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INDEPENDENT POWER PRODUCERS

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RATING: HOLD

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Investment Conclusion

Independent Power Producers face a challenging economy in the short term. We believe the market has priced much of the uncertainty into most of the companies in the short term, as the companies are trading at discounted multiples in comparison to the S&P500. Although much of the pessimism has been priced into the stocks, we do not see any positive drivers in the near term to believe these issues will outperform the market. Therefore, we are initiating coverage on the sector with a HOLD rating.

Some of the issues in today's environment that lead us to our investment conclusions are:

- Energy demand grows with the economic growth. The economy has shown no signs of a recovery and there remains too much uncertainty over the coming quarters. While analysts project double-digit growth rates for the near to intermediate term, we do not believe that generating companies can sustain these rates in the long term.
- Natural gas supplies have increased due to capital expenditures in late 2000 and should continue to increase, placing downward pressure on natural gas prices making electricity relatively inexpensive.
- Combination of an increase in electricity supply and a decrease in demand will hurt the sector.

- Remains uncertainty as to the collection of receivables owed to IPP's by the now bankrupt California utilities.
- Political issues with deregulation have surfaced with the California crisis and have to be resolved.

The uncertainty associated with the economy plays an important role in our investment decision. The Federal Reserve has recently cut another 50 basis points, which makes a 350 basis point cut since the beginning of 2001. This could be the impetus to turn the market around. If capital spending increases before the end of the fourth quarter, this could significantly drive demand for electric power. At this point we have seen no signs of a bottom in this declining economy, so we remain neutral on the sector.

Overview

The electric power industry is generally divided into three functions – generation, transmission, and distribution. Amongst the generators are the IPPs (independent power producers) and utilities which are ISOs (independent system operators), public, co-ops, or federal. In the U.S., there are three major power grids. RTOs (regional transmission organizations) and ISOs (subset of the regions) control the grids. Other players in the industry are power marketers that do not own generation, transmission, or distribution facilities. Hybrids such as Enron both own some generation assets and trade power.

Electricity is generated by any of the various sources such as water, nuclear power, coal, natural gas, and oil. It is then transmitted from these power plants to the local distribution systems that deliver to the retailers. The transmission networks, or the power grid, operators essentially switch different parts of the power grid on or off based on the continuous ebb and flow of supply and demand.

Recent Developments

The deregulation of the power industry has brought about several developments. First, an explosion of participants in power generation has led to increased activity in mergers, acquisitions and divestitures. The rationale behind the mergers is that these power producers can improve the economies of scale as well as increase the generation capacity. Divestitures are also becoming equally common as Order 888 mandates that vertically integrated utilities divest the generation assets in order to open up the transmission grid.[1]

The result of FERC Order 888 has essentially created alternatives for the investment community. Investors who seek high growth turn to generating companies (gencos). Those seeking low growth or income turn to transmission companies (transcos) and distribution companies (discos) that normally pay out dividends to shareholders. Although discos still exhibit characteristics of a monopoly market, transcos are undergoing an embryonic stage in the restructuring process encouraged by the FERC Order 2000. Should competition be opened up to transcos, the companies might become attractive high growth investment alternatives.[2]

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[1] www.eia.doe.gov/cneaf/electricity
[2] The Changing Structure of the Electric Power Industry. http://www.eia.doe.gov/cneaf/electricity/chg_stru_update

A second development is that the free market mechanism has led to the emergence of power exchanges and trading hubs. Power exchanges such as PJW ISO, NY ISO, and the California Exchange are places where IPPs must submit their bids in order to sell power in defined regions. Alternatively, trading hubs like NYMEX are free marketplaces where other firms come together voluntarily to trade.

A third issue is that the problem of power outages following de-regulation in California has brought about re-regulation in the form of price caps. With limits placed on spot prices, the stock prices of generators, marketers, and traders have been declining. Traders such as Enron particularly profit from wide spreads in volatile markets.[3]

A fourth development is that the recent power outages have led utilities to revisit demand-side management (DSM). In order to encourage retail customers to spread their usage across different times during the day, incentives have been created to shift demand from peak to off-peak.

