Modeling Electricity Restructuring using POEMS:

Shaping Competitive Prices Through Cost Shaving and Shifting

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Technological advances and changes in economic conditions favor increased reliance on competition in electricity markets, until recently considered to be natural monopolies. Recent action by the Federal Energy Regulatory Commission to provide for open access to the electricity transmission system is already aiding increased competition in wholesale markets (i.e., sales of power for resale). States such as California, Pennsylvania, New Hampshire, and Rhode Island are introducing competition in retail markets (i.e., sales of electricity to residential, commercial, and industrial customers). Many other states, including New York and Massachusetts, are seriously considering restructuring proposals.

The existing federal legal framework obstructs desirable changes in some areas and fails to provide clear guidance and authority to federal and state regulators in others. Several electric reform bills were offered in both the previous Congress and the current one, and the issue is receiving increasing attention from government, media, and lobbyists. Issues that could be addressed include, among others, Federal/state jurisdictional boundaries; federal policy or requirements related to retail electric competition and/or recovery of utilities' "stranded costs;" mechanisms for support of electricity-related public policy objectives, such as investments in energy efficiency, renewable technologies, electricity-related research and development, and universal service programs; ensuring bulk power system reliability; reform of PUHCA and PURPA; and the environmental impacts of restructuring. In testimony last year, the Department stated its view that comprehensive federal legislation, addressing a broad range of major issues related to restructuring (but not necessarily all of the issues listed above) is needed.

Assessments of the impacts of a broad restructuring of electricity markets on key variables such as electricity prices, generating asset values, environmental emissions, capacity decisions, the delivery of so-called public benefit programs, and overall economic performance, are hotly disputed. Controversy also surrounds provisions to achieve more narrowly focused goals, such as promoting the market penetration of renewable generation technologies, supporting public purpose programs, or advancing environmental quality, that could be incorporated in restructuring legislation at the state or federal level.

There are large interests at stake in restructuring, and factors other than analysis are likely to play a critical role in determining both the content and the timing of restructuring action at the federal level. Nonetheless, experience suggests that credible analysis can play a useful role in helping legislators sort out alternative formulations of restructuring. The experience of the 1990 Clean Air Act process, in which alternative acid rain proposals were evaluated using a common framework, illustrates the constructive use of analysis in support of the legislative process.[2] With the end of supporting the evaluation of alternative restructuring provisions in mind, the Department's Policy Office has been developing the Policy Office Electricity Modeling System (POEMS).

This paper has two objectives. First, it provides a brief overview of POEMS, including model structure and data sources. Second, it discusses some of the issues that arise in comparisons of cost-of-service pricing to competitive pricing.

POEMS

POEMS is a "system" that integrates two existing models, the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) and TRADELEC™, a detailed electricity model addressing alternative market (i.e., pricing) mechanisms including the impact of increased trading of electricity, associated network power flows, and resulting capacity utilization (dispatch).

NEMS is an energy-economy modeling system of U.S. energy markets. NEMS provides projections of the production, imports, conversion, consumption, and prices of energy subject to assumptions regarding macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological cost criteria, cost and performance characteristics of energy technologies, and demographics. NEMS is used to develop the baseline energy forecasts published annually by EIA in the *Annual Energy Outlook*. It can also be used as a tool for energy policy analysis related to existing and proposed changes in a wide variety of laws and regulations related to energy production and use, environmental protection, environmental requirements, or tax provisions. Documentation of NEMS is available from EIA.

NEMS is modular in structure. On the supply side, there are separate modules for oil and gas supply, gas transmission, coal markets, and renewable fuels. On the demand side, each end-use sector (residential commercial, industrial, and transportation) is represented , with interfuel competition to meet end-use demands as appropriate. The electricity supply and distribution and petroleum refining sectors are classified as conversion modules. An integrating module interacts with all three categories of modules described above, together with modules representing the macro-economy and international energy markets. The integrating module controls the solution process, iterating the individual models until convergence representing equilibrium in the producing and consuming sectors is achieved.

