US POWER GEN
A Primer on the Power Generation Business
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Industry Profile

With nearly 900,000 MW of installed generating capacity, the $250 billion-a-year U.S. electricity industry is by far the largest power system in the world. China, with the second largest national electric system, has about 340,000 MW. Today, the industry is a patchwork of more than 3,000 public and private entities operating in regional markets, linked by connections with various capacities. The industry includes about 100 investor-owned power companies, over 2,000 public power systems, nearly 1,000 consumer-owned rural electric cooperatives, and a growing number of financial sponsors.

Interconnections and Regional Markets

For reasons related to the historical development of electric utilities, the North American power system consists of separate regions with limited interregional electricity transfer capacity. The U.S. power system comprises three distinct power grids (or “interconnections”), which also include smaller groupings or power pools. The grids consist of extra-high-voltage connections between individual utilities and non-utility generators designed to permit the transfer of electrical energy from one part of the network to another. As shown in Figure A1.1, the three networks are the Eastern Interconnected System, consisting of the eastern two-thirds of the U.S.; the Western Interconnected System, serving the Southwest and areas west of the Rocky Mountains; and the Texas Interconnected System (also, known as “ERCOT”). Each of these interconnections operates synchronously, as connected AC machines have to do, and each can be thought of as a single machine composed of many connected generators. The three interconnections are independent, in the sense that they are not synchronized with each other, and have only limited DC ties. Both the Western and Texas Interconnects are linked with parts of Mexico. The Eastern and Western Interconnects reach northward to include the electrical grid in the adjoining parts of Canada. These two interconnects also have DC links with the Quebec Province power grid, which is a separate synchronous interconnection, and the fourth of the major North American interconnections.
In 1996, the Federal Energy Regulatory Commission (FERC) deregulated portions of the electric power industry, and set forth several principles to assure market participants open and fair access to transmission systems; facilitate market-based, wholesale electricity rates; and ensure effective management and operation of the bulk power system in each region. In the late 1990s, free market competition was new to the U.S. electric power industry, and deregulation evolved in a patchwork fashion as individual states and regional markets implemented divergent market models with differing commercial rules.
The competitive power supplier share of installed capacity has increased five-fold in five years, rising from just over 70,000 MW in 1997 to about 383,000 MW in 2002. During 1997-2002, competitive generation and cogeneration (including combined heat and power) has grew from 8.5 percent of total U.S. capacity in 1997, to 39 percent of the total in 2002. (Source: EIA Electric Power Annual 2003)

A Cyclical Industry

The domestic power generation business has characteristics of a classic cyclical industry with long (12 to 15-year) cycles moving through four phases: Boom→Recession→Depression→Recovery. As first defined by Nobel Prize winning economist Joseph A. Schumpeter, a boom is a rise which lasts until the peak is reached; a recession is the drop from the peak back to the mean; a depression is the slide from the mean down to the trough; a recovery is the rise from the trough back up to the mean. From the mean, we then move up into another boom and thus the beginning of another four-phase cycle. We believe the generation sector now
is at, or near the depression-recovery inflection point in a cycle with the following general dimensions:

<table>
<thead>
<tr>
<th>Phase</th>
<th>Years</th>
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<tbody>
<tr>
<td>Initial Boom</td>
<td>1995-1999</td>
</tr>
<tr>
<td>Recession</td>
<td>2000-2002</td>
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<tr>
<td>Depression</td>
<td>2003-2005</td>
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<tr>
<td>Recovery</td>
<td>2006-2010</td>
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The latest construction spree began in the late 1990s and hit full stride in 2002, just as the electricity market softened due to the economic downturn and as public misgivings about continued energy-market deregulation crested. In the continental U.S., nearly 200,000 MW of new generating capacity—the equivalent of 400 big power plants—has been added since 1999. This construction wave increased our domestic capacity to supply electricity by nearly 25% while demand for electricity continued to grow at its historic slow but steady rate of about 1.5%-3.0% annually.

The Economics of Merchant Power Generation.