Finally, the adoption of retail choice by different states is currently underway. Texas is the only non-FERC-regulated state. It began the Pilot Program in June 2001 to unbundle power services. Other states followed. Pennsylvania is the first state to completely phase in retail choice. Texas will follow in 2002.

Regulatory timeline

- The Federal Regulatory Energy Commission (FERC) was created through a Department of Energy Act on October 1, 1977.
- 1992 -FERC encouraged new projects.
- 1996 - Unbundling of components & wholesale trading was allowed.
- 1999 – RTOs were established:
    - to enhance transmission reliability;
    - to safeguard open access for customers.

Changing Industry

The face of the electric power industry has changed and will continue to change with further deregulation. The industry is no longer made up of monopolies that generate, transmit, distribute and sell power. Now the industry consists of companies that compete in the generation and trading of power as a commodity. The changes have given rise to a class of competitive power suppliers. It is anticipated that at the end of 2001, 25 percent of the nation's power generating capacity will be owned by competitive power suppliers.[4]

Since the early 1990's, increased competition has become a major characteristic of the power producing industry. A combination of low natural gas prices, emerging information and control technologies, and the emergence of efficient modular generation technologies have driven the

[3] http://www.energy.ca.gov/ California Energy Commission
[4] www.eia.doe.gov U.S. Electric Utility Demand Side Management

increased competition. Regulatory changes such as the Energy Policy Act of 1992 has facilitated competition. The industry is changing and the following trends have been recognized in the past several years.

Utilities divesting power generation assets. In April 2001, total U.S. net generation of electricity was 333 billion kilowatt-hours (kwh). Competitive power suppliers generated 82 billion kwh, or 29 percent of total generation. Since 1997, a total of more than 118,000 MW of utility generation capacity ($22 billion) has been or is scheduled to be sold to competitive power suppliers. In 1999, approximately 50,000 MW of electric utility generating assets were purchased by non-utilities.[5]

Independent power producers gaining market share. Non-utility capacity in 1999 was 19.8 percent of the total industry capacity. The total installed capacity of non-utility generating facilities was 167,357 MW at the end of 1999, 70.6 percent more than in 1998. Twenty-one percent of the increase represented new plants. As of August 2001, competitive power suppliers also have announced the potential development of about 300,000 MW in proposed merchant power plant capacity to be completed by 2007.[6]

The top 10 wholesale marketers, by market share, for the year 2000:

Enron	13.03%
American Electric Power Service Corp.	8.86%
PG&E Energy	6.24%
Duke Energy	6.10%
Reliant Energy	4.51%
Mirant	4.47%
Aquila Energy Marketing	4.12%
Cinergy	3.67%
Constellation Power Source	3.58%
Williams Energy	3.05%

(source: Power Marketer Sales Statistics, McGraw Hill, March 12, 2001)

Industry Change Drivers

For the first time in 1992, generating capacity added by independent power producers exceeded capacity added by traditional electric utilities. Three factors have contributed significantly to the restructuring of the power producing industry.

- **Demand by large commercial and industrial customers for lower prices.** If customers gain access to the wholesale power markets, consumer prices will be lower.

[5] McCann, Justin. Industry Undergoing Change. Standard & Poors. August 2001.
[6] EIA Electric Power Monthly July 2001

For most utilities, the embedded costs of generation built into their rates exceed wholesale spot prices. Across most utilities the differentials in generation costs varies significantly.

- **Implementation of the Energy Policy Act of 1992.** EPACT provided Federal regulators the authority to order utilities to provide transmission access for the purpose of facilitating competition in wholesale power markets.[7]

