State. Generally, the Commission has primary jurisdiction over both wholesale and retail sales of power by public utilities within the geographical boundaries of the Electric Reliability Council of Texas (ERCOT).[160] Sales by electric public utilities located within Texas but outside of ERCOT are subject to the Commission's jurisdiction to the extent these sales are in *intrastate*, as compared to *interstate*, commerce.[161] The Commission does not have jurisdiction over electric power sales by municipally owned utilities.[162]

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[160] Exceptions to this general rule are discussed below.

[161] Except for wholesale sales by Central Power and Light Company and West Texas Utilities Company, sales within the boundaries of ERCOT are sales in intrastate commerce. See *Central Power and Light Co.*, 56 FPC 432 (1976). The Federal Energy Regulatory Commission (FERC) has jurisdiction through the Federal Power Act over wholesale sales within Texas but outside of ERCOT to the extent those sales are deemed to be in *interstate* commerce. 16 U.S.C.A. §824(b)(1) (West 1985).

[162] PURA95 §§ 2.0011(1) and 2.101(a). A municipality typically has "exclusive original jurisdiction over all electric utility rates, operations, and services provided by an electric utility within its city or town limits." PURA95 §2.101(a). A municipality, however, may elect to have the Commission regulate its electric utility rates, operations, and services. PURA95 §2.101(b). Unless specifically indicated otherwise, references to "municipally owned utilities" in this chapter assume that the municipally owned utility is regulated by its municipal governing authority,

For purposes of this chapter, the Commission defines the term *wholesale* to mean a "sale for resale."[163] A *retail* power sale is defined as a sale of electric power to "ultimate consumers" (i.e., to a party that will consume, rather than resell, the power).[164]

Regardless of whether the discussion focuses on wholesale or retail markets, the relevant constituencies of the electric power industry directly affected by ECOM allocation in Texas include: consumers, shareholders, bondholders, cooperative associations, river authorities, municipalities, municipally owned electric utilities, and investor-owned utilities (IOUs). This chapter does not discuss in detail the legal rights and expectations of exempt wholesale generators (EWGs) and power marketers. At present, EWGs and power marketers are unregulated wholesale sellers of electric power.[165] As such, they cannot incur (or recognize) ECOM because their sales and facilities are governed by the unregulated market and are already subject to competitive market forces. EWGs and power marketers, however, have a substantial interest in how ECOM is recovered.[166] These and other recovery-related interests are addressed in the next chapter.

IOUs and cooperatives, as regulated "public utilities" under PURA95, and municipally owned utilities, as entities regulated by their local governing authorities, may incur ECOM attributable to wholesale or retail operations because their rates and services are regulated by the Commission or by the applicable municipal authority.[167] If a public

[163] Federal Power Act §201(d), 16 U.S.C.A. §824(d) (West 1985); Edison Electric Institute, "Glossary of Electric Utility Terms," Washington, D.C. at 9 (1991) ("Glossary").

[164] Glossary at 48.

[165] PURA95 §2.053(a). Services provided by EWGs and power marketers are not regulated by the State, and EWGs and power marketers are prohibited by PURA95 from engaging in retail sales. PURA95 §2.0011(1), (2), and (3).

[166] For instance, if it is determined that some or all ECOM is recoverable through charges assessed on service over electric transmission or distribution wires, these charges may or may not affect the price that a customer on the downstream end of the wire is willing to pay to an EWG or power marketer for electric power.

[167] Unless indicated otherwise, the term "public utilities" refers to IOUs, cooperatives, and river authorities. The term "municipally owned utilities" refers to electric utilities owned by municipalities. If used alone, the term "utilities" refers generically to both public utilities and municipally owned utilities.

River authorities typically qualify as "public utilities," but may not be subject to the otherwise generally-applicable regulatory provisions of PURA95. Compare PURA95 § 2.0012 with PURA95 §2.0011(a). The river utility or a municipally owned utility finds that competition in the wholesale or retail power sales market has reduced the value of its generation facilities or purchased power contracts, it may claim that the lost value—that is, the difference between the book price and the prevailing market price—is its ECOM. Further, as a regulated entity, a public utility or municipally owned utility may argue that the applicable regulatory authority must allow it to recover its ECOM through some ratemaking mechanism.

B. WHOLESALE POWER SALES CONTRACTS

Texas utilities are not subject to a statutory obligation to serve wholesale customers.[168] IOUs, cooperatives, river authorities, municipally owned utilities, EWGs, and power marketers, however, participate as sellers in the Texas wholesale electric power market.[169]

This section focuses exclusively on wholesale issues, and primarily on IOU-related ECOM arising in utility-to-utility wholesale transactions. While cooperatives, river authorities, and municipally owned utilities may incur wholesale ECOM, their structure and regulation are distinct from IOUs, and may warrant different legal and practical considerations. ECOM issues affecting cooperatives, river authorities, and municipally owned utilities with respect to wholesale power sales are discussed at the end of this section.

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authorities' concerns are most closely aligned with the ECOM allocation concerns of the generation and transmission (G&T) cooperatives (discussed below). The primary function of the river authorities, as with the G&T cooperatives, is to generate and sell electricity in wholesale transactions. The Lower Colorado River Authority (LCRA) is the only river authority that filed comments in the Commission's docket established to address ECOM-related issues (Project No. 15001).

A cooperative may elect to be exempt from regulation by the Commission and set its own rates. PURA95 §2.2011(a). Unless otherwise indicated, this chapter assumes that the Commission exercises PURA95-jurisdictional rate regulation over Texas cooperatives.

[168] While Texas utilities are required by statute to serve all customers in their certificated service territories, this obligation pertains only to retail, and not to wholesale, customers. See *Application of Texas Utilities Electric Co. for Authority to Change Rates*, Docket No. 9300, 17 P.U.C. BULL. 2557 - 58 (Sept. 27, 1991).

[169] Of the Texas net electricity system sales for 1995, approximately 12.6 percent are structured as wholesale sales. See Public Utility Commission of Texas, Office of Regulatory Affairs, *1996 Statewide Electrical Energy Plan for Texas*, Austin, Texas: PUC of Texas at Appendix I (June 1996).

1. Wholesale Transactions are Governed by Written Contracts

While the Commission may authorize utilities to recover costs incurred under wholesale purchased power contracts, it does not directly regulate or approve the terms and conditions contained in the wholesale agreements.[170] Wholesale sales transactions, instead, are memorialized in privately-enforceable written contracts negotiated between the wholesaler and purchaser. Because wholesale transactions are governed by a written contract, the utility:

1. Does not have a definitive legal right, based on contract law, to demand continued purchases by the wholesale customer after the lawful termination of the contract; and
2. Cannot reasonably claim that it is legally required to serve a wholesale customer that lawfully terminated (or never commenced) service in accordance with its wholesale service contract.

The scope and effect of individual wholesale power sales contracts may vary from contract to contract. Generally, however, these agreements contain traditional contract provisions addressing items such as pricing, capacity, delivery location, successor rights, and the length or term of the contract. The contracts may also refer to tariffs on file with the Commission, and incorporate specified terms and conditions from a filed tariff into the wholesale contract. The terms and conditions of the contract establish and control the rights and obligations of the parties, and presumably reflect the bargains and compromises reached by the signatories.

Wholesale power sales contracts are subject to interpretation based on established concepts of contract law. Therefore, it is necessary to review the applicable contract to determine whether a wholesale purchaser is legally obligated to contribute to a utility wholesaler's recovery of ECOM, and to gain insight into the reasonable expectations of both the wholesaler and the purchaser. Most wholesale power sales contracts do not explicitly address ECOM allocation. If a contract does not explicitly address ECOM, the most obvious contract provisions that may have a bearing on ECOM allocation are the pricing and term/termination clauses. These clauses may indicate that the purchaser

[170] See, e.g., PURA95 §§ 2.051(r)(2) and 2.212(g)(1).

is obligated to contribute to the cost of the wholesaler's facilities, or that the contract will remain in effect until the wholesaler recovers specified costs.

If the contract is silent as to ECOM or continuing cost allocation and recovery issues, and is otherwise unambiguous, the wholesaler arguably does not have a valid legal right or expectation to ECOM recovery from the purchaser beyond the term of the contract. This conclusion is based on the well-settled "parol evidence" rule, which:

> *renders inadmissible any testimony to vary the legal effect of a writing in the absence of any ambiguity, accident, mistake, or fraud shown in connection with the contract.*[171]

The parol evidence rule presumes that all applicable rights, obligations, and expectations are evident in the written document that memorializes the parties' agreement.[172] Thus, assuming the contract is a valid, legal agreement, the legal rights *and* expectations of the parties to a wholesale power contract are, by law, reflected solely in the contract. Put simply, a party's unwritten expectations simply have no relevance in the context of an unambiguous and enforceable wholesale power sales contract.

Alternatively, one may adopt the "rebuttable presumption" course taken by the FERC in its Order No. 888.[173] If this rebuttable presumption approach is adopted, a party to a wholesale contract would be permitted to rely on parol evidence in an attempt to prove that an apparently clear and unambiguous wholesale contract does not absolutely reflect the parties' expectations. As the FERC explained:

> *We reaffirm that a utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. Whether a utility had a reasonable expectation of continuing to*

[171] *Huddleston v. Fergeson*, 564 S.W.2d 448, 452 (Tex. App. — Texarkana 1978, no writ); *Ross v. Skinnett*, 540 S.W.2d 493, 495 (Tex. App. — Tyler 1976, no writ). See also *Entzminger v. Provident Life & Accident Co.*, 652 S.W.2d 533, 537 (Tex. App. — Houston [1st Dist.] 1983, no writ) ("Where no ambiguity exists, parol evidence is not admissible to create an ambiguity.")

[172] *Id.*

[173] FERC Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs., Regulations Preambles 1991— June 1996 ¶ 31,036 at 31,826 - 31 (1996).

> *serve a customer, and for how long, will be determined on a case-by-case basis, and will depend on all the facts and circumstances. . . .*
>
> *We also reaffirm our determination that the existence of a notice provision in a contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the specified period. . . .*
>
> *Whether a utility had a reasonable expectation of continuing to serve a customer, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provisions in a contract, will depend on the facts of each case.*[174]

Thus, while strict application of the parol evidence rule would not countenance reliance on external evidence to interpret an unambiguous contract, the FERC precedent of establishing a rebuttable presumption in favor of a contract may be used as an alternative approach to addressing wholesale-related ECOM allocation issues.

2. Special Considerations for G&T Cooperatives and Municipally Owned Utilities

Generation and transmission (G&T) cooperatives and municipally owned utilities face different concerns with respect to wholesale contract interpretation. The ownership structure of such entities may result in different expectations and practical considerations with respect to allocating ECOM.

a) G&T Cooperatives.

G&T cooperatives in Texas exist primarily to provide wholesale service to their distribution-only member cooperatives. These wholesale transactions are memorialized in contracts between the G&T cooperative and its member distribution-only cooperatives, as are the wholesale transactions involving IOUs. In addition to the

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[174] *Id.* at 31,831. Some parties that filed comments with the FERC prior to the issuance of Order No. 888 argued that contractual provisions in a wholesale contract may not demonstrate a "sufficient meeting of the minds" between the parties as to the actual termination of services. *Id.* at 31,827. For example, some contracts may contain a "notice" provision that allows a party to terminate the contract after a prior notice period of some stated months or years. Similarly, some contracts contain "evergreen" clauses that allow the agreement to remain in effect indefinitely unless either party gives notice that it intends to terminate the contract. Some commentors suggested that these "indefinite" types of clauses require the seller to "proceed on the assumption that it will have to meet its contract obligations on a continued basis," thus implying that there are valid expectations that extend beyond the four corners of the contract. *Id.* at 31,827 - 28.

wholesale sales or transmission contracts, however, every G&T cooperative in the State that owns generation facilities is financed, in part, with loans obtained from the Rural Utilities Service (RUS) of the U.S. Department of Agriculture. The only cooperatives in the State that are not funded at least in part by the RUS are cooperatives that either: (1) do not own facilities, but instead "aggregate" services for their members; or (2) are fully funded by their members.

Based on discussions with RUS officials,[175] the Commission understands that the RUS will not loan funds to a G&T cooperative unless the contracts between the G&T cooperative and its member cooperatives remain in effect for at least as long as the term of the RUS loan. Because of this linkage between G&T cooperative financing and membership cooperative contracts, a member cooperative cannot leave a G&T cooperative and thereby *strand* a portion of the G&T cooperative's generation and transmission facilities. This financial structure also establishes the "reasonable" expectation of the G&T cooperative that its members will not leave until the power G&T facilities are paid off. The relationship between the G&T cooperative and its member cooperatives (as well as cooperatives in general) presents additional difficulties with respect to retail competition and retail ECOM. These retail-related issues are discussed separately below.

b) Municipally owned utilities

Some municipally owned utilities that own or have an interest in generation facilities, or that have excess capacity, may sell power at wholesale to other entities. As with wholesale power sales by other entities, wholesale sales by a municipally owned utility are typically governed by written agreements that set forth the legal rights and expectations of the seller and buyer. If this contract expires before the municipally owned utility has paid off its generation plant obligations, the municipally owned utility may be left with some level of ECOM. In this situation, the municipally owned utility's owners/ratepayers will be the parties of first recourse for funding the ECOM through

[175] Discussions were held in late July 1996 via telephone with Messrs. Dave Oblich and Tom Eddy of the RUS. Messrs. Oblich and Eddy may be contacted at (202) 720 - 2764 and (202) 720 - 1439, respectively.

either their utility bills or local taxes. While the Legislature can assert jurisdiction over a municipally owned utility's rates and services, the Commission cannot. The Commission, therefore, cannot order a municipality to calculate, allocate, and recover its utility's ECOM in some prescribed manner.

3. Wholesale Purchases by Utilities for Resale to End-Use Customers

Public utilities and municipally owned utilities provide power to their customers through either their own generation facilities or through the purchase of power at wholesale from other suppliers or generators. The costs incurred by the utilities under the wholesale purchased power contracts are passed along to customers in the utilities' rates as either a cost of service expense, or as a separate cost-tracking mechanism referred to as a "power cost recovery factor" (PCRF). ECOM may arise in the context of such a wholesale contract to the extent that the costs of providing service under the contract exceed the prevailing market price. This type of ECOM, however, is one that arises at the retail level because the utility is passing the costs of the purchased power to its retail customers through its base rates or the PCRF. This retail-related ECOM is discussed in the following section.

4. Conclusion as to Wholesale Transactions

Wholesale contracts define the legal rights and expectations of the parties to wholesale transactions. If ECOM is created by a wholesale purchaser leaving the wholesaler during or at the end of a contract term, the purchaser's obligation for the ECOM may be ascertained from the written agreement. If the contract allows the wholesale purchaser to terminate the contract without any continuing obligation to the seller, reliance on the parol evidence rule would indicate that the departing customer has no continuing obligation to reimburse the wholesaler for any associated ECOM. The same would hold true under the "rebuttable presumption" approach adopted by the FERC if the wholesaler is unable to prove that some form of an external continuing obligation exists.

The issue left open, however, is *whether and, if so, to what extent* the remaining wholesale-related ECOM should be allocated between the wholesaler and its wholesale and retail customers. The utility's options include:

1. Locate other purchasers that will take on the excess capacity left by the departing wholesale customer;
2. Raise rates for remaining wholesale customers (or retail customers of integrated utilities);
3. Otherwise reduce its operating costs sufficiently to recover this ECOM through its existing rates; or
4. Simply absorb the loss.

This conclusion is predicated on the policy that the wholesaler bears the responsibility for wholesale-related ECOM because the wholesaler entered into a written contract that allowed the purchaser to exit the system at a date certain. Thus, the wholesaler (and its shareholders or members) explicitly and knowingly assumed a risk of potential decreased sales and lost revenues by agreeing to a fixed-term wholesale contract.

IOUs may argue that they should be permitted to recover wholesale ECOM through their retail rates because their systems were constructed to serve peak retail load. As stated above, utilities are not legally obligated to serve wholesale loads in their service territories unless they agree to do so by contract. Utility facilities were constructed primarily to serve retail customers. Utilities used the excess capacity to serve the wholesale market through wholesale sales contracts as a way to mitigate costs that otherwise would have been recovered through retail rates. The IOUs' argument continues that because retail customers benefited from the utility's wholesale sales, the utility should not be penalized, and any remaining wholesale ECOM should be recovered from either the wholesale purchaser (if possible) or otherwise shifted to the retail customers (for whose eventual benefit the facility was constructed).

C. Retail Power Sales Transactions

This section addresses issues affecting retail-related ECOM. Wholesale and retail ECOM issues are closely related, particularly given the possibility of shifting wholesale

ECOM responsibility to retail customers. Because approximately 87.4 percent of the electricity sales in Texas are retail sales, most ECOM in Texas is experienced at the retail level, even if wholesale ECOM is not shifted to the retail side.

1. The Difference Between Retail and Wholesale Transactions

The State, through the Commission, regulates public utility *retail* (or final use) rates and services. Generally, utilities and their ratepayers do not enter into written contracts for retail electric services.[176] Instead, retail electricity consumption is typically predicated on a form of unwritten "implied contract." This implied contract requires the consumer to pay for service "taken from the utility at the rate established in the ordinance then in effect."[177]

2. Issues Affecting Retail Transactions

On April 24, 1996, the Commission's staff issued a request for comments on the allocation and recovery of ECOM. The request solicited specific comments on the legal rights and expectations of consumers, IOU shareholders, cooperative associations, river authorities, and municipal corporations, as well as potential alternative ECOM recovery mechanisms.[178]

In early May of 1996, nineteen parties filed comments in response to some or all of the questions posed in the staff's April 24 request. Although the questions posed in the request were not couched in terms of "wholesale" or "retail" transactions, the responses filed by parties predominately address retail-based transactions.[179]

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[176] Some retail customers, particularly large industrial customers, have entered into written contracts for retail service with utilities. See comments filed in Docket No. 15001 on November 7 and 8, 1996 by: Nucor Steel (Nucor) at 8 and Destec Energy (Destec) at 4 - 5, respectively.

[177] *Amarillo Gas Co. v Amarillo*, 208 S.W. 239, 240 (Tex. App. — Amarillo 1919, no writ); *see also City of El Paso v. Public Utility Comm'n*, 839 S.W.2d 895, 918 - 19 (Tex. App. — Austin 1992, *error granted in part and rev'd in part*, 883 S.W.2d 179 (Tex. 1994); *Southwestern Bell Tel. Co. v. Public Utility Comm'n*, 615 S.W.2d 947, 956 (Tex. App. — Austin 1981), writ ref'd n.r.e., 622 S.W.2d 82 (Tex. 1981).

