Electric Generating Plant Operating Efficiency and Mitigation of Stranded Investment Costs

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1.0 Introduction

The "stranded asset" legacy of inefficient electric utility regulation is eroding the value of electric utility shareholder equity and will delay full consumer realization of the benefits of competitive electricity markets for many years after deregulation has occurred. Stranded assets are capital investments, power purchase contracts, fuel supply contracts, and other regulatory assets, the cost of which are not expected to be recovered through the sale of competitively priced electricity.

The magnitude of stranded assets and who should bear the costs are contentious issues at the core of regulatory/legislative proceedings aimed at evolving competitive electricity markets. On the issue of cost allocation, the California Legislature and the Public Utilities Commission (CPUC) have set a precedent, essentially ruling that the California ratepayers will incur one hundred percent of the stranded asset costs and will be levying non-bypassable competitive transition charges on ratepayers to be paid through the year 2002.

While the magnitude of these charges has not been adopted, estimates vary from $21 - $39 billion for California's stranded investment.[2] The low estimate is higher than the combined annual electric operating revenue of the California IOU's ($17 billion). Amortized over a four-year period (1998 - 2002), at 12%, the $21 billion estimate would require payments of $6.6 billion per year (39% of current annual California electricity expenditures) to pay it off.

These figures imply that the stranded asset overhang will substantially delay the cost-reducing benefits of competition (at least for California consumers) until after the turn of the century. Utility shareholders are also adversely affected by the stranded asset overhang through depressed electric utility stock prices, partially because of the uncertainty concerning recovery of their stranded investments.

To date, the dialogue about stranded assets has focused primarily on guessing at the magnitude of stranded investments and debating about who will bear the cost. Scant attention has been given to evaluating whether actions might be taken during the period of transition to competitive markets that would reduce the magnitude of stranded assets, and therefore, the cost burdens on ratepayers, and the losses of shareholders.[3] In the case of generating plant investments, there may be substantial potential for reducing the magnitude of the stranded investment by changing the way the plants are operated. The following research shows that implementing more efficient plant operating procedures will increase the revenue stream and reduce per unit costs, thereby reducing the level of stranded asset charges to consumers.

This is accomplished by reductions in variable production costs and reductions in fixed O&M costs. The efficiency gains estimated in this analysis translates into a very sizable reduction in stranded assets. All this can be accomplished by implementing performance based rates (PBR) before ratepayers and stockholders are required to pay for those stranded assets. The purpose of this paper is to examine the magnitude of stranded asset reductions possible with better plant efficiency and how performance based ratemaking can cause those efficiencies to occur. The research is divided into five sections. The first section develops the rationale behind generation plant efficiencies and how those efficiencies can impact the amount of stranded assets. The second section is the methodology for establishing simple efficiency benchmarks with which to gauge plant performance. Section three presents the empirical results of applying this methodology to 583 generating plants. The fourth section explains the sizable contribution that can be made to plant efficiency by performance based ratemaking. The final section states the conclusions and implications of the analysis.

2.0 Overview of Generating Plant Market Valuation, Operating Efficiency, and Stranded Investment

A visual overview of the factors affecting stranded assets is presented in Figure 1. This figure segregates a number of factors that are available to management for mitigating the magnitude of stranded assets.

The level of stranded investment in a generating plant is the difference between the plant's net book value and its market value (when operated under competitive market conditions). Market value of a generating plant that sells its output in competitive electricity markets is the discounted stream of net cash flow that can be expected over the remaining life of the plant. Net cash flow is the difference between the plant's future revenue and its future operating costs combined with the costs of any new capital additions to the plant.

Although the current net book value of a generating plant is essentially cast in stone, utility management can, in many cases, reduce the level of stranded investment by pursuing a strategy to increase the plant's discounted stream of net cash flow and market value. The key element of this strategy is to implement more efficient operating procedures that reduce per MWh plant operating costs.

In competitive electricity markets, per MWh operating cost reductions can produce a double impact on cash flow by increasing the revenue stream as well as reducing per unit cost. Recall that the price of electricity in competitive markets, is determined by overall market supply and demand, and the individual plant manager is a price taker.[4] The hourly market prices for electricity will vary by time of day, day of the week, season, etc. In competitive electricity markets, generating plants will be dispatched by price. Plants will be offered for service and dispatched when the market price (price = marginal cost) equals or exceeds the average variable production cost.[5] Plants with lower average variable production cost will be dispatched more hours, produce more MWh's, revenue, cash flow, and market value (other things equal, e.g., age) per unit of capacity, than will higher cost, less efficient plants.[6]

Therefore, reductions in per MWh variable production costs (where inefficiencies exist), can substantially increase the cash available to cover fixed O&M expense and payments to capital. Reductions in fixed O&M additionally increase the cash available for payments to capital, further mitigating the magnitude of stranded generating plant investments. To illustrate these points, consider the following simplified example.

> Genplant with 200 MW of capacity sells power in a competitive market. For the first case, assume Genplant's average variable production cost (= marginal cost) is $30/MWh. The annual price duration curve[7] (shown in Figure 2) for the electricity market has a price range from $10/MWh to $55/MWh, and an average price (for the year) of $32.57/MWh. The shape of the price duration curve is such that the hourly price of electricity equals or exceeds $30/MWh 5,120 hours (58% of the time) during the year. This implies that Genplant would run 5,120 hours and produce 1,024,000 MWh of electricity.[8] (The double cross-hatched area on Figure 2 shows the revenue per MW of plant capacity when the marginal cost is $30/MWh.)
>
> During the hours that Genplant is dispatched, the time weighted average price of electricity (from the price duration curve) would be $40.51/MWh. This figure with the MWh production implies total Genplant revenue of $41,482,240. Variable production costs are $30,720,000 and if fixed O&M costs are $6,000,000/year, then only $4,762,240 would be left for payments to capital (interest, principal or debt, dividends, and equity).[9]
>
> Now suppose that the Genplant managers are able to reduce the plant's average variable production cost to $25, a 16.7% reduction. In this second case, the plant would be dispatched 6,435 hours (73% of the time) and produce 1,287,000 MWh of electricity. (The single cross-hatched area plus the double cross-hatched area on Figure 2 shows the revenue per MW of plant capacity when the plant's marginal cost is $25/MWh.) With increased hours of production, the time weighted average price of electricity would be $37.87/MWh which yields revenue of $48,738,690. This level of production also increases variable production cost to $32,175,000. Fixed O&M expense would remain at $6,000,000/year as in the first case. This leaves $10,563,690 for payments to capital. This case compared to the first one implies that a 16.7% reduction in variable per MWh production cost would have increased the cash available to cover capital by 222%.

> Suppose for the third case that management similarly reduced fixed O&M by 16.7% to $5,000,000. This would directly increase the cash available for payments to capital by $1,000,000. This implies a 21% increase in cash available for payments to capital compared to the first case, and a 9.5% increase compared to the second case.[10]

These hypothetical examples illustrate the simple, obvious fact that the more efficiently a plant is operated, the less it will cost ratepayers to pay off the balance of undepreciated plant investments, and the more secure will be shareholder's equity. In this instance, a reduction in variable production costs and fixed O&M costs by very modest amounts, have produced very large cash flows. At issue then, is the extent of potential for efficiency improvements in generating plant operations.

The remainder of this paper focuses on the examination of utility generating plant operating statistics to quantify apparent potential for efficiency improvement. The next section describes the analytic methodology and develops simple, reasonable efficiency benchmarks for measuring plant operating and cost performance.

3.0 Generating Plant Analysis Methodology

The analysis relies on data reported by electric utilities in their FERC Form 1 filings. The approach of our analysis is to develop estimates of efficiency frontier benchmarks for key measures of cost and/or operating performance, and to evaluate the potential for efficiency improvement by comparing actual plant operating statistics against these benchmarks.

