Critical Factors Impacting Investment Valuations of U.S. Power Assets

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During the past three years, structural changes in the U.S. power markets have accelerated, rapidly altering the way power assets are valued and, consequently, financed. In this article, we discuss issues affecting the valuation of U.S. power assets and outline new ways to value these assets in the changing U.S. electricity market.

Our perspective on this market comes from being a global energy finance business and a business involved in valuing the types of power assets represented by new merchant plants and new power generation technologies. It is also the perspective of a group in the process of reinventing the way it looks at its world. Financing domestic power has been a core activity for the GE Capital Structured Finance Group since its beginning in the early 1980s. In total, it has participated in more than $20 billion of energy financings and maintains more than a $3 billion portfolio of leases, loans, and equity investments, 80% of which are in domestic power.

In 1997, when the market was beginning to show signs of resurgence, our level of investment was declining not for a lack of opportunity, but because of the difficulties posed by valuing what was becoming an entirely new industry. Record new greenfield merchant plants were being announced, particularly in New England where over 30,000 MW[1] was proposed for a 23,000 MW[2] peak load system. Clearly, some but not all of this new capacity would be built. California and Texas were also hotbeds of activity. Most of the planned additions were gas turbine-based; we understand this technology because of our manufacturing heritage.

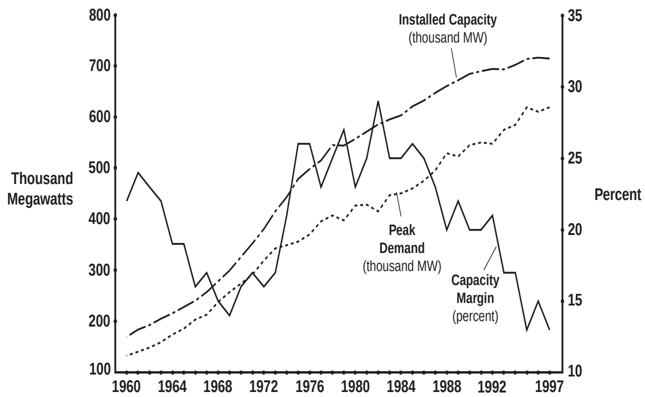
Additionally, a new phenomenon was emerging. Billions of dollars of assets — over $20 billion as of May 1999[3] — were being divested by utilities in preparation for market competition, and at a higher premium over book value than anyone had anticipated. Average sale price per KW is well in excess of $500, and the average ratio of market price to book value is more than 3.0 for the more than forty generation plant sales in the U.S. during the first four months of 1999.[4]

PARADOXICAL MARKETPLACE

This rapidly evolving market presents multiple contradictions. On the one hand, the slow growth in demand for new domestic power plants in the early 1990s appears to be a result of excess capacity. On the other hand, recent record activity levels for new plant development and high sale prices for existing assets suggests a capacity shortage.[5]

After reviewing the past fifteen years of U.S. power supply and demand, we see that peak demand has outpaced capacity additions. In fact, today few U.S. markets have any surplus peak capacity at all. Exhibit 1 compares U.S. installed capacity, peak

EXHIBIT 1
U.S. Installed Capacity — Peak Demand and Capacity Margin



Source: Cambridge Energy Research Associates.

demand, and the capacity margin from 1960 to 1995. Exhibit 2 compares August 1997 actual and summer 2006 projected reserve margins for the New England Regional Cooperative (NERC) region.

The growing scarcity was most evident during the summer of 1998 in the Midwest when shortages caused nightmares for market participants who lacked physical capacity and had relied on weak suppliers. During that period, daily power prices increased from $50 to as much as $5,000 per MWh (the peak hour maximum actually reached $7,500 on June 25, 1998).[6]

A simple, back-of-the-envelope calculation showed that what had been an eight-year payback for a new "peaker" had dropped to much less than a year — potentially less than three days of operation — if one assumes that the plant had a net margin of $5,000/MWh. These high peak prices inspired both new development and drove up the value of existing assets. And, they compelled investors to look deeper at the underlying causes for these unpredictable valuations.

