First Six Months of Revised ISO New England Power Generation Market Shows Large Disparity in Value of Gas Turbine Units

By Dr. Jeffrey N. Phillips

Abstract

Fern Engineering, Inc., a Cape Cod-based engineering consulting firm which specializes in gas turbines, has reviewed the ISO New England pricing data from the first six months of operation with the new Locational Marginal Pricing (LMP) market rules with an eye toward evaluating the impact of LMP on gas turbine power plants. The review shows that gas turbine power plants in Connecticut are earning 50 to 100% more than similar plants in Maine. As a result, the economic value of the power plants in Maine is now far less than those in Connecticut. In addition, the combination of the market rules and the relatively high price of natural gas have placed a premium on fuel efficiency. Consequently, new gas turbine plants that are highly efficient have an earning potential up to seven times greater than older, inefficient gas turbines.

Introduction

On March 1, 2003, the independent system operator of New England's wholesale electric power market, ISO New England, adopted a location-based pricing structure for electric power production. The new structure, called LMP for Locational Marginal Pricing, pays generators higher prices for power that is produced near the largest demands for power and lower prices for power produced far from the load centers. Before the LMP process was adopted, ISO New England paid the same price for power across the region.

The primary motivation for adopting the LMP market structure was to address the limits in the electrical transmission grid which make it difficult, if not impossible, to transport power produced in remote locations to load centers in the large metropolitan areas of New England. A secondary motivation was to create a monetary incentive to build new power plants in the areas that have the highest demand for power.

As was the case in the pre-LMP market, power producers still submit bids for generating power to ISO New England. Typically, the bid is based on the power plant's marginal operating cost and represents the minimum amount of money needed to cover the cost of fuel and wear and tear on the equipment. ISO New England then ranks the bids from lowest to highest and then looks at the demand for power at a given point in time. They dispatch the power plants in the order from lowest bid to highest until they have enough production to meet demand. The price of the highest bidder that is needed to meet the electric load is then paid to *all* the power plants that are dispatched. Thus, if a plant has submitted a bid of $40/MW-hr and the highest accepted bidder had a price of $63/MW-hr, one can assume that the $40/MW-hr bidder has made a gross profit of $23/MW-hr during that particular period.

Wholesale power prices have always fluctuated with the time of day and day of the week. Figure 1 shows the hour-by-hour price of electricity in southeasthern Massachusetts during a typical week this past summer. The chart shows that the price normally peaks during the late afternoon and then falls to its minimum value during the early morning hours. Prices can even fall to zero if the supply exceeds demand. (Some power producers will continue to operate even if they are getting paid $0/MW-hr because it often takes several hours to re-start the power plant and they do not want to miss the opportunity for profits during the upcoming hours.)