The data sample for this study is drawn from the universe of all large investor-owned nuclear and steam-electric generating plants (combustion turbine, internal combustion and geothermal plants were not included) reported in FERC Form 1 filings for 1995.[11] Plants initially included in the sample are those that reported positive net generation.
Multiple reports for multiple-owner plants were consolidated into single total plant statistics to avoid multiple counting. Plants with apparent reporting errors or omissions that could not be reasonably corrected or completed were excluded from the analysis.

The plant statistics were segmented into three regional markets: Western (WSCC), Texas (ERCOT), and Eastern (all other NERC areas). This segmentation was intended to reduce the distortions from transportation costs (primarily for coal) and to account for the fact that Texas is a relatively closed electricity market. The segmentation yielded the following matrix of regional and generating plant (fuel type) groups:

Number of Plants

	Nuclear	Coal	Gas & Oil	Total
Western	3	43	24	70
Texas	2	13	42	57
Eastern	59	318	79	456
Total	64	374	145	583

The key statistics for the concepts examined for each market group were ordered into quartiles, except nuclear. In the case of nuclear plants, the quartiles were set up for the national market, since their are only three plants in the West and two in Texas. The mean value of the "best practices" quartile for each key statistic was then calculated and defined as the "efficiency frontier benchmark" for that key statistic for the market segment.[12] National benchmarks were set for nuclear plant statistics. Potential cost savings were then estimated using actual plant statistic deviations from the frontier benchmarks. The analysis examined data related to: fuel procurement efficiency, thermal conversion efficiency, and non-fuel operating cost efficiency.

3.1 Fuel Procurement Efficiency

While fuel procurement is not an element of the physical operation of generating plants, it is a dominant element in determining the marginal and variable costs of generation. Fuel procurement practices are also fully under the control of utility management and can be changed as the electricity market evolves toward competition.

Fuel is the largest component of variable electricity production cost. Per MWh fuel cost is essentially the on/off switch for dispatching generating plants in competitive markets. The per MWh fuel cost of electricity is the product of the cost of fuel per BTU and the plant's heat rate.

The potential cost savings from improved fuel procurement for a plant was calculated as the positive product of: the difference between the plant's 1994 fuel cost per BTU and the benchmark fuel cost per BTU, the plant's 1995 heat rate, and the plant's 1995 level of generation.

3.2 Thermal Conversion Efficiency

The thermal conversion efficiency of a plant is measured by its heat rate, the thermal energy (BTU's) from fuel required to produce one kWh of electricity. A plant's heat rate is determined by the plant's design, location, and the patterns and levels of operation. Typically, plants operated near capacity will experience their most efficient heat rates. Plant cycling and low levels of operation will produce higher heat rates. Under competitive markets, it is expected that most plants that are dispatched will be operated at their most efficient levels. In addition, some plant design modifications can be undertaken to improve heat rates. In the case of nuclear units, however, redesign is a costly undertaking, so no analysis of potential cost savings from heat rate improvements for nuclear plants was developed.

The potential cost savings from improved heat rates for a plant was calculated as the positive product of: the plant's 1995 fuel cost per BTU, the difference between the plant's actual 1995 heat rate and the benchmark heat rate, and the plant's 1995 level of generation.

3.3 Non-fuel O&M Efficiency

Non-fuel O&M includes all operation and maintenance expense, other than fuel expense. Non-fuel O&M is generally referred to as "fixed O&M" because it is budgeted and set annually and for the most part does not vary directly with electricity output. The potential cost savings from more efficient non-fuel O&M for each plant type, in each market area, was calculated as the positive product of: the difference between the plant's actual non-fuel O&M expenditure per MW and the non-fuel O&M expenditure per MW benchmark, and the plant's MW capacity.

The next section shows the results of taking actual plant operating statistics, as reported in FERC Form 1, and comparing them to the benchmarks developed above.

Empirical Analysis of Generating Plant Operating Costs

4.1 Fuel Costs/MMBTU:

The distributions of fuel cost are shown on Figure 3, Figure 4, and Figure 5 for nuclear, coal, and gas & oil plants, respectively. The ranges of fuel costs reported for each fuel type are very wide. The maximum fuel cost relative to the minimum for nuclear fuel was 371%, for coal was 777%, and for gas & oil was 271%.

The best practices benchmark values for fuel cost are shown on the top tier of Table

1. The potential annual cost savings that could be achieved by reducing fuel costs/BTU to the benchmark values are shown on the top tier to Table 2. Of the $7.1 billion annual potential savings, the largest portion of the savings potential, is in improved coal acquisition practices**.**

4.2 Heat Rates

The distributions of heat rates are shown on Figure 6 and Figure 7 for coal and gas & oil, respectively. The ranges of heat rates reported for both coal and gas & oil fired plants show the maximum heat rate to be approximately 290% of the minimum.

The best practices benchmark values for heat rates are shown on the middle tier of Table 1. The potential annual cost savings that could be achieved by reducing heat rates to the benchmark values are shown on the middle tier of Table 2. The potential heat rate cost savings of $1.58 billion is much smaller than is the potential savings from fuel acquisition shown above.

Coal plant technology shows the greatest potential for cost reductions through improvement in heat rates.

The cost reductions available from gas and oil technologies are considerably smaller than coal primarily because these technologies are newer and presently incorporate improved efficiencies.

4.3 Nonfuel O&M/MW-Yr

The distributions of non-fuel O&M expense per MW-Yr. are shown on Figure 8, Figure 9, and Figure 10 for nuclear, coal, and gas & oil plants, respectively. The ranges of non-fuel O&M costs are very surprising. The maximum O&M cost/MW-Yr. relative to the minimum reported was 544% for nuclear, and more than 1000% for coal, and for gas & oil.

The best practices benchmark values for non-fuel costs are shown on the lower tier of Table 1. The potential annual cost savings that could be achieved by reducing non-fuel O&M expenditures to the benchmark levels are shown on the bottom tier of Table 2. Of the $4.7 billion calculated potential savings, about 43% is in nuclear plant operations and about 47% is in coal plant operations.

The data analyses presented here have examined electric generating plant statistics to explore whether there is potential for mitigating the magnitude of stranded generating plant investment that erodes shareholder equity and reduces the consumer benefits of competitive electricity markets. By setting performance benchmarks and comparing actual plant operating statistics to those benchmarks, the analysis has shown an annual potential cost savings of $13.4 billion. Note that these calculations include only the direct savings that would accrue from reductions in fuel costs, heat rates, and non-fuel O&M expenditures per MW-Yr., assuming the level of each plant's production remains at its 1995 level. Therefore, the effects of increased run time and increased revenue that were discussed with respect to the hypothetical Genplant are not included in this analysis. Even without estimating these additional stranded asset reducing effects, the estimates calculated here could substantially reduce the stranded asset overhang. The present value of the annual $13.4 billion estimated savings over 10 years using a 12% discount rate is $75.7 billion.

5.0 Performance Based Ratemaking -- A Tool for Mitigating the Stranded Asset Overhang

It is apparent from examination of plant operating statistics, that the current regulatory oversight of utilities has not achieved uniform best practices efficiency. Neither regulatory incentives nor enforcement have been adequate to prompt utility management's to focus on efficiency to the degree that will ultimately be accomplished by competitive markets. Even the specter of rapidly approaching competition has not prompted some operators to change old practices that were developed under cost pass-through rules. Lack of motivation to prepare for competition is somewhat nurtured by *unconditional* rulings allowing full recovery of stranded assets such as has been issued by the California CPUC.

If it is acknowledged that the more efficiently a plant is operated, the less it will cost ratepayers to pay off the balance of plant investments, and the more secure will be shareholders' equity, then it is apparent that regulatory policies should be put in place to encourage efficiency during the transition to competition. The obvious target should be that all plants be brought to the efficiency frontier before market valuation is determined and competitive transition charges are set.