[178] Question Nos. 5, 8, and 9 of the request also sought comment on equitable considerations, such as the effect of ECOM recovery on competition, as the use of incentives to reduce ECOM, and whether ECOM recovery through transmission or distribution rates constitutes an illegal tying arrangement.

[179] The comments filed in response to the April 24, 1996 request are referred to in this chapter as the "May 1996 comments." Subsequent comments filed in response to the public issuance of a draft of this Report are referred to

a) Comments On ECOM Allocation For IOUs

Aside from the distinctions among and between cooperatives (including river authorities), municipally owned utilities, and IOUs, the May 1996 comments are generally divided into three camps: ratepayer parties and independent generators who oppose any allocation of ECOM to ratepayers;[180] those who favor full or significant allocation of ECOM to ratepayers (and thus full recovery by the IOUs, cooperatives, and municipally owned utilities);[181] and parties who suggest that some, but generally not full, ECOM allocation to ratepayers may be appropriate, particularly if recovery is tied to retail access, competition, more efficient generation, or other such concerns.[182] For clarity, these three groups are referred to respectively in this chapter as: the ratepayer parties, the utility parties, and the middle-ground parties.[183]

The ratepayer parties argue that IOU shareholders cannot have a legal right or expectation to ECOM recovery. Generally, these parties claim that IOU shareholders must absorb all ECOM because the shareholders:

- Took investors' risks (and commensurate returns) in a potential loss of their invested funds;
- Have been aware that their utilities faced the risk of lost revenues from competitors since at least the late 1970's; and

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as the "November 1996 comments." The May 1996 comments are summarized in the text of this Report. The November 1996 comments are discussed as necessary in the footnotes to this Report.

[180] See generally May 1996 comments filed by: Asarco Inc.; Consumers Union; Destec; Gulf Coast Power Connect, Inc.; the group of cooperatives filing jointly as the "East Texas G&T's"; Office of Public Utility Counsel (OPC); and Texas Ratepayers Organization to Save Energy (Texas ROSE).

[181] See generally May 1996 comments filed by: Central and Southwest Corp. (CSW); El Paso Electric Corp. (EPEC); Entergy/Gulf States Utilities Co. (Entergy); Houston Lighting & Power Co. (HL&P); San Miguel Electric Cooperative (San Miguel); Texas Electric Cooperatives, Inc. (TEC); Texas-New Mexico Power Co. (TNP); and Texas Utilities Electric Company (TU Electric). The cooperatives and municipally owned utilities argue, as noted above, that they are subject to unique considerations and should not necessarily be treated the same as IOUs with regard to ECOM allocation and recovery.

[182] See generally May 1996 comments filed by: Chaparral Steel Co. (Chaparral); Enron Capital & Trade Resources (Enron), (which asserts that shareholders do not have a right or expectation to ECOM recovery, but acknowledges that some ECOM recovery may be necessary in the transition to a competitive market); Environmental Defense Fund (EDF); Nucor (which asserts at page 8 of its comments that shareholders must at least bear a majority of stranded costs); Southwestern Public Service Co. (SPS); Texas Industrial Energy Consumers (TIEC); and Texas Retailers Association.

[183] Here, the term "utility" as used in the generic phrase "utility parties" typically refers to IOU public utilities.

- Must have assumed that the value of their utilities' generation plants could decrease prematurely because wholesale customers could leave at the end of their contractual terms, and retail customers could leave when new utilities entered the service area, or with the advent of retail competition.

The ratepayer parties claim that allocating ECOM to the ratepayers will eliminate any incentive for the utilities to become more efficient, and will eliminate any cost savings that they would otherwise enjoy in a competitive market. These parties also argue that IOU shareholders could not reasonably expect that their utilities would continue to serve a stable or increasing retail load because:

- PURA95 and PURA75 prohibit exclusive service territories;
- The Texas Constitution prohibits monopolies and retroactive rates that might otherwise give rise to an expectation that an IOU's customers are inextricably bound to the IOU; and
- Shareholders have no right to recover costs of property that are no longer used and useful, or that currently do not satisfy a "prudent investment" rule.

The ratepayer parties argue that a utility's ECOM cannot be deemed to be either a prudently-incurred cost or *used and useful* in a competitive market. Recovery of this excess cost over market, therefore, must be disallowed. These parties also argue that ECOM allocation to ratepayers constitutes an illegal tying arrangement because it requires consumers to pay for something they do not want from the utility (i.e., generation) when they purchase transmission or distribution service.

The utility parties, on the other hand, place significant reliance on PURA95 §2.203(a), which states that utilities will be permitted a "reasonable opportunity to earn a reasonable return on invested capital." These parties argue that §2.203(a), as supported by Commission and court precedent, establishes a statutory right for utilities to recover 100 percent of their prudently-incurred invested capital. They also argue that the Commission, in either the initial orders certificating the generation plant or in subsequent orders authorizing recovery of plant costs through the utility's rate base, has already deemed all invested capital (less depreciation) in rate base to be prudent. The utility parties argue that shareholders did not assume the risk that the State or federal government would at some future date disallow recovery of Commission-approved costs. Instead, utilities and their shareholders expect the State to honor its past commitments to keep utilities whole and financially sound.

The utility parties argue that invested capital, once allowed in rate base, is protected from disallowance by statute and court precedent. They also argue that their capital investment in generation facilities was necessary and required by statute to provide adequate and reliable service to all persons in their service territories, and that the Commission cannot disallow some or all of these costs without "taking" utility property in contravention of the Fifth and Fourteenth Amendments to the U.S. Constitution and Article 1, §17 of the Texas Constitution. The utility parties also note that the FERC has allowed interstate natural gas pipelines and electric utilities to recover ECOM (referred to by the FERC as "stranded costs") in the interstate pipeline and utility restructuring projects, including Order No. 888. These parties argue that there is no illegal tying arrangement inherent in ECOM allocation and recovery because ECOM is not a separate "product" or "commodity" tied to the purchase of transmission or distribution services. In any event, the utility parties argue that state action ruling that ECOM recovery is in the public interest would insulate utilities from "tying arrangement" charges.

The middle-ground parties generally do not believe that IOU shareholders have a clear right to ECOM recovery, or that IOUs could reasonably expect that all ECOM would be allocated to the ratepayers.[184] Some claim that utility shareholders must share the ECOM burden because the utilities will benefit from the emerging energy market through relaxed regulation and increased opportunities to earn a higher profit.[185] The middle-ground parties argue, however, that some allocation to ratepayers may be necessary to hasten or ease the transition to the ultimate goal—a competitive and efficient retail market. Generally, the middle-ground parties consider allocation of

[184] Except for the comments discussed above, numerous commentors did not take a position on whether cooperatives and municipally owned utilities should be treated differently than IOUs.

[185] E.g., Texas Retailers Association, *supra* at 2 (May 1996 comments).

some ECOM to ratepayers as a *quid pro quo* for the utilities agreeing to open their services to competition. These parties focus less on a purely legal resolution of the ECOM issues, and more on a compromise or equitable approach as necessary to foster the transition to a fully competitive market.

The middle-ground parties are split on the issue of whether ECOM should be allocated solely to firm customers, or to both firm and interruptible customers. Interruptible customers argue that they should not be allocated any ECOM because the facilities and purchased power contracts that give rise to ECOM were not constructed or entered into to provide interruptible service.[186] The Environmental Defense Fund, on the other hand, argues that

> *All customers are responsible for ECOM. . . . Interruptibility is not a matter of right. Interruptibles are a load management program with costs based on peaking capacity. . . . [C]ustomers who demand firm sustained energy for most of the hours of the year even though they can be interrupted a few hours per year [should] pay for these costly mistakes [of building base load facilities] which were made on their behalf as much as on fully firm customers.*[187]

Some of the middle-ground parties suggest that utilities should be required or encouraged to divest their generation plant in return for at least some ECOM recovery.[188] Divestiture of generation plant to unaffiliated third parties would, among other things, definitively establish the market value of that plant, which would allow a precise but simple calculation of the ECOM attributable to that plant—book value less market value.[189]

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[186] E.g., May 1996 comments filed b: Aluminum Company of America at 2; Gulf Coast Power Connect, *supra* at 8; Nucor Steel, *supra* at 15 - 17; and SPS, *supra* at 10.

[187] EDF, *supra* at 3 (May 1996 comments).

[188] E.g., May 1996 comments filed by: Destec, *supra* at 16 - 17; EDF, *supra* at 2 - 3; and TIEC, *supra* at 9.

[189] E.g., May 1996 comments filed by: Enron, *supra* at 2 and EDF, *supra* at 2 - 3. TIEC argues for divestiture (in return for any ECOM recovery) to ensure that the utility does not "recover the costs of the uneconomic assets and then market the capacity from those plants at a higher market rate." TIEC, *supra* at 9 (May 1996 comments).

b) Issues Distinguishing Cooperatives and Municipally Owned Utilities from IOUs

As in the preceding section, ECOM allocation issues that apply to IOUs do not necessarily pertain to cooperatives (including river authorities) and municipally owned utilities. The organizational and financial structure of cooperatives and municipally owned utilities entails other considerations.

i) Distinct Issues Affecting Cooperatives and Municipally Owned Utilities

There are a number of significant differences affecting cooperatives and municipally owned utilities that arise in the context of allocating retail-related ECOM. A cooperative's or municipally owned utility's owners, "shareholders," ratepayers, and customers are generally one-and-the-same.[190] This is a crucial difference affecting ECOM allocation within the context of cooperative and municipally owned utility transactions because there are no distinct classes of owners, shareholders, and customers within a cooperative or municipally owned utility to which ECOM can be allocated separately; there is only one class, and that class will bear all ECOM allocated to the cooperative or municipally owned utility. Because of this singularity of interest, these parties argue that it is meaningless for the Legislature or Commission to allocate ECOM to different classes within a cooperative's or municipally owned utility's structure. Regardless of the allocation, the members/citizens, as well as the "shareholders"/owners, must foot the entire bill.[191]

Further, cooperatives and municipally owned utilities suggest that they should not be precluded from recovering all of their ECOM because these entities and their members,

[190] E.g., May 1996 comments filed by: Brazos Electric Power Cooperative, Inc. (Brazos Electric) at 1; the Cities of Denton, Garland, and Greenville (the Cities) at 4; and San Miguel, *supra* at 2 - 3. In addition, Entergy states at page 5 that "[a]s a matter of equity and policy, cooperatives and municipality systems should be allowed to recover whatever stranded costs they may have."

[191] This point also applies between G&T cooperatives and their distribution-only cooperative members because the distribution-only cooperative members own the G&T cooperative.

unlike IOU shareholders, did not take an investor's risk in potential under-recovery.[192] Instead, cooperatives and municipally owned utilities are generally non-profit entities.

Cooperatives and municipally owned utilities also face financial considerations that may not apply to private companies because they may be subject to bond indentures or loans that require them to recover sufficient revenues to repay these obligations.[193] Another major distinction is that cooperatives and municipally owned utilities, unlike IOUs, may be exempt from the Commission's rate jurisdiction in accordance with PURA95 §§ 2.101 and 2.2011, respectively. Accordingly, while the Commission can issue orders that specify the amount of ECOM that *should* be borne by a cooperative or municipally owned utility, the Commission cannot, under current law, compel the exempt cooperatives and municipally owned utilities to implement a specific ECOM allocation or recovery mechanism.

Some IOUs contend that cooperatives and municipally owned utilities have no greater or lesser right to ECOM allocation and recovery than do the shareholders of investor-owned utilities.[194] While most municipally owned utilities may be exempt from Commission regulation under PURA95, most cooperatives are subject to the same PURA95 provisions that apply to IOUs, and should not be treated differently. Gulf Coast Power Connect, Inc. asserts that cooperatives and municipally owned utilities do not have either a legal right or expectation to continue to serve their historic customers because of the Texas Constitution's prohibition against monopolies and exclusive service territories.[195] In addition, the Federation of Austin Industrial Ratepayers (FAIR), in addressing the expectations of municipally owned utilities, submits that the

[192] E.g., May 1996 comments filed by: the City of Austin (Austin) at 2; the City of Bryan (Bryan) at 2; the Cities, *supra* at 4; Consumer's Union, *supra* at 3; San Miguel, *supra* at 2 - 3; SPS, *supra* at 3 - 4; and Texas Retailers Association, *supra* at 3.

[193] *Id.* See also the East Texas G&T's, *supra* at 3 (May 1996 comments).

[194] E.g., May 1996 comments filed by: EPEC, *supra* at 10 - 11; HL&P, *supra* at 3; and TNP, *supra* at 2 (which asserts that the expectations and legal rights of cooperatives are no different than those of IOUs' shareholders, but that municipally owned utilities are different because their generation assets have not been subjected to the same regulatory scrutiny as have the assets of cooperatives and IOUs). See generally Gulf Coast Power Connect, *supra* (May 1996 comments).

[195] *Id.* at 2 - 3.

Legislature and Commission should strive to ensure that the customers of the municipally owned utilities "have the same competitive alternatives and are not worse off than if they were instead served by an IOU or other type of utility."[196]

ii) Allocating ECOM Within Cooperatives, River Authorities, and Municipally Owned Utilities

The practical effect of a "unitary" structure is that ECOM allocation has a different impact on cooperatives (including river authorities) and municipally owned utilities than on IOUs. Unlike an IOU, a cooperative or municipally owned utility does not have a pool of unsecured equity that can absorb a significant ECOM allocation and still remain viable.[197] Instead, non-IOU utilities and municipally owned utilities are funded through mortgage instruments or bonds that require a sure revenue stream. The lenders may have the right to declare the bondholders or debtors in default if that revenue stream is interrupted, and thereby perhaps force the bondholder or debtor into bankruptcy.[198]

In the end, cooperative and municipality citizens/ratepayers will pay for any ECOM allocated to their cooperative or municipally owned utility supplier. This result, however, does not necessarily apply to IOUs. If ECOM is allocated to an IOU's shareholders, the shareholders, rather than the IOU's ratepayers, will bear the allocation.

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[196] FAIR, *supra* at 8 (May 1996 comments).

[197] The Commission is fully aware that utility shareholders are real people, many of whom are IOU ratepayers and citizens of Texas. All utility investors and ratepayers in Texas are "stakeholders" in the ECOM allocation issue. The issue confronting the Legislature and Commission is whether and, if so, how the ratepayer stakeholders should be treated relative to the investor stakeholders.

[198] E.g., May 1996 comments filed by: Brazos Electric, *supra* at 1; Austin, *supra* at 2; LCRA, *supra* at 1 - 2. See November 1996 comments filed by: the Texas Public Power Association at 3; City Public Service of San Antonio at 5.

Some municipal electric services are primarily funded through debt issued in the form of public bonds secured by the revenues from electric service. To the extent that some municipal electric services may be funded through non-debt revenue streams, such as general tax revenues, a municipality could conceivably write-off some or all of its utility's ECOM without: filing for bankruptcy; defaulting on its municipal bonds; or curtailing electric power service. But, to maintain the same level of municipal services and financial creditworthiness while also absorbing ECOM, the municipality will very likely need to raise its general taxes. Thus, unless the municipality can either reduce its utility's power costs, reduce other services, or rely on a revenue surplus, the municipality's citizens ultimately will pay for the municipally owned utility's allocated ECOM through utility rates or through a tax increase.

3. Legal Issues Associated with Retail ECOM Allocation

This section addresses three topics involving retail ECOM:

- the Commission's duty to protect the public interest;
- legal issues involving the utilities' retail rate base-related ECOM; and
- legal issues involving the utilities' retail expense-related ECOM.

The Commission addresses the equitable concerns of the parties after the following discussion on legal issues.

a) The Public Interest

The Texas Legislature enacted PURA95 "to protect the public interest inherent in the rates and services of public utilities."[199] This protection is deemed necessary because traditional public utilities "are by definition monopolies in the areas they serve" and, accordingly, "the normal forces of competition which operate to regulate prices in a free enterprise society do not operate."[200]

To protect the public interest from detrimental monopoly forces, the Commission is charged with regulating utility rates, operations, and services "with the objective that this regulation shall operate as a substitute for competition."[201] Specifically, the Commission is charged with regulating public utilities "to assure rates, operations, and services which are just and reasonable to the consumers and to the utilities."[202]

The public interest, however, does not pertain solely to protecting ratepayers at the expense of utilities. Instead, the public interest includes both utility and ratepayer interests:

> *The PURA balances the important objective of protecting consumers from monopoly power with the need for financial stability which is required to attract large amounts of investment capital essential to dependable utility*

[199] PURA95 §§ 1.002 and 2.001(a).

[200] E.g., PURA95 §1.002.

[201] *Id.*

[202] PURA95 §§ 1.002 and 2.001(a).

> *service. When balancing the interests of consumers and utilities, the financial integrity of the utility weighs in favor of both sides.*[203]

The public interest, therefore, requires the Commission to weigh potentially conflicting interests between the consumers and the utilities. This weighing requires analysis of both objective, legal considerations and subjective, equitable considerations.

b) Retail Rate-Based ECOM

The legal rights affecting IOUs pertain equally to G&T cooperatives, distribution-only cooperatives, and most river authorities because all of these entities are public utilities under PURA95. As discussed above, the expectations and practical effects of ECOM allocation to cooperatives and river authorities, however, are significantly different from those affecting the IOUs. Nevertheless, the Legislature may assume that the *legal* rights of IOUs, cooperatives, and river authorities are the same if it desires to adopt identical treatment for these forms of public utility.

i) The "Regulatory Compact"

The concept of a "regulatory compact" has arisen in the context of public utility regulation. The regulatory compact requires a public utility to serve all consumers in its certificated service area with adequate and reliable service. In return for this mandatory service, the state agrees to fix a utility's rates at a level that will provide the utility with a reasonable opportunity to earn a reasonable return on the funds prudently expended by the utility to render its required service through "used and useful" facilities.[204] In addition to the reasonable return on investment, the state also agrees to allow the regulated utility to recover reasonable operating expenses.[205] Based on treatises and decisions in other jurisdictions, one can conclude that a regulatory

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[203] *State v. Public Utility Comm'n*, 883 S.W.2d 190, 202 (Tex. 1994) (citations omitted). See also *Gulf States Utils. v. Coalition of Cities for Affordable Util. Rates*, 883 S.W.2d 739, 747 (Tex. App.—Austin 1994, writ granted). See also *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03 (1944) (*Hope*).