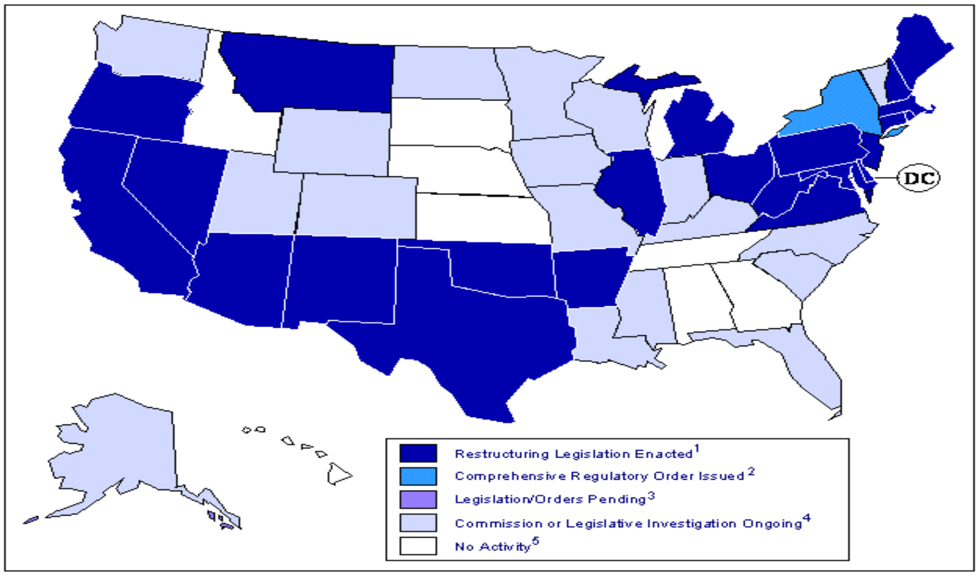
- **Based on economics, the idea of competitive markets should produce economic efficiency**. Privatization of electric utilities has been successful in the United Kingdom, Norway, New Zealand, Australia, and Argentina. The restructuring of other industries such as natural gas and telecommunications in the United States has also proven successful.[8]

According to a study conducted by the EPSA, competitive markets contributed to a 36 percent decline in retail electricity prices among surveyed utilities. The decrease is in sharp contrast to the increases that consumers experienced in the days of solely cost-plus rate regulation. In the days of cost-plus regulation between 1970 and 1985, inflation-adjusted electricity prices increased 25 percent for residential customers and increased 86 percent for industrial/commercial customers. During the start of the deregulation period from 1985-1999, inflation-adjusted electricity prices decreased an average 30 percent for residential customers and 36 percent for industrial/commercial customers. With the recent turmoil in California, more people have questioned the move away from cost-plus rate regulation. The study enforces the notion of further deregulation and a move toward more efficient wholesale markets. States should continue to move quickly toward opening their retail power markets, and Congress should quickly adopt comprehensive legislation to help them along.[9]

In Illinois, nonresidential customers have been free to choose a supplier since December of 2000. Residential customers will be free to choose at the beginning of May 2002. Unlike California, Illinois is actively involved in new independent power producer generation. More states are moving to ensure that their systems and suppliers will facilitate the smooth transition to retail competition. In the Texas region, things are moving quickly toward implementing full retail competition. The Electric Reliability Council of Texas (ERCOT) plans include building 36,000 miles of transmission lines, creating an interconnection agreement with new generators. The following figure details the extent of electric deregulation throughout various regions of the United States.

[7] http://www.rapmaine.org/epact92.html
[8] Wall Street Journal. Out of the Darkness. September 17, 2001.
[9] EPSA Report. http://www.epsa.org/news/index.cfm?section=news

Figure 1. Status of Electric Industry Restructuring Activity as of August 2001



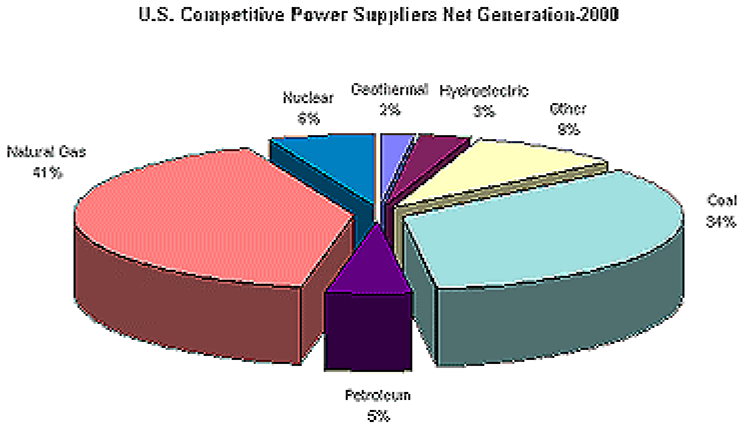
Source: Energy Information Administration.