The performance based ratemaking (PBR) price cap formula may be the appropriate tool to apply to achieve the efficiency improvements.

The price cap formula frequently used in connection with electric utility Performance Based Regulation is :

$$P_t = (1 + INF_t - X_t + Z_t) * P_{t-1}$$

where:

P_t is a measure of the system average rate or price of electricity,
INF_t is a measure of inflation relevant to the cost of inputs to electric service,
X_t is the productivity offset and,
Z_t is an adjustment for other exogenous factors

The price cap formula implies that the annual growth rate of electricity price should increase with the rate of electric utility industry cost inflation less the rate of growth of electric industry total factor productivity, plus the rate of growth of other costs outside the control of the electric company such as customer growth, disaster recovery, etc.[13]

The productivity offset is intended to be a reasonable measure of electric utility industry total factor productivity growth. It is a measure of the shift of the industry efficiency frontier. It is an indicator of the productivity improvements an efficient utility (one that operates on the efficiency frontier) would accomplish by adopting new technologies and thereby remain on the efficiency frontier.

For utilities that do not operate on the efficiency frontier, the price cap formula should be revised to include a decomposed productivity offset term into: XTP_t measuring the industry productivity growth due to technical progress, and XEF_t measuring an annual *target* change in efficiency. This approach tailors the price cap formula to the efficiency position of each utility.[14]

To promote more efficient plant operations, the XEF_t term can be further decomposed to the plant level. An efficiency analysis of each plant could establish an efficiency index for each plant. The XEF_t term can then be set as an annual efficiency improvement target for each plant from the plant's efficiency index and the number of years allowed to achieve frontier efficiency.

6.0 Conclusion

The focus of this paper has been to establish reasonable benchmarks to judge electric generating plant efficiencies in order to reduce the amount of stranded assets subject to repayment. Those operating inefficiencies place huge penalties on ratepayers and stockholders. Further, recovering the full cost of those stranded assets rewards inefficient management practices. This research has established that there are enormous opportunities to improve efficiencies and reduce the regulatory burdens of stranded assets. With improved efficiencies in fuel procurement, thermal conversion, and non-fuel O&M, we have been able to show a potential reduction in the value of stranded assets by a minimum of $13.4 billion annually for the United States. This figure translates to approximately $75.7 billion in savings over a 10-year period. However, under the current regulatory approach of assessing current ratepayers 100% of the stranded asset cost through the levying of a competitive transition charge, there is no incentive to accomplish these improvements.

One highly effective method for stimulating these operational efficiencies is through the application of performance based ratemaking. Application of the performance based ratemaking price cap formula specified in this analysis, would move generating plants to new, higher efficiency levels and provide an incentive for the most efficient plants to adopt new technologies to keep them at the efficiency frontier. If instituted before the initiation of stranded asset repayment, performance based ratemaking can considerably reduce the amount of stranded asset charges. This provides direct benefit to all ratepayers and stockholders. In addition, it institutes operating conditions that will help ensure that all consumers of electricity realize the benefits which are possible under a competitive electric industry.

TABLE 1: BEST PRACTICES BENCHMARKS

Fuel Purchasing
($/MMBTU)

	Nuclear	Coal	Gas & Oil
Western	0.41	0.67	1.65
Texas	0.41	1.08	1.54
Eastern	0.41	1.06	1.64

Heat Rates
(BTU/KWh)

	Nuclear	Coal	Gas & Oil
Western	-	10,021	9,537
Texas	-	9,325	10,086
Eastern	-	9,537	9,328

Non-fuel O&M
($/MW-Yr)

	Nuclear	Coal	Gas & Oil

Western	66,694	16,508	9,047
Texas	66,694	9,063	4,571
Eastern	66,694	13,437	6,751

TABLE 2: POTENTIAL COST SAVINGS

Fuel Purchasing

	Nuclear	Coal	Gas & Oil	All Plants
Western	$31,796,856	$517,754,564	$178,913,022	$728,464,442
Texas	$68,844,983	$435,163,676	$355,853,221	$859,861,880
Eastern	$734,133,377	$4,102,065,059	$707,935,845	$5,544,134,281
Total	$834,775,216	$5,054,983,299	$1,242,702,088	$7,132,460,603

Heat Rates

	Nuclear	Coal	Gas & Oil	All Plants
Western	-	$76,095,511	$35,344,891	$111,440,402
Texas	-	$89,114,735	$126,127,182	$215,241,917
Eastern	-	$916,043,123	$341,980,707	$1,258,023,830
Total	-	$1,081,253,369	$503,452,780	$1,584,706,149

Non-fuel O&M

	Nuclear	Coal	Gas & Oil	All Plants
Western	$349,456,872	$283,311,235	$115,329,957	$748,098,064
Texas	$30,354,743	$93,131,167	$69,928,030	$193,413,940
Eastern	$1,656,370,827	$1,816,932,065	$274,066,250	$3,747,369,142
Total	$2,036,182,442	$2,193,374,467	$459,324,237	$4,688,881,146

Grand Total	$2,870,957,658	$8,329,611,135	$2,205,479,105	$13,406,047,898

Endnotes:

1. Authors Lessly Goudarzi is president of OnLocation, Inc., a management consulting firm in Dunn Loring, VA.; and Bill Roberts is president of Economic Sciences Corporation, an economics consulting firm in Berkeley, CA.
2. *Utility Spotlight*, August 12, 1996, page 7, reported that utility estimates of $39 billion. Moody's Investor Services, December 1996, offered an estimate of $21 billion.
3. Charles Studness in the article, "Stranded What, Exactly?," *Public Utilities Fortnightly*, December 1, 1994, recognized the need for operating efficiency improvements in the transition to competitive markets: "...successful adjustment to competition rests primarily with management. The transition to markets will rise or fall on cuts in operating costs -- not on the unwinding of unfortunate investment decisions originally sanctioned by regulators."
4. Producers may actually have the ability to marginally affect prices in local markets that are remote from other generators and or can exploit transmission constraints.
5. This simple statement abstracts from complications of startup and shutdown for short periods of operation.
6. It should be noted that average annual prices which are often used in discussions of market valuation and stranded investment are too blunt for use in plant value assessment.
7. This is conceptually similar to the familiar Load Duration Curve used for plant dispatch analysis in regulated markets.
8. This assumes there are no physical (e.g., ramp-up) constraints on the cycling of the unit to meet market demands.
9. This analysis excludes consideration of the potential implications of taxes.
10. The analysis also assumes behavior and costs of the other industry participants remains essentially unchanged, i.e., the price duration curve is **unchanged**.
11. ESC UQAR utility database.
12. This approach is clearly less rigorous than the statistical estimation of frontier cost functions which would also identify the sources of cost variations among plants. The objective here is much less ambitious and attempts only to show the variations in several cost related factors across plants to explore the potential for improvement.
13. See Morin, Roger A., *Regulatory Finance: Utilities Cost of Capital*, Public

Utility Reports, Inc.

14. See B. F. Roberts "Performance Based Regulation: Efficiency and the Measurement of the Productivity Offset," ESC Electric Utility Analysis Report 95-1.