[204] See, e.g., Gioia, P., "The Prudence Standard: Recent Experience and Future Relevance," *Public Utilities Fortnightly* at 10 (April 27, 1989); Baumol, W., and J. Gregory Sidak, "Transmission Pricing and Stranded Costs in the Electric Power Industry," *The AEI Press* at 104 - 05, Washington, D.C. (1995); Rose, K., "An Economic and Legal Perspective on Electric Utility Transition Costs," *The National Regulatory Research Institute* at 68 - 72, Columbus, Ohio (July 1996).

[205] *Id.*

compact exists in Texas, and that this compact serves as the "substitute of competition" envisioned in PURA95.[206] The Commission, however, is unaware of any Texas court decision or Commission decision that explicitly adopts or explains the concept of a regulatory compact between or among the State, the utilities, and the consumers.

The parties disagree over the scope of the regulatory compact, and whether it even exists. On one extreme, OPC argues that there is no "compact" because existing statutes and court precedents "are subject to change at the pleasure of the Legislature and the courts."[207] On the other extreme, TU Electric insists that a regulatory compact is "explicitly codified in PURA."[208] TU Electric, however, does not cite to a judicial decision or legislative history that "explicitly" codifies a regulatory compact in the State's laws.

The obligations embodied in a regulatory compact are found at least in part in PURA95 and case law interpreting utility regulation within Texas.[209] Numerous sections in PURA95 describe the obligations of public utilities. In particular, §2.259(a) requires the holder of any certificate of public convenience and necessity "to serve every consumer within its certificated area and [to] render continuous and adequate service within the area or areas."[210] The public utility's rates also "may not be unreasonably preferential, prejudicial, or discriminatory."[211]

In consideration for requiring the public utility to serve all consumers within its certificated area at non-discriminatory rates, PURA95 §2.203(a) provides that the

[206] See, e.g., Peter Bradford, "A Regulatory Compact Worthy of the Name," *The Electricity Journal,* Seattle; Vincent Butler, "A Social Compact to Be Restored," *Public Utilities Fortnightly* (Dec. 26, 1985); Charles Studness, "The Regulatory Compact that Never Was," *Public Utilities Fortnightly* (September 1991).

[207] See OPC, *supra* at 6 - 7 (November 1996 comments).

[208] See TU Electric, *supra* at 10 (November 1996 comments).

[209] See, e.g., PURA95 §2.203(a).

[210] The one exception to this requirement is that the certificate holder shall refuse to serve a customer if it is prohibited from doing so by §§ 212.012 or 232.0047 of the Local Government Code. See PURA95 §§ 2.259(a) and 2.260.

[211] PURA95 §2.202. Public utilities are also required to: "furnish such service, instrumentalities, and facilities as shall be safe, adequate, efficient, and reasonable" without granting or making "any unreasonable preference or advantage to any corporation or person." See PURA95 §§ 2.155 and 2.214, respectively. The public utility also may not charge rates other than those prescribed in filed tariff. PURA95 §2.215(a).

Commission shall fix the utility's overall revenues "at a level which will permit such utility a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable operating expenses."[212] A legal analysis of these statutory provisions is necessary to develop a better understanding of the legal rights and obligations of the public utilities and the State under the assumed regulatory compact.

(a) The Utility's Obligation to Serve, and the Commission's Corresponding Duty to Fix Reasonable Rates

There is little dispute regarding the scope and meaning of the utility's obligation to serve as set forth in PURA95 §2.259(a). This provision establishes a quantifiable and concrete requirement—the utility "shall serve every consumer within its certificated area."

Section 2.203(a) of PURA95, however, does not establish a quantifiable requirement on behalf of the Commission. Instead, §2.203(a) includes numerous terms that are open to interpretation such as "reasonable" opportunity, "reasonable" return, and "invested capital" that is "used and useful in rendering service." These general terms used in §2.203(a) require further explanation and consideration to understand the rights and expectations of Texas utilities and ratepayers.

(b) The Utility's Right to a "Reasonable Opportunity to Earn a Reasonable Return"

The use of the word "reasonable" to qualify both the "opportunity" and the "return" in PURA95 §2.203(a) establishes a non-specific expectation. *Opportunity* itself indicates that a guaranteed return is not a legal right under PURA95, and neither the statute nor applicable case law guarantees a specified return to a utility.[213] To the contrary, the required balancing of the interests of the ratepayers and the utilities "does not

[212] See also P.U.C. SUBST. R. 23.21(d)(1).

[213] In addition, the Commission is not required to fix an exact rate of return, and may impose an "earnings sharing" plan on a utility that requires the utility to share its earnings, within specified ranges, with its ratepayers. *Cities of Abilene v. Public Utility Comm'n*, 854 S.W.2d 932, 941 - 42 (Tex. App. — Austin 1993), *aff'd in part and rev'd in part*, 909 S.W.2d 493 (Tex. 1995).

necessarily insure that the utility will produce net revenues."[214] The absence of a guaranteed return requirement is also confirmed by the regulatory policy that precludes a utility from retroactively raising its rates to recover a past under-recovery.[215] Accordingly, the use of the terms "reasonable" and "opportunity" in PURA95 §2.203(a) provide the Legislature and Commission with at least some discretion under current law to structure ECOM allocation in a way that does not guarantee or authorize full recovery of ECOM by the utilities and their shareholders.[216] Instead, rates of return could be adjusted downward to some extent so that consumers, through the resulting utility rates, do not bear the full brunt of ECOM allocation.[217]

A utility's return, however, is integral to its financial viability. If the utility is not authorized to earn a return sufficient to maintain its financial integrity, the utility's customers may suffer. For example, a decline in a utility's financial integrity could result in a downgrading of its bond and debt ratings, which will result in increased costs of capital. Alternatively, as return declines, the utility may be prompted to cut costs in an effort to maintain revenues. Cost-cutting may result in a decline in the quality of

[214] *El Paso Elec. Co. v. Public Utility Comm'n*, 917 S.W.2d 846, 862 (Tex. App. — Austin 1995 (citing *Hope*, 320 U.S. at 603), *judgment withdrawn*, 917 S.W.2d 872 (Tex. App. — Austin 1996). Although the court withdrew its judgment, it stated that "[t]he majority and dissenting opinions of this Court dated July 12, 1995, are not withdrawn." 917 S.W.2d at 872.

[215] *City of El Paso v. Public Utility Comm'n*, 839 S.W.2d 895, 918 - 19 (Tex. App. — Austin 1992, *error granted in part and rev'd in part*, 883 S.W.2d 179 (Tex. 1994); *Southwestern Bell Tel. Co. v. Public Utility Comm'n*, 615 S.W.2d 947, 956 (Tex. App. — Austin 1981, writ ref. n.r.e.)

[216] *Southwestern Bell Tel. Co. v. Public Utility Comm'n*, 571 S.W.2d 503, 515 - 16 (Tex. 1978) ("[T]he Commission has discretion in setting a reasonable or fair return on the value of Bell's property used and useful in rendering service.") Despite the Legislature's use of the terms "reasonable" and "opportunity" in the context of return on investment, a number of utilities insist that they are entitled to "fully" recover their ECOM. See November 1996 comments filed by: EPEC, *supra* at 6; HL&P, *supra* at 7; and TU Electric, *supra* at 6, 15, and 18.

[217] Some parties argue that utilities' returns should be reduced to a "risk-free" rate if utilities are permitted to recover ECOM: "Investors in electric utility stocks are currently compensated for risk. Once any amount of stranded investment is guaranteed, the rate of return should be lowered to reflect rates on risk free investments." See Texas ROSE, *supra* at 2 (November 1996 comments). Similar points were made by parties orally at the technical conference convened in Project No. 15001 on November 8, 1996. Former PUC Commissioner Ms. Marta Greytok, representing Aluminum Company of America, stated that if the utilities now believe that they are guaranteed recovery of ECOM, the Commission should "strip out the risk factor from here forward. But I actually question whether it should have been there at all. I'm not sure we haven't already seen the recovery of stranded costs to some extent if indeed we were guaranteeing the utilities all along that they were going to receive all of their investment." See also oral comments of Mr. Robert Webb appearing as counsel for Gulf Coast Power Connect.

utility services. To prevent such adverse consequences, the Legislature and Commission should remain cognizant of the utility's financial integrity when addressing ratemaking policies. As noted, the Texas Supreme Court has ruled that "[w]hen balancing the interests of consumers and utilities, the financial integrity of the utility weighs in favor of both sides."[218] Without this balance, the overall public interest, including consumers' interests, may not be protected if a substantially-reduced rate of return is imposed on utilities in an effort to allocate ECOM away from ratepayers and toward utility shareholders.

(c) "Invested Capital"

The term "invested capital" is specifically defined in PURA95 §2.206 as:

> *a) [T]he original cost of property used by and useful to the public utility in providing service. . . .*
>
> * * *
>
> *c) Original costs shall be the actual money cost . . . of the property at the time it will have been dedicated to public use . . . less depreciation.*

Texas courts have succinctly interpreted the term "invested capital" to mean "original cost less depreciation;" invested capital is the utility's "rate base."[219] This definition of "invested capital" is crucial because it addresses a major ECOM allocation issue raised by some ratepayer parties. These parties suggest that ECOM allocation and recovery can be resolved simply by de-valuing the utility's rate base from its current above-market level down to a fair market value with the utility's shareholders bearing the burden of the ECOM write-down.[220] This argument holds that a unilateral write-down of value is warranted to the extent the utility wants to remain a viable entity in a competitive environment, just as non-regulated entities must sometimes write-off obsolete or inefficient assets.

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[218] *State v. Public Utility Comm'n*, 883 S.W.2d 190, 202 (Tex. 1994). See also *Hope*, 320 U.S. at 603.

[219] *Southwestern Bell Tel. Co. v. Public Utility Comm'n*, 571 S.W.2d 503, 515 - 16 (Tex. 1978). *See also* P.U.C. SUBST. R. 23.21(d)(2).

[220] E.g., OPC, *supra* at 8 - 9 (November 1996 comments); East Texas G&Ts, *supra* at 4 - 5 (May 1996 comments).

While writing-down booked assets to a market value amount is a superficially simple solution, it would likely face a serious court challenge because PURA95, as currently written, does not allow a *fair value* interpretation of a utility's rate base. Instead, the utility's rate base is valued in accordance with PURA95 as the original cost of the rate base items less depreciation. And, by law, the utility is to be given a "reasonable opportunity to earn a reasonable return" on its "original cost" rate base, rather than on a "fair value" rate base.[221] For this reason, attempts to resolve the ECOM allocation problem simply by revaluing a utility's rate base will likely face serious challenge in the courts.

*(d) "Return on [*and of*] Invested Capital"*

In addition to the "reasonable opportunity to earn a reasonable return on invested capital," utilities are also entitled to earn a return *of* their rate base.

> *By statute, a utility is allowed to recover its reasonable and necessary operating expenses and both a return on, and a return of, its rate base.*[222]

This means that a utility's "return" is not simply interest computed or earned on its rate base, but is also a return, over time, of the rate base itself. This return *of* rate base is recognized in the definition of "invested capital" discussed above because "rate base" is "original cost *less* depreciation." (Emphasis added.) This construction indicates that there are two primary components to a rate base calculation: (1) the original cost of

[221] See also *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989) (*Dusquesne*). In *Dusquesne*, the Court noted that the "fair value" rule is not the only constitutionally acceptable method of fixing utility rates. Instead, an "historical cost" rule, or other valuation methods, are also valid ratemaking tools. *Id.* at 310.

OPC disagrees with the foregoing characterization of *Duquesne*, and insists that the case instead "stands for the proposition that a state legislature is not constitutionally required to perpetuate *original cost* ratemaking." OPC, *supra* at 8 (November 1996 comments) (emphasis in original). The Commission does not intend to suggest that the Legislature is precluded from legally modifying current statutes. OPC, however, fails to acknowledge a crucial admonition in *Dusquesne*: "[A] State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would *raise serious constitutional questions.*" *Id.* at 315 (emphasis added). Accordingly, if the Legislature adopted OPC's suggested course, utility parties may raise a formidable constitutional challenge. The utilities presumably would argue that a change to a fair value methodology is an "arbitrary switch" instituted to require utility investors to fully bear the risk of bad investments.

[222] *State v. Public Utility Comm'n*, 883 S.W.2d 190, 199 (Tex. 1994).

the facility (e.g., of a generation plant); and (2) the depreciation expense collected to date to reduce the original cost of the facility to its current net book value.

(i) The Original Cost Component

The original cost of a facility is readily ascertainable from the system of accounts that a utility is required to maintain under the Commission's rules.[223] Accordingly, the Legislature and Commission should not have a problem in determining the original cost of each utilities' jurisdictional facilities. While the *original cost* valuation approach requires the Commission to adhere to the original cost (as compared to *fair value*) of the facility, some parties suggest an alternative rate base valuation solution. Through this alternative, a utility's rate base would be re-valued (rather than de-valued) by writing-down the generation plant recorded on the utility's books, *while* writing-up the value of utility's transmission and distribution assets by the same amount.[224] This approach would shift ECOM from the utility's over-market generation plant to its regulated transmission and distribution facilities. The difference between a de-valuation approach and a re-valuation approach is that, in the latter, the overall original book value of the utility's plant is maintained.[225]

(ii) The Depreciation Component

The depreciated original cost of a facility can also be determined from the utility's accounts. The extent and method of depreciation are crucial concepts in the ECOM allocation debate because: (1) depreciation rates can be adjusted to increase or decrease the speed at which a given facility's original cost is reduced; and (2)

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[223] P.U.C. SUBST. R. 23.12.

[224] E.g., May 1996 comments filed by: HL&P, *supra* at 5 - 6 and TNP, *supra* at 2 - 3.

[225] PURA95, however, may require a revision to allow a write-up in the value of the utilities' transmission and distribution (T&D) facilities. As discussed above, the invested capital in facilities, including T&D facilities, is currently the *original cost less depreciation* of those facilities. If ECOM is transferred from a utility's generation plant accounts to its T&D plant accounts, the book value of the T&D assets will very likely exceed the original cost less depreciation of these assets. Accordingly, PURA95 §2.206 would need to be modified to allow the Commission to value T&D assets for ratemaking purposes at something other than original cost less depreciation. While such a revision may be challenged as an "arbitrary switch" contrary to the admonition in *Dusquesne, supra*, this form of statutory revision may be structured as a more palatable resolution of the ECOM allocation issue (as compared to revaluing rate bases to fair value, or ruling that one constituency will bear all of the ECOM exposure).

depreciation expenses recovered through rates allow the utility to recoup its investment. Through the rate-setting process, the utility recovers sufficient expense over the depreciable life of the investment to, in theory, depreciate the utility's various plant accounts to zero. Depreciation rates are typically set so that utility investment in generation, transmission and distribution facilities are recovered over a long period of time, e.g., 20 to 40 years. These depreciation rates are generally predicated, at least to some extent, on the expected life of the plant. However, if depreciation rates or methods are accelerated, the plant can be depreciated down to a more market-responsive level at a faster pace than would occur if the rates were set based on the expected physical life of the plant.[226]

(e) "Used and Useful in Rendering Service"

The depreciable life of a facility is also pertinent to the question of whether the facility is "used and useful." As a general rule, "only assets that are 'used and useful' in providing service may be included in rate base."[227] The term "used and useful" refers to "such property as has been acquired . . . in good faith and held for use in the reasonably near future in order to enable [a utility] to supply and furnish adequate and uninterrupted . . . service."[228]

Application of the "used and useful" concept to ECOM allocation is invoked primarily by the ratepayer parties.[229] These parties argue that if all or a portion of a utility's generating plant is priced above the market, this ECOM cannot be "used and useful" in providing service in a competitive world. Instead, the utility must remove (i.e., write-off) this ECOM from its rate base, and its shareholders must absorb the loss. There is some validity to this argument, but it is contradicted by Commission decisions that interpret the term "used and useful."

[226] PURA95 §2.151(a) allows the Commission to "fix proper and adequate rates and methods of depreciation. . . ."

[227] *Cities for Fair Utility Rates v. Public Utility Comm'n*, 884 S.W.2d 541, 547 (Tex. App.— Austin 1994, writ granted).

[228] *Lone Star Gas. Co. v. State*, 153 S.W.2d 681, 698 (Tex. 1941).

[229] E.g., TIEC, *supra* at 3 - 4 (May 1996 comments).

(i) The "Physical" Used and Useful Standard

The commentors who argue for ECOM allocation to the utility based on a *used and useful* test raise a valid point to the extent that the utility's shareholders may be expected to absorb all ECOM (and in fact all capital investment) in a generating facility that the utility mothballs or shuts-down. In this event, the capital invested in the abandoned physical facility should be removed from the utility's rate base because that invested capital clearly is no longer "used and useful in rendering service."[230] The same set of underlying facts, however, may not apply to the allocation of ECOM attributable to facilities that remain in rate base. No party has alleged in comments filed in Commission Project No. 15001 that current plant in service will become *physically un-used and un-useful* simply because the plant's book value exceeds its market value. Even with retail access, it is likely that a vast majority of generation facilities currently in the utilities' rate bases will continue to operate. These facilities were, are, and most likely will be "used and useful in rendering service" regardless of wholesale and retail competition, and the concomitant creation of ECOM.

It is possible, however, that some generation facilities will be uneconomic in a competitive market if the market price for electricity falls below the average variable cost of operating these facilities. Good business and regulatory practice will require closure of such uneconomic facilities. In a strictly legal sense, the Legislature or Commission could simply require the utilities to remove the costs of these facilities from their rate bases and rates because the facilities are not, or should not be, physically used and useful. But this drastic solution may result in the utilities attempting to justify the continued operation of uneconomic facilities in an effort to forestall potentially

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[230] Likewise, capital costs attributable to plant that is not physically "used and useful" should not be recovered through the utility's rate base. *Application of Texas-New Mexico Power Co. for Authority to Change Rates,* Docket No. 9491, 16 P.U.C. BULL. 2825, 2863, 3217 (Feb. 7, 1991) (Examiner's Proposal for Decision). The Commission has already disallowed from rate base the costs of inactive nuclear or fossil fuel generating facilities.

But see *Town of Norwood v. FERC*, 80 F.3d 526 (D.C. Cir. 1996), which upholds a recent FERC decision that allowed a utility to recover the outstanding costs of a decommissioned nuclear power plant. *Town of Norwood* may limit the "used and useful" test as it traditionally would have applied to capital investment reflected in rate base. The effect of *Town of Norwood* on the used and useful test, however, may be circumscribed by the weight given by the court to the specific wording of the written contracts underlying the construction and operation of the nuclear plant at issue in that case. *Id.* at 529 - 31.

significant write-offs. To provide the utilities with appropriate economic incentives to shut-down and write-off uneconomic plants, ECOM allocation and recovery should be indifferent to utilities' decisions to continue to operate or to shut-down generating facilities.