The electricity market module in NEMS represents 13 regions in the lower 48 states -- basically, the NERC regions with WSCC divided into three parts and NPCC into two parts. The demand for electricity and its corresponding load shape are aggregated within these regions. Six distinct seasons are modeled to reflect important interim loads and scheduled maintenance. Peak, off-peak, and shoulder load conditions are represented, but there is no characterization of individual time blocks. Generating plants are grouped by similar characteristics (fuel type, heat rate, etc.) and dispatched to satisfy the aggregated regional load. Transmission constraints within regions are not modeled. To limit the potential for substantial over-optimization resulting from the aggregate approach to representation of supply and demand, capacity factors are constrained to historical levels. Economy trade is modeled by allowing surplus capacity in selected regions to be dispatched for a neighboring region's needs. Economy trading restricted to neighboring regions and limited by transmission constraints established by NERC. An electricity finance and pricing submodule calculates total revenue requirements for and computes average electricity prices on a cost-of-service basis.

The design requirement to run all of the modules to equilibrium together constrains the level of detail provided in each NEMS module. While recognizing the advantages of the NEMS system, POEMS is more narrowly aimed at addressing questions surrounding electricity markets. For this purpose, there are significant advantages to a more disaggregated representation of the electricity sector. The approach taken in POEMS is to substitute TRADELEC™ for the electricity market module (EMM) in NEMS. Starting from a NEMS solution, TRADELEC™ is run in a standalone mode. The TRADELEC™ results for electricity prices, fuel mix, and other variables can then be iterated with the rest of NEMS until a full equilibrium is achieved.

TRADELEC™ is a network model of electricity dispatch, trade, and pricing. The POEMS version of the model operates at the level of the power control area (PCA), representing approximately 130 regions. PCAs are represented as a series of nodes, connected by transmission interties whose capacities are specified based on transfer capabilities reported to FERC. Within each PCA, supply resources are represented in considerable detail, including utility plants, exempt wholesale generators, traditional and non-traditional cogenerators, and firm power contracts. Plant characteristics, such as capacity, heat rate, and forced and maintenance outage rates, are represented based on data in EIA filings and NERC GADS data.[3]

Demand information is drawn from the NEMS system. Loads are estimated for 10 daily time blocks (8 2-hour day blocks, 2 4-hour night blocks) as well as a peak spike block within each of 6 seasons for residential, commercial, and industrial customers. NEMS develops a demand forecast based on projected activity levels for each customer class at the census region level. Demands at the PCA level in POEMS are represented by disaggregating the NEMS load forecasts based on sales (i.e., load) information from companies located within each power control area.

TRADELEC™ constructs native area supply curves adjusting for contracted flows in and out of each area. A search is performed to systematically identify economic trade opportunities by identifying high-cost capacity that can be replaced with less expensive capacity from another area. Transmission costs are reflected through representation of transmission tariffs (which can be implemented on a PCA or regional level) and transmission losses (a non-linear, distance sensitive measure). Further, a user specified "hurdle level" is input to limit transactions to those that provide a specified minimum level economic gain. The hurdle rate can be adjusted to reflect reductions in potential inefficiencies and transactions costs as markets provide greater incentives to exploit profitable trades. The search is conducted within each of the 66 time/season blocks modeled - maintaining the chronological simultaneity.

TRADELEC™ can represent either cost-of-service or competitive pricing[4] in retail markets. The cost-of-service pricing reflects financial information aggregated from filings made by investor-owned, public, federal, and cooperatively-owned utilities.[5] At present we are working to aggregate the financial data to the PCA level. This work has yet to be completed. However, it is already clear that the relationship between competitive and cost-of-service prices will not be uniform across PCAs. Indeed, it is certainly possible that competitive prices (on average) will exceed cost-of-service prices in areas with low embedded costs. The relationship between competitive and cost-of-service prices is a primary focus of attention in the restructuring debate, and the likely variation this relationship across PCAs highlights the value of modeling at a disaggregated level. Disaggregation also allows for an evaluation of a piecemeal implementation of restructuring, which is of considerable interest to some policymakers.