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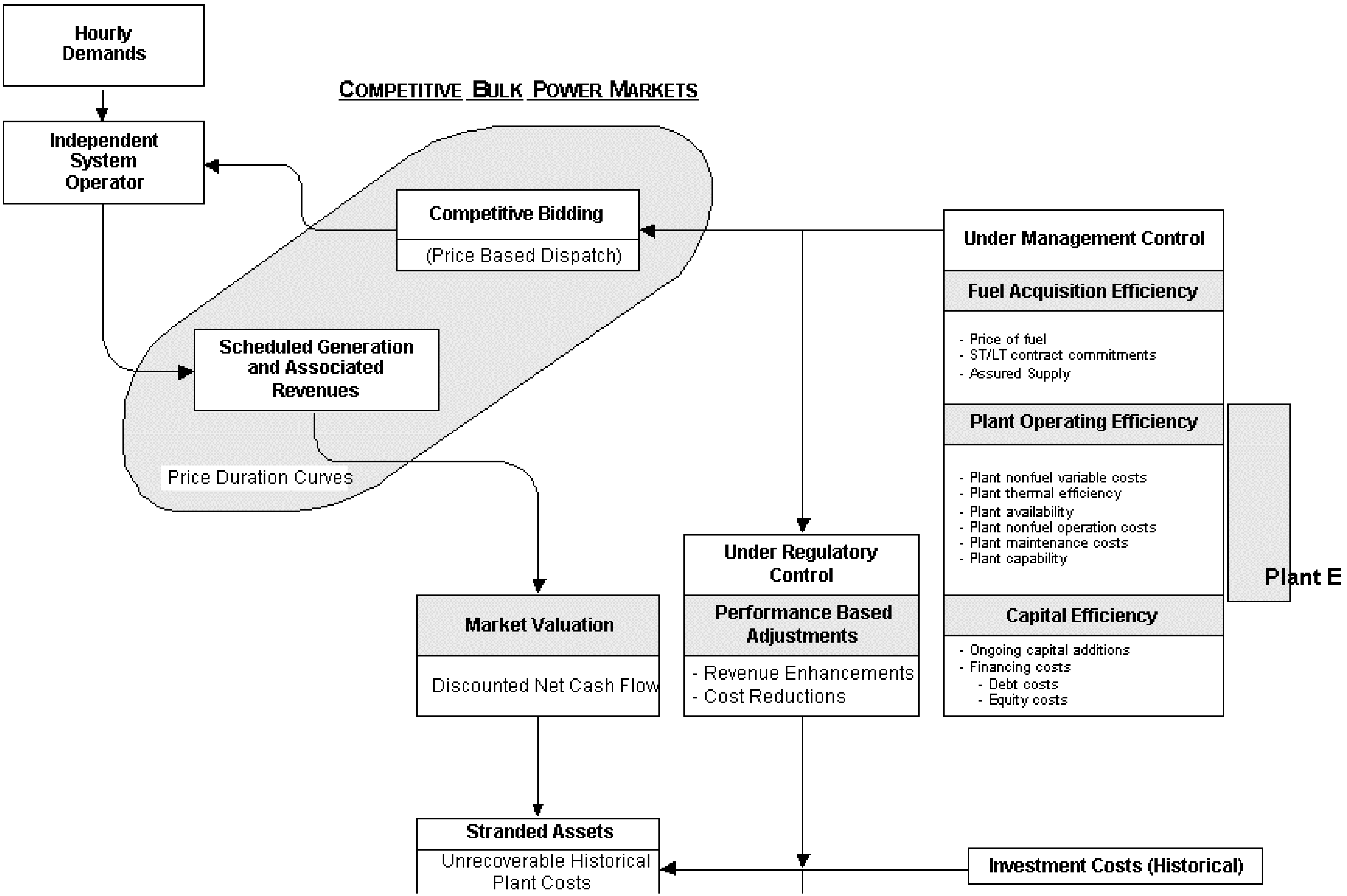
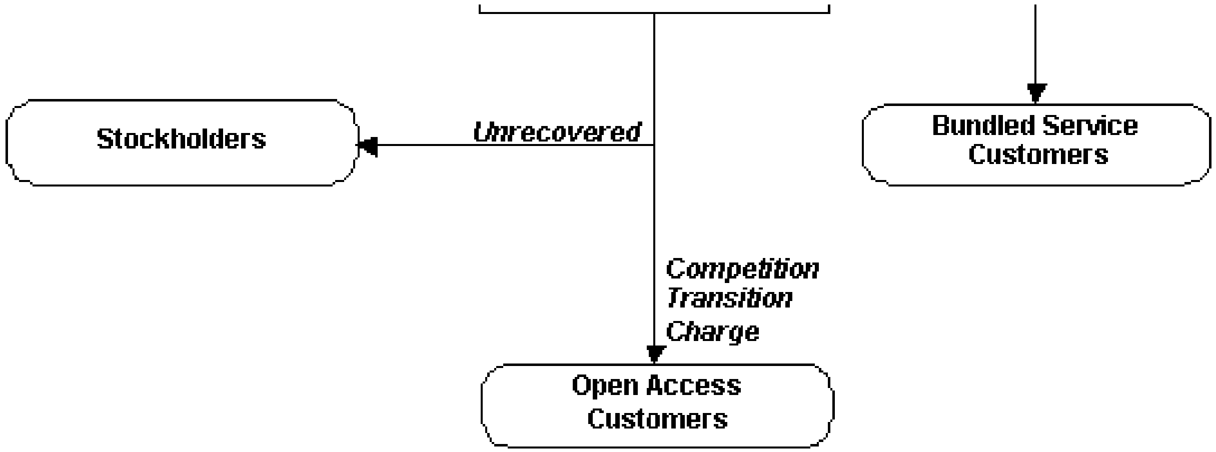
Figure 1
Market Valuation - Electric Generating Plant in Competitive Markets
Mitigation Strategies and Performance-Based Ratemaking