(ii) The "Prudence" Standard

Some may argue that the Commission can direct utilities to absorb uneconomic or currently imprudent costs of facilities that continue to be used and useful.[231] This argument may be flawed to the extent it presumes that the used and useful standard currently used by the Commission embodies a dynamic economic capacity test, rather than a physical test.[232] Under a dynamic economic capacity test, the Commission could reconsider a previously-approved prudence finding in a current rate case. For example, the Commission could rule that, although it found a $100 million investment to be prudent in 1986, changed circumstances evident in 1996 now dictate that only some portion of that initial $100 million investment continues to be prudent.

The legal problem with adopting a dynamic economic capacity test to deny previously-approved investment is that it may be considered to be a form of impermissible retroactive ratemaking.[233] In any event, the Commission has in the past rejected the application of an economic excess capacity test in determining whether a facility is in fact used and useful. In a 1987 case, the Commission noted that an economic excess capacity test is "patently unreasonable" because it applies a "perfect foresight standard" to a utility's investment in a facility.[234]

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[231] E.g., TIEC, *supra* at 3 - 4 (May 1996 comments).

[232] An economic test looks solely to the capacity needed to provide reliable service, while a physical test looks to whether a facility is "physically" used to render service.

[233] *State v. Public Utility Comm'n*, 883 S.W.2d 190, 198 - 99 (Tex. 1994).

[234] *Application of West Texas Utilities for Authority to Change Rates*, Docket No. 7510, 14 P.U.C. BULL. 620, 640 - 41 (Nov. 30, 1987) (adopted by the Commission) (*WTU*). See also *Application of Central Power and Light Co. for Authority to Change Rates*, Docket Nos. 8646, 9141, 9595, 9561, 16 P.U.C. BULL. 1388, 1485 (Oct. 19, 1990); *Application of Houston Power & Light Co.*, Docket Nos. 8425 and 8431, 16 P.U.C. BULL. 2199 (Sept. 18, 1990).

An economic excess capacity test also ignores the prudence of the utility's initial decision to invest capital in its certificated facilities. The "prudent investment test," which Texas follows,[235] provides that "the utility is compensated for all prudent investments at their actual costs when made (their 'historical' cost), irrespective of whether individual investments are deemed necessary or beneficial in hindsight."[236] Under this rule, capital investments that are not prudent should not be allowed in rate base. In turn, because imprudent costs are not allowed in rate base, such costs cannot be recovered through the utility's rates. Accordingly, based on judicial precedent, hindsight or retroactive determinations that reverse a prior finding of prudence may be struck down on judicial review unless the subject facilities are no longer in service.

This "prudent investment" rule is also embodied in the standard that the Commission uses to calculate invested capital—"prudence and reasonableness."[237] Under the "prudence and reasonableness" standard, the utility is not permitted to place facilities in rate base and charge the costs of the facilities to ratepayers until it has shown "the prudence and reasonableness [of each element of] its expenditures."[238] This "prudence and reasonableness" showing is made after the Commission has issued a certificate authorizing the construction of the facilities.[239] These expenditures are also deemed to be prudent in each subsequent rate proceeding in which the Commission approves the utility's rates as "just and reasonable." For this reason, PURA95 §2.206(a), which defines the term "invested capital" as *original* cost less depreciation, "does not mandate and cannot reasonably be interpreted as requiring the use of a hindsight

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235 *Application of Gulf States Utilities Co. for Authority to Change Rates*, Docket Nos. 7195 and 6755, 14 P.U.C. BULL. 1943, 2429 (May 16, 1988); see also 16 P.U.C. BULL. 2825 at 3216.

236 *Duquesne*, 488 U.S. at 309.

237 *Texas-New Mexico Power Co. v. Texas Industrial Energy Consumers*, 806 S.W.2d 230, 233 (Tex. 1991) (citing *Coalition of Cities for Affordable Utility Rates v. Public Utility Comm'n*, 798 S.W.2d 560, 563 (Tex. 1990), *cert. denied*, 499 U.S. 983 (1991) (*Coalition)*.

238 *Id.* "When a new installation begins supplying service, the PUC must still determine what portion of the investment is properly chargeable to ratepayers with the burden of proving 'the prudence and reasonableness of [each element of] its expenditures' firmly fixed on the utility."

239 *Id.*

economic excess capacity analysis to determine the extent to which plant is used by and useful to a public utility in providing service."[240]

(iii) Res judicata

On a related point, disallowing costs in a current period that were deemed to be prudent in the past raises significant issues involving the legal doctrine of *res judicata*. *Res Judicata* means that a "matter judicially determined bars the retrial of claims pertaining to the same cause of action which has been finally adjudicated."[241] In a case giving rise to a *res judicata* claim, the Commission disallowed recovery of nuclear plant capital costs in excess of $2.273 billion because the utility failed to demonstrate that costs in excess of this amount were "prudently incurred."[242] The utility subsequently initiated a new rate increase proceeding before the Commission on the same prudence question. The utility's customers challenged the right of the utility to a second opportunity to prove the same facts as justification to increase its rates. The Texas Supreme Court ruled that the utility could not relitigate the prudence of its past investment.

> *With a complex and controversial project like a nuclear power installation, a utility and its investors need a determination to prevent relitigation of the same previous investment decision on each occasion that a rate increase is requested. The same finality that benefits the utility investors can serve the interests of consumers who know that if a utility is once denied relief because of its failure to prove its case, it may not return repeatedly on the same facts until the PUC yields.*[243]

Res judicata is a general legal doctrine; it does not pertain solely to utilities, but instead applies to all parties to a case and to the Commission. As the utility in *Coalition* could not subsequently relitigate a final ruling on the prudence of its disallowed investment, it is unlikely that a court would allow other parties, such as ratepayers, to relitigate a final

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[240] *WTU*, 14 P.U.C. BULL. at 641.

[241] *Coalition*, 798 S.W.2d at 562 - 63.

[242] *Id.*

[243] *Id.* at 565.

ruling.[244] *Res judicata* would arise, however, if the Commission determined that costs that were finally determined to be prudent and includable in rate base at some point in the past are, in a subsequent case, now suddenly "imprudent."

On the other hand, *res judicata* may not apply if *changed circumstances* require a subsequent change in rates or ratemaking methodology. While the Commission is generally prohibited from revisiting prior final orders, case law exists that may support subsequent revisions to a prior final decision if there is an adequate showing of changed circumstances.[245] Based on a changed circumstances argument, the "changed circumstances" effected by retail competition in the electric utility industry may warrant some adjustment to a utility's formerly prudent rate base and historically "reasonable" expense allowances.[246]

(iv) "Grandfathered" Facilities

Prudence issues may also arise in cost allocation and recovery disputes in Texas because not all utility plant costs currently recovered through rates were explicitly deemed prudent when the plant costs were first included in a utility's rate base. The Legislature and Commission did not begin to regulate utility rates through PURA until 1975. At that time, all of the utility facilities used to provide jurisdictional service, and jurisdictional facilities then under construction, were "grandfathered" as certificated facilities. With respect to these facilities, the Commission did not make an explicit finding that the capital already invested in the facilities and already included in rate base was *prudently* incurred. Instead, through the grandfathering process, the prudence

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[244] In addition to a *res judicata* claim, litigation that changes a previously final rate may constitute impermissible retroactive ratemaking.

[245] *West Texas Utilities v. Office of Public Utility Counsel,* 896 S.W.2d 261, 268 - 69 (Tex. App. — Austin 1995, no writ) (*WTU v. OPC).* In this case, the court held: "Absent a showing of changed circumstances, the Commission is generally prohibited from revisiting its prior final orders. . . . All parties . . . were bound by the Commission's prior decision . . . regarding non-Oklaunion depreciation rates ***absent a showing of changed conditions*** that would necessitate an adjustment in those depreciation rates." (emphasis added) Despite the unambiguous language of *WTU v. OPC*, EPEC and HL&P insist that changed circumstances could not justify relitigation of historical investments. See November 1996 comments filed by: EPEC at 5; HL&P at 4 - 5

[246] As a cautionary note, the *WTU v. OPC court* explicitly relied on the doctrine of *res judicata* and *Coalition* to find that "some" changed circumstances did not warrant a reexamination of prior depreciation rates. *WTU v. OPC*, 896 S.W.2d at 269.

determination arguably was either not made, or was made without actually determining whether the expenditures were prudent. It is therefore possible that the Commission can now rule that those expenditures (or portions of these expenditures) for grandfathered facilities were imprudent because the Commission has not previously explicitly ruled that the expenditures were, in fact, prudently incurred.

This conclusion has merit in that neither the Legislature nor the Commission explicitly ruled, after some form of hearing, that the capital spent to construct the grandfathered facilities was, in fact, prudently expended before the facilities were allowed into rate base. On the other hand, the utilities have been recovering these grandfathered costs through rates for over 20 years. In all utility rate cases initiated after September 1, 1975, and since resolved, the Commission has approved the resulting rates as "just and reasonable." This continuing rate approval could be interpreted to signify that the capital invested in the plants was prudently incurred and recoverable through the utility's just and reasonable rates. Accordingly, it may be legally difficult for the Legislature or the Commission to now rule, in hindsight, that some portion of the original cost of the facilities constructed prior to 1975 (and still in rate base) was not prudently incurred.

ii) Expectations Derived from Legal Authorities

In addition to PURA95 and the "regulatory compact" discussed above, there are a number of ECOM allocation issues that turn on other legal authorities and expectations. These issues involve interpretation of Constitutional and other statutory authorities and judicial decisions.

Some parties argue that utilities must absorb all ECOM because the utilities should have known that their customers could exit the system and, therefore, the utilities have no legal right to expect that they could recover all ECOM from their customers.[247] This legal *expectation* argument is based primarily on the provisions in the Texas

[247] E.g., Gulf Coast Power Connect, *supra* at 2.

Constitution and PURA95 that prohibit monopolies, exclusive service territories, and retroactive rates:

> *Perpetuities and monopolies are contrary to the genius of a free people and shall never be allowed. . . .*[248]

> *No bill of attainder, ex post facto law, retroactive law, or any law impairing the obligation of contracts, shall be made.*[249]

> *Except as otherwise provided in this subtitle, a retail public utility may not furnish, make available, render, or extend retail public utility service to any area to which retail utility service is being lawfully furnished by another retail public utility without first having obtained a certificate of public convenience and necessity that includes the area in which the consuming facility is located.*[250]

Taken separately and together, the foregoing constitutional and statutory provisions are interpreted by some parties to mean that an electric utility cannot rightfully expect to maintain a captive customer load through a monopoly service territory, or retroactively collect costs from a customer that wants to switch to another electric power seller.[251] These parties conclude that, because the utility has no legal expectation to a captive customer load, it cannot expect its customers to bear any ECOM at any time.

There is merit to these arguments as to what the utilities should or should not *expect* with regard to ECOM allocation, but not necessarily as to what the utilities are or are not *legally* entitled to recover. The Commission is aware of and adheres to the prohibitions against monopolies, retroactive ratemaking, and exclusive service territories. It is noteworthy, however, that a legal prohibition against a practice does not necessarily mean that the practice does not, in fact, exist. For example, while the

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[248] TEX. CONST. art. 1, §26.

[249] TEX. CONST. art. 1, §16.

[250] PURA95 §2.252(b).

[251] If properly structured, an ECOM allocation and recovery method should not result in retroactive ratemaking. Any allocation and recovery of ECOM should be forward looking, based on services taken in the present and future, rather than based on some method that allocates and recovers ECOM based on historical events.

Constitution prohibits monopolies, the Texas courts and PURA95 explicitly recognize that public utilities are monopolies.[252]

(a) *"Takings" Claims Arising Under the U.S. and Texas Constitutions*

A number of IOUs vehemently assert that the Commission is constitutionally required to authorize utility shareholders to "fully" recover ECOM.[253] If full recovery is not authorized, these IOUs claim that they will be deprived of property in contravention of "takings" provisions of the Fifth and Fourteenth Amendments to the U.S. Constitution, and Article 1, Section 17 of the Texas Constitution.[254] In support of these claims, the IOUs refer to numerous cases that address a fundamental tenant of Constitutional law: the government cannot "take" private property without adequately compensating the owner.[255]

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[252] See, e.g., *State v. Southwestern Bell Tel. Co.*, 526 S.W.2d 526, 529 (Tex. 1975) ("Bell is a privately owned public utility supplying a necessary communication service in which, for all intents and purposes, it enjoys a monopoly."); *State v. Public Utility Comm'n*, 883 S.W.2d 190, 202 (Tex. 1994); PURA95 §§ 1.002 and 2.001 ("The legislature finds that traditional public utilities are by definition monopolies [in many of the areas they serve].")

[253] See, e.g., November 1996 comments filed by: EPEC, ***supra*** at 6; HL&P, ***supra*** at 7; and TU Electric, ***supra*** at 6, 15, and 18. These utilities, however, do not explain whether: (1) *full* ECOM recovery is tantamount to *guaranteed* recovery of capital investment; and (2) if so, how *guaranteed* recovery is consistent with the "reasonable opportunity" standard of PURA95 §2.203. In addition, Commission or Legislative authorization of *full* ECOM recovery may tend to further justify the counter-arguments that full or guaranteed ECOM recovery constitutes a risk-free investment, which in turn necessitates a decrease in the utilities' rates of return. See Texas Rose, ***supra*** at 2 (November 1996 comments); and oral comments of Ms. Marta Greytok and Mr. Robert Webb at the November 8, 1996 Technical Session convened in Project No. 15001.

[254] *Id.* See also November 1996 comments filed by: CSW, ***supra*** at 4-6; Entergy, ***supra*** at 6 - 8. Subsumed within the "takings" arguments is a claim by the utilities that they will be saddled with impermissible "confiscatory" rates if they are not authorized full ECOM recovery. See, e.g., TU Electric, ***supra*** at 15 - 17 (November 1996 comments).

[255] E.g., ***Dusquesne***, 488 U.S. at 315; *Pennsylvania Coal Co. v. Mahon*, 260 U.S. 393, 415 - 16 (1922) (*Mahon*) ("a strong public desire to improve the public condition is not enough to warrant achieving the desire by a shorter cut than the constitutional way of paying for the change"); *Penn Central Transp. Co. v. New York City*, 438 U.S. 104, 124 and 127-28 (1978) (*Penn Central*); *Kaiser Aetna v. United States*, 444 U.S. 164, 179 (1979); *Steele v. City of Houston*, 603 S.W.2d 786, 789 (Tex. 1980) ("This Court has moved beyond the earlier notions that the government's duty to pay for taking property rights is excused by labeling the taking as an exercise of police powers.")

Among other arguments, TU Electric suggests that a takings violation will occur if the Commission or Legislature engages in "Taking by Physical Occupation" or "Taking by Denying Access." See TU Electric, ***supra*** at 22 - 24 (November 1996 comments); see also HL&P, ***supra*** at 5 (November 1996 comments). These suggestions do not bear on the ECOM allocation issue, but instead involve the wholly distinct issue of whether and how the government can or should mandate ratepayer physical access to a utility's wires and facilities. Allocating ECOM does not entail "physical occupation" of property; mandated physical access and occupation of utility facilities

A definitive treatise on what is and what is not a constitutionally-impermissible taking would significantly lengthen this chapter. As the U.S. Supreme Court has noted: "[the] question of what constitutes a 'taking' for purposes of the Fifth Amendment has proven to be a problem of considerable difficulty."[256] The Commission will not here attempt to address the many nuances of the myriad cases that address the takings clauses. However, in contrast to the IOU's arguments, the Commission notes that there are numerous cases that may be read as holding that a Constitutional taking does not result from government action that provides less-than-full ECOM recovery to utilities.[257] In the context of ECOM allocation and recovery, it is certainly arguable that state action that involves *de*regulation rather than regulation, may not go "so far" as to constitute an unconstitutional "taking,"[258] and that competitive market forces, not the State, are *taking* value from the utility.[259]

(b) Tying Arrangements

Some parties also addressed the federal statutory issue of whether the allocation and recovery of ECOM through transmission and distribution rates would constitute an illegal "tying" arrangement.[260] Those who argue that such action would be illegal

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may. See, e.g., *Federal Communications Comm'n v. Florida Power Corp.*, 480 U.S. 247, 251 - 53 (1987); *Loretto v. Teleprompter Manhatten CATV Corp.*, 458 U.S. 419 (1982).

[256] *Penn Central*, 438 U.S. at 123. In the same decision, the Court also noted that: (1) whether an impermissible taking has occurred "depends largely 'upon the particular circumstances [in that] case;'" and (2) "A 'taking' may more readily be found when the interference with property can be characterized as physical invasion by government, . . . than when interference arises from some public program *adjusting the benefits and burdens of economic life to promote the common good.*" *Id.* at 123 - 24 (emphasis added).

[257] For example, a regulatory takings claim by IOUs may fail because the IOUs and their investors presumably are on notice that they could be allocated some or all of their ECOM. See, e.g., *Loveladies Harbor, Inc. v. United States*, 28 F.3d 1171, 1176 - 77 (Fed. Cir. 1994). This notice could be predicated on federal and state actions in regulating other industries (such as telecommunications and natural gas), court interpretations of regulatory statutes, and media articles addressing deregulation and utility cost recovery. See also *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1005 - 06 (1984) ("[a] 'reasonable investment backed expectation' must be more than 'a unilateral expectation or an abstract need"); *Usery v. Turner Elkhorn Mining Co.*, 428 U.S. 1, 16 (1986) ("legislation readjusting rights and burdens is not unlawful solely because it upsets otherwise settled expectations"); *Connolly v. Pension Benefit Guaranty Corp.*, 475 U.S. 211, 223 (1986) ("Given the propriety of the government power to regulate, it cannot be said that the Taking Clause is violated whenever legislation requires one person to use his or her assets for the benefit of another.")

[258] *Mahon*, 260 U.S. at 415.

[259] This reasoning is akin to the reasoning in *Market Street Railway* discussed below.