Modeling Competition

The potential economic impacts of a change from regulated to competitive retail markets can be considered as falling into two broad categories. First, restructuring can lead to a reallocations and transfers among different interests participating in electricity markets, notably existing electric utilities and different groupings of their customers. The likely magnitude of such reallocations and transfers, as well as the particulars of arrangements such as competitive transition charges that might (partially, fully, or more than fully) offset them, are hotly debated, with each interest bringing its own particular perspective of fairness to the dialogue. However, the competing equities are ultimately sorted out, the allocation or reallocation of rents and surpluses is not a source of net societal gain.

The second category of impacts relates to the potential of competition to provide net societal gains. Several types of gains are possible. First, competition can open the door to new service combinations. The gains here are not particularly amenable to modeling, but experience in telecommunications, airlines and other regulated markets opened to competition illustrates the potential for large gains. Second, competition can create opportunities to make more effective use of the generating capital stock through pricing practices that reflect the actual costs of supply at different points in time. These opportunities are amenable to modeling, and it is our intention to explore them through parametric changes in load shapes within the POEMS modeling system. Finally competition can impose more effective discipline on costs, providing incentives that will result in improved efficiencies driving down the cost of electricity.

The remainder of this paper examines the potential gains available in this third category. The current regulatory pricing approach, i.e., cost of service rate-making, has not encouraged or provided significant incentives to reduce the costs incurred in the delivery of electricity. The approach emphasizes reviewing the historical costs of providing electric power. Questions regarding prudent levels of costs, particularly the operations and maintenance of facilities, are generally beyond the reach of the regulators.[6]

The historical approach to setting the price of electricity has resulted in a cost structure that emphasizes fixed costs. With the exception of fuel costs, few costs are viewed as variable costs. With a shift to competition, generation owners are likely to re-examine and re-engineer activities being undertaken at their power plants. A likely outcome of the re-engineering at the plant level is a potentially significant shift in costs from fixed to variable. While cost shifting does not affect overall societal welfare, it can affect the relationship between bidding and competitive prices, and the amount of revenue generated under competition that can be applied to the return on and of the investment in existing and future generating assets.

For these reasons, a preliminary step to implementing the POEMS model involves an examination of alternative assumptions about opportunities for both shaving and shifting of existing costs under a competitive regime. The next section of the paper addresses these issues.

The Current Delivered Costs of Electricity

Table 1 provides a summary of the expenditures associated with the three primary functions of the electric power industry, i.e. generation, transmission, and distribution. For the investor-owned segment of the industry, the average delivered cost of electricity is 7.1 cents per kilowatt-hour. The generation function is responsible for almost two-thirds of the total delivered cost of electricity. It is this function that most states are considering for deregulation and open competition. The transmission and distribution functions, the latter defined here to include customer-related costs, account for 7 and 27 percent of total accounting costs, respectively.[7] The transmission and distribution functions (except for the customer-related activities) are, for the most part, considered to be natural monopolies and will remain regulated under virtually all current restructuring proposals.[8]

As shown in Table 1, there is a wide variation in the delivered cost-of-service of electricity around the country. The variation persists in all three functions. It is clear that utilities operating in the Northwest are enjoying below average generation costs, substantially lower than the rest of the country. The power flowing from these generating assets could potentially be priced higher in a competitive market, driving up the consumer costs in a competitive market. . On the other hand, utilities operating the New York are experiencing costs that are double the national average. Even if the generation function was reduced to the national average (a 32 percent reduction), the costs of transmission and distribution are sufficiently high as to leave the delivered cost 36 percent higher than the national average in 1995.

Cost Shaving

How might these costs be reduced and the cost structure changed in a competitive market? First, we direct our attention to potential reductions in costs. Using the data presented in Table 1, the total operations and maintenance costs of the generation function of the investor-owned segment of the industry is approximately $76 billion, which is 3.4 cents or 47 percent of the total.[9] These costs are under the direct control of management and therefore potentially reduced under the pressure of competition. We refer to these reductions in costs as cost **shaving**.