<u>ALTERNATIVE OUTLETS FOR UTILITY-OWNED GENERATION</u>

o SOLD BUNDLED TO EXISTING RETAIL CUSTOMERS

o SOLD TO POWER EXCHANGE IN SPOT MARKET

o SOLD TO MARKETER/BROKER FOR RESALE

Figure 2

Inverted Electricity Price Duration Curve

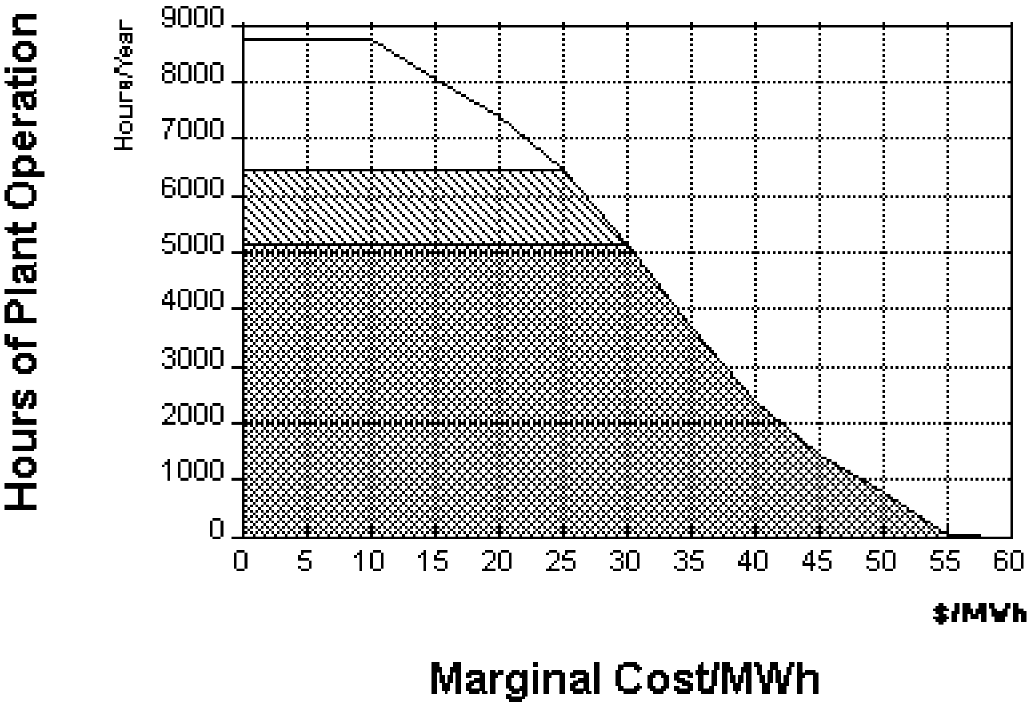
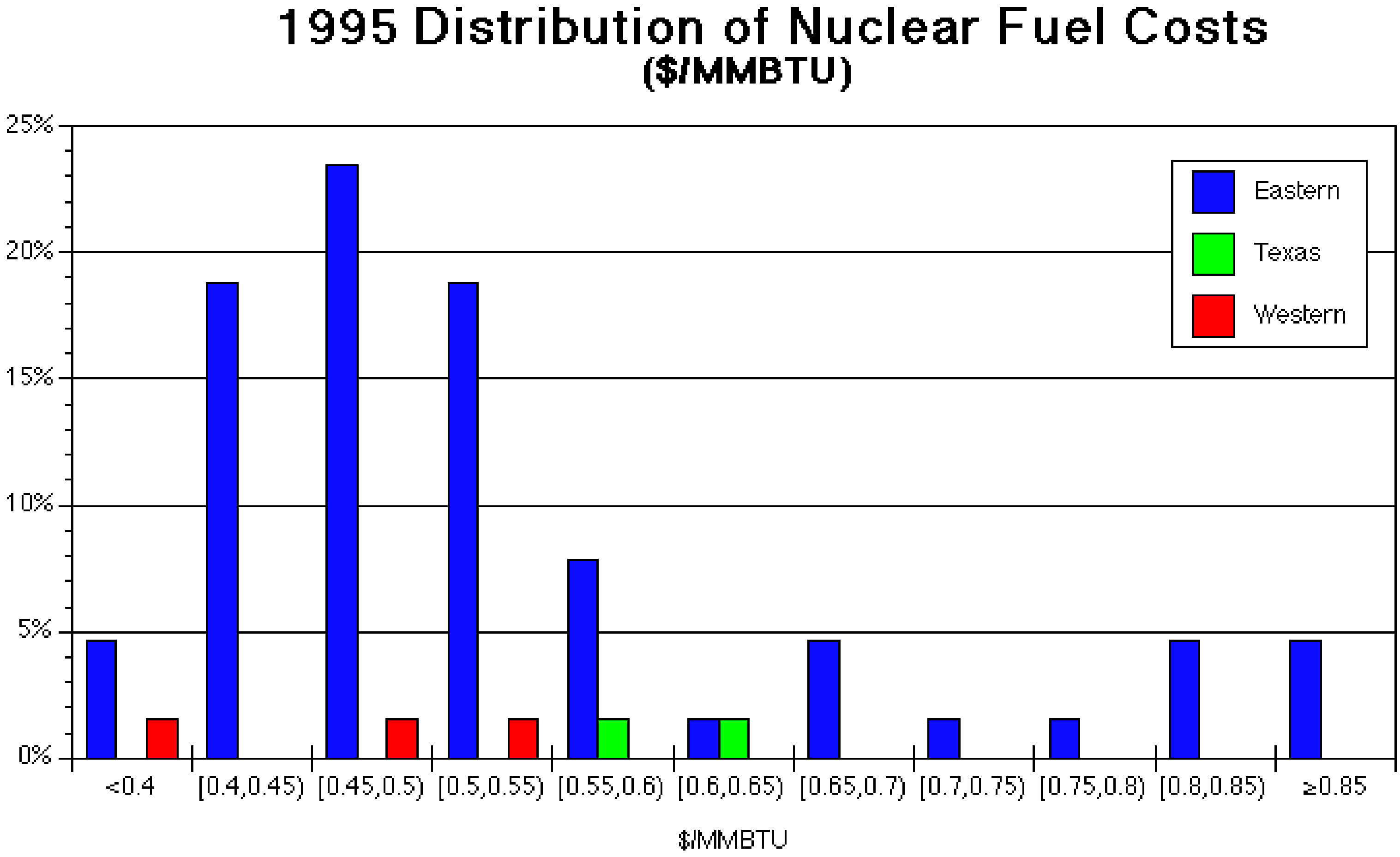
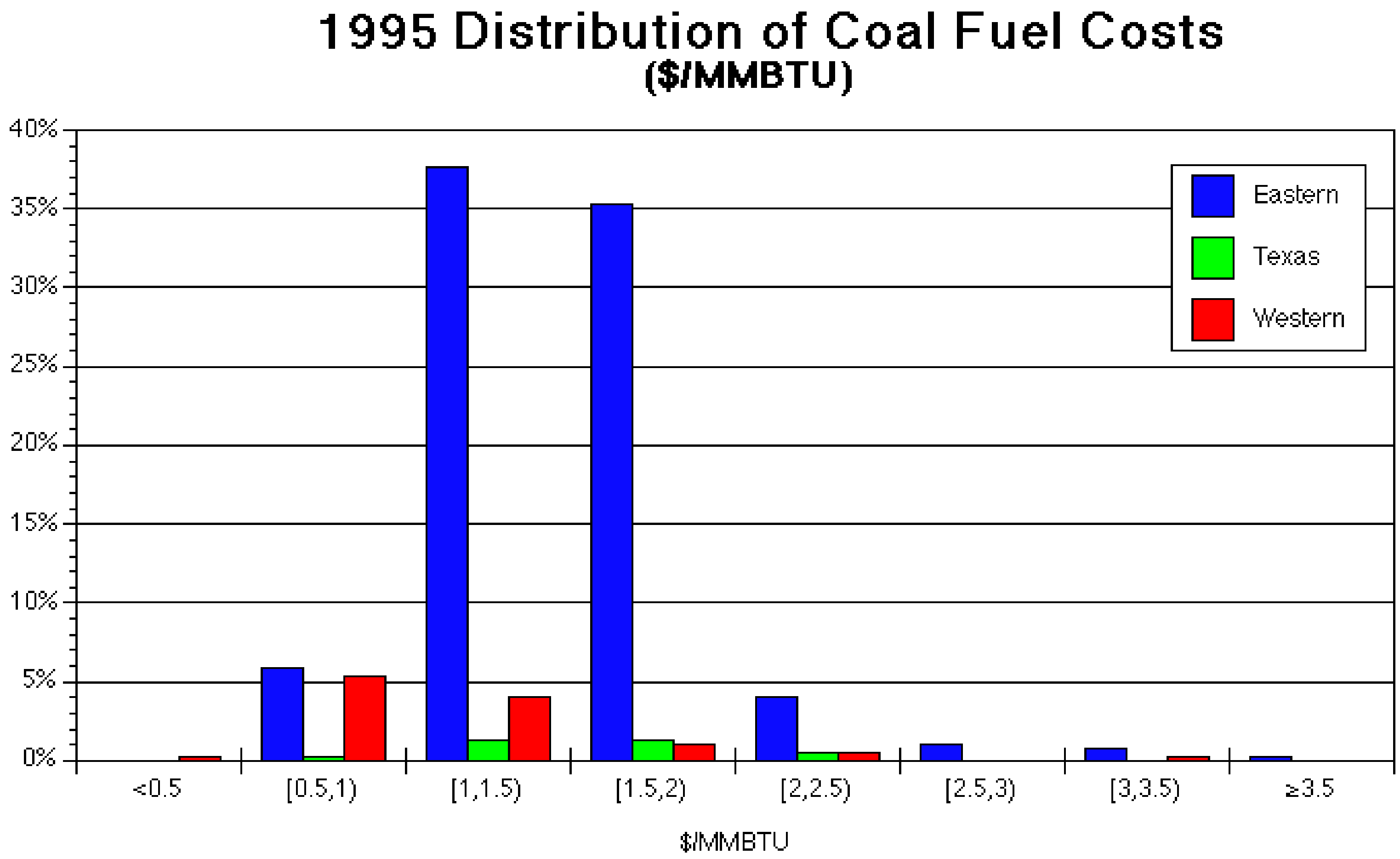