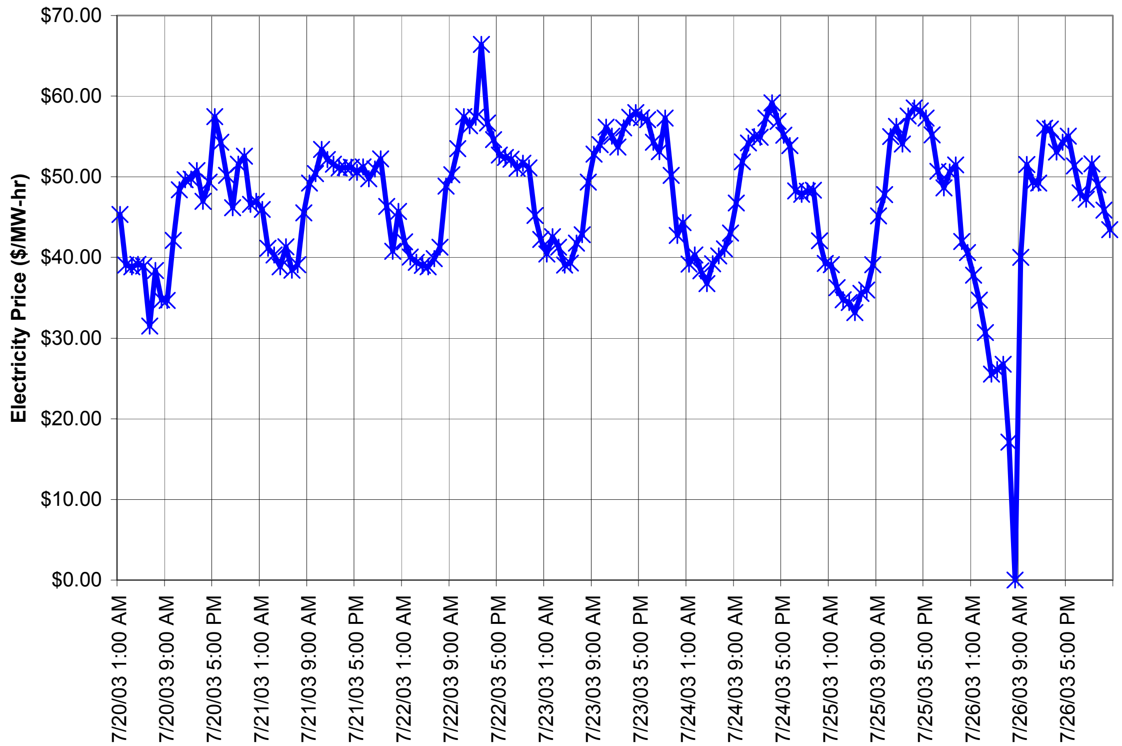

Figure 1 – Hourly Wholesale Electricity Price in southeastern Massachusetts during the week beginning Sunday, July 20, 2003.

What is new with the LMP rules is that ISO New England now calculates a bonus or surcharge for each power plant location in the network based on the ability of the grid to transport the generator's power to the location where it is needed. For example, the total demand for power in the New England network might be 16,000 MW and, when all the power plant bids are submitted, ISO New England calculates that the highest bid, regardless of location, that is needed to meet the demand for 16,000 MW is $53/MW-hr. However, if it sees that there are 3,000 MW of bids at $53/MW-hr or less from power plants in Maine and the demand for power in Maine is 2,000 MW, ISO New England has to find a market for the excess 1,000 MW. If the transmission lines leading from Maine to Boston where additional power is needed can only deliver 500 MW, then ISO New England will decrease the highest accepted price in Maine to the point that power plants totaling only 2,500 MW will be willing to operate. If that price is $43/MW-hr, then ISO New England will impose a $10/MW-hr transmission congestion penalty on the power price in Maine and pay those producers only $43/MW-hr, while power plants in the other New England states are paid $53/MW-hr or more.

ISO New England actually calculates a unique congestion penalty for every power plant location, not just statewide penalties. It then publishes the ultimate price paid by each location or node and also calculates an average price for eight different load zones:

- Maine
- New Hampshire
- Vermont
- Connecticut
- Rhode Island
- Western & central Massachusetts
- Southeastern Massachusetts
- Northeastern Massachusetts (including Boston)

Real-time price data is posted on the ISO New England website at: http://www.iso-ne.com/smd/operations_reports/rt-5min.php.

Price Duration Curves

When evaluating the earning potential of power plants, it is useful to plot power prices in the form of a "price duration curve". These curves show how often the electricity price exceeded a certain value during the period. The price duration curve for the southeastern Massachusetts load zone for the first six months of the LMP market is shown in Figure 2.