Resources Fueling Electricity Generation

Key lawmakers on the Senate Energy and Natural Resources Committee support a mix of fuels to meet the nations increasing demand for power. The US must keep all their fuel options open so that the United States is not dependent on any one fuel type. Coal, natural gas, nuclear, petroleum, hydropower, and other renewable resources must all be available. Experts believe that the US natural gas pipeline and distribution network must grow by a third in the next two decades to keep pace with demand. Although coal makes up more than half of the power generation market, gas makes up much of the difference.

Natural gas has become the fuel of choice for many power-producing companies. Companies in the electric markets must consider the gas markets, as the two have become very interdependent. Electricity generation actually has accounted for 50 percent of the gas demand growth. As gas prices go up, management of the “spark-spread”, the difference in cost between electricity and the conversion of natural gas to electricity, becomes increasingly important. As the spread widens, generation margins increase. The makeup of power supplies for electricity generation is shown in the diagram below.

Figure 2. Makeup of Competitive Power Supplies for Electricity Generation



Oil Markets

U.S. and global oil supplies appear to have been minimally impacted by the attacks on the World Trade Center and Pentagon. While the NYMEX and New York Harbor were temporarily closed, operations are expected to resume soon. Most, if not all petroleum industry infrastructure is expected to resume normal operations in the very near term. Global oil markets are expected to continue tightening through December, with WTI rising to the $28 to $29 level as the supply surplus from earlier this year continues to erode. Stocks were seen as drawing but remaining high enough relative to last year, that crude prices were likely to remain several dollars lower than the very high prices seen a year ago. This takes into account no extraordinary changes affecting the oil supply including normal weather, a sluggish economy, no Iraqi outages, rising non-compliance by OPEC 10, and no unusual logistical or refinery problems. Any changes in the events listed above could act as a catalyst to alert markets to the potential for very tight supplies this winter, and oil prices could swing upward. Resuming full U.S. downstream operations should also help to calm any initial wholesale and retail reactions.

With new OPEC cutbacks starting this month, there is good reason to expect average crude oil prices to rise further (by about $1.50 per barrel) by the fourth quarter of this year.[10] The loss of UN-sanctioned Iraqi exports in June and further OPEC production quota cuts effective September 1 are expected to further reduce OECD commercial oil inventories over the next few months. The West Texas Intermediate oil price, which we now expect to average about $28 per barrel in 2001, is expected to average slightly less than $27 per barrel in 2002.

Natural Gas

Natural gas prices rose dramatically in 2000 and have remained high through the first part of 2001. Since then, inventories have been building significantly, and the price of natural gas has dropped considerably to the sub $3/MMBtu range. The sudden decline represents concern that gas will continue to grow at stronger than expected rates toward the system capacity of 3.2 Tcf.[11] At the beginning of the year, high prices had raised concerns about the longer term prospects for

[10] www.oilprices.com Futures Gas Prices
[11] www.oilprices.com Natural Gas Prices

natural gas prices and their potential impact on consumers and on economic growth. The sudden correction in prices has alleviated concerns with some policymakers as to whether natural gas can play a dominant role in fueling U.S. economic growth in the next 20 years.

With the prices of natural gas rising over the past year, companies increased capital spending to increase natural gas drilling and production. The cash flow from the sale of natural gas is important in determining drilling investments and had been a major factor in limiting increases in natural gas productive capacity, particularly from 1997 to 1999. Periodic downturns in the gas industry, such as in the 1984-89 and 1998-99 periods, have triggered downsizing and cutbacks in spending for exploration and development of new gas sources. With increasing prices in 2000, the number of new gas well completions increased by almost 45 percent. The increased capital expenditures resulting in an increased supply is finally being felt in the market directly affecting the pricing declines in natural gas.

The average growth rate for gas demand closely follows GDP growth. With the recent downturn and the economy, GDP growth has fallen to nearly zero growth. Depending on the time expected for economic recovery, this could significantly impact the recovery in the natural gas market. With the increased spending as gas rates climbed in 2000, natural-gas-fired fired capacity is expected to increase significantly. The long term annual growth rate for natural gas consumption is approximately 2.3 percent, reaching 34.7 trillion cubic feet by 2020.[12] Over half of this increase is expected in the electricity generation sector.