Figure 3



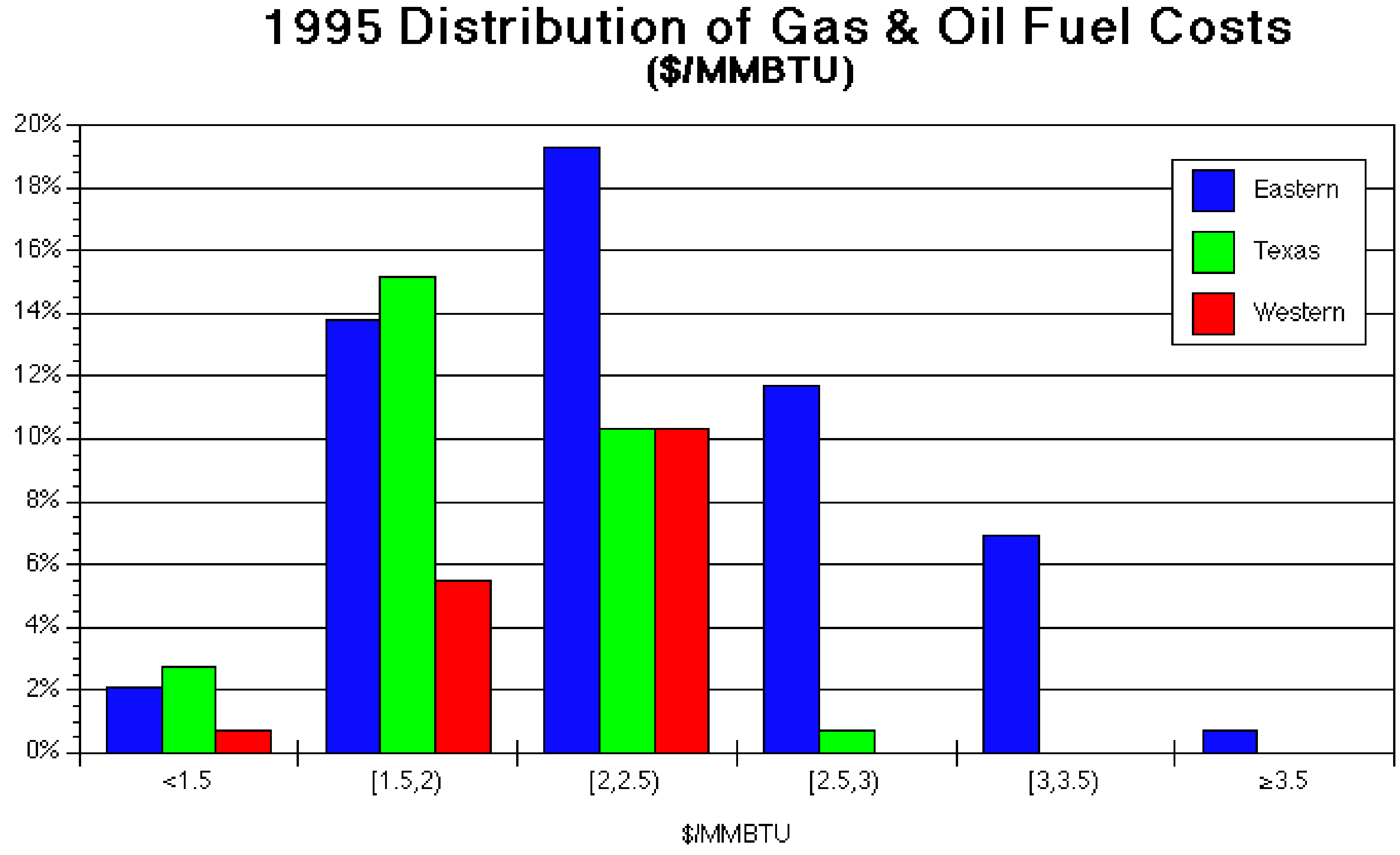
Source: ESC UQAR Utility Database

Figure 4



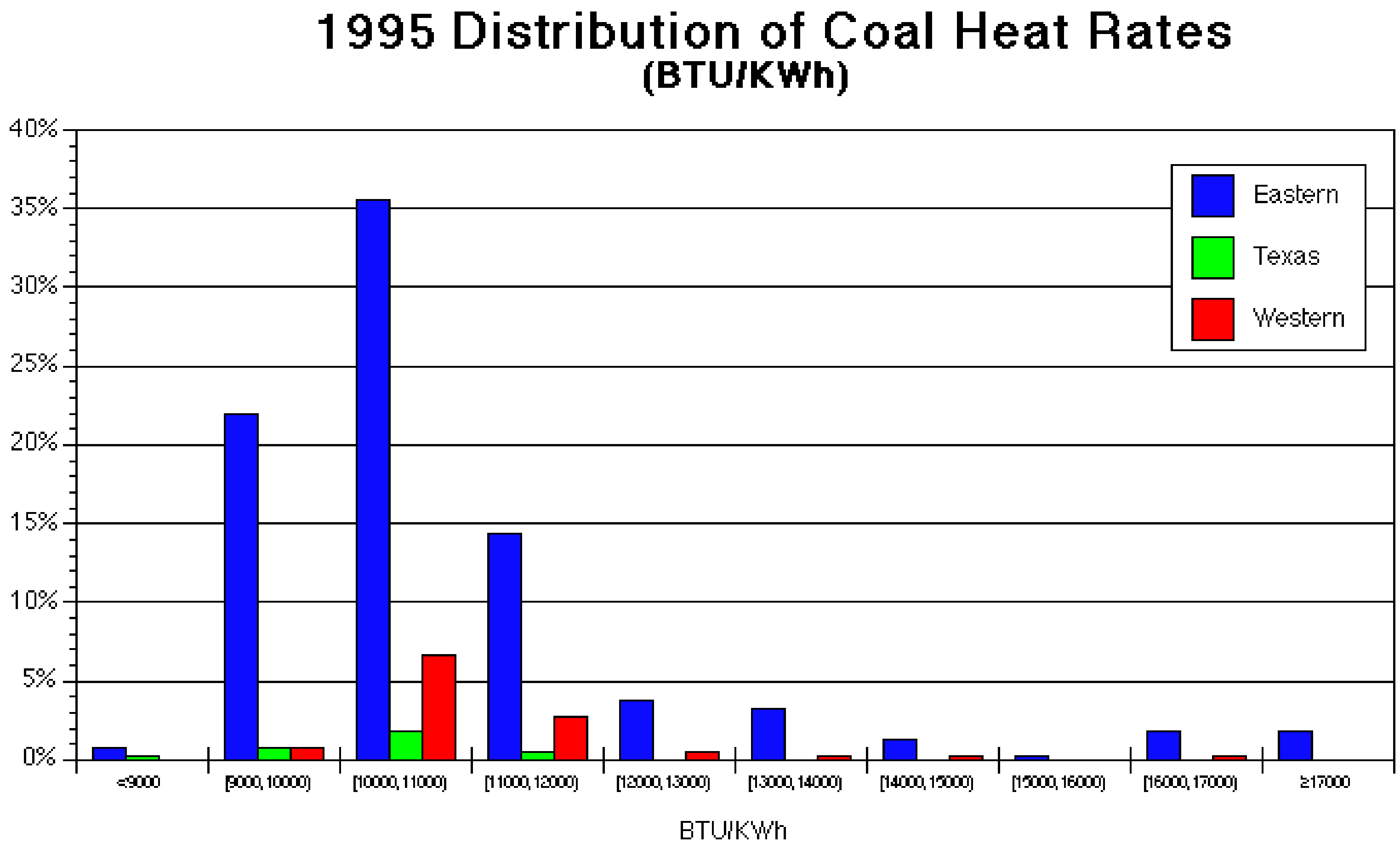
Source: ESC UQAR Utility Database

Figure 5



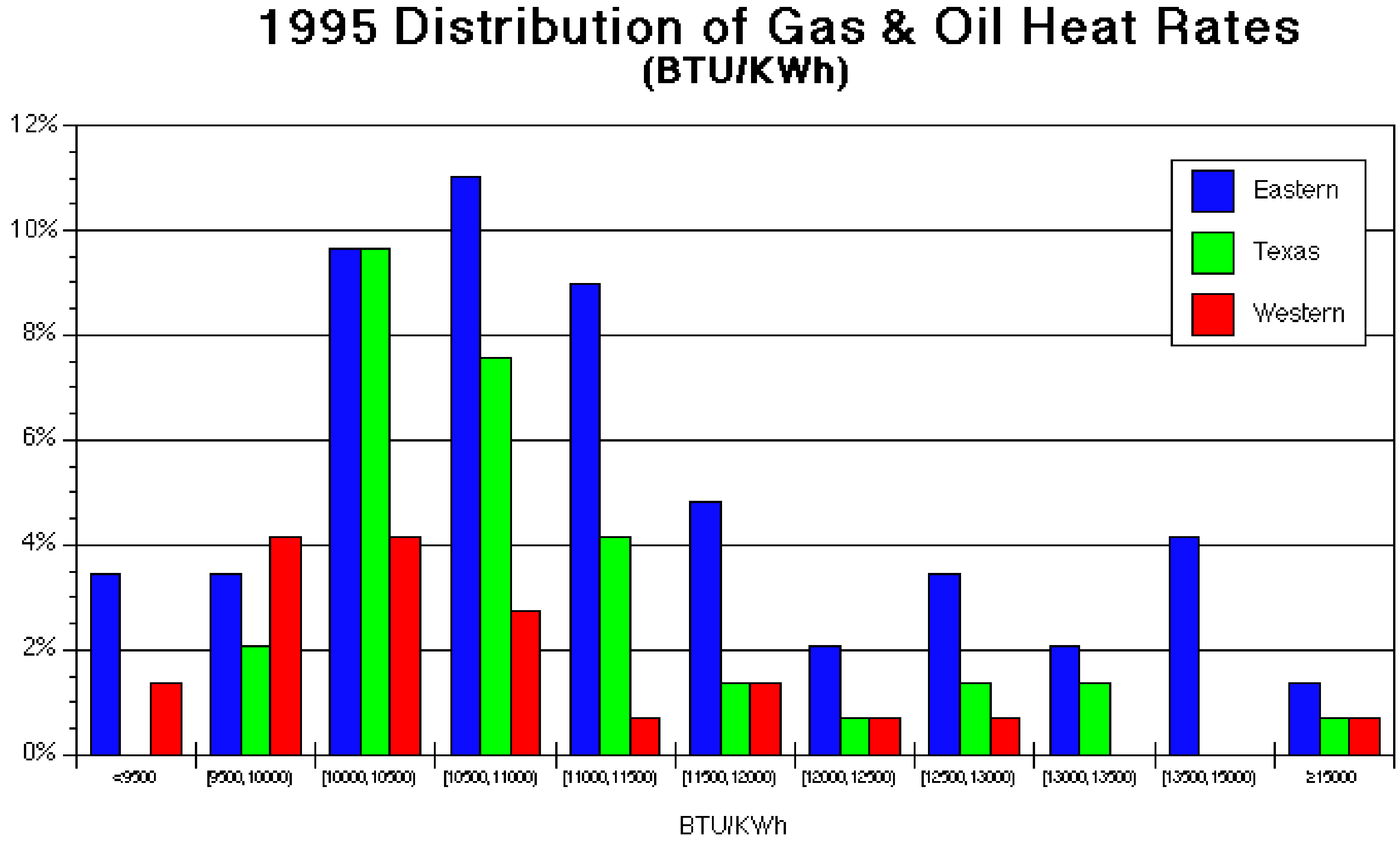