Based on some preliminary analyses, we have attempted to establish the extent to which we believe costs could potentially be shaved, once the industry is exposed to the pressures of an open market for electricity generation.[10] The approach used in this analysis was to develop estimates of efficiency frontier benchmarks for key measures of cost and operating performance and to evaluate the potential for efficiency improvements by comparing actual plant operating statistics against these benchmarks. Regional assessments were performed for the fossil-based generating plants, while the nuclear assessments were performed on a national basis. Clearly, there are many ways to establish benchmarks. We chose to use the mean value of the "best practices" quartile for each key statistic to define our "efficiency frontier benchmark". Savings were estimated by calculating deviations in actual plant costs from the frontier benchmarks. The analysis focused on three potential areas of improvement in plant operations: reductions in non-fuel operations and maintenance expense, reductions in fuel acquisition expenses, and reductions in plant heat rates (improvement in thermal efficiency).

Potential reductions in fuel acquisition costs represent the largest potential improvement in the operations of power plants, by far. Many utilities have re-negotiated their delivered fuel costs over the last several years. However, the data suggests there still are considerable variations in the delivered cost of fuels. Competition for the sale of electricity in the wholesale market, particularly spot markets, will likely lead to great incentives for the fuel suppliers and plant operators to reduce these costs. This is particularly true as the inter-fuel competition among coal, gas, and electricity increases. The preliminary analysis suggests that, taking into account regional variations, delivered coal costs could potentially be reduced as much as $5.0 billion per year. We suspect that as current contracts expire and utilities and power marketers utilize coal tolling, the costs of the fuel component of coal-fired generation will be significantly reduced. Existing long-term contracts that are outside a relatively tight market range will come under increasing pressure for re-pricing due to the emergence of these competitive forces. Similarly, coal transportation costs will likely experience considerable downward pressure.

Improvements in the delivered costs of gas and nuclear fuels (excluding spent fuel disposal costs) will likely also experience some downward pressure. The preliminary analysis suggests these costs could come down by as much as $1.2 billion and $0.8 billion, respectively. The estimates of reductions in fuel acquisition costs in all fuel categories amounts to an overall lowering of fuel costs on the order of $7.1 billion or 25 percent.[11]

Next, we turn to non-fuel operations and maintenance costs. Our analyses suggest that annual non-fuel operations and maintenance expenses at coal-fired, gas/oil-fired and nuclear plants could be potentially reduced by $2.2 billion, $0.5 billion and $2.0 billion, respectively.[12] This level of savings amounts to a 27 percent reduction in this category of expense. The aggregate $4.7 billion in savings, if fully achieved, could reduce the delivered costs electricity by 0.2 cents.

Taken together, the total potential for reducing fuel and non-fuel O&M costs in the generation function appears to be about $11.8 billion. Looking back to Table 1, fuel and non-fuel O&M costs represent only 43 percent of the total production function costs. Purchased power costs, which are generally perceived to be high due to historical commitments to QF contracts, can be expected to come down over the next few years as these contract commitments expire. Further, Table 1 includes about $6.2 billion of A&G costs *allocated* to the generating function. A significant portion of these A&G costs are associated with employee benefits and pensions and likely are not going to be eliminated. However, the other A&G costs associated with headquarters salaries and other related facilities costs are likely to experience significant pressure for reductions and may be reduced or eliminated under the incentives of competition.

Finally, it is important to decompose the capital related costs. These costs are easily assumed to be primarily associated with the sunk capital investments tied up in generating plant. However, as is evident in Table 1, taxes other than income taxes represent about 18 percent of the capital related costs, amounting to $13.6 billion. When income taxes (and a small amount of other costs) are eliminated, it appears that the return on (i.e., operating income) and return of (i.e., depreciation expense) amounts to about two-thirds of the total $76.9 billion of capital related costs. Assuming this same proportion of capital related costs can be assigned to the production function, the return on and of capital associated with the production function amounts to about $29 billion or 1.3 cents out of the total of 4.7 cents.