Although given the uncertainty for future growth over the next 2 years, prices are not expected to ease back to the $2 per million Btu seen just a year ago. For 2001, the annual average wellhead price is projected to be about $4.00/MMBtu. With slight improvement in 2002, the average annual wellhead price is expected to decline to about $3.00/MMBtu. Because natural gas inventory buildup rates have visibly slowed recently, the prices of natural gas should stabilize with the normalized storage build up rates. Over the following 10 years, the price of natural gas is expected to fluctuate around the $3.00 to $4.00/MMBtu level.[13]

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[12] www.eia.doe.gov Natural Gas: Trends for the Future
[13] Annual Energy Outlook 2001

Figure 3. Natural Gas (NG, NYMEX) Monthly Futures Pricing

Coal

For the first time in more than 40 years, U.S. coal production has decreased for a second consecutive year. In 2000, coal production declined by 2.3 percent from 1999, to 1,075.5 million short tons, according to preliminary data from the Energy Information Administration. The decline in production was attributable to several factors including,

- a substantial draw down in total coal stocks
- a lack of excess production capacity at some mines
- a reluctance on the part of some producers to expand production to meet increasing demands in the latter part of the year.

Coal consumption in the United States in 2000 grew 2.4 percent to reach a level of 1,070.5 million short tons. More than 90 percent of all coal was consumed in the electric power sector. Coal was used to produce 51.4 percent of all electricity generated in the United States. Two factors affected the growth in coal consumption for power generation in 2000. The increase of 34.1 million short tons for the generation of electricity was in part a result of a decline in hydroelectric generation in 2000. Preliminary data for hydroelectric generation showed a drop of 43.5 billion kilowatthours from the 1999 level. The other factor affecting the higher level of consumption was weather. The summer of 2000 was warmer in some parts of the country than it was in 1999. Coal prices, on an annual basis, declined in 2000, continuing the downward trend of the last several years. Although there were higher prices for some of the consuming sectors as a result of the increasing fuel costs at the end of the year (on a delivered basis), the average price of utility coal (on a delivered basis) declined 3.6 percent, for an annual average of $23.83 per short ton ($1.211/MMBtu).[14]

The negative factors that led to lower production are not expected to change through 2001. Factors expected to keep coal demand and production down would include:

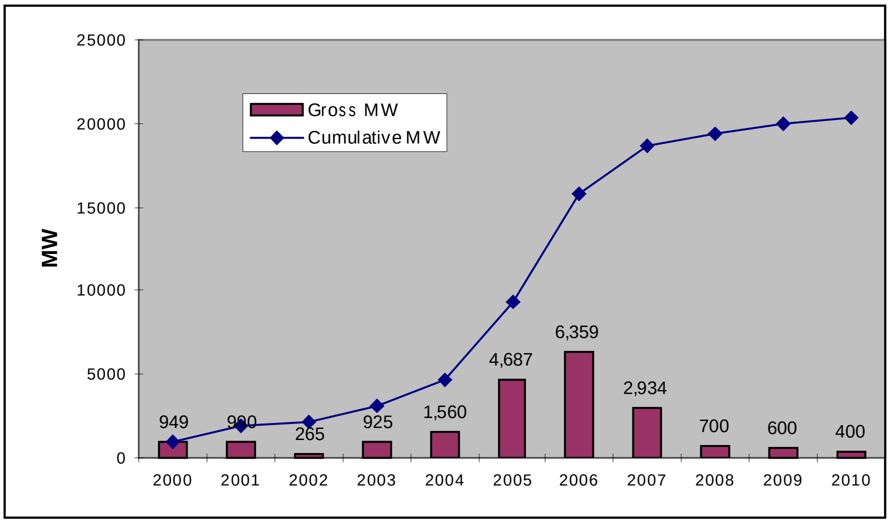
- Slowing economic growth
- Large declines in natural gas prices from their year-ending highs

[14] Annual Energy Outlook 2001

- Replenishment of stocks by the electric power industry

Spot coal prices in the final quarter of 2000 reached levels that were higher than had been seen in decades. With the factors discussed above putting pressure on the coal markets, 2001 may not be the year to expect a reverse in a trend of 25 years of declining prices. Overall, the outlook for U.S. coal for the end of 2001 is not likely to be better than 2000.