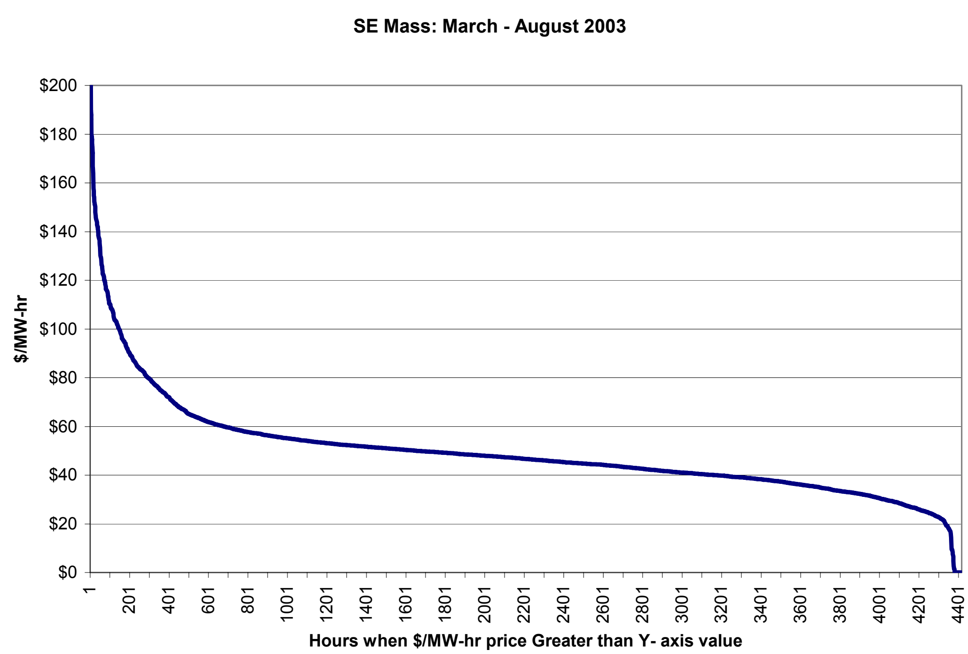

Figure 2 – Price duration curve for the average real-time wholesale electricity price in the southeastern Massachusetts load zone covering the 4416 hour period from March 1 through August 31, 2003 (prices higher than $200 not shown – maximum price was $393/MW-hr).

The price duration curve shows that the average price in the load zone exceeded $100/MW-hr for less than 200 hours during the six month period. On the other hand, the price exceeded $40/MW-hr for approximately 3200 hours. Consequently, a power plant with a marginal operating cost of $100/MW-hr would have been operating less than 5% of the time during the March-August season, while a power plant with a marginal operating cost of $40/MW-hr would have operated more than 70% of the time.

Figure 3 shows the price duration curves for all eight load zones in the ISO New England network for the first six months of the LMP market. It is clear that only Connecticut and Maine had prices which were significantly different from the norm. Connecticut prices were higher, reflecting the relatively high demand for power in that state, and Maine prices were lower due to a surplus of power generation capacity in that state.