Clearly, the potentials for cost shaving outlined above bear significantly on an evaluation of the net societal gains resulting from increased reliance on competitive forces in generation markets. Two interesting questions not addressed here are what part of the potential gains is likely to be realized under competition, and what share of those gains might also be captured though an improved regulatory approach, such as performance based regulation. Cost shaving, in conjunction with cost shifting, can also have important implications for revenue flows available to provide returns on and of existing capital. These are discussed below.

Cost Shifting

Cost shifting, the movement of fixed operating costs to variable costs, is one of the more difficult areas to assess. Using the existing accounting data, it is nearly impossible to separate fixed from variable operating costs, with the notable exception of the fuel costs. Even the reported fuel costs are of limited use in determining the actual variable costs of fuel consumption (due in large part to the direct impact that fuel contract provisions have on these costs). Certainly, some non-fuel costs could be designated as variable costs, but which costs and how significant they are is far from clear. Further, costs that are currently seen as fixed are likely to be redefined as variable by re-engineering the business approach. These issues are quite significant because it is anticipated that in competitive markets, the bid-based dispatch (i.e., price based dispatch) will be quite different than the historical incremental cost approach.

Bidding strategies designed by generating plant owners will determine market clearing prices. Plant owners can make some contribution to fixed costs and/or returns of or on invested capital by operating whenever the market price is above variable cost. However, fixed costs can be entirely avoided by a shutdown decision -- which means that economically rational bids must at least generate sufficient surplus above variable cost to cover annual fixed costs. The partial or total incorporation of annual fixed operating costs in the bids of plant operators will drive upward the market clearing price. Plant operators are also likely to re-engineer selected activities at the plant and outsource other activities (e.g., selected maintenance activities). This will enable them to avoid some costs if the plant is not dispatched. Under these circumstances, we would anticipate that these costs will in fact become variable and directly impact the bidding strategy of the plant owner/operator.

By way of illustration, non-nuclear steam production costs amounted to about $32.8 billion in 1995. Once the fuel component is eliminated, the remaining costs total $7.8 billion. Of these remaining costs, maintenance costs represent $4.1 billion. Assuming all these costs could be made variable and included in the marginal costs of the facilities, the incremental costs associated with maintenance at these facilities would be about $2.65 per mWh. As should be apparent, the conversion of any significant portion of these costs to variable and including these additional variable costs in the bids of producers will increase the market clearing price, potentially quite significantly. For example, assuming a $30 per mWh market clearing price, the $2.65 represents almost 9 percent of the bid price.

Impacts of Shaving and Shifting

In competitive markets, cost shaving will boost net cash flow by increasing the net flow per hour of operation and also by increasing the number of hours that a plant is operated. Further, reductions in fixed O&M additionally increase the cash available for payments to capital, thereby mitigating stranded investments.

Taken together, shaving and shifting can have a substantial impact. The sidebar illustrates the opportunities flowing from cost shaving. The problem confronting the plant owner is complicated by the opportunity to shift selective fixed costs to variable by re-engineering his operations. The assumption is that the resulting total cost function, after re-engineering plant operations, is more steep but has a lower break-even output level. Further, the operating leverage[13] gained should put the plant operator in a better cash flow position vis a vis a competitor.

Conclusion

The extent to which electricity providers can improve their performance by shaving costs and moving to the efficient frontier and the extent to which operations can be restructured so that fixed costs could be considered marginal costs could have a significant effect on competitive prices. While not likely achieved easily or quickly, if all electricity providers shaved costs so that they averaged the same as those in the "best practices" quartile, electricity prices would be about 0.6 cents per kilowatt-hour (or almost 8 percent) less for the nation. Further, there is currently $17.2 billion in non-fuel fixed operating expenses being incurred at power plants.[14] If these costs were to be fully reflected as adders to the variable costs in the asking price of producers, the end result would be a potential increase in the market clearing price of 0.8 cents per kilowatt-hour. Clearly, the outcome of changes and treatments in these costs will play critically in the evaluation of stranded costs that electric utilities might face in a competitive environment. Also, the consumer benefits of moving to retail choice and a competitive market for generation services will be substantially influenced by the level and treatment of these costs in producers' operations and asking prices.