Source: ESC UQAR Utility Database

Figure 6



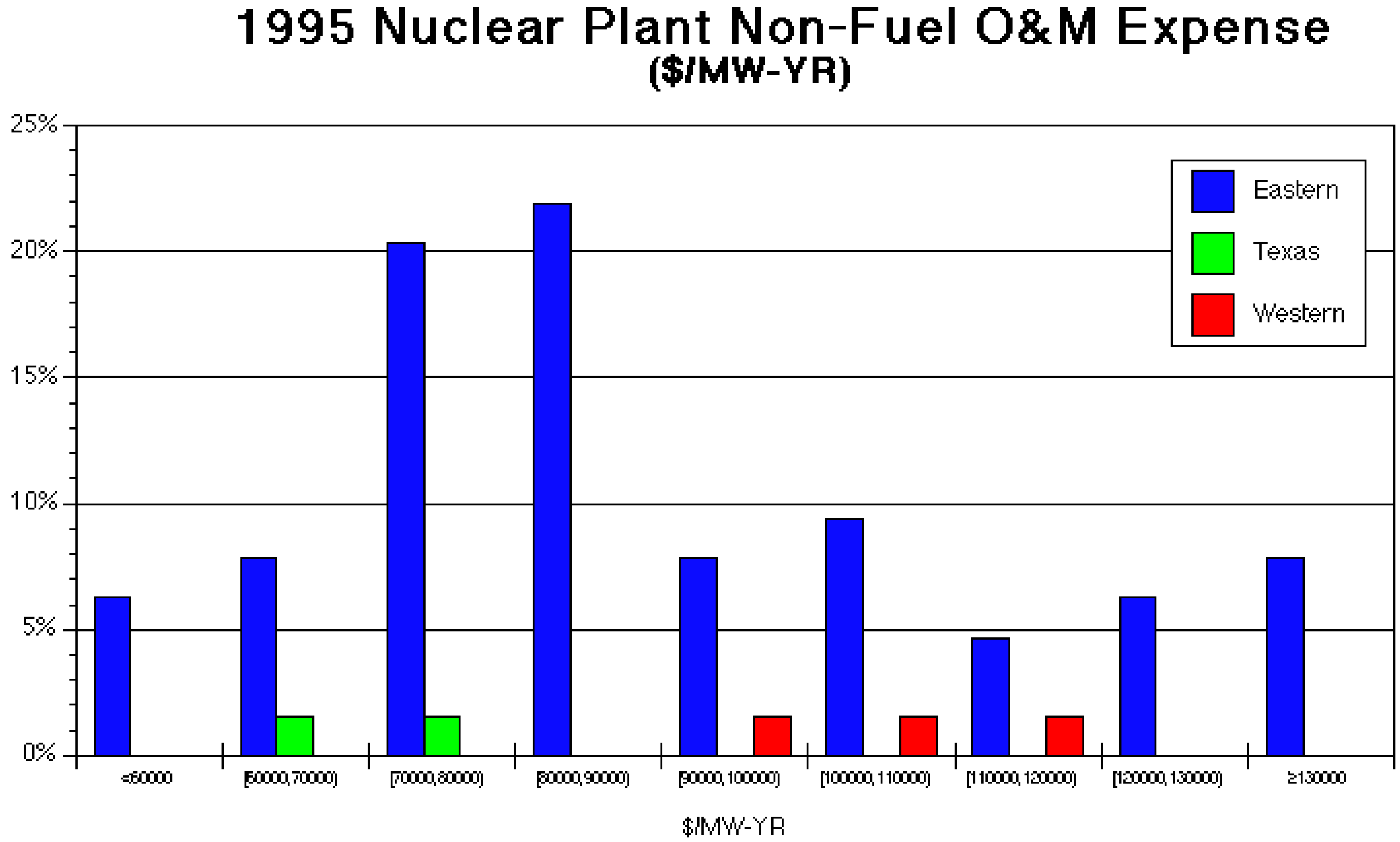
Source: ESC UQAR Utility Database

Figure 7



Source: ESC UQAR Utility Database

Figure 8

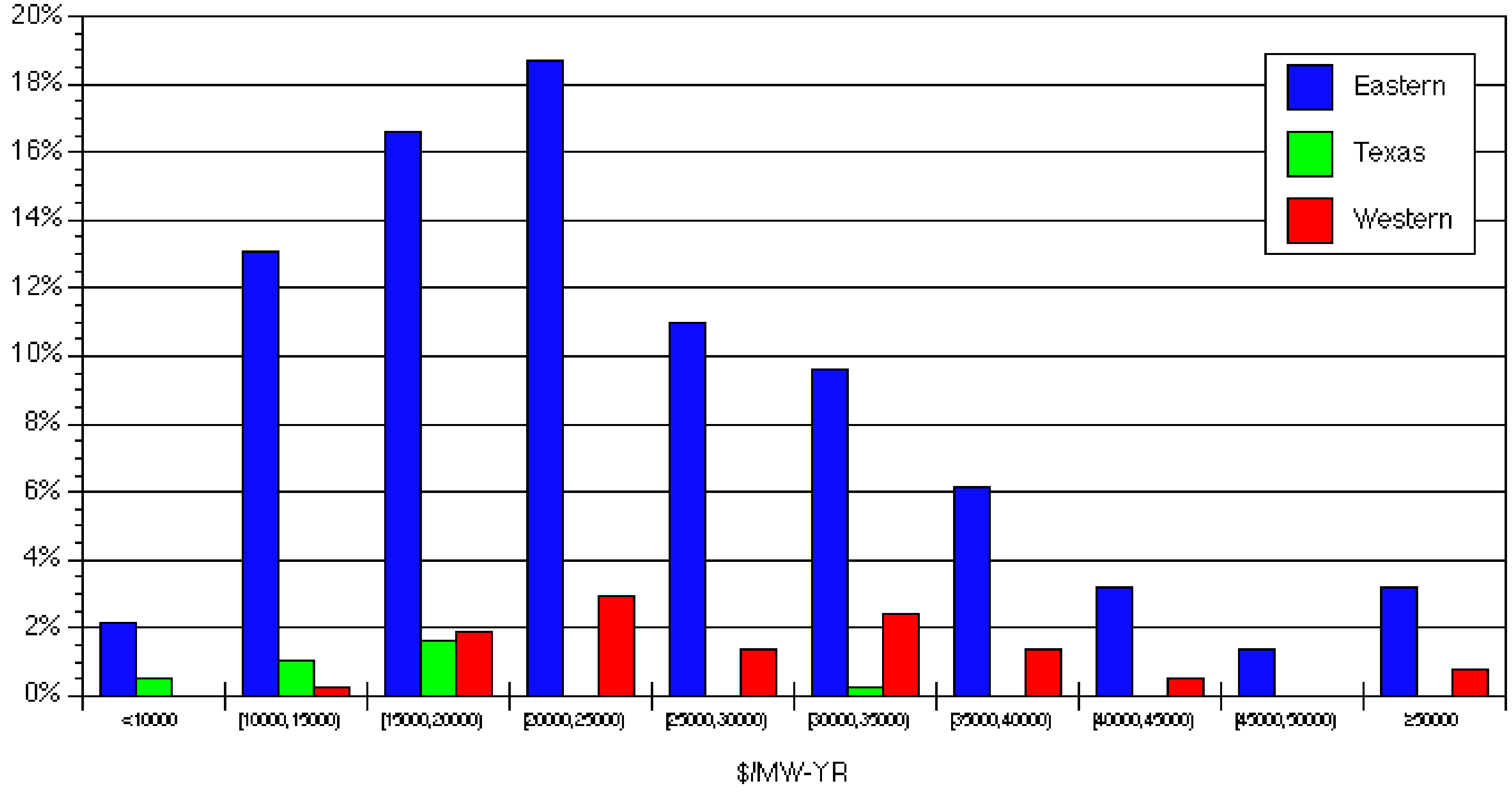