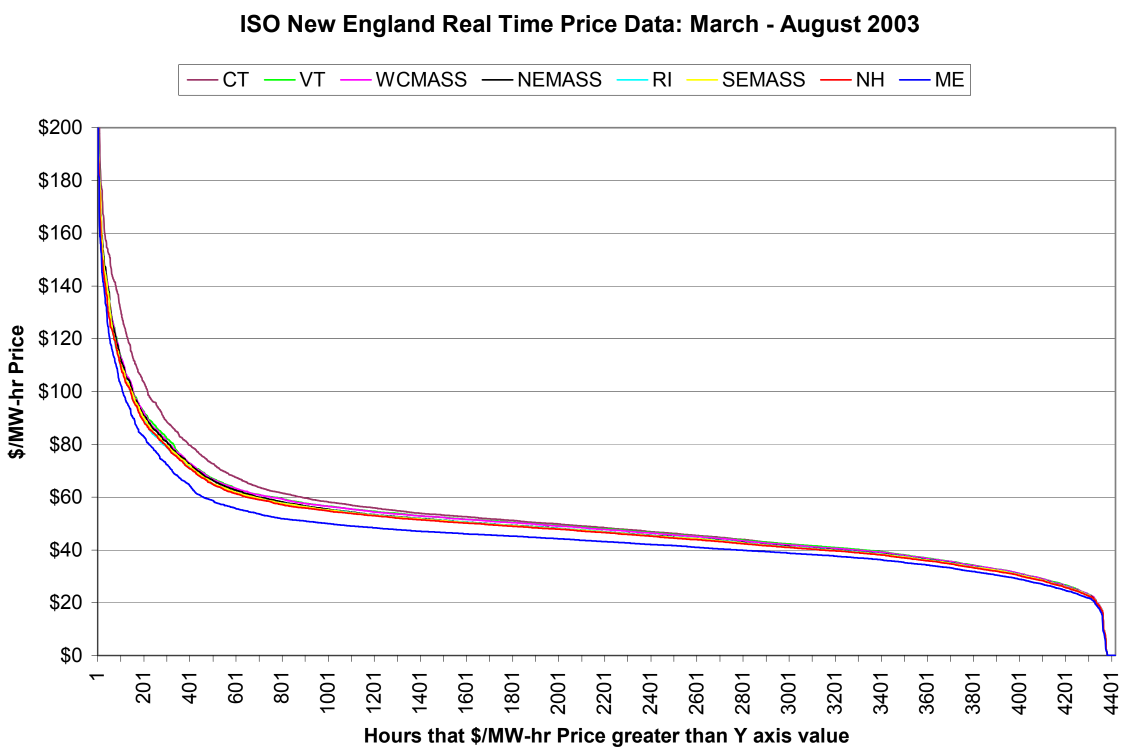

Figure 3 – Price duration curves for all eight load zones in ISO New England (data above $200/MW-hr not shown).

Gross Revenue versus Marginal Operating Cost

The data in the price duration curves can be used to calculate the gross revenues that would have been received by a power plant as a function of its marginal operating cost or breakeven cost. For example, if a power plant had a breakeven cost of $40/MW-hr, one can assume that it would have been operating whenever the wholesale power price was greater than $40/MW-hr. By summing up the total price paid during all the hours when the price was greater than $40/MW-hr, one arrives at the total gross revenue for the power plant on a per MW of capacity basis. When this calculation is carried out for a full range of marginal operating costs, the result is the set of curves shown in Figure 4.

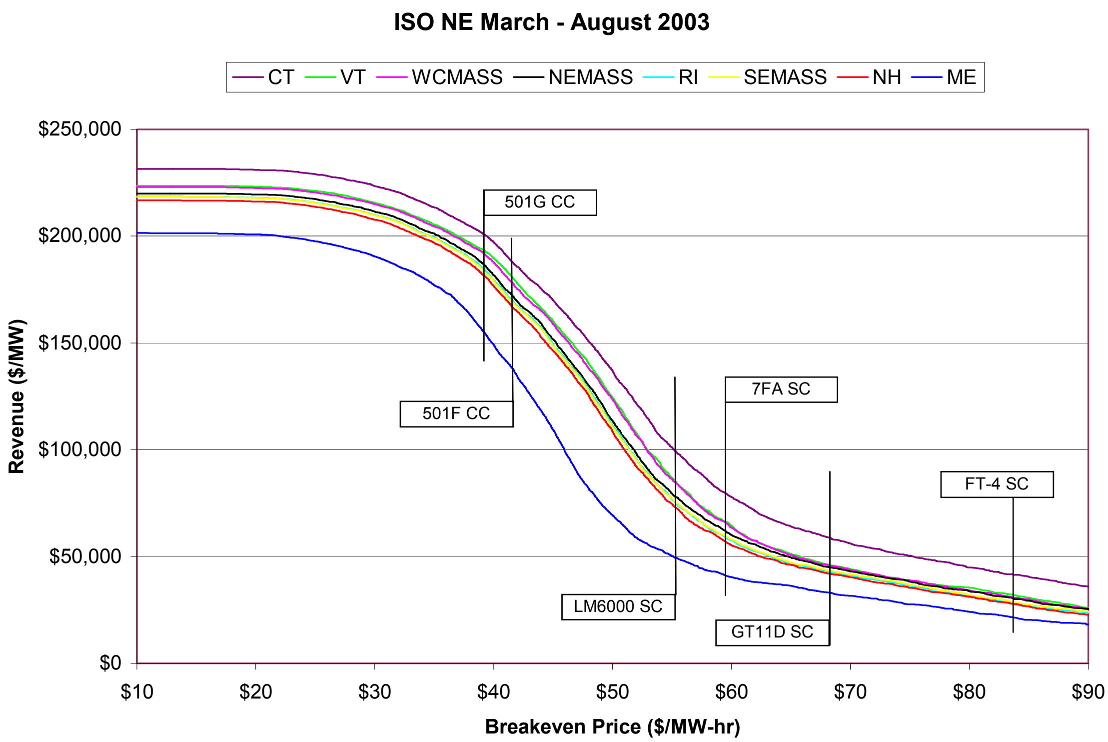

Figure 4 – Gross revenues per installed MW of generation capacity as a function of breakeven price for the eight load zones in New England during the period of March through August 2003.