Table 1

Investor-Owned Utility Components of Price for 1995

	NATIONAL		**New York Power Pool**		**Northwest Power Pool**	
	Cents / kWh	Dollars (xooo)	Cents / kWh	Dollars (xooo)	Cents / Kwh	Dollars (xooo)
Total	**7.13**	**162,280,840**	**11.87**	**13,610,101**	**5.10**	**5,844,856**
A. Production	**4.71**	**107,190,582**	**6.88**	**7,885,336**	**2.70**	**3,089,835**
1. Purchased Power[15]	0.53	12,131,671	2.29	2,621,056	0.31	358,131
2. Fuel	1.27	28,991,852	1.02	1,173,393	0.69	794,767

3. Nonfuel O&M	0.76	17,184,115	0.75	865,084	0.47	540,637
4. Capital Related	1.87	42,637,734	2.51	2,883,388	1.07	1,226,633
5. A&G Allocation	0.27	6,245,210	0.30	342,415	0.15	169,666
B. Transmission	**0.51**	**11,600,095**	**1.06**	**1,214,430**	**0.64**	**733,724**
1. O&M	0.09	2,151,254	0.24	273,991	0.16	177,924
2. Capital Related	0.39	8,821,811	0.77	880,593	0.46	526,036
3. A&G Allocation	0.03	647,030	0.05	59,845	0.03	29,765
C. Distribution	**1.91**	**43,470,163**	**3.93**	**4,510,336**	**1.76**	**2,021,297**
1. O&M	0.26	5,841,949	0.55	635,168	0.22	252,145
2. Capital Related	1.12	25,404,979	2.33	2,668,112	1.08	1,240,849
3. Customer Related	0.26	5,860,025	0.47	543,879	0.20	226,399
4. A&G Allocation	0.28	6,363,210	**0.58**	663,175	0.26	301,904

Further Detail of Selected Costs Included Above

D. Capital Related and Revenue Related (Included on Allocated Basis Above)						
1. Depreciation	0.82	18,661,429	0.96	1,103,616	0.58	663,262
2. Taxes other than Income Taxes	0.60	13,612,769	1.91	2,193,043	0.35	399,183
3. Operating Income	1.47	33,390,988	2.23	2,560,645	1.25	1,432,285
4. Subtotal	*2.89*	*65,665,186*	*5.11*	*5,857,303*	*2.18*	*2,494,730*
5. Income Taxes, Reg, & Other	0.49	11,199,338	0.50	574,790	0.44	498,789
6. Total Capital	*3.38*	*76,864,524*	*5.61*	*6,432,094*	*2.61*	*2,993,518*
E. A&G Costs (Included on Allocated Basis Above)						
1. Salary Allocation: A&G Salaries		3,067,991		267,785		184,656
2. Pension Allocation		4,186,992		362,148		240,530
3. Other A&G Allocation $		6,000,468		435,502		76,149
4. Total	*0.58*	*13,255,450*	*0.93*	*1,065,435*	*0.44*	*501,335*