$$\text{Payback} = \frac{\text{Capital Cost}}{\text{Net Margin}} =$$

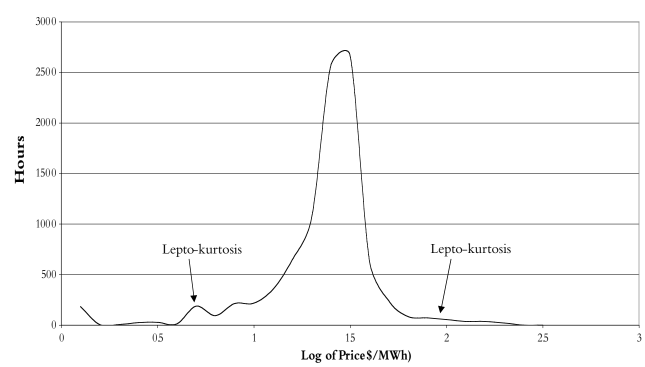
$$\frac{\$250/\text{kW}}{\$5{,}000/\text{MWh}} \times \frac{1{,}000\ \text{kW}}{\text{MW}} = 50\ \text{hours}$$

EXHIBIT 2
Historical and Projected Reserve Margins for North American Reliability Council (NERC) Region with and without Demand-Side Management (dsm)

Region	1997 Reserve Margin (%) with DSM	1997 Reserve Margin (%) w/o DSM	2006 Reserve Margin (%) (projected) with DSM	2006 Reserve Margin (%) (projected) w/o DSM
ECAR	18.5	14.6	14.8	11.1
ERCOT	21	14.4	14.8	8.3
FRCC(S0	20.3	10.9	10.7	1.6
FRCC(W)	16	5.5	5.5	–4.3
MAAC	24.4	18.6	19	13.3
MAIN	18.9	11.8	18.7	9.6
MAPP	21.3	13.4	4.1	–3.9
NPCC	19.7	19.5	10.9	10.6
SERC	15.5	8.7	12.5	6.7
SPP	17.5	12.2	10.1	6.8
WSCC	32.8	27.7	13.8	10.4
AZNM	19.6	15.2	13.4	10.9
NEPOOL	7.4	7	4.2	3.6
U.S. Total	21.2	15.7	13.3	8.3

Clearly, new factors for evaluating domestic power investments had to be identified. To accomplish this, we had to develop a better understanding of supply/demand characteristics and pricing behavior. We concluded that future electricity prices would be mean reverting rather than subject to a random walk, and exhibit leptokurtosis

EXHIBIT 3
California Energy Prices — April 1998 to April 1999



Source: California Px hourly prices, GE Capital.

(or "fat tails"), distribution, characteristic of volatility and the inability to store power.[7]

Leptokurtic behavior is demonstrated in Exhibit 3, a graphic representation of California Energy Prices from April 1998 through April 1999. This statistical concept allows us to better account for the more extreme occurrences, like aberrant power peaks, than a normal distribution with the same mean and standard deviation allows. The resultant conclusions turned out to be central to our understanding of investments in the newly-forming merchant markets for electricity. In addition, it solves the problems posed by traditional production cost models that are unable to price this volatility without significant modification and, subsequently, underpredict asset value.

THREE KEY FACTORS FOR PROFITABLE INVESTING IN POWER ASSETS

We also realized how dramatically different investment decisions in the domestic power market would be going forward from what they had been in the past. Results of our analysis can be summed up as the three keys to success necessary for profitable investing in the new domestic power market.

Going forward, greater consideration will have to be given to these key factors:

1. Structural changes in the power markets and how these changes impact asset valuation and how truly, the devil will be in the details;
2. The increased number of market players and how players' tactics will also influence asset values; and
3. Transaction structuring and how it can and will be utilized to maximize value and protect investment.

Structural Changes Are Impacting Valuations

Throughout the world and now in the U.S., different market structures and rules to sell electricity are emerging. For example, there are seven ways to sell electricity in New England. It can be sold as Energy, Installed Capability, Operating Capability, 10-Minute Spinning Reserve, 30-Minute Reserve, 10-Minute Non-Spinning Reserve, and Automatic Generation Control.[8] As a result, one must understand and model seven different electricity products to properly reflect the value of a power asset.

Once we understand the seven ways to sell electricity in New England, we then have to understand the structural differences between New England and other markets. Not only is there the potential for each market to be structured differently, but each is also evolving at a different pace. Key assumptions include the following:

- Nodal versus Zonal pricing (Nodal pricing is the price at each generator's busbar or interface with the grid and zonal pricing is the average regional price, which many observers believe does not permit markets to function properly);
- The inclusion of start-up and no load costs in variable pricing;
- How much will be imported;
- How many of the planned additions will be built and when; and
- Timing of plant retirements.

All these assumptions have a huge impact. Therefore, having a unique regional view of forward prices in each market and understanding the key assumptions that drive them is essential to making smart investment decisions.