In addition to the revenue versus breakeven cost curves for each of the eight load zones in ISO New England's market, Figure 4 shows the breakeven price for six different types of gas turbine power plants. These six do not represent specific power plants in New England, but instead represent generic power plants based on different gas turbines. An explanation of the labels used in Figure 4 can be found below:

Label	Plant Description	Heat Rate
501G CC	Siemens Westinghouse 501G Combined Cycle	5884 Btu/kW-hr
501F CC	Siemens Westinghouse 501F Combined Cycle	6354 Btu/kW-hr
LM6000 SC	GE LM6000 Simple Cycle	8600 Btu/kW-hr
7FA SC	GE Frame 7FA Simple Cycle	9340 Btu/kW-hr
GT11D SC	Alstom GT11D Simple Cycle	10,735 Btu/kW-hr
FT-4	Pratt & Whitney FT-4 Simple Cycle	13,300 Btu/kW-hr

It should be noted that the breakeven costs used in Figure 4 are based on an assumed fuel cost of $5.50/MMBtu and a variable operating and maintenance (O&M) cost of $3/MW-hr. The latter is typical of the costs paid to gas turbine OEMs for long-term service agreements. The actual fuel and variable O&M costs of a specific plant may have been quite different during the March through August time frame depending on the fuel and maintenance contracts it had in place. In any event, it is felt that the assumptions made here provide the basis for a valid comparison of the relative revenue potential of different power plants.

Location Matters!

Several conclusions can be drawn from the information in Figure 4. First, plant location matters. Regardless of plant type, if it was located in Connecticut, it received a lot more revenue than a similar plant located in any other load zone. The difference in revenue was particularly striking for the less efficient (i.e., higher heat rate) simple cycle gas turbine power plants. A GE LM6000 simple cycle power plant located in Connecticut would have received approximately $100,000 per MW of capacity (an LM6000 can produce 40 to 49.5 MW depending on its design), while an LM6000 in Maine would have received half that ($50,000/MW).

Even the differences in revenue between locations other than Connecticut and Maine are not trivial, particularly for those units located in the steep portion of the revenue versus breakeven cost curves. For example, an LM6000 located in New Hampshire would have received $73,000 per MW while an LM6000 in Vermont would have pocketed $85,000 per MW.

Efficiency Matters!

The other conclusion to be drawn from Figure 4 is that heat rate or fuel efficiency matters greatly. A fuel hog like a 1960s vintage Pratt & Whitney FT-4 located in Connecticut would have generated less revenue per MW than a highly efficient LM6000 simple cycle located in Maine.

Heat rate (defined as the BTUs of fuel consumed per kW-hr of electricity produced) is the dominant ingredient in the breakeven cost of a gas turbine power plant. Plants with lower heat rates have lower breakeven costs and therefore, get dispatched by ISO New England more often. Heat rate is particularly important for those power plants which have a breakeven cost in the $40-60/MW-hr range as even small changes in heat rate could result in large changes in revenue. For example, if the breakeven price of a 501F combined cycle located in Maine increased by 2% due to less efficient operation, its revenue over the six month period would have decreased by more than $7,000 per installed MW or about 3%. Since a 501F combined cycle typically can produce 250 MW, this means a 2% increase in fuel use would result in a revenue reduction of $1.75 million.

Profits Drive Plant Value

The revenue reduction of $1.75 million due to higher heat rate in the previous example above only tells half the story. Revenues go down because the plant operates fewer hours, but costs also go up because the plant consumes more fuel when it does operate. Therefore, the impact on gross profits (revenues – fuel and variable O&M costs) is even greater on a percentage basis than the impact on revenues alone. For the same 501F combined cycle plant cited earlier, a 2% increase in breakeven costs would result in a drop of gross profits of $2000 per installed MW or 6%.