In a competitive wholesale power market, the market clearing price of electricity is established by the last power plant employed (or “dispatched”) to meet the demand at a point in time. Generally, the sequence in which the power plants in the market are called into service depends upon their respective availability and operating cost, with the least expensive units dispatched first. As the demand for electricity changes during daily and seasonal peaks, the last plant dispatched varies as supply and demand is matched. As long as existing generating capacity can supply power demand, competition among the owners of underutilized power plants will tend to drive power prices down to the short-term marginal cost (SRMC) of production, equivalent to the variable cost of operation of the least efficient unit to be dispatched.

Because incrementally higher-cost units are dispatched only as necessary to meet daily and seasonal increases in demand, the operating hours of each class of generator differ markedly. Reflecting their extremely low variable costs, nuclear plants operate practically continuously (being taken off line only as required for maintenance, refueling and unscheduled outages). Referred to as base load plants, these generators supply that component of demand that is invariable 24 hours a day, 365 days a year. Coal-fired steam plants serve a similar function, although they tend to have higher down time for maintenance and may be taken off line occasionally, as demand dips during night or weekend hours.
Currently in the U.S., the least efficient units generally are simple-cycle gas or oil-fired (SCGT) and combined-cycle gas turbines (CCGT). Across the domestic gas-fired generating fleet, plants range from 30 year old facilities with inefficient heat rates above 10,000 Btu/kW to new CCGTs with highly-efficient 7,000 Btu/kW heat rates. Compared to nuclear and coal plants, CCGTs have much higher variable operating costs and, therefore, are dispatched mainly during on-peak hours, generally from 7:00 a.m. to 11:00 p.m. during the working week, or some 16 hours a day, five days a week. SCGTs have the highest variable cost of operation and therefore enter operation only during seasonal peaks in demand. These generally occur during the summer when air-conditioning drives up the demand for power, and in winter, when heating has a similar effect.

Today, the power industry uses coal to produce more than half the nation’s electricity. By a rough calculation, it costs about $23 in operating costs to make a megawatt hour of electricity from Eastern coal compared with $42 to $44 for a megawatt hour of electricity from a modern gas-fired plant.

In certain regions such as New England, Texas and California, gas-fired generators are the marginal, price-setting facilities most of the time. In other regions such as the Midwest, underutilized coal-burning facilities with lower short-run marginal costs (SRMCs) than gas-fired generators are usually the marginal units. A principal focus of USPG’s merchant plant investment strategy is the acquisition of new CCGTs in regional markets where gas-fired generators are the marginal units most of the time. In addition to the capital appreciation expected with the purchase of such units at a fraction of their replacement cost, USPG expects that as reserve margins begin to trend down, these new CCGTs should experience increased profitability as less efficient power plants are called into service. If spark spreads increase, which is a reasonable assumption as markets tighten, the profitability of new CCGTs should be further enhanced.

When electric demand growth absorbs excess generation capacity and reserve margins fall toward the 15% level, the dynamics of power pricing change radically. To induce the construction or acquisition of new capacity, the price of electricity must rise to a level sufficient not only to cover variable operating costs, but also to recover the capital invested in the procurement of new power plants. In economic terminology, the combined operating and capital cost of a new power plant, calculated on a per MWh basis over the useful life of the plant is known as the long-run marginal cost (LRMC). Therefore, estimates of the LRMC of a new power plant are sensitive both to the projected variable cost of operation and the cost of recovering the capital invested in its construction.

As demand grows each year, the percentage of hours that demand will be
above the current peak will increase, causing previously idled plants to be dispatched. Therefore, average price of electricity will rise as more expensive units are dispatched for longer periods of time, increasing the spark spreads for all the units lower on the supply curve.
Power Market Basics

**Demand.** Since 1975, the annual average growth rate in demand for electricity in the U.S. has been about 2.9 percent. Electric demand is correlated with growth in the nation’s Gross Domestic Product (GDP). For every one percent increase in GDP, electricity demand generally grows by about 0.7 percent. About 15,000 to 20,000 MW of new generating capacity is needed each year to supply organic growth in U.S. demand for electricity. Figure A1.3 depicts the electric demand growth in the U.S. since 1970.