We also have observed that subtle differences in market structures can have significant impacts on asset values, and that these differences can, and have been exploited. In the U.K., for instance, original rules failed to adequately prevent gaming of the capacity market, leading to artificially high prices. In February 1994, in response to the Director General of Electricity Supply, the major generators, National Power and PowerGen, agreed to cap pool prices for two years. And in the ancillary services market in California, limiting the number of competitors to only four resulted in prices initially rising to the four-digit software-imposed cap of \$9999/MWh.[9] Subsequently, the Independent System Operator imposed a more rational price cap of \$250/MWh.

Market participants also are innovatively searching for and finding loopholes to create value. For example, one company outsmarted another — when competing to add a new plant — when it discovered that plants that did not use steam for generation were not required to go through that state's power plant siting process. Thus, by proposing a peaker, the company created an advantage over the competition's proposed combined cycle plant and gained quicker access to the market.

Increased Number of Players and Their Tactics Influence Asset Values

In the process of deregulation, resolution of the stranded cost issue has in part sped up the shift in market power. Many utilities, as a quid pro quo for stranded cost recovery, have agreed to sell their generating assets in order to rapidly foster competition.

Consider USGen's acquisition of the NEES assets (Dymond and Sturges [1999]) or Sithe's acquisition of the BECo assets, or their recently announced acquisition of the GPU assets. The acquirers have emerged with up to 20% market share in various regions — USGen's 4,000 MW (20%) in NEPool[10] and Edison Mission Energy's acquisition of ComEd's 10,000 MW (20%) in MAIN.[11] As this trend continues, behavior of these new and sizeable market participants will materially impact asset values.

Previously, in determining the value of a power asset, investors looked at the economics of a power sales agreement. If there was no PPA, or if you wanted to assess the plant's viability in the event that the contract was terminated, you would run a production cost model to determine how often the plant would run, and at what price. This type of analysis assumed receiving the marginal cost of the least efficient unit in the system on an hourly basis. The model sought to optimize the grid with the objective of minimizing dispatch costs, subject to transmission and stability constraints.

This type of model still holds for valuing assets in today's market, but with one major, vastly different constraint. It now assumes that market participants will bid prices from each of their plants that maximize the profitability of their entire portfolio, not just that of each single asset. While the effect of this may be somewhat dampened in a market with regional pricing, its effect can be quite significant on a nodal or locationally priced market.[12]

Not only can differences in market structures be subtle, but player behavior can be subtle too. Consider these two examples:

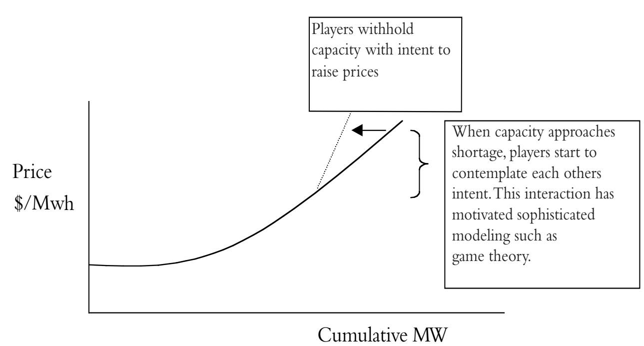
- First, the power market is one of the only markets in the world where adding additional supply is capable of actually raising prices. Recently, a news report indicated that a power marketer overscheduled a transmission line apparently to cause congestion. When the electric grid was congested, prices rose 2x as the system operator had to tell certain plants not to generate while other, more costly units were called into service to maintain a stable grid.[13]
- Second, not all players who have market power will use it to increase prices. Subsidies for must-run units or continued recovery in rate base may temper pricing behavior.

Let's examine our first example of new economic behavior in more detail. Historically, the dispatch of uneconomic units was justified to maintain electric grid stability and reliability. Today, players whose portfolios of generating assets have differing economics seek to maximize profitability, which provides incentives to behave differently. For example:

- Most industries can withhold capacity to raise prices. Consider a base load portfolio with some peakers — holding back some of the lower cost, peaker capacity within the portfolio can raise the overall price as delivered to the grid.
- Alternatively, unlike the case in many other industries, a generator can cause transmission congestion (as in the California case cited previously), which forces the commitment of less economic, typically better electrically situated (location-advantaged) generation to maintain stable loop flow on the grid.

The electric power supply curve in Exhibit 4 illustrates an example of players withholding capacity with the intent to raise prices and then starting to contemplate each other's intent when capacity approaches shortage. This interaction has motivated sophisticated modeling such as game theory.