[260] A "tying" claim arising under federal antitrust statutes is an ECOM recovery issue, rather than an allocation issue.

generally assert that the State (and Commission) cannot "tie" the purchase of a product (generation) to the sale of a tying product (transmission) through the exercise of market power in the "tying" product (transmission) market.[261] Most commentors, however, argue that ECOM recovery achieved through some form of a wires or access charge would not constitute an illegal tying arrangement because this mechanism would not tie two separate and distinct "product" markets, and that such recovery mechanisms have been authorized in FERC proceedings.[262]

Parties who file a lawsuit alleging an illegal tying arrangement will need to surmount significant and well-established precedents to prevail. As discussed at length by a number of commentors, numerous federal Supreme and appellate court decisions can be interpreted to conclude that an access or wires charge should not be illegal under the circumstances involving a transition from a regulated to a competitive market.[263]

(c) Expectations Derived from Case Law

Ratepayer parties who oppose allocating ECOM to ratepayers rely on *Market Street Railway* for the proposition that utilities are not entitled to recover ECOM from their customers because competition, not state action, caused the utility to lose money.[264] *Market Street Railway* may be read broadly to hold that regulation cannot be used as a shield to protect utilities from potentially losing money in a competitive market. On this point, the Supreme Court ruled:

> *The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.* [265]

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[261] E.g., May 1996 comments filed by: Destec, *supra* at 18 - 19; and TIEC, *supra* at 17 - 18 (but TIEC notes that a definitive answer cannot be given until the particular wires charge is examined).

[262] E.g., May 1996 comments filed by: Chaparral, *supra* at 11 - 12; CSW, *supra* at 30; the Cities, *supra* at 9; EPEC, *supra* at 15 - 20; and HL&P, *supra* at 6 - 7.

[263] *Id.* See also *Associated Gas Distributors v. FERC* , 824 F.2d 981, 1027 (D.C. Cir.), *cert. denied*, 485 U.S. 1006 (1987) (*AGD I*) and FERC Order No. 888, *supra.*

[264] *Market St. Ry. Co. v. Railroad Comm'n. of Calif.*, 324 U.S. 548 (1945).

[265] *Id.* at 567. The Court also noted:

This holding may reasonably be interpreted to mean that utilities do not have some definitive right to some level of return, or any return, to the extent "economic forces" reduce the value of the utility's invested capital.

The rationale in *Market Street Railway*, however, may not be directly applicable to the Texas ECOM allocation issue. In *Market Street Railway*, the streetcar company lost value due to direct and indirect competition from other competing streetcars and "jitney" competition.[266] The competition was already in the relevant *retail* market, and was not created or unleashed by the California regulatory authorities. In California, the State did not take some action that could arguably be attributed to the loss in the streetcar utility's value. Some may argue, however, that retail-related ECOM in Texas may arise purely as a result of governmental action authorizing retail competition.

To further distinguish *Market Street Railway*, utility parties may argue that ratepayers cannot reasonably expect the utilities to forego a return on and of their investment. Instead, both the utilities and their customers must assume that the utility would not build a plant or enter into a purchased power contract unless it expects to get back its investment. With respect to such bilateral expectations, a Texas appellate court has noted that:

> *The public has an interest in obtaining a reasonable quantity and quality of service. The utility should generate the service safely, under the guidance of efficient management, and make the service obtainable at reasonable rates. . . . Further, a ratepayer could not reasonably expect a utility to spend millions of dollars building a nuclear facility, use the*

> *[most] of our [unconstitutional takings] cases deal with utilities which had earning opportunities, and public regulation curtailed earnings otherwise possible. . . . The problem of reconciling the patron's needs and the investors' rights in an enterprise . . . whose investment already is impaired by economic forces, and whose earning possibilities are already invaded by competition from other forms of transportation, is quite a different problem.*

Id. at 554. See also *Public Serv. Comm'n of Montana v. Great Northern Utilities Co.*, 289 U.S. 130, 135 (1932). In *Great Northern*, a nonexclusive franchise ordinance allowed competition to develop between two natural gas utilities. In response to a jurisdictional question brought by Great Northern, the Supreme Court held that, among other things, the Fourteenth Amendment to the U.S. Constitution "does not assure to public utilities the right under all circumstances to have a return upon the value of the property so used. The loss of, or the failure to obtain, patronage due to competition does not justify the imposition of charges that are exorbitant and unjust to the public."

[266] *Id.*

> *facility to generate electricity, and then not seek a return on its investment therein. In addition, the fact that the Commission had previously granted [the utility] a certificate of convenience and necessity to participate in the project thereafter precluded any interested person from reasonably claiming surprise at finding themselves obligated to pay the costs of building and operating the new plant.*[267]

The court's rationale is closely tied to the prudent investment rule. As discussed above, the prudent investment rule is a rule of law that precludes using hindsight judgment to disallow costs in a current or future rate period. But the prudent investment rule also establishes expectations for *both* utilities and their customers. Once an investment is deemed prudent and allowed into rate base, the utility and customers have a reasonable expectation that the utility will recover that investment until the plant built and purchased with the investment is no longer physically used and useful.

In summary, ratepayers have convincing arguments, based on constitutional and statutory provisions and precedent such as *Market Street Railway,* that they did not and do not expect to pay for above-market costs in a competitive environment. Instead, shareholders should bear the risk of loss as a result of changed market circumstances and their choice to invest in utility securities.

Utility shareholders, on the other hand, also have convincing arguments that the regulatory scheme ensures that they should recoup at least a reasonable portion of their investment in utility plant. Shareholders' investments support utilities that have provided significant benefits to ratepayers through reliable service at regulated rates. The utilities assert that, in return, the ratepayers and the State cannot ignore the bargain struck in the regulatory compact by requiring shareholders to bear a significant (or any) portion of ECOM.

c) Retail Expense-Related ECOM

The foregoing sections focus on the legal precedents that bear on rate base and "invested capital" issues. Electric power purchased by a utility from another utility,

[267] *City of El Paso v. Public Utility Comm'n,* 839 S.W.2d 895, 919 (Tex. App. — Austin, 1992).

EWG, "qualifying facility," or other generator, however, is not a capital item recorded in the utility's rate base accounts. Instead, the cost of purchased power is an expense recovered through a utility's cost of service or through its PCRF. Expenses and rate base items, while together constituting a utility's revenue requirement, are subject to different recovery standards under PURA95. Capital invested in rate base is subject to the "reasonable opportunity to earn a reasonable return" standard discussed above. Operating expenses, however, are subject to the "reasonable and necessary" standard set forth in PURA95 §2.203(a).

The phrase "reasonable and necessary" is a general, rather than a specific, concept. Accordingly, under PURA95 as currently written, the Commission may have greater discretion in determining how to allocate expense-related ECOM, as compared to rate base-related ECOM. The "prudence" and "used and useful" standards otherwise applicable to invested capital do not necessarily circumscribe a "reasonable and necessary" expense.[268] Instead, the Commission may use discretion to determine that some or all costs incurred under a purchased power contract are not a "reasonable and necessary" operating expense.

By analogy to the natural gas industry, the Commission notes that the FERC required pipelines to "share" some portion of their above-market take-or-pay costs (i.e., "expenses") with their customers.[269] There were, admittedly, a number of significant

[268] E.g., *Suburban Utility Corp. v. Public Utility Comm'n,* 652 S.W.2d 358, 362 - 63 (Tex. 1983). The Commission is aware of judicial decisions in which Texas courts used the word "prudent" in conjunction with the term "operating expense." *Public Utility Comm'n v. Houston Lighting & Power Co.*, 748 S.W.2d 439, 441 (Tex. 1987), *appeal dismissed,* 488 U.S. 805 (1988); *Cities for Fair Utility Rates v. Public Utility Comm'n.*, 884 S.W.2d 540, 543 (Tex. App. — Austin 1994). The precedents relied upon in these two decisions, however, do not use the word "prudent" in conjunction with "operating expense," and the courts do not explain why they added the word "prudent" to the precedential language.

[269] See, e.g., FERC Order No. 500, *et seq.*, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* FERC Stats. & Regs.., Regulations Preambles 1986 - 1990 ¶ 30,761 (1987).

The issues involving unrecovered take-or-pay expenses may be analogous to ECOM allocation and recovery issues: both involve situations in which the company incurs greater expenses or costs than it can recover in a competitive market. To resolve the take-or-pay allocation and recovery issues, the FERC, in Order No. 500, allowed a pipeline to recover between 25 percent and 50 percent of its take-or-pay expense through a fixed charge to its customers, to the extent that the pipeline absorbed an equal share of the expense. If a pipeline agreed to absorb 50 percent of its take-or-pay expense, it could recover the remaining 50 percent through a fixed charge. If it agreed to absorb only 25 percent, it could recover only 25 percent through a fixed charge, and the remaining 50 percent would be recovered, if at all, through a charge on the volumetric (or energy) component of the pipeline's rates. The volumetric charge could only be recovered to the extent the pipeline actually sold the gas to its legal issues that arose in the context of this take-or-pay cost sharing approach, particularly regarding the method used to assign costs to each customer.[270] Nevertheless, the take-or-pay sharing mechanism ultimately prevailed.[271] Subsequently, in its Order No. 636 addressing the restructuring of the natural gas industry, the FERC did not require any sharing by the utility in gas supply realignment costs. A federal appellate court, however, recently remanded FERC Order No. 636 with instructions for the FERC to explain why a cost absorption or sharing approach, such as used in the take-or-pay cases, should not also be applied in the context of the FERC's restructuring of the natural gas industry.[272]

Based on these precedents, there is at least some discretion to adjust utilities' expenses as necessary to ensure that the expenses are "reasonable and necessary" in light of more competitive markets. If implemented by either the Legislature or the Commission, expense adjustments would in effect require the utilities to share the ECOM allocation burden with their ratepayers.

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customers. If the pipeline could not sell the gas because its rates were priced above the market, it would forego recovery of this portion of the take-or-pay expense.

[270] *Associated Gas Distributors v. FERC*, 893 F.2d 349, 354 - 57 (D.C. Cir. 1989), *reh'g en banc denied*, 898 F.2d 809, *cert. denied*, 498 U.S. 907 (1990) (*AGD II*). FERC Order No. 528, *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, 53 F.E.R.C. (CCH) ¶ 61,163 (1990), issued in response to *AGD II*, also addressed cost sharing and allocation between customers and pipelines. E.g., *Western Resources, Inc. v. FERC*, 72 F.3d 147, 149 - 52 (D.C. Cir. 1995).

[271] *Id.* Entergy disagrees, and states that the Commission has misread the "litigation involving the recovery of take-or-pay contract expenses. . . ." See Entergy, *supra* at 7 - 9 (November 1996 comments). Entergy's position, however, fails to account for, much less mention, the FERC proceedings involving Order Nos. 500 and 528, *supra*. These proceedings resulted in the FERC-mandated and court-approved take-or-pay expense sharing mechanism, and were initiated in response to the appellate court's vacatur of Order No. 436 in *AGD I, supra*.

[272] *United Distribution Cos. v. FERC*, 88 F.3d 1105, 1188 - 90 (D.C. Cir. 1996). The court stated:

> *While we do not conclude that the Commission necessarily was required to assign the pipelines responsibility for some portion of their GSR costs, we do agree with the petitioners that the Commission's stated reasons for exempting the pipelines do not rise to the level of "reasoned decisionmaking." We therefore remand this issue to the Commission for further consideration.*

Id. at 1188 (emphasis in original). The court also noted that the FERC itself had concluded in FERC Order No. 500-H (which is an order on rehearing of Order No. 500, *supra*) that pipelines should bear some of the pipeline take-or-pay buyout or buydown burden. The FERC had reasoned in Order No. 500-H that

> *allowing a pipeline to recover 100 percent of its settlement costs through a fixed charge would be inconsistent with the Commission's holding in Order No. 500 that all segments of the natural gas industry should share in the burden of resolving the take-or-pay problem, since no single segment of the industry was to blame for its take-or-pay problem.*

Id. (quoting Order No. 500-H, FERC Stats. & Regs., Regulations Preambles ¶ 30,867 at 31,575).

4. Equity Considerations

Much of the foregoing discussion is predicated on an interpretation of constitutional provisions, regulatory statutes, legal concepts, and judicial decisions. These are legal considerations, in contrast to *equitable* considerations. ECOM allocation issues, however, are not simply legal points that can be determined solely from statutes and case law. In addition to legal considerations, the public interest and the Legislature's and Commission's power to establish or enforce public policy require consideration of equitable issues. This section briefly outlines the equitable considerations that are distinct from the foregoing legal analysis. While the Legislature and Commission should be mindful of controlling legal policy and precedent, equitable considerations that do not run directly counter to clearly controlling legal policy may be relied upon to reach policy decisions that further and protect the public interest.

The equitable considerations outlined in this section are derived from numerous sources, including the comments filed in Project No. 15001, published articles, statements, and studies that address ECOM allocation issues, and the Commission's own consideration of potential equities.[273] Pertinent equitable considerations bearing on ECOM allocation are summarized below.

a) Equitable Arguments Favoring ECOM Allocation to Shareholders

- Utility shareholders took investors' risks by purchasing utility stocks. As investors in unsecured interests, shareholders do not have an equitable expectation to a guaranteed or full return of any portion of their investment, including ECOM.
- Utility shareholders have already been adequately compensated for potential ECOM absorption because they recovered a risk premium through their authorized rates of return.

[273] See, e.g., articles contained in *The Electricity Journal*, Vol. 7, No. 8 (Oct. 1994) (edition is titled *Stranded Investment: What to Do?*); Scott Hempling, Kenneth Rose, & Robert Burns, "The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transmission to a Competitive Electric Generation Market," *National Assoc. of Regulatory Utility Comm'rs*, Washington, D.C. (Nov. 7, 1994); William Baumol and Gary Sidak, "Stranded Cost Recovery: Fair and Reasonable," *Public Utilities Fortnightly* (May 15, 1995); and "Transmission Pricing and Stranded Costs in the Electric Power Industry," Washington, D.C.: The AEI Press, (1995); Statement of Commissioner John Hanger, "Investigation Into Electric Power Competition," Harrisburg, PA: Pennsylvania Public Utility Comm'n. (July 3, 1996).

- Utilities have known since at least the passage of the Public Utility Regulatory Policies Act of 1978 that the electric utility industry would be opened to competition, and that they would likely become subject to competitive, market-based regulation, rather than cost-based regulation.[274]
- Utilities chose to build unnecessary or overly-large generation and transmission facilities, which allowed them to increase their rate bases and thereby earn more revenues, rather than using existing capacity and supply to serve their customers. If they had not invested in unnecessary plant, there would be less or no ECOM. Therefore, because the utilities chose to engage in unnecessary investments for their own gain, they should be liable for all ECOM allocation.
- Utilities used the shield of regulation and certificated service territories to stifle or fend off competition. As such, utilities should not be compensated for engaging in such self-serving and uneconomic actions by requiring consumers to bear some or all of the ECOM allocation.
- ECOM, in the form of stranded costs or transition costs, was fully absorbed by regulated trucking, airlines, and telecommunications companies when those industries were deregulated. Electric public utilities have no greater expectation or right to recovery.

b) Equitable Arguments Favoring ECOM Allocation to Ratepayers

- By allowing utilities to recover ECOM, the utilities have no financial reason to delay the transition to a competitive market in an effort to recoup costs that otherwise would be written-off.
- Shareholders should not be required to absorb ECOM because shareholder absorption:
  - Is inconsistent with historical regulatory practice that allowed the opportunity for full recovery of reasonable costs;
  - Undermines the "goodwill" of the State by vitiating the regulatory compact to the detriment of the electric industry in particular, and business in general;
  - Will create a disincentive for future investment in utilities; and
  - Unfairly benefits non-utility power suppliers by burdening utilities with costs that were incurred for the benefit of all consumers.

[274] The Commission also notes that articles have been appearing for years in trade publications that address the coming role of competition in the electric utility industry. See, e.g., Bouknight, J.A. and David B. Raskin, *Planning for Wholesale Customer Loads in a Competitive Environment: The Obligation to Provide Wholesale Service Under the Federal Power Act*, 8 Energy L. J. 237, 238 (1987) ("The purpose of our analysis is to provide a legal background for the current debate over expanding the role of competition in the electric industry.")

- The State has an equitable (if not legal) duty to honor its past commitments implicitly agreed to through the regulatory compact. For example:
  - Depreciation rates were set low on the assumption that the utility would recover its investment over a long period such as 20 to 40 years. If the State or the Commission now changes the basis for that assumption, it must authorize accelerated depreciation rates so that the utilities can recover their capital investments before retail competition creates the ECOM that, in effect, *takes* that investment.
  - Shareholders were not allowed to reap benefits of potentially higher returns in an unregulated market. They should not now be penalized when regulation is relaxed or removed.
  - Utilities have always been required to, and did, provide instantaneous, reliable service to any retail customer in their service territories for which they should be compensated.
- Utilities should not be held responsible for failing to foresee actions that state and federal governments would take to alter the use of their systems in a move from regulation to competition.
- Utilities are caught in "an unusual transition" that merits some form of cost recovery caused by the state-mandated transition from regulated to competitive markets. [275]
- Allocating ECOM to customers will act to maintain the financial integrity of existing utilities, and thereby ensure a competitive market for generation once the transition is complete.
- Shareholders have an expectation to substantial recovery of ECOM because the FERC has allowed interstate pipelines and public utilities subject to its jurisdiction to recover all of their verifiable and prudently-incurred stranded costs.

c) Equitable Arguments Favoring ECOM Sharing

As an alternative to a resolution in which ECOM is fully allocated to either the ratepayers or to the utilities, the Legislature may consider whether some form of an ECOM sharing method is warranted.

[275] *AGD I,* 824 F.2d at 1027: "[Interstate natural gas] pipelines have been caught in an unusual transition. They entered into the now uneconomic contracts in an era when government officials berated pipeline management for failures of supply and constantly predicted continuing energy price escalations."

- A sharing mechanism is a reasonable, legally supportable, and fair resolution of the ECOM allocation issue.
- The FERC adopted a sharing approach to address the natural gas pipeline take-or-pay problem in its Order Nos. 500 and 528.
- A sharing mechanism may be appropriate to ease the transition to effective competition without debilitating one class to the benefit of another.
- A sharing approach may be consistent with the concept of an assumed regulatory compact by providing benefits in return for parties accepting burdens. For example, if utilities absorb some ECOM through reduction in allowed rates of return or expenses, or written-down generation assets, the State could agree to open retail competition and deregulate generation pricing. Open markets and deregulated generation, in turn, will provide the utilities with an opportunity to earn unregulated generation function returns that may be higher than their current regulated returns. The ratepayers should also benefit from lower, market-based prices and competition in return for bearing some portion of the ECOM necessary to ensure a transition to the competitive market.
- Sharing may be justified because all segments of the industry stand to benefit from a more competitive, open electric power market, and all segments participated in or benefited from the historical system of full, cost-of-service regulation.