**Figure A1.3:** U.S. Electric Demand Growth (1970-2003)

![End Use – Retail Sales](image)

Source: U.S. Energy Information Administration

**Supply.** While demand for electricity grows steadily over time, supply grows through the construction of new power plants which add step (or, “lumpy”) increments to installed generating capacity. Depending on the technology, the capacity of most new power plants ranges from about 50 to 1,000 MW. The planning, siting, permitting, construction and commissioning of a new generating facility takes from two to ten years and is very capital intensive. As Figure A1.4 shows, industry-wide expansion of generating capacity tends to be cyclical, and only imperfectly mirrors demand growth. As a case in point, during the decade of the 1990s, a construction lull added only about 17,000 MW of new capacity in the Western Electricity Coordinating Council (WECC) region. Then, during the five-year construction boom beginning in 1999, over 40,000 MW of new capacity
was added in the region. In 2003 alone, nearly as much new generating capacity was added in the WECC as had been during 1991-2000. While the U.S. still has significant excess generating capacity, new supply additions peaked in 2002, and now should decline through 2007.

Figure A1.4: U.S. Electric Supply Growth (1970 – 2008E)

Reserve Margin. The critical relationship between a power market’s electric demand and supply often is expressed in terms of the “reserve margin”, which is the amount of unused available generating capacity at peak demand (or, “load”) as a percentage of total installed capacity. A reserve margin of about 15% generally is regarded to be the optimal level to assure system reliability while protecting customers from an unacceptable number of service interruptions, and protecting investors from the costs of over-building. As Figure A1.5 shows, the reserve margin tends to move through long cycles reflecting the imperfect matching of gradual demand growth and lumpy supply additions. On a national basis, the reserve margin topped 40% in the early 1980s, dropped below 10% in the late 1990s and climbed back to about 30% as a result of the recent construction boom. The reserve margin trend reflects the fact that cumulative generation additions fell behind cumulative load growth during the decade of the 1990s. Reserve margins should decline in 2005 for the first time since 1999, perhaps to about 25%, but still will be well above the “equilibrium” level of about 15%, which may not be
attained until the end of the decade. A market’s reserve margin is an important determinant of short- and longer-term electricity prices, as well as the level of volatility in those prices.

**Figure A1.5**: U.S. Reserve Margin (1970 – 2003)

**U.S. Electric Supply Reserve Margin**

Source: Cambridge Energy Research Associates

*Price Spikes and Volatility.* Electricity price spikes are the result of the fundamental supply and demand balance in regional markets. Figures A1.6 and A1.7 show that as reserve margins tightened in northeastern and southern markets in the late 1990s, huge spikes in electricity prices occurred in each region. In the summers of 1998 and 1999, when reserve margins fell below 10%, wholesale markets became prone to the effects of sudden shifts in bidding strategies. Sellers switched from their typical marginal cost-based bidding system to bids reflecting what the market would bear.

While tight reserve margins have been the single most important factor leading to extreme power price spikes, other factors such as abnormal weather and flawed market structures also contribute to the frequency and magnitude of spikes. Retail price caps are one example of a structural flaw that can significantly impact wholesale price levels and volatility. These caps disconnect wholesale prices from retail prices, so when wholesale prices move up, few retail customers see price increases and therefore do not respond by lowering demand. In economic terms, electric demand is inelastic.
With on-peak prices shooting above $1,000 per MWh in several markets, the spreading price boom of the late 1990s sent strong signals for new power supply development. A massive building cycle was triggered among power plant developers and the supply response far exceeded growth and replacement needs in most regional markets. As new generating capacity is added in a region, the demand and supply balance is loosened and market clearing prices decline and volatility is dampened. In addition, new power plants are more efficient than at least some existing plants. This means that more efficient, lower-cost plants become the marginal units, which usually leads to lower power prices.