Figure 4. New Coal Plants Projected for North America
Includes under construction and anouncments



Recent Pressures on Independent Power Producers

The power supply crisis in California was the result of a number of factors. In the past decade very few power plants were constructed due to depressed natural gas prices as mentioned previously. With peak GDP growth reached in 2000, the ramp up in demand for electricity outpaced the supply of energy. The year also proved to be a dry hydropower year, so the reserves that the western interconnection depended on were not available. Due to political price caps, the utilities were forced to purchase energy on the volatile spot markets at prices in excess of what they were able to sell to their customers. Without being able to pass the burden on to their customers, the utilities were losing money on any excess capacity purchased which eventually mounted to huge losses and bankruptcy.

The utilities currently owe independent power producers over $9 billion in accounts payable for purchased power on the spot markets. With the utilities in bankruptcy, the independent power producers are attempting to recoup the losses from the state of California. This has caused the state credit rating to be at risk in California. Governor Davis has also felt the pressures, and realizes the importance of these matters in conjunction with his re-election.

Although there have been pressures from Governor Davis in California, President Bush has vowed to fight any attempt to regulate power prices and the Federal Energy Regulatory Commission (FERC), the regulatory body with sole authority to order price caps, continues to reject pleas from California to regulate wholesale prices. The concern is imminent that some compromise still might result in some type of pricing restrictions in California.

The FERC has instituted a new regulatory scheme limiting the price charged for power in California during periods of intense demand. Although the plan's effectiveness has been questioned by state regulators, some analysts fear regulators might consider additional action if the power producers continue to post record profits. Currently the FERC has a core group of commissioners on record against broad price caps, and favoring "circuit breakers" to ease temporary pricing pressure. With two new Bush appointees joining the FERC, it isn't likely outspoken Commissioner William Massey can gather support to implement more rigorous price caps.

California Gov. Gray Davis has made threats to sue the FERC while seeking court-ordered price caps. While a federal court in California already has rejected arguments similar to Davis', Davis' comments regarding the power producers as price-gougers has given investors reason to take profits on the sector. Many of the producers have not yet been paid and will most likely not recoup all the money they are owed. Davis has proposed that the generators take 70 cents on the dollar for the receivables owed to them. With the utilities in California declaring bankruptcy, the likelihood of full payment is uncertain. Many of the power producers have now offset their receivables with reserves, since they are not expecting full payment. The receivables expected from California utilities are also a small percentage of each company's receivables, which should ease some concerns for the group.

Current Power Prices

Since the price of electricity is very dependent on the commodity markets, current power prices can be reflected in the activity of the natural gas and oil commodities markets. Natural gas has fallen from highs of $10/MMBtu to approximately $2.50/MMBtu since the beginning of 2001. Oil has also fallen from highs of $35/barrel to $28/barrel since the beginning of 2001. With price pressures easing in both markets, wholesale electricity prices have also fallen.

The recent downturn in the economy has also affected demand for power. With GDP growth levels down from highs of 6 percent to less than 1 percent growth, the demand for power has significantly decreased. Technology spending and growth, which previously drove energy demand, has reached a halt in less than a year. Increased natural gas prices at the end of 2000 also drove increased capital spending on drilling and development projects. The spending should result in further supply increases in the short-term as spending translates to increased production. Due to a reversal in the supply/demand mechanics in the market electricity prices should stabilize as they have already fallen significantly.

The nationwide trend toward restructuring will push electricity prices upward in some parts of the country and pull prices downward in others as a result of regional differences in demand, natural gas prices, transmission capacity and other market conditions.

Table 2. Market Drivers in Major Regions

Region	Supply Cycle Position	Environmental Restrictions	RTO Progress	Retail Restructuring
Northeast	Surplus	Major impact	Advanced	Advanced
Southeast	Surplus	Minor impact	Moderate	Moderate
Midwest	Surplus	Minor impact	Minimal	Minimal
ERCOT	Surplus	Minor impact	Advanced	Advanced
WSCC	Shortage	Major impact	Mixed	Mixed

Long Term Demand

NERC predicts that in the long term, electric supply adequacy will require the long term development of additional generating and transmission capacity beyond the capacity additions that have been announced to keep pace with growing customer demand and changes in transmission use patterns driven by industry restructuring and market forces. Actual demand growth rates experienced over the last few years are significantly higher than current projections. However, with the current downturn in the economy, demand may ease with less growth in GDP projected in the short-term.