D. Overarching Considerations and Conclusions

A number of overarching allocation considerations can be gleaned from the foregoing legal and equitable considerations. Regardless of the allocation method adopted, ECOM should be allocated and recovered in a way that places the lowest possible cost burden on the parties. To reach this goal, the public interest would appear to require an allocation method that:

1. Does not inhibit the transition to competition;
2. Provides benefits, if possible (such as shuts-down inefficient generation facilities that may otherwise continue to operate in a regulated market);
3. Allocates only verifiable, non-mitigatable ECOM; and
4. Provides incentives to ensure that the utilities' ECOM is reduced to the lowest amount possible.

The Legislature may also consider whether utility divestiture of generation plant will further the public interest and enhance competition. If so, an allocation method could be adopted that provides a utility and its shareholders with significant ECOM recovery if it agrees to divest its generation plant. This approach has the added benefit of clearly defining that utility's ECOM—the difference between the present book value of the plant and the purchase price paid by the entity that acquires the divested plant.

An allocation method may also best serve the public interest, both equitably and legally, if it ensures that ECOM is allocated to the broadest possible base. For example, if ECOM is allocated to all constituencies, it should be allocated in an appropriate manner to: (1) all ratepayers, regardless of whether they are firm or interruptible, high or low load factor, industrial, commercial, or residential ratepayers; and (2) the utilities. If ECOM is allocated only to ratepayers, it should be allocated in an appropriate manner to all ratepayers regardless of class. If ECOM is to be allocated solely to the utilities, the utilities can be left with the discretion to determine how to deal with the allocation internally, subject to the caveat that the utilities cannot shift any ECOM allocated to them back to the ratepayers.

On one end of the spectrum, the utility parties would prefer full ECOM recovery while, on the other end, the ratepayer parties would prefer full ECOM absorption by the utilities' shareholders. Numerous alternatives lie between the two ends, including adjustments to rates of return, adjustments to expenses, adjustments to generation plant depreciation rates, as well as a more general sharing of ECOM among all constituencies. Given the differences between the parties, it is likely that any ECOM allocation method adopted will face a court challenge. For this reason, ECOM allocation (and recovery) is an issue that lends itself to resolution as one part of a multi-issue, multi-party negotiation in which all transition and restructuring issues are on the table. Recent experience in other states has shown that it is possible to reach such a settlement and thereby move those states more swiftly to a market-based regulatory regime.

X. ECOM RECOVERY

This report attempts to draw distinctions between the quantification, allocation, and recovery of ECOM to provide the Legislature a discrete analysis of each of the topics included in its legislative mandate. Over the course of this study, however, it has become clear that the three are closely intertwined. Nowhere is the link between these three aspects of ECOM so evident as when alternative recovery mechanisms are considered. The recovery mechanism determines how well the policy goals set forth in the allocation decision are fulfilled.

This chapter discusses the various methods available to recover any portion of ECOM that has been allocated to ratepayers. Section A lists general criteria that should be considered when selecting ECOM recovery mechanisms. Section B describes the alternative ECOM recovery mechanisms. Section C describes true-up mechanisms that may be necessary if ECOM is quantified in an administrative manner. Section C also briefly discusses performance-based ECOM recovery mechanisms.

A. ALTERNATIVE ECOM RECOVERY METHODS

The five types of recovery mechanisms that are widely discussed are summarized in Table X–1. The recovery mechanisms can be used in various combinations. Two of the mechanisms, access charges and exit fees, utilize a separately identified payment or payment stream designed to recover the amount of ECOM that an individual customer has been allocated.[276] Two structural methods, revaluing assets and adjusting depreciation, recover ECOM by adjusting current regulatory accounting rather than identifying specific separate charges for customers. A final method that may be utilized to recover ECOM is to cap or freeze current rates and apply any additional earnings due to gains in efficiency or reductions in fuel costs against the utilities' ECOM.

[276] See Hempling, Scott, Kenneth Rose and Robert E. Burns, *The Regulatory Treatment of Embedded Costs Exceeding Market Prices*, (November 7, 1994) for a discussion of recovery mechanisms that divides recovery mechanisms into transaction-related and non-transaction-related methods.

Table X–1: Summary of ECOM Recovery Mechanisms

Recovery Mechanisms	Definition	Advantages	Disadvantages
Access charges	Charges imposed on customers that are tied to continued transmission and distribution service.	Nonbypassable charge is competitively neutral.	Must design the access charge in a manner that will not distort customer behavior (e.g., encourage self-generation).
Exit fees	Fees charged to departing customers that are scaled to recover specific costs attributable to that customer.	Clearly identifies customers' ECOM responsibility and allows customers to structure their own payment plan.	Assignment to departing customer may imply a penalty for leaving incumbent (even though the value should be equivalent to the remaining customer's access charge).
Revaluing assets	Writing down the book value of generation assets while writing up the book value of transmission and distribution assets.	Does not require identification of specific charges.	Transmission and distribution are not competitive, will continue to be regulated, and should not be valued at market.
Adjusting depreciation	Accelerating the depreciation of generation assets while decelerating the depreciation of transmission and distribution.	Does not require identification of specific charges.	May not comply with generally accepted accounting principles.
Rate freeze	Rates are frozen at current levels and additional earnings from efficiency gains and decreases in fuel prices are applied against ECOM.	Does not require identification of specific charges.	Primarily used to pay off ECOM *in advance* of competition.

1. Access Charges and Exit Fees

Access charges and exit fees are distinguished from other ECOM recovery mechanisms in that electric rates will clearly identify the customer's responsibility for ECOM. The primary difference between the two is that access charges apply to all customers of the utility while exit fees are applied only when a customer leaves the utility for another generation provider.

a) Access Charges

The access charge is applied to *all* transmission and distribution customers of the utility, regardless of whether they continue to purchase generation from the current provider or depart from the current provider to purchase from a new supplier. The access charge—representing the allocated share of ECOM—is actually part of electric rates today. These costs are not currently separately identified, but are instead bundled into the utility's current rates. Even though the access charge is implicit in current rates, for competitive neutrality, it should not appear that a customer is responsible for *new* costs simply because the customer wants to choose an alternative supplier. If a customer perceives it must pay *additional* costs just to exercise competitive choice, the customer is less likely to exercise that choice. The inhibition of customer choice could constitute an entry barrier for alternative suppliers. In contrast, this inhibition of customer choice would not occur if the ECOM responsibility of *all* customers is identified.

In order to be an effective means of recovering ECOM, access charges must be "nonbypassable."[277] The design of an access charge must account for two considerations. First, customers should not be able to avoid their ECOM responsibility by their choice of generation supplier. Second, the application of an ECOM recovery mechanism should not distort a customer's choice of generation supplier. Customers should choose generation based on marginal cost and other specific criteria (e.g., resource type, pricing options, reputation of supplier, etc.) in order for the market to produce the economically efficient outcome.

To ensure that an access charge is nonbypassable, the charge is usually linked to the provision of transmission or distribution services.[278] Very few residential and

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[277] A nonbypassable charge is an assessment or charge that customers are not able to avoid or *bypass* by changing their behavior.

[278] Some parties have argued (citing Cajun Electric Power Cooperative, Inc. v. FERC, 28 F.3d 173 (D.C. Cir. 1994)) that recovering generation stranded costs through an access charge tied to transmission is illegal. In FERC

commercial customers will have the opportunity or means to completely disconnect from the electric grid solely to avoid an ECOM access charge.[279] Industrial customers may have a greater ability to leave the grid, but most industrial customers who self-generate today still purchase some power from their local utility and will continue to require a source of backup and emergency power. The access charge could be explicitly linked to these purchases. If bypassing the grid by self-generation is perceived to be a serious concern, an exit fee may be a more appropriate recovery mechanism.

The access charge must be designed to avoid subsidizing generation. In other words, the purpose of any ECOM allocation and its associated access charge is to put incumbents and entrants on a level playing field. Each market participant should have an equal opportunity to attract customers and earn profits. An access charge should not be so high as to provide a generation subsidy to the incumbent that inhibits the ability of entrants to compete for generation. Likewise an access fee should not be so low as to place the incumbent at a competitive disadvantage.[280]

There are two ways an access charge can be used to promote dynamic efficiency. If an access fee is set to make the customer indifferent to choosing between the incumbent utility and an entrant, then competition will promote efficiency with the incumbent and the entrant both striving to lower their production costs, offer a low price, and win the customer. Alternatively, an access charge can be purposely set at a level below full cost recovery, to force the incumbent to improve its operating efficiency to maintain its profits.

It is important to remember that if a utility has ECOM, the excess costs are embedded in the utility's current rates. The decision to allow ECOM recovery will not require a

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Order No. 888, the FERC held that the Cajun decision does not bar the recovery of stranded costs. Instead, the Court merely faulted the Commission for not having an adequate proceeding nor fully explaining its stranded cost recovery decision.

[279] To completely bypass the transmission and distribution system, a customer must become solely responsible for its own power needs through self-generation or co-generation.

[280] One exception could be if the access fee is intentionally set low to compel the incumbent to become more efficient.

net increase in rates over time if the excess costs are recovered over the current depreciation lives of the above market assets. Rates may increase only if customers or policy makers desire to accelerate the recovery of the ECOM component of rates. However, if electricity generation continues to be a declining cost industry, it is possible to accelerate ECOM recovery without any increase in rates.[281]

b) Exit Fees

An exit fee assigns ECOM to the *departing* customer. The magnitude of the exit fee must reflect appropriate ECOM quantification and allocation decisions. Theoretically, the size of an exit fee should be the net present value of the ECOM attributable, and allocated, to the departing customer. Once the magnitude of the exit fee is identified, the exit fee can be charged as a lump sum or amortized over a period of time.

Because an exit fee and the terms of payment are considered on a case-by-case basis, exit fees are more appropriate for departing wholesale and large industrial customers. It would be unwieldy to calculate a separate exit fee for each departing residential and commercial customer. For residential and commercial customers, calculating a generic access charge on the basis of peak demand or usage would be easier to implement. However, the ability of wholesale and large industrial customers to use individual cases to lessen their ECOM responsibility relative to residential and commercial customers must be discouraged.

c) Method of Application

There are a variety of ways in which an access charge or exit fee may be applied. In this sense, the design of access charges or exit fees is analogous to the variety of tariffs available for the purchase of electricity. Electric rates typically have a fixed component—or demand charge—that is meant to recover the fixed capacity costs that are required to serve a specific customer. There is also a usage sensitive component—the energy charge—that is meant to recover the variable costs associated with a

[281] In Docket No. 15560 (withdrawn), Texas-New Mexico Power Inc. proposed to recover ECOM in five years by freezing current rates while becoming more efficient and applying the savings earned against the book value of its generation assets.

customer's energy consumption. The portion of costs recovered through fixed or variable components varies across classes of customers.

ECOM charges can also have a fixed and/or variable component. Since ECOM recovery is the recovery of sunk costs, the method of application should attempt to minimize the distortion of consumers' behavior.[282] Placing too much of the ECOM payment on a per kWh charge would induce customers to consume less to avoid the payment. Among the types of customers, residential customers would be expected to be least responsive to such price changes. Industrial customers would have a greater incentive to adjust their consumption by installing self-generation (i.e., uneconomic bypass). A larger fixed charge and smaller variable component would lessen the ability of customers to avoid the charge by reducing consumption or moving to alternative suppliers.[283] At the same time, ECOM is a controversial and unpopular subject. Representing ECOM as a fixed fee that could comprise a relatively large portion of a residential customer's monthly bill may cause exaggerated attention to the charges.

Because the exit fee or access charge essentially guarantees recovery of the ECOM that has been allocated to ratepayers, some argue that its recovery should be calculated with either a risk-free rate of return or, no return at all.[284] Any ECOM allocated to ratepayers in the form of access charges becomes risk-free (i.e., fully guaranteed to the utilities) and therefore should at most be accorded a risk-free rate of return. If the mechanism is nonbypassable, the utility faces no risk of nonrecovery. On the other hand, the argument to allow no return on ECOM suggests that the ECOM payment becomes severed from the specific capital investment that historically earned a return. If ECOM is amortized over time in an access charge, the payment structure still does not escape the time value of money.[285]

[282] Because fixed costs are "sunk," efficient future economic decisions will not take fixed costs into account.

[283] There would still be some incentive to manage loads to lessen peak demand.

[284] Holding everything else constant, applying a risk-free rate of return to allocated ECOM would result in a rate decrease.

[285] In their comments on the draft report, the Office of Public Utility Counsel notes that recovery of ECOM is analogous to the amortization of abandoned plant, which is typically carried out without earning a return on the

2. Structural Recovery Mechanisms

Two structural methods of ECOM recovery are widely discussed: writing down generation assets with a concomitant write-up of transmission and distribution assets; and accelerating depreciation of generation assets while decelerating depreciation of transmission and distribution assets.[286] Although the accounting treatment of these two methods is different, the resulting total rate can be identical to imposing a nonbypassable access charge on transmission and distribution facilities.

The first method, writing down generation assets with a concomitant write-up of transmission and distribution assets, recognizes that the booked value of some generation assets exceeds market value. A firm could adjust the book value to match market value. But the rationale for writing up transmission and distribution is more tenuous. Proponents argue transmission and distribution assets may be written up because they are currently *below* market value. However, many believe that transmission and distribution are not competitive, and will remain under rate regulation for quite some time. Therefore the concept of *market value* of transmission and distribution may not be appropriate. Transmission and distribution services are traditionally offered at cost-of-service, not value-of-service.[287]

The second method, accelerating the depreciation of generation assets while decelerating depreciation of transmission and distribution assets, does not require a *revaluation* of assets. One problem associated with this approach is that adjusted depreciation lives may not be based on the useful life of the plant. This is a possible violation of Generally Accepted Accounting Principles (GAAP).[288] There is some flexibility available in this approach, for instance, depreciation lives could be

unamortized balance. *Office of Public Utility Counsel's Comments on the Staff's Draft Report*, Project No. 15001 at 11 (November 8, 1996).

[286] Other non-transaction-related recovery mechanisms discussed in Hempling, et al., *supra*, include entrance fees charged to new suppliers, pooling ECOM recovery among all generators in the state, and collecting ECOM payments through general revenue taxes.

[287] A form of value-of-service pricing or congestion pricing for transmission may be appropriate for determining the existence of transmission constraints and signaling when new transmission should be constructed.

[288] Hempling, *supra* at 62.

restructured so that ratepayers do not experience a rate increase.[289] In effect, this approach amounts to a simple redistribution of costs over time. However, some utilities may not have sufficient transmission and distribution assets that can be adjusted to fully offset the generation adjustments. In such cases, the utilities would have to assume greater responsibility for lowering generation costs (e.g., write down assets) or increase near-term rates.

3. Rate Freeze/Cap

The final recovery method commonly discussed involves freezing rates at current levels and applying any additional earnings from efficiency gains and/or decreases in fuel prices against the ECOM allocated to customers.[290] This method would not require identification of specific access charges or adjustment. In effect, this method would be similar to accelerating the depreciation of generation assets. One difficulty presented by this method is that it is only effective in advance of adoption of retail access. After a customer has a choice of generation supplier, any remaining share of ECOM must be recovered through exit fees or charges associated with transmission and distribution service. A variation that would not require customers to pay ECOM charges subsequent to being allowed retail access, would be to predetermine a target date for the onset of retail competition and not allow the recovery of ECOM past that date. An alternative to the target date idea would be to allow customers to depart early, but take with them the obligation to pay their share of ECOM for the remaining years of the rate freeze.

On May 2, 1996 and November 26, 1996, Texas-New Mexico Power Company (Docket No. 15560) and Gulf States Utilities Company (Docket No. 16705), respectively, filed applications with the commission for approval of voluntary

[289] Another complication that results from any attempt to adjust transmission value or depreciation is the potential for cost shifting under the transmission pricing guidelines found in P.U.C. SUBST. R. 23.70. Increased transmission costs (and the ECOM they are meant to recover) could be borne in part (in the way of higher wheeling charges) by third party users of the utility's transmission system.

[290] The Office of Public Utility Counsel, *supra*, comments that these cost reductions should flow through to customers in lower rates. This chapter of the report, however, assumes that some allocation of ECOM responsibility has been made to ratepayers. In this context, foregoing rate reductions is one way to pay off an allocated share of ECOM.

restructuring plans. A component of each plan would allow the utilities to freeze or cap certain rates for a period of time and apply additional earnings against the companies' ECOM. At the conclusion of each companies' transition period, some form of access to alternative generation suppliers would be offered. On November 20, 1996 Texas-New Mexico Power Company filed a motion to withdraw its application from the commission without prejudice for refiling.

B. TRUE-UP MECHANISMS AND PERFORMANCE-BASED RECOVERY MECHANISMS.

Once an allocation of ECOM responsibility has been made, the real difficulties of quantification and recovery become apparent. As discussed above, any set of market price projections will be wrong, even those that look only at the relatively near future. Underestimating market price will result in a fixed ECOM payment larger than the actual ECOM allocation (revealed *ex post*), and will allow incumbents to earn excess profits from excessive customer rates. Overestimating market price will result in a fixed ECOM payment smaller than the actual ECOM allocation, causing shareholders to bear more of the transition costs than policy makers intend. Any *one-time* ECOM quantification method is subject to a dramatic estimation risk.[291] Estimation risk refers to the degree to which the actual level of ECOM may differ from the predicted level of ECOM as a result of incorrect assumptions (such as the level of future market prices and fuel and operating costs). As discussed in Chapters VI and VIII, changes in market price have a substantial effect on the magnitude of ECOM.

a) Simple True-up

One solution to the problem of estimation risk is to implement an ECOM true-up mechanism. As the name implies, every year utilities would determine the realized market price for that year and use the realized market price to reconcile the ECOM fee. The following year's ECOM factor could be adjusted downward if the market price were higher than expected and ECOM payments were overcollected. The ECOM

[291] This is true of all administrative ECOM estimation methods, and is independent of the type of ECOM recovery method (i.e., access charge, exit fee, or change in depreciation).

factor could be adjusted upward if market price were lower than expected and ECOM payments were undercollected. The main problem presented with a simple true-up mechanism is that utilities would have no incentive to become more efficient. Over time, the amount collected between ECOM fees and generation fees would add up to the utility's expected revenue stream under regulation. Consumers would not receive any total price reductions.

b) Stabilization True-up

A stabilization true-up is a one-time true-up that takes place long enough after the onset of the competitive market that prices have begun to stabilize. It is expected that in the first year or two of a competitive market, prices could fluctuate as newcomers vie for entry into the market, incumbents sell off generation assets, mergers and acquisitions take place, interstate transactions increase, and the role of transmission constraints becomes evident. After this activity settles down, the market price volatility is likely to subside. At this point a one-time true-up could be undertaken. To be sure, there will still be price volatility, and the volatility will convey unexpected costs and benefits to shareholders and ratepayers. However, the order of magnitude of the estimation error a year or two after the electric market is opened to competition should be substantially smaller than the estimation error associated with *ex ante* estimates. An effective true-up could occur no later than three or four years after the start of competition--long enough for the pressures of competition to take effect, yet close enough for comparisons between current and past conditions to remain relevant. The true-up should be an end-point, closing the book on the old world. Once ECOM has been recalculated and compared to actual collections over the relevant period, and the final ECOM adjustment (if any) is determined and set for collection, it should be collected as quickly as possible, so that utilities, competitors and customers can all focus on realizing the benefits of competition rather than prolonging the transition.

c) Performance-based ECOM Recovery Mechanisms

One type of ECOM recovery mechanism that provides an incentive for firms to reduce costs and benefits ratepayers would be a mechanism that links ECOM recovery to performance (i.e., performance-based ECOM or PB ECOM).[292] More so than any other recovery mechanism, PB ECOM is consistent with the concept of allowing utilities a reasonable *opportunity* to recover an allocated amount of ECOM. Just like any other performance-based ratemaking methodology, PB ECOM would require firms to achieve specified levels of operating performance. Firms would be rewarded for additional performance improvements. While there is some risk that utilities will not recover 100 percent of the ECOM allocated to ratepayers with a PB ECOM recovery mechanism, there is a greater likelihood of consumers receiving some of the benefits of a competitive market. If the policy makers' ECOM allocation decision offers utilities something less than 100 percent *guaranteed* recovery, a PB ECOM recovery mechanism would allow the utility an opportunity to maximize the amount of recovery possible.