**Figure A1.6**: Electric Price Spikes and Volatility in Northeastern Markets
As previously noted, demand for electricity varies during the day and across the seasons, and individual power plants have widely disparate variable operating costs. As the marginal facility is dispatched, the price of electricity is set by that unit’s short run marginal cost (SRMC). The price duration curve for a market is a useful tool for conceptualizing how often different price thresholds were reached, and therefore, how often different types of generating plants were dispatched. Figure A1.8 shows New England’s annual price duration curves for 2000-2003.
Regional Generation Stack. A region's generating capacity can be aggregated and depicted by individual power plants arranged in order of increasing variable operating cost for each unit. This so-called “generation stack” shows the order in which individual plants would be dispatched, assuming they are available. Figures A1.9 and A1.10 show characteristic stacks for NEPOOL and ERCOT, and demonstrate the point that baseload nuclear and coal facilities have the lowest operating costs, CCGTs tend to fall in the middle of the stack, and peaking units are the most expensive units to operate. A comparison of a region's price duration curve and generation stack provides an indication of how frequently a unit is likely to be dispatched. If generating capacity remains constant, then as demand tightens, and power prices increase, power plants with higher operating costs are called into service. If demand is held constant, then as new supply is added, power prices will tend to fall and existing units with higher operating costs will be taken out of service.

Figure A1.8: NEPOOL's Price Duration Curve
Figure A1.9: NEPOOL's Generation Stack

Figure A1.10: ERCOT's Generation Stack
Wholesale Electricity Trading

Like any commodity market, the wholesale electricity market establishes a price for its commodity—electricity—by matching supply and demand. The marketplace consists of buyers and sellers whose bids and offers determine a price at which supply is willing to produce electricity and demand is willing to consume it. Unlike other commodities, however, electricity cannot be stored and therefore must be produced at nearly the same instant it is consumed, requiring a continuous and instantaneous balancing of supply and demand.

In a wholesale electricity marketplace, generators offer prices and quantities of electricity supply they are willing to produce and schedule. At the same time, demand bids the maximum amount it is willing to pay for the anticipated amount to be used. The interaction of these offers and bids ensures that the right amount of power is produced and consumed at an economic price. Establishing this “market price” provides the basis for trading and competition among participants in the market. When supply is tight, prices go up, inducing suppliers to produce more and consumers to use less. When supply is plentiful, prices go down, resulting in less production and normal consumption levels.

Second-quarter 2004 wholesale power sales, as reported by more than 250 companies to the Federal Energy Regulatory Commission, were down 10.3% from 2003 totals for the comparable period. For the first half of this year, 2.79 million MWh have been sold, an 11.5% decline from the first half of 2003. Much of the falloff can be attributed to the steady pull-back of former key players.

A changing of the guard is in progress. Three former top-ranked participants—American Electric Power Service Corp., Duke Energy and affiliates, and Reliant Energy and affiliates—continue to see significant declines in wholesale sales, while the new top-tier players, Constellation Power Source and affiliates, Morgan Stanley Capital Group, Exelon Power Team and affiliates, and Calpine and affiliates have not yet been able to pick up the slack.

Constellation Energy was North America’s top wholesale power seller in each of the first two quarters of 2004. Morgan Stanley was ranked second for their first half of 2004. Other large financial institutions are also playing an increasingly prominent role among wholesale power market participants. In the second quarter of this year, Goldman Sachs’ trading operation, J Aron, saw its power sales increase 68% over a year ago. Goldman is also invigorating the trading arm of Cogentrix, which Goldman bought late last year. Cogentrix Energy Power Marketing and affiliates sold 242,637 MWh in Q2 ’04, an 82.8% increase over Q1 ’04, and a 4,909% increase over Q2 ’03. Another financial group, UBS Warburg
Energy LLC, saw its Q2 ’04 totals jump 74.7% compared with the year before. Its first-half 2004 sales versus first-half 2003 were up 101%. Merrill Lynch also is planning to re-enter the sector once it completes its announced acquisition of Entergy-Koch LP.

Among traditional wholesale market players, increased activity was posted in the first half of 2004 by Exelon, Sempra and Calpine. Declining sales were posted during the period by former big players El Paso, Allegheny Energy Supply and Williams Power.