EXHIBIT 4
Illustrative Electric Power Supply Curve



When considering behavioral shifts, another new development is the emergence of the power marketer or perhaps, more appropriately, the trader. This development is somewhat of a wildcard for investment decisions. Although most investors would prefer to invest in projects with a contract or tolling agreement, the jury is still out regarding the creditworthiness of many of these new players. Their lack of creditworthiness in some instances means that upside may be traded without achieving adequate downside protection.

To date, more than 420 of these power marketers have been formed.[14] Several have failed, while others have exited and investors have suffered financial losses in the shakeout. *Power Markets Week* recently reported that 137 marketers had traded more than 1MWh in 1Q 1999 and that the top twenty marketers traded more than 80% of the market.[15] This consolidation trend is expected to continue with the only surviving players being those who have the financial strength and scale necessary to be best in class. Ultimately, we expect this Darwinian process will have a positive impact on the role of traders in the market.

Adapting Transaction Structures for this Marketplace

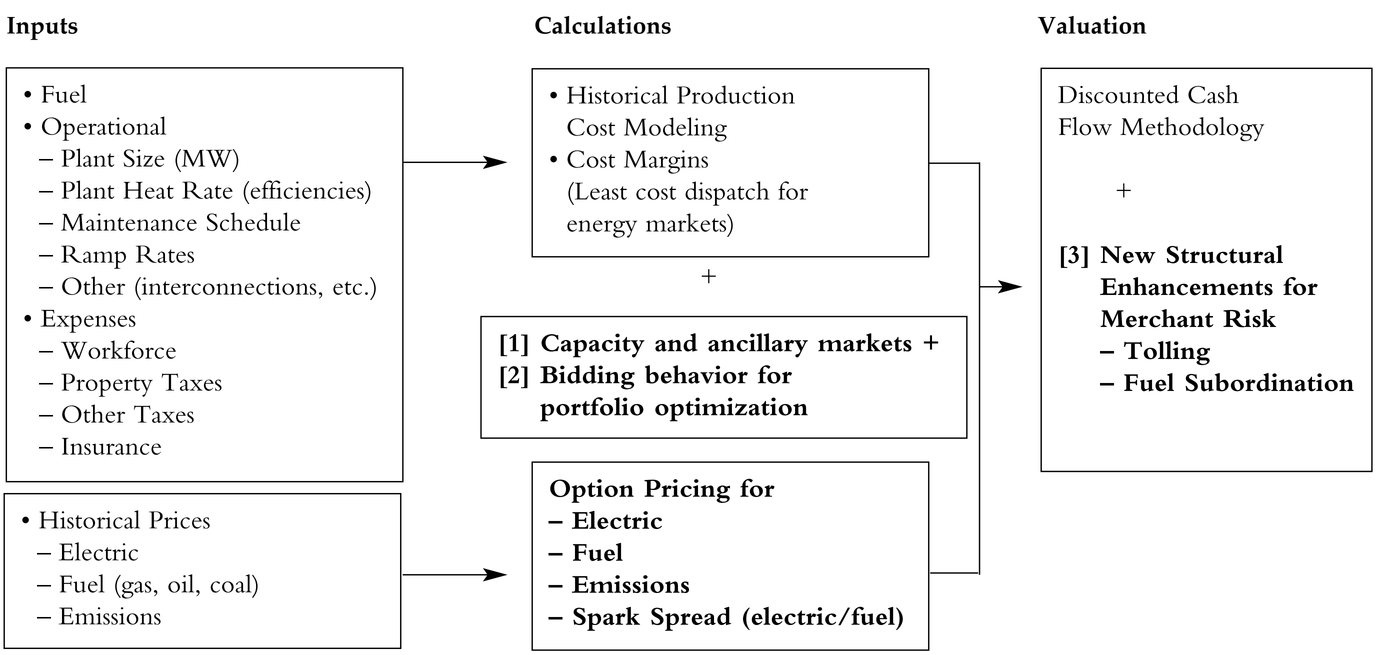
We already have seen a number of innovative financial structures utilized in the new domestic power market. First, tolling agreements have emerged in lieu of contracts as a way of removing commodity price risk from owners and investors, leaving them with operating risk which they are more able to understand and control. For example, Williams and AES utilized a tolling structure on the Southland and Ironwood transaction,[16] and PECO and Tenaska utilized one on the Frontier transaction.[17] Again, the key element in evaluating a tolling transaction is the creditworthiness of the commodity marketer.