The staff of the New York Public Service Commission has proposed a variation on PB ECOM, in which a utility's rates would be unbundled into a transmission and distribution element and a generation element.[293] The generation element would be further unbundled into a market price component and an ECOM component. The market price component would be determined each year. ECOM in each year would equal the generation element minus the market price component. A declining proportion of the ECOM component would be recovered over a ten-year period. In the first year, 100 percent of the annual ECOM is recovered, in the second year 90 percent, in the third year 80 percent, and so on. At the end of ten years, there would be no ECOM component left in rates. If by superior performance the utility is able to pay down ECOM earlier, the utility then receives the benefits.

[292] A general discussion of performance-based regulation, also known as incentive regulation, may be found in Chapter XII of the Scope of Competition report.

[293] New York Public Service Commission. In the matter of Cases 94-E-0099, and 94-G-0100 (Niagara Mohawk Power Corporation), Prepared Staff Testimony (August 1994).

Another performance-based approach to stranded cost recovery has been described by Paul Joskow: [294]

1. An access charge is set for customers to recover sunk costs.
2. Regulators determine the avoidable (marginal) cost of production in \$/kWh. The avoidable cost will be adjusted by the appropriate inflation indexes and performance factors (e.g. fuel price indexes, comparative performance indexes, etc.).
3. The *adjusted* avoidable cost is translated into a commodity charge in \$/kWh.
4. All customers have access to a competitive generation market.
5. The utility must offer a contract for power consisting of the fixed access charge and the performance-based commodity charge.
6. If the market price is greater than the commodity charge, customers receive an implicit credit to the fixed access charge.
7. If the market price is less than the utility's commodity charge, customers can purchase power on the market and pay the fixed access charge to the utility.

While the example described above assumes an initial 100 percent recovery of fixed costs from ratepayers, a partial allocation of ECOM to shareholders can be incorporated by simply adjusting the fixed access charge by the percent of shareholder responsibility. It is important to remember that any PB ECOM recovery should set achievable performance standards that do not impair a utility's ability to provide reliable, high quality service.

A very simple PB ECOM recovery mechanism could be instituted as part of the rate freeze/cap recovery method. The performance required by a utility to recover the allocated amount of ECOM can be altered by allowing the utility a greater or shorter time period in which to recover ECOM before the onset of retail competition. It would also be possible to monitor the performance of the utility during the transition period and adjust the length of the transition period if warranted.

[294] Joskow, Paul L., "Does Stranded Cost Recovery Distort Competition?" *The Electricity Journal* at 31 - 45 (April 1996).

d) Adjustment for Administrative Determinations of ECOM

The degree of estimation risk inherent in administrative determinations of ECOM is naturally greater than any error possible in market determinations of asset value and ECOM. Therefore, if ECOM is determined by administrative rather than market means, the target ECOM recovery amount could be shifted down by some percentage to force the utility to absorb the risk of the estimation error. In other words, if the allocation decision states a utility may recover 100 percent of ECOM from its ratepayers, but the margin of error from administrative determinations leaves open the possibility that utilities could recover an amount greater than the allocated ECOM, the ECOM recovery mechanism could be targeted to recover less than 100 percent, minimizing the possibility of over-recovery. There is also the possibility that the margin of error will work in the opposite direction and result in under-recovery by the firm. But this possibility is mitigated in three ways. First, the utility has better information on its own production costs and customers than any other parties in any administrative proceeding to determine the magnitude of ECOM. Second, the utility has the ability to improve its performance in a competitive market. And third, if the utility believes that assuming the risk of estimation error is too great a burden, the utility may opt for a market valuation of its assets and associated ECOM. It is important to note that the determination of the margin of error, and thus the amount by which to shift the ECOM target recovery, will be no simple matter and will be different for each utility.

C. CRITERIA FOR ECOM RECOVERY

In evaluating alternative ECOM recovery mechanisms, the following criteria should be considered:

1. Impact on rates;
2. Incentives of utilities to reduce costs;
3. Impact on the competitive market;
4. Time horizon; and
5. Ease of administration.

Two key requirements of an ECOM recovery mechanism are that the mechanism promotes economic efficiency[295] and that the benefits of additional efficiency gains in electric generation accrue to customers. In other words, upon initiation, the ECOM recovery mechanism should compel the incumbent utility to change its behavior to mirror any additional improvements in reducing the marginal cost of production being made by the industry as a whole. The industry-wide cost reductions should largely be translated into rate reductions for customers. Reductions in operating costs for a particular utility that extend *beyond* the average performance of the industry may be translated into additional profits to the firm. An ECOM recovery mechanism accomplishes these goals in part by being competitively neutral. The recovery mechanism should not confer a competitive advantage on any market participant. Entrants and incumbents should have an equal opportunity to compete for customers.

[295] For a discussion of economic efficiency, see Chapter IV of The Scope of Competition Report.

Appendices to the Stranded Investment Report

Appendix A

ECOM Model Annual Average

Market Prices

Appendix A - ECOM Model Annual Average Market Prices

	Base Market Price			Low Market Price			High Market Price		
	Industrial ($/MWh)	Commercial ($/MWh)	Residential ($/MWh)	Industrial ($/MWh)	Commercial ($/MWh)	Residential ($/MWh)	Industrial ($/MWh)	Commercial ($/MWh)	Residential ($/MWh)
1996	24.8	25.8	26.8	20.3	21.1	21.9	29.3	30.5	31.7
1997	25.5	26.6	27.6	20.9	21.7	22.6	30.2	31.4	32.6
1998	26.3	27.4	28.4	21.6	22.4	23.2	31.1	32.3	33.6
1999	28.9	30.5	32.0	23.8	25.0	26.2	34.1	35.9	37.8
2000	31.6	33.6	35.6	26.0	27.6	29.2	37.2	39.6	41.9
2001	34.2	36.7	39.2	28.2	30.2	32.2	40.2	43.2	46.1
2002	35.1	37.7	40.2	28.9	31.0	33.1	41.3	44.3	47.3
2003	36.0	38.7	41.3	29.7	31.8	34.0	42.4	45.5	48.6
2004	37.0	39.7	42.4	30.5	32.7	34.9	43.5	46.7	49.9
2005	38.0	40.8	43.5	31.3	33.6	35.8	44.7	47.9	51.2
2006	39.0	41.9	44.7	32.2	34.5	36.8	45.9	49.2	52.6
2007	40.1	43.0	45.9	33.0	35.4	37.8	47.1	50.5	54.0
2008	41.1	44.1	47.1	33.9	36.4	38.8	48.4	51.9	55.4
2009	42.3	45.3	48.4	34.8	37.3	39.9	49.7	53.3	56.9
2010	43.4	46.6	49.7	35.8	38.4	40.9	51.0	54.8	58.5
2011	44.6	47.8	51.1	36.8	39.4	42.1	52.4	56.2	60.1
2012	45.8	49.1	52.4	37.8	40.5	43.2	53.8	57.8	61.7
2013	47.0	50.5	53.9	38.8	41.6	44.4	55.3	59.3	63.4
2014	48.3	51.8	55.3	39.9	42.7	45.6	56.8	60.9	65.1
2015	49.7	53.3	56.9	40.9	43.9	46.8	58.4	62.6	66.9
2016	51.0	54.7	58.4	42.1	45.1	48.1	60.0	64.3	68.7
2017	52.4	56.2	60.0	43.2	46.3	49.5	61.6	66.1	70.6
2018	53.9	57.8	61.7	44.4	47.6	50.8	63.3	67.9	72.5
2019	55.3	59.4	63.4	45.7	48.9	52.2	65.0	69.8	74.5
2020	56.9	61.0	65.1	46.9	50.3	53.7	66.8	71.7	76.6
2021	58.4	62.7	66.9	48.2	51.7	55.2	68.7	73.7	78.7
2022	60.1	64.4	68.8	49.6	53.1	56.7	70.6	75.7	80.9
2023	61.7	66.2	70.7	50.9	54.6	58.3	72.5	77.8	83.1
2024	63.4	68.0	72.6	52.4	56.1	59.9	74.5	80.0	85.4
2025	65.2	69.9	74.7	53.8	57.7	61.6	76.6	82.2	87.8
2026	67.0	71.9	76.7	55.3	59.3	63.3	78.7	84.5	90.2
2027	68.9	73.9	78.9	56.9	61.0	65.0	80.9	86.8	92.7
2028	70.8	75.9	81.1	58.5	62.7	66.9	83.2	89.2	95.3
2029	72.8	78.1	83.4	60.1	64.4	68.7	85.5	91.7	98.0
2030	74.8	80.3	85.7	61.8	66.2	70.7	87.9	94.3	100.7
2031	76.9	82.5	88.1	63.5	68.1	72.6	90.3	96.9	103.5
2032	79.1	84.8	90.6	65.3	70.0	74.7	92.9	99.7	106.4
2033	81.3	87.2	93.1	67.1	72.0	76.8	95.5	102.4	109.4
2034	83.6	89.7	95.7	69.0	74.0	79.0	98.2	105.3	112.5
2035	86.0	92.2	98.4	71.0	76.1	81.2	100.9	108.3	115.6

Appendix B

ECOM Model Results

Appendix B - ECOM Model Results

Total Texas Retail

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	22,245	21,126	14,188	12,816	4,847	3,475
2000Full	15,593	14,628	8,393	7,243	337	(832)
I98/C00/R02	14,938	13,959	7,777	6,661	(191)	(1,327)
I98/C02/R06	10,884	10,088	4,970	4,065	(1,708)	(2,635)
I98/C00/R02 Phase-in	13,772	12,840	6,935	5,862	(709)	(1,800)
R98/C00/I00	18,832	17,767	11,165	9,913	2,643	1,368

Probabilistic Results

	95 Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	17,806	16,396	14,188	12,816	10,560	9,188
2000Full	11,126	9,945	8,393	7,243	5,637	4,487
I98/C00/R02	10,317	9,172	7,777	6,661	5,235	4,120
I98/C02/R06	7,316	6,411	4,970	4,065	2,618	1,715
I98/C00/R02 Phase-in	9,503	8,400	6,935	5,862	4,365	3,293
R98/C00/I00	14,243	12,961	11,165	9,913	8,086	6,834

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	2,609	2,415	2,324	2,020	1,582	1,269
Coal/Lignite	1,104	583	(4,071)	(4,630)	(9,832)	(10,374)
Nuclear	17,841	17,439	15,592	15,085	13,103	12,589
Purchased Power/Other	687	687	341	341	(5)	(5)

West Texas Utilities Company Texas Retail ECOM Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	93	77	(47)	(63)	(188)	(203)
2000Full	17	4	(109)	(122)	(236)	(249)
I98/C00/R02	16	3	(107)	(120)	(231)	(243)
I98/C02/R06	(7)	(17)	(110)	(120)	(214)	(224)
I98/C00/R02 Phase-in	6	(6)	(113)	(125)	(232)	(244)
R98/C00/I00	52	38	(80)	(94)	(212)	(226)

Probabilistic Results

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	7	(9)	(47)	(63)	(101)	(117)
2000Full	(71)	(84)	(109)	(122)	(147)	(160)
I98/C00/R02	(77)	(90)	(107)	(120)	(137)	(150)
I98/C02/R06	(88)	(98)	(110)	(120)	(132)	(142)
I98/C00/R02 Phase-in	(89)	(101)	(113)	(125)	(137)	(149)
R98/C00/I00	(36)	(50)	(80)	(94)	(124)	(138)

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	42	33	24	14	5	(4)
Coal/Lignite	50	44	(71)	(77)	(193)	(199)
Nuclear	0	0	0	0	0	0
Purchased Power/Other	0	0	0	0	0	0

Texas Utilities Electric Company Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	7,661	7,181	4,658	4,090	763	195
2000Full	5,104	4,691	2,389	1,913	(911)	(1,386)
I98/C00/R02	4,674	4,245	1,998	1,544	(1,217)	(1,672)
I98/C02/R06	3,049	2,688	914	553	(1,710)	(2,070)
I98/C00/R02 Phase-in	4,231	3,822	1,694	1,260	(1,379)	(1,813)
R98/C00/I00	6,504	6,049	3,560	3,043	27	(490)

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	6,168	5,600	4,658	4,090	3,148	2,580
2000Full	3,521	3,045	2,389	1,913	1,257	781
I98/C00/R02	2,956	2,502	1,998	1,544	1,040	586
I98/C02/R06	1,852	1,491	914	553	(24)	(385)
I98/C00/R02 Phase-in	2,782	2,348	1,694	1,260	606	172
R98/C00/I00	4,852	4,335	3,560	3,043	2,268	1,751

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	681	681	758	670	432	344
Coal/Lignite	(2,376)	(2,589)	(3,995)	(4,208)	(6,102)	(6,316)
Nuclear	8,676	8,409	7,333	7,066	5,990	5,723
Purchased Power/Other	680	680	562	562	443	443

Central Power and Light Company Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	2,967	2,863	2,367	2□,251	1,749	1,633
2000Full	2,229	2,143	1,708	1,611	1,172	1,073
I98/C00/R02	2,174	2,089	1,656	1,560	1,122	1,025
I98/C02/R06	1,696	1,626	1,259	1,177	805	722
I98/C00/R02 Phase-in	2,037	1,956	1,540	1,447	1,027	933
R98/C00/I00	2,568	2,475	2,018	1,913	1,453	1,347

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	2,633	2,517	2,367	2,251	2,101	1,985
2000Full	1,866	1,769	1,708	1,611	1,530	1,433
I98/C00/R02	1,802	1,706	1,656	1,560	1,510	1,414
I98/C02/R06	1,387	1,305	1,259	1,177	1,131	1,049
I98/C00/R02 Phase-in	1,684	1,591	1,540	1,447	1,396	1,303
R98/C00/I00	2,214	2,109	2,018	1,913	1,822	1,717

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	120	100	69	49	15	(5)
Coal/Lignite	(215)	(225)	(472)	(482)	(728)	(738)
Nuclear	3,070	2,999	2,785	2,702	2,485	2,401
Purchased Power/Other	(14)	(14)	(18)	(18)	(23)	(23)

Houston Lighting and Power Company Texas Retail ECOM Model Results

	Extreme High		Expected Value		Extreme Low	
Discrete Results	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	6,420	6,079	3,954	3,587	1,338	953
2000Full	4,526	4,253	2,381	2,084	87	(229)
I98/C00/R02	4,214	3,959	2,144	1,864	(76)	(373)
I98/C02/R06	3,052	2,870	1,378	1,171	(445)	(670)
I98/C00/R02 Phase-in	3,918	3,678	1,935	1,671	(198)	(480)
R98/C00/I00	5,391	5,088	3,131	2,803	722	376
Probabilistic Results	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	4,876	4,509	3,954	3,587	3,032	2,665
2000Full	3,119	2,822	2,381	2,084	1,643	1,346
I98/C00/R02	2,886	2,606	2,144	1,864	1,402	1,122
I98/C02/R06	2,048	1,841	1,378	1,171	708	501
I98/C00/R02 Phase-in	2,607	2,343	1,935	1,671	1,263	999
R98/C00/I00	3,951	3,623	3,131	2,803	2,311	1,983
Scenario *1998 Full* Discrete Results by Fuel Type						
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	1,486	1,352	1,272	1,131	1,048	898
Coal/Lignite	1,944	1,736	44	(182)	(1,903)	(2,137)
Nuclear	3,079	3,079	2,784	2,784	2,396	2,396
Purchased Power/Other	(89)	(89)	(146)	(146)	(203)	(203)

El Paso Electric Company Texas Retail ECOM Model Results

	Extreme High		Expected Value		Extreme Low	
Discrete Results	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	1,381	1,310	1,123	1,051	854	781
2000Full	1,069	1,006	841	778	603	539
I98/C00/R02	1,097	1,032	861	795	608	542
I98/C02/R06	903	844	691	631	462	401
I98/C00/R02 Phase-in	1,043	979	812	748	566	501
R98/C00/I00	1,186	1,118	948	879	697	628
Probabilistic Results	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	1,221	1,149	1,123	1,051	1,025	953
2000Full	925	862	841	778	757	694
I98/C00/R02	943	877	861	795	779	713
I98/C02/R06	773	713	691	631	609	549
I98/C00/R02 Phase-in	902	838	812	748	722	658
R98/C00/I00	1,046	977	948	879	850	781
Scenario *1998 Full* Discrete Results by Fuel Type						
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	63	63	63	63	63	63
Coal/Lignite	7	3	(16)	(21)	(50)	(54)
Nuclear	1,311	1,244	1,077	1,009	841	773
Purchased Power/Other	0	0	0	0	0	0

Gulf States Utilities Company Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	658	632	452	426	214	188
2000Full	392	370	203	181	(8)	(30)
I98/C00/R02	447	421	240	214	12	(15)
I98/C02/R06	357	331	152	126	(67)	(94)
I98/C00/R02 Phase-in	410	384	204	178	(22)	(48)
R98/C00/I00	530	505	330	304	104	78