Fern Engineering has estimated the gross profits that would have been generated by four different types of gas turbine power plants during the first six months of the LMP market. In calculating the results, it was assumed that the plants would have a forced outage rate of 5%, meaning that 5% of the time when the wholesale power price was greater than the plant's breakeven price it could not run because of unexpected maintenance problems. The results of our analysis are summarized in Figure 5 and Table 1.

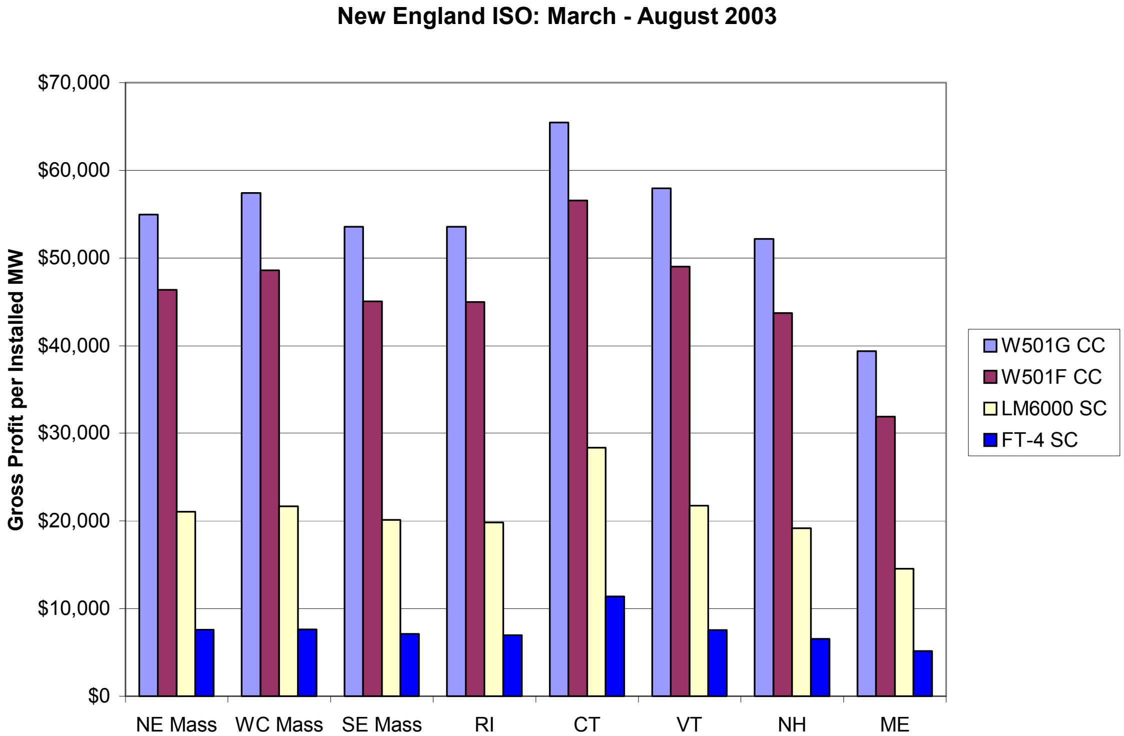

Figure 5 – Estimated Gross Profits of four different types of gas turbine power plants for the first six months of the ISO New England LMP market.

Table 1 – Gross Profits per installed MW for four types of power plants during Mar-Aug 2003.

	NE Mass	WC Mass	SE Mass	RI	CT	VT	NH	ME
501G CC	$ 54,967	$ 57,432	$ 53,578	$ 53,578	$ 65,471	$ 57,952	$ 52,197	$ 39,360
501F CC	$ 46,361	$ 48,602	$ 45,069	$ 44,985	$ 56,571	$ 49,011	$ 43,735	$ 31,897
LM6000	$ 21,038	$ 21,651	$ 20,130	$ 19,818	$ 28,349	$ 21,727	$ 19,162	$ 14,560
FT-4	$ 7,574	$ 7,605	$ 7,121	$ 6,952	$ 11,390	$ 7,530	$ 6,535	$ 5,151

It should be recognized that gross profits do not take into account a plant's fixed costs such as labor, property taxes, insurance and debt service. For new power plants, debt service is by far the largest fixed cost. Consequently, the gross profits of a power plant provide an indication of how much debt load it can sustain. Since many of gas turbine-based power plants in New England have either been handed over to the financing banks or are owned by companies in Chapter 11 bankruptcy proceedings, information on the capability to provide cash flow to cover debts should be of great interest.