Second, fuel subordination structures also have been utilized to minimize commodity price risk. Under these structures, fuel suppliers subordinate all or a part of their payment to lenders, effectively becoming additional equity in a transaction, thus allowing for increased debt. EMI incorporated this structure on a recent greenfield project in New England.[18]

And finally, corporate finance and project finance structures have been married for added flexibility. The

EXHIBIT 5

New Inputs to Historical Power Asset Valuations (in bold)



Bear Swamp transaction recently completed by USGen[19] is an example of this. While the transaction is secured by the asset, the lease payment is dependent upon the entire performance of the NEES portfolio.

Although innovative transaction structures can help, they can't replace a rigorous understanding of the factors that determine asset value. And, recently announced asset sale prices have only added to the confusion. When essential, must-run plants are sold for $100 per kW in one region, while at the same time, poorly sited plants are sold for $700 per kW in another, more is at work than just innovative structuring. Some buyers must be getting a bargain, while others will be in for a loss.

FOUR NEW PRINCIPLES THAT DRIVE POWER ASSET VALUE

In order to navigate these uncertain waters, our research has led us to identify four principles that drive power asset value:

- ***Like real estate, location, location, location.*** Siting advantages always will have value, particularly where they include access to constrained fuel or transmission. Over time, these advantages can diminish, for example as new transmission gets built, but in today's not-in-my-back-yard environment, this is usually a prolonged process.
- ***Size matters.*** Having significant portfolio size can help generate and protect profits. The number of MWHs controlled in a given market allows for bidding block advantages and greater capability to maximize the options market. Additional economies of scale can be captured in fuel procurement and operating costs.
- ***Potential for top line growth.*** Repowering or expansion of existing permitted sites can offer significant top-line growth, and finally, if one cannot get it from the top line.
- ***Reduce costs to improve the bottom line.*** Technological advances resulting in increased fuel efficiency and improved operating and maintenance procedures allow for significant cost savings from older plants.

In summary, there are three key determinants of a successful investment strategy: 1) thorough understanding of evolving market structures; 2) powerful, predictive modeling to anticipate player tactics; and 3) flexible utilization of innovative transaction structures. A successful investment strategy brings with it additional, broader benefits: if investors can make money, then new capital will flow, allowing market players to produce more electricity more efficiently. Electricity customers will benefit through lower cost and the promise of deregulation will be realized.

ENDNOTES

[1]ISO New England Inc. Web Site — http://www.iso-ne.com, Interconnection Studies, May 24, 1999.

[2]NEPool Forecast Report of Capacity, Energy, Loads and Transmission, 1999-2008, April 1, 1999, p. 1.

[3]"Americas Report." *Project Finance International*, May 1999, p. 7.

[4]Ibid, note 3.

[5]EEI Divestiture Action & Analysis Newsletter, May 1999, Announced Sales Table. See Makovich [1998].

[6]"Daily Prices Soar to $4,900/MWh Range in Reply to Heat Wave, Marketer Default." *Power Markets Week*, June 29, 1998, p. 1. *Daily Energy Notes*, McGraw-Hill, January 21, 1999, p. 3-14. See Makovich [1998].

[7]See Pilipovic [1998].

[8]Ibid, note 1.

[9]"Advisory Panel Recommends FERC Let Calif. ISO Keep Ancillary Price Caps." *Power Markets Week*, August 24, 1998, p. 10, and "FERC Urged Not to Revoke Market Pricing for Calif. Ancillary Services," *Power Markets Week*, September 14, 1998, p. 9.

[10]Ibid, note 4.

[11]"Edison Mission to Pay $4.8-Billion for ComEd's Fossil-Fueled Generating Assets of 9,772 MW." *Electric Power Daily*, March 24, 1999, p. 1.

[12]Ibid, note 1.

[13]See Hogan, GE MAPS Users Conference [1998, p.1]. "California PX Prices Spike Above $50/MWh as 18-kv Silver Peak Line is Overbooked." *Electric Power Daily*, May 26, 1999, p. 3.

[14]Power Marketing Association Directory of Power Marketers, December 31, 1998.

[15]"Power Marketers Ranked by Sales." *Power Markets Week*, May 17, 1999, p. 10.

[16]"Power Deal of the Year, AES Southland." *Project Finance International 1998 Yearbook*. "CSFB AES primary over," PFI, June 3, 1998. "AES Tolls Ironwood." *Project Finance International*, February 24, 1999, p. 29.

[17]"Tenaska Closes." *Project Finance International*, December 16, 1998, p. 31.

[18]"Boom Times for U.S. Merchants." *Project Finance International*, February 24, 1999, p. 31. Also, *Project Finance International* Yearbook 1999, p. 89.

[19]"USGen's Innovative Power Sale and Leaseback." *Project Finance International*, December 16, 1998, p. 25.

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