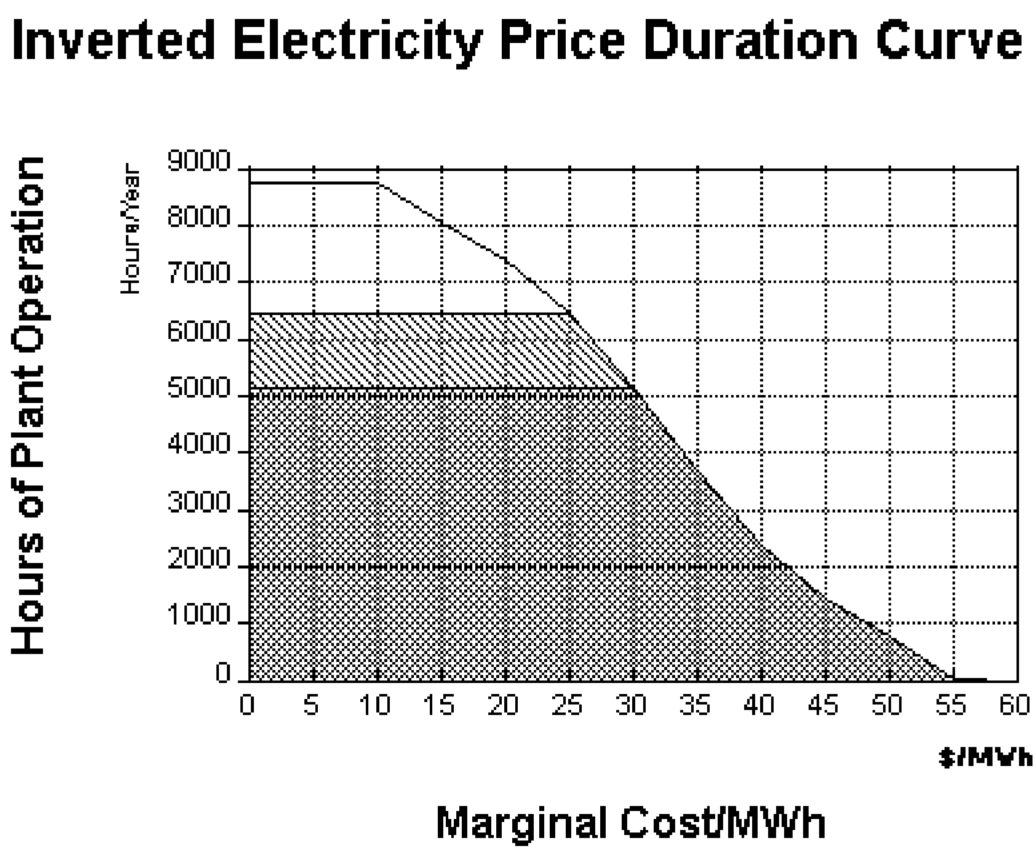
Source: FERC Form 1's for 1995

SIDEBAR[16]

This example demonstrates the potential impact of cost shaving on net cash flow. It assumes that the owner/operator of a generating plant with a capacity of 1,200 MW is a price taker in a competitive market.[17]

Initially, assume the plant's average variable production cost (= marginal cost) is $30/mWh. The annual price duration curve (shown in Figure 1) for the electricity market served by the plant 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. In this situation, the plant in our example would run 5,120 hours and produce 6,144,000 mWh of electricity. (The double cross-hatched area on Figure 1 shows the revenue per MW of plant capacity when the marginal cost is $30/mWh.)

Figure 1



The time-weighted average price of electricity during periods when the plant in this example is dispatched (from the price duration curve) would be $40.51/mWh. Total revenue to the generating plant is $248,893,440, and variable production costs are $184,320,000. If fixed O&M costs are

$60,000,000/year, then $4,573,440 would be left for payments to capital.

Now suppose that the plant managers were able to reduce the plant's average variable production cost to $25/mWh, a 16.7% reduction. In this second case, the plant would be dispatched 6,435 hours (73% of the time) and produce 7,722,000 mWh of electricity. (The single cross-hatched area plus the double cross-hatched area on Figure 1 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 $292,432,140. This level of production also increases variable production cost to $193,050,000. Fixed O&M expense remain at $60,000,000/year as in the first case. This leaves $39,382,140 for payments to capital. A 16.7% reduction in variable per mWh production cost compared to the first case increases the cash available to cover the return of or on capital by 861%.