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	562	536	452	426	342	316
2000Full	275	253	203	181	131	109
I98/C00/R02	328	302	240	214	152	126
I98/C02/R06	218	192	152	126	86	60
I98/C00/R02 Phase-in	278	252	204	178	130	104
R98/C00/I00	424	398	330	304	236	210

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	(143)	(163)	(115)	(134)	(119)	(138)
Coal/Lignite	64	57	(75)	(82)	(213)	(219)
Nuclear	817	817	817	817	817	817
Purchased Power/Other	(78)	(78)	(174)	(174)	(270)	(270)

Southwestern Electric Power Company Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	(137)	(153)	(453)	(470)	(770)	(787)
2000Full	(181)	(194)	(443)	(457)	(706)	(720)
I98/C00/R027	(178)	(192)	(455)	(469)	(732)	(746)
I98/C02/R06	(173)	(184)	(411)	(422)	(649)	(661)
I98/C00/R02 Phase-in	(183)	(196)	(446)	(459)	(709)	(722)
R98/C00/I00	(159)	(173)	(435)	(449)	(711)	(726)

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	(301)	(318)	(453)	(470)	(605)	(622)
2000Full	(342)	(356)	(443)	(457)	(545)	(559)
I98/C00/R02	(345)	(359)	(455)	(469)	(565)	(579)
I98/C02/R06	(313)	(324)	(411)	(422)	(509)	(520)
I98/C00/R02 Phase-in	(326)	(339)	(446)	(459)	(566)	(579)
R98/C00/I00	(315)	(329)	(435)	(449)	(555)	(569)

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	12	10	6	4	0	(2)
Coal/Lignite	(157)	(172)	(464)	(478)	(771)	(785)
Nuclear	0	0	0	0	0	0
Purchased Power/Other	8	8	4	4	0	0

Southwestern Public Service Company Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	516	480	51	(8)	(458)	(517)
2000Full	315	284	(90)	(145)	(539)	(594)
I98/C00/R02	375	342	(55)	(111)	(528)	(584)
I98/C02/R06	307	279	(87)	(139)	(525)	(577)
I98/C00/R02 Phase-in	306	276	(98)	(153)	(547)	(601)
R98/C00/I00	377	344	(42)	(98)	(503)	(560)

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	259	200	51	(8)	(157)	(216)
2000Full	78	23	(90)	(145)	(258)	(313)
I98/C00/R02	103	47	(55)	(111)	(213)	(269)
I98/C02/R06	55	3	(87)	(139)	(229)	(281)
I98/C00/R02 Phase-in	30	(25)	(98)	(153)	(226)	(281)
R98/C00/I00	104	48	(42)	(98)	(186)	(242)

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	123	111	14	1	(98)	(111)
Coal/Lignite	410	387	65	18	(322)	(368)
Nuclear	0	0	0	0	0	0
Purchased Power/Other	(18)	(18)	(28)	(28)	(39)	(39)

Texas-New Mexico Power Company Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	759	758	708	707	657	682
2000Full	550	549	518	518	486	492
I98/C00/R02	576	571	525	521	475	475
I98/C02/R06	469	461	417	409	365	363
I98/C00/R02 Phase-in	542	536	492	485	442	441
R98/C00/I00	666	662	621	616	575	577

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	742	741	708	707	674	673
2000Full	536	536	518	518	500	500
I98/C00/R02	557	553	525	521	493	489
I98/C02/R06	443	435	417	409	391	383
I98/C00/R02 Phase-in	522	515	492	485	462	455
R98/C00/I00	649	644	621	616	593	588

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	0	0	0	0	0	0
Coal/Lignite	610	609	610	609	610	635
Nuclear	0	0	0	0	0	0
Purchased Power/Other	149	149	98	98	47	47

City of Austin Electric Utility Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	890	880	633	519	241	121
2000Full	716	683	401	305	59	(43)
I98/C00/R02	664	626	354	262	23	(74)
I98/C02/R06	473	447	237	164	(31)	(111)
I98/C00/R02 Phase-in	617	583	324	236	7	(87)
R98/C00/I00	839	799	501	398	142	33

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	789	639	633	519	477	363
2000Full	529	403	401	305	273	178
I98/C00/R02	454	333	354	262	254	164
I98/C02/R06	325	251	237	164	149	77
I98/C00/R02 Phase-in	428	311	324	236	220	133
R98/C00/I00	639	507	501	398	363	261

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	123	129	162	152	196	187
Coal/Lignite	(169)	(188)	(369)	(383)	(568)	(583)
Nuclear	888	891	797	707	575	479
Purchased Power/Other	48	48	43	43	39	39

Public Utility Board of Brownsville Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	(36)	(40)	(97)	(100)	(158)	(161)
2000Full	(47)	(51)	(103)	(107)	(160)	(163)
I98/C00/R02	(42)	(45)	(98)	(101)	(154)	(157)
I98/C02/R06	(40)	(43)	(91)	(94)	(142)	(145)
I98/C00/R02 Phase-in	(44)	(47)	(98)	(102)	(153)	(156)
R98/C00/I00	(43)	(46)	(101)	(104)	(159)	(163)

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	(83)	(86)	(97)	(100)	(121)	(124)
2000Full	(95)	(99)	(103)	(107)	(111)	(115)
I98/C00/R02	(90)	(93)	(98)	(101)	(106)	(109)
I98/C02/R06	(83)	(86)	(91)	(94)	(99)	(102)
I98/C00/R02 Phase-in	(90)	(94)	(98)	(102)	(106)	(110)
R98/C00/I00	(91)	(94)	(101)	(104)	(111)	(114)

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	(5)	(7)	(36)	(38)	(67)	(69)
Coal/Lignite	(31)	(33)	(61)	(62)	(91)	(92)
Nuclear	0	0	0	0	0	0
Purchased Power/Other	0	0	0	0	0	0

City of Bryan Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	231	228	181	178	130	127
2000Full	194	191	150	147	105	103
I98/C00/R02	199	197	155	152	110	108
I98/C02/R06	173	171	135	133	97	94
I98/C00/R02 Phase-in	194	191	151	148	108	105
R98/C00/I00	201	198	156	153	112	109

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	201	198	181	178	161	158
2000Full	170	167	150	147	130	127
I98/C00/R02	175	172	155	152	135	132
I98/C02/R06	149	147	135	133	121	119
I98/C00/R02 Phase-in	169	166	151	148	133	130
R98/C00/I00	176	173	156	153	136	133

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	23	23	23	23	23	23
Coal/Lignite	208	205	157	154	107	104
Nuclear	0	0	0	0	0	0
Purchased Power/Other	0	0	0	0	0	0

City of Denton Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	225	222	174	171	124	121
2000Full	194	192	150	147	105	103
I98/C00/R02	194	192	150	147	105	103
I98/C02/R06	168	166	130	127	92	89
I98/C00/R02 Phase-in	187	185	144	142	102	99
R98/C00/I00	194	192	150	147	105	103

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	198	195	174	171	151	149
2000Full	168	165	150	147	130	127
I98/C00/R02	168	165	150	147	130	127
I98/C02/R06	147	144	130	127	110	107
I98/C00/R02 Phase-in	164	162	144	142	123	121
R98/C00/I00	172	169	150	147	126	124

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	17	17	17	17	17	17
Coal/Lignite	208	205	157	154	107	104
Nuclear	0	0	0	0	0	0
Purchased Power/Other	0	0	0	0	0	0

City of Garland Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	511	505	401	394	291	284
2000Full	425	419	328	322	230	225
I98/C00/R02	431	425	334	328	236	231
I98/C02/R06	369	364	286	281	202	197
I98/C00/R02 Phase-in	412	407	319	313	225	219
R98/C00/I00	433	427	336	330	239	233

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	441	434	401	394	360	353
2000Full	368	362	328	322	287	281
I98/C00/R02	374	368	334	328	293	287
I98/C02/R06	326	321	286	281	245	240
I98/C00/R02 Phase-in	359	353	319	313	278	272
R98/C00/I00	376	370	336	330	295	289

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	57	57	57	57	57	57
Coal/Lignite	455	448	344	338	234	227
Nuclear	0	0	0	0	0	0
Purchased Power/Other	0	0	0	0	0	0

City of Greenville Texas Retail ECOM Model Results

Discrete Results

	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	107	105	83	82	60	58
2000Full	90	89	70	68	49	48
I98/C00/R02	97	95	76	75	55	54
I98/C02/R06	88	86	70	68	52	50
I98/C00/R02 Phase-in	95	93	75	73	55	53
R98/C00/I00	93	92	72	71	52	50

Probabilistic Results

	95th Percentile		Expected Value		5th Percentile	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
1998Full	93	92	83	82	73	72
2000Full	80	78	70	68	60	58
I98/C00/R02	84	83	76	75	68	67
I98/C02/R06	78	76	70	68	62	60
I98/C00/R02 Phase-in	83	81	75	73	67	65
R98/C00/I00	82	81	72	71	62	61

Scenario *1998 Full* Discrete Results by Fuel Type

	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Natural Gas	10	10	10	10	10	10
Coal/Lignite	97	95	73	72	50	48
Nuclear	0	0	0	0	0	0
Purchased Power/Other	0	0	0	0	0	0

Total Texas Wholesale ECOM Model Results

Discrete Results

	Extreme High 0% O&M effic.	Extreme High 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	Extreme Low 0% O&M effic.	Extreme Low 10% O&M effic.
Contract Expiration	138	115	(29)	(57)	(230)	(258)
Contract Abrogation	376	279	(908)	(1,007)	(2,223))	(2,325)

Probabilistic Results

	95th Percentile 0% O&M effic.	95th Percentile 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	5th Percentile 0% O&M effic.	5th Percentile 10% O&M effic.
Contract Expiration	28	5	(29)	(57)	(87)	(115)
Contract Abrogation	(461)	(558)	(908)	(1,007)	(1,335)	(1,457)

Texas Utilities Electric Company Texas Wholesale ECOM Model Results

Discrete Results

	Extreme High 0% O&M effic.	Extreme High 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	Extreme Low 0% O&M effic.	Extreme Low 10% O&M effic.
Contract Expiration	135	120	44	25	(81)	(99)
Contract Abrogation	225	206	109	86	(40)	(63)

Probabilistic Results

	95th Percentile 0% O&M effic.	95th Percentile 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	5th Percentile 0% O&M effic.	5th Percentile 10% O&M effic.
Contract Expiration	86	71	44	25	2	(17)
Contract Abrogation	165	145	107	87	49	26

West Texas Utilities Company Texas Wholesale ECOM Model Results

Discrete Results

	Extreme High 0% O&M effic.	Extreme High 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	Extreme Low 0% O&M effic.	Extreme Low 10% O&M effic.
Contract Expiration	(38)	(43)	(91)	(96)	(144)	(149)
Contract Abrogation	(13)	(19)	(80)	(87)	(148)	(154)

Probabilistic Results

	95th Percentile 0% O&M effic.	95th Percentile 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	5th Percentile 0% O&M effic.	5th Percentile 10% O&M effic.
Contract Expiration	(81)	(86)	(91)	(96)	(102)	(107)
Contract Abrogation	(51)	(57)	(80)	(87)	(109)	(115)

Houston Lighting & Power Company Texas Wholesale ECOM Model Results

Discrete Results

	Extreme High 0% O&M effic.	Extreme High 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	Extreme Low 0% O&M effic.	Extreme Low 10% O&M effic.
Contract Expiration	23	22	20	19	17	16
Contract Abrogation	36	35	32	31	28	27

Probabilistic Results

	95th Percentile 0% O&M effic.	95th Percentile 10% O&M effic.	Expected Value 0% O&M effic.	Expected Value 10% O&M effic.	5th Percentile 0% O&M effic.	5th Percentile 10% O&M effic.
Contract Expiration	21	20	20	19	19	18
Contract Abrogation	34	33	32	31	30	29

Central Power & Light Company Texas Wholesale ECOM Model Results

Discrete Results	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	18	16	(2	(5)	(23)	(26
Contract Abrogation	54	51	26	23	(2)	(6)
Probabilistic Results	**95th Percentile**		**Expected Value**		**5th Percentile**	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	4	2	(2)	(5)	(8)	(11)
Contract Abrogation	40	37	26	23	12	8

Lower Colorado River Authority Texas Wholesale ECOM Model Results

Discrete Results	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	0	0	0	0	0	0
Contract Abrogation	(154)	(213)	(790)	(849)	(1,427)	(1,486)
Probabilistic Results	**95th Percentile**		**Expected Value**		**5th Percentile**	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	0	0	0	0	0	0
Contract Abrogation	(576)	(635)	(790)	(849)	(1,004)	(1,063)

Brazos Electric Power Company Texas Wholesale ECOM Model Results

Discrete Results	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	0	0	0	0	0	0
Contract Abrogation	166	158	(186)	(195)	(539)	(548)
Probabilistic Results	**95th Percentile**		**Expected Value**		**5th Percentile**	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	0	0	0	0	0	0
Contract Abrogation	(90)	(98)	(186)	(195)	(282)	(291)

South Texas Electric Power Cooperative Texas Wholesale ECOM Model Results

Discrete Results	Extreme High		Expected Value		Extreme Low	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	0	0	0	0	0	0
Contract Abrogation	62	62	(17)	(17)	(95)	(95)
Probabilistic Results	**95th Percentile**		**Expected Value**		**5th Percentile**	
	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.	0% O&M effic.	10% O&M effic.
Contract Expiration	0	0	0	0	0	0
Contract Abrogation	17	17	(17)	(17)	(51)	(51)

Note: O&M efficiency improvement was not calculated because STEC's generation resources consist almost entirely of purchased power which is not affected by the O&M efficiency factor in the ECOM Model.

Appendix C

Modifications to the ECOM Model

Appendix C - MODIFICATIONS TO THE ECOM MODEL

1. PLANT ECONOMICS

Subsequent to the filing of the Public Utility Commission of Texas ECOM Model results on June 24, 1996, some minor changes have been incorporated to the ECOM Model's *Plant Economics* calculation. These changes, both individually and taken together, have a relatively small impact on the results as filed by the utilities. The revised version of the ECOM Model is version 3.1 and is available from Commission Staff as well as on the Commission Internet homepage at *http://www.puc.texas.gov* under the *rulemakings* directory. The modifications consist of the following:

1. The *Plant Economics* calculation analyzes variable costs and operating revenues to determine the economic viability of a particular resource type. Among other variable costs, incremental investment was intended to be treated as a variable cost. In version 3.0 of the ECOM Model, while the return component of incremental investment was treated as variable, the depreciation component inadvertently was allocated as a fixed cost. This has been corrected such that the depreciation component of incremental investment is treated as a variable cost in the *Plant Economics* calculation.
2. In version 3.0 of the ECOM Model, the *Plant Economics* calculation incorporates a two-stage test to determine whether an asset group is economical. A modification has been made to the second stage of the test such that the net present value of the variable costs must be greater than 110 percent, rather than 100 percent, of the net present value of the revenues attributable to a particular resource type before a shut-down decision is triggered. This change was incorporated to account for (1) costs that may be incurred because of an early retirement decision, and (2) uncertainty associated with the decision to retire a plant due to economic considerations. In other words, the change represents the situation in which a plant may continue to operate while experiencing a loss, on average, in the short-run, but will be shut down if the situation persists over the long-run.
3. In version 3.0 of the ECOM Model, once a resource type was determined to be uneconomic from an operations standpoint, the variable costs and revenues attributable to that resource type were intended to be removed from the ECOM calculation. Because the shut-down decision is based upon the net present value of the variable costs and revenues, each should be removed from the calculation in all years subsequent to the shut-down decision to function properly. In developing the model, it was not anticipated that there may be years, subsequent to a shut-down decision, in

which revenues actually exceed variable costs. However, in certain circumstances, this situation does occur. Therefore, the calculation has been modified to deduct revenues and variable costs from the ECOM result in *all* years subsequent to a shut-down decision.

4. In version 3.0 of the ECOM Model, the *Plant Economics* assessment was applied beginning in 1998, regardless of the retail access scenario. Because the *Plant Economics* calculation is based upon an analysis of market-based revenues, the calculation did not produce a reliable result in years in which a utility's revenues were a combination of regulated and market-based rates. To correct this calculation, the calculation was modified such that an assessment of the economics of a particular resource type is performed only subsequent to full retail access by all classes.

2. Other Modifications and Corrections

Some other minor generic and utility-specific modifications have been made to the electronic files submitted by the utilities.

One generic change relates to the discounting of annual ECOM estimates. In the *Sales Impact* sheet, the stream of annual ECOM estimates was inadvertently discounted one extra year in the net present value calculation in version 3.0 of the ECOM Model. This error has been corrected in version 3.1 to properly represent ECOM results in terms of 1996 dollars.

Other changes are primarily related to inconsistencies in data reported for jointly-owned generating units and errors related to the input of data into the various spreadsheets within the ECOM Model. Commission Staff has generally consulted with the various utilities over the course of this project regarding such modifications. The details of these modifications are not presented in this report; however, individual utilities may review the changes to their ECOM Model data by making arrangements with Commission Staff in the Office of Policy Development.

3. Description of the @RISK© Software Used to Perform the Probabilistic ECOM Analysis

The use of @RISK software in the ECOM analysis provides the ability to include the uncertainty present in the ECOM estimates to generate a set of probability-weighted

ECOM estimates. The following is extracted from the @RISK User's Manual as an overview of the risk analysis capability of @RISK.[1]

> Traditionally, analyses combine single "point" estimates of a model's variables to predict a single result. This is the standard Excel or 1-2-3 model—a spreadsheet with a single estimate of results. Estimates of model variables must be used because the values which actually will occur are not know with certainty. In reality, however, many things just don't turn out the way you have planned. The combined errors in each estimate often lead to a real-life result that is significantly different from the estimated result. The decision you made based on your "expected" result might be the wrong decision, and a decision you never would have made if you had a more complete picture of all possible outcomes. Business decisions, technical decisions, scientific decisions . . . all use estimates and assumptions. With @RISK, you can explicitly include the uncertainty present in your estimates to generate results that show all possible outcomes.
>
> @RISK uses a technique called "simulation" to combine all the uncertainties you identify in your modeling situation. You no longer are forced to reduce what you know about a variable to a single number. Instead, you include all you know about the variable, including its full range of possible values and some measure of the likelihood of occurrence for each possible value. @RISK uses all this information, along with your Excel or 1-2-3 model, to analyze every possible outcome. It's just as if you ran hundreds or thousands of "what-if" scenarios all at once! In effect, @RISK lets you see the full range of what could happen in your situation. It's as if you could "live" through your situation over and over again, each time under a different set of conditions, with a different set of results occurring.

[1] Adapted from *@RISK: Advanced Risk Analysis for Spreadsheets* at i - ii (March 1996).