Based on the data in Table 1, one can calculate the market value of the different plants relative to the market value of a Siemens Westinghouse 501G combined cycle located in Connecticut (the plant with the highest $/MW gross profits). These relative market values are presented in Table 2.

Table 2 – Relative Market Value on a $/MW-installed basis of four different types of gas turbine power plants.

	NE Mass	WC Mass	SE Mass	RI	CT	VT	NH	ME
501G CC	84.0%	87.7%	81.8%	81.8%	100.0%	88.5%	79.7%	60.1%
501F CC	70.8%	74.2%	68.8%	68.7%	86.4%	74.9%	66.8%	48.7%
LM6000	32.1%	33.1%	30.7%	30.3%	43.3%	33.2%	29.3%	22.2%
FT-4	11.6%	11.6%	10.9%	10.6%	17.4%	11.5%	10.0%	7.9%

The data in Table 2 reveal similar trends to those derived from the revenue curves in Figure 4. Location matters and fuel efficiency matters. A highly efficient 501G combined cycle located in Maine is worth only 60% of a similar plant located in Connecticut, and a highly fuel inefficient FT-4 located in Maine is worth less than 10% of a Connecticut 501G combined cycle.

An obvious question, then, is: how much is a 501G combined cycle plant in Connecticut worth?

It would cost approximately $700,000/MW to build a new 501G combined cycle power plant. If annual fixed costs (excluding debt service) were equal to 5% of the installed cost, this would amount to $35,000/MW-yr. If the gross profits for a 501G combined cycle located in Connecticut were twice the 6-month value shown in Table 2, the annual gross profits would be $130,942/MW-yr. Subtracting the allowance for non-debt-related charges leaves $95,942/MW-yr to service a $700,000/MW debt. That cash flow could support a 20-year loan at an interest rate of approximately 12%. While that seems like a reasonable return on investment, those providing the loan might have a different opinion.

Nevertheless, it can be argued that the value of a 501G combined cycle located in Connecticut appears to be similar to its original cost: $700,000 per MW of generating capacity or $700/kW. If that is true, then a 501F combined cycle in Maine is worth $341/kW, which is more than a third less than it would cost to build such a plant. No wonder so many power generators are filing for Chapter 11.

Biographical Sketch: Jeffrey N. Phillips

Dr. Phillips has been involved in performance evaluation of gas turbines for 20 years. His involvement began with his PhD research in Mechanical Engineering at Stanford University. As part of his thesis work, sponsored by the Electric Power Research Institute, he created a detailed computer model of the process performance of Integrated Gasification Combined Cycle (IGCC) power plants. A portion of this software was later converted into the widely used GateCycle package for design and analysis of combined cycle power plants.

Dr. Phillips then spent 10 years with Shell Oil Company. There he played a lead role in the development of the Shell Coal Gasification Process (SCGP) including the final design, construction, and start-up of the first commercial application of SCGP, a 2000 ton/day gasifier for the 250 MW Demkolec IGCC plant in The Netherlands.

In 1998, Dr. Phillips became a project manager at Fern Engineering where he has served as the lead engineer on a variety of projects including feasibility studies, cycle analysis and design, and in the development and implementation of customized software for monitoring the thermodynamic performance of turbomachinery.

In addition to his consulting duties, Dr. Phillips also provides training on gas turbines to a variety of organizations. His most recent training project was in Adana, Turkey, where he provided a comprehensive 3-week orientation for the operators of a new 100 MW cogeneration plant. Later this year, he will teach an intensive one-day course on gas turbine emission control technologies at the Power-Gen conference in Las Vegas.