Suppose now that management is able to reduce fixed O&M by 16.7% to $50,000,000. This would directly increase the cash available for payments to capital by $10,000,000. This implies a 218% increase in cash available for payments to capital compared to the first case, and a 25% increase compared to the second case.

These simple examples illustrate the obvious fact that increases in the efficiency of plant operations greatly enhance the security of shareholders' equity. In this instance, a reduction in variable production costs and fixed O&M costs by modest amounts produces very large increases in net cash flows. THE EXTENT OF POTENTIAL FOR EFFICIENCY IMPROVEMENTS IN GENERATING PLANT OPERATIONS IS A CRITICAL ISSUE IN ANY EVALUATION OF THE IMPACT OF RESTRUCTURING ON OWNERS OF EXISTING GENERATING ASSETS.

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1. Conti and Gruenspecht are with the Office of Economic, Electricity, and Natural Gas Analysis, Office of Policy and International Affairs, U.S. Department of Energy. Goudarzi is President of OnLocation. The views expressed in this paper are those of the authors, and do not necessarily represent the views of the U.S. Department of Energy.
2. As well as the possibility that ex post outcomes will diverge from even the most carefully crafted ex-ante estimates.
3. NERC **G**enerating **A**vailability **D**ata **S**ystem
4. While TRADELEC^{TM} can estimate competitive prices under alternative approaches, the competitive pricing in POEMS is implemented as a second-price auction.
5. The information is drawn from federal filings including FERC Form 1, EIA Form 412 and RUS Forms 7 and 12.
6. In recent times, regulators have attempted to look into the costs incurred operating nuclear power plants and questioned the level of costs and effectiveness of utility management of these facilities. Since the capital carrying costs typically associated with these facilities are relatively large, regulators have attempted to ensure that the facilities perform well or management (and therefore stockholders) be penalized if the facilities can be shown to be operating in a particularly inefficient manner. More recently, regulators have begun to question purchased power contracts entered into by utilities, particularly the contracts with qualifying facilities under PURPA which tend to be rather expensive in todayís power market.
7. Table 1 also provides a separate breakout of the customer-related costs of service. These include the customer accounts (meter reading, customer records and collection), customer service and information (customer assistance, informational and instructional expenses) and customer sales expenses (advertising and demonstration & selling). Customer related costs

represent 0.3 cents of the cost of delivered electricity, or 3.6 percent of the total cost.

8. This segment of the business is also being unbundled and opened to competition in California.
9. This figure excludes the allocation to this function of 1) capital related and 2) administrative and general costs. Table 1 reports these figures separately. Further, the purchased power costs reported in this table are **net** of the revenues generated by wholesale sales of electric power which amounted to $17.6 billion in 1995.
10. Refer to "Electric Generating Plant Operating Efficiency and Mitigation Of Stranded Investment Costs", OnLocation, Inc., Working Paper 97-3, Goudarzi and Roberts, May 1997, for a complete discussion of the approach and results thereof.
11. Improvements in plant efficiencies (heat rates) at the fossil-fired steam plants could also contribute to cost shaving. The preliminary analysis suggests that these improvements, if achieved could contribute about $1.6 billion in lower fuel costs. This estimate of savings would be moderated somewhat by the reduction in fuel acquisition costs.
12. The analysis was performed on plant level data reported in the FERC Form 1. As such, we were able to separate the coal, gas/oil fired steam and nuclear plants into individual groups for analysis purposes.
13. Operating leverage can be thought of in terms of the change in operating income that results from a change in unit sales.
14. $76.4 billion of total production expenses less $59.3 billion of fuel and purchased power expenses.
15. Net of wholesale revenues.
16. Refer to "Electric Generating Plant Operating Efficiency and Mitigation Of Stranded Investment Costs", OnLocation, Inc., Working Paper 97-3, Goudarzi and Roberts, May 1997, for a complete discussion of the approach and results thereof.
17. This ignores any market power that could be a result of transmission constraints or domination by the producer in the given market.

OnLocation, Inc.