Source: ESC UQAR Utility Database

Figure 9

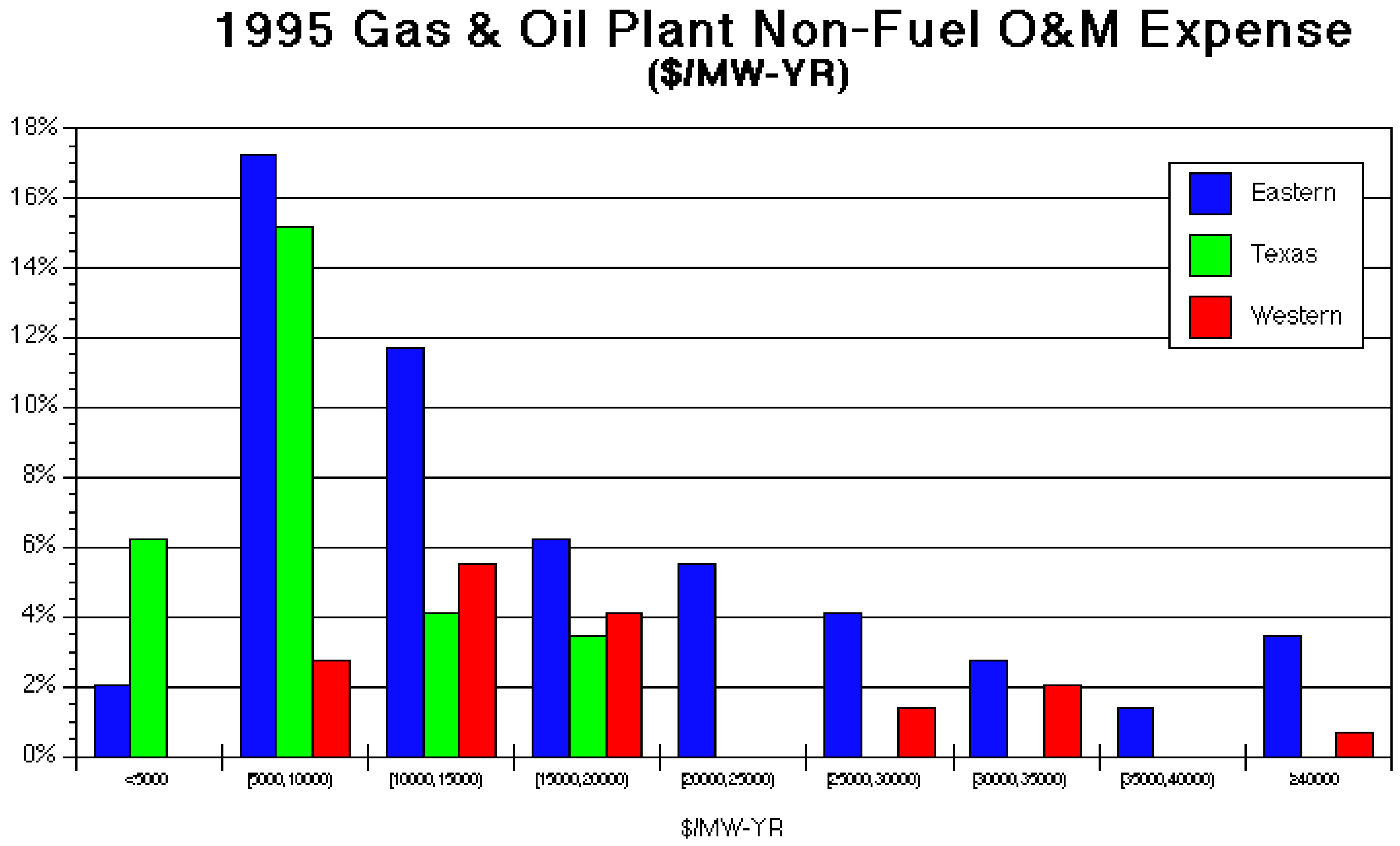
1995 Coal Plant Non-Fuel O&M Expense

($/MW-YR)



Source: ESC UQAR Utility Database

Figure 10



Source: ESC UQAR Utility Database