The gap between the growth in electricity sales and the growth in GDP growth has been narrowing in the past few decades. In the 1960s, electricity demand grew at 7%+, twice the GDP growth; that ratio dropped from 2.0% to 1.5% in the 1970s and to 1.0% in the 1980s. Why the decline? Electric appliances saturated the market. Demand-side management became more efficient, resulting in the replacement of old equipment with more efficient equipment.

Once the economy recovers and settles into a steady state, demand for electricity is likely to grow by three percent annually through 2007. This rate reflects the fundamental shift in the U.S. economy that has made electricity-intensive technologies such as computers, telecommunications and the Internet the engines of U.S. economic growth.

To meet this demand and build sufficient reserves to avoid price shocks, U.S. power generators would have to build 330,000 MW of new and replacement capacity by 2007, a 41 percent increase from the 822,000 MW of capacity in 2000.[15] There will be adequate gas supply to fuel new plants being built this year and next, when 43,000 MW and 36,000 MW of new generating capacity are expected to come on line. If gas prices remain at current suppressed levels for the following years, companies will again continue to cut back on drilling and exploration which could result in another price cycle swing in 2003.

If 50 percent of all the new plants are gas fired, demand for natural gas would grow by between 6 and 8 trillion cubic feet, requiring the gas market to grow from 22.4 trillion cubic feet to between 28 and 30 trillion cubic feet.

[15] www.eia.doe.gov US Electric Utilities: Trends and Analysis

Table 3. Announced MW generation capacity through 2007

NERC Region	MW
ECAR	62,531
ERCOT	35,697
FRCC	15,845
MAAC	20,268
MAIN	30,437
MAPP	2,787
NPCC	31,143
SERC	71,211
SPP	8,510
WSCC	74,265
TOTAL	**353,054**

To meet that demand, natural gas supply would have to increase closer to the order of 3 percent, 0.7 percent more rapidly than the expected 2.3 annual growth rate. If companies cut back on production again due to depressed prices, it is doubtful that the level of production can be sustained. Natural gas will play an important role in the expansion of power producing assets in the coming years.

As a consequence of insufficient gas supplies, power generators would have to build generating capacity fueled by coal or uranium to meet long-term demand. However, because of the lengthy development cycle and public policy concerns, new plants relying on these energy sources will not begin to come on line in sufficient numbers until 2005 or 2006.

Overview of IPP Industry Leaders

(Data is from Standard and Poor's RatingsDirect Company Analyses, and Business Browser OneSource Corporate Analyses.)

AES Corporation (BB-) was incorporated in 1981. It currently has a total capacity of 42,133 Megawatts, of which only 18% are located in North America. 36% of AES' capacity is located in South America, 27% in Asia, and 18% in Europe. The company has a significant presence in Brazil, El Salvador, Venezuela, the Dominican Republic, and the Republic of Georgia. Its Brazilian investments are primarily purchases of privatized state hydroelectric facilities, and currently face some political risk from governmental production limits which became operative during the current severe drought in Brazil. AES's total generating capacity consists of 38% coal/coke, 18% natural gas, and 33% hydroelectric. The company owns a high percentage of coal-fired facilities. The company's holdings are so varied, that it is difficult to gauge its operational efficiency.

Calpine Corporation (BB+) was incorporated in 1984. It has a total generating capacity of 5,849 MW, all of which are located in the U.S. and Canada. Calpine has significant exposure to California- 23% of its generating capacity. Calpine is expanding aggressively. The company is constructing natural gas-fired projects which will total 14,028 MW of capacity. It has also announced construction of gas-fired projects which will total 15,142 MW. The projected 40% growth rate reflects this aggressive expansion. To date, all of Calpine's projects have been completed on time and within budget. In addition, Calpine has a strong operating history, with 96% availability in its gas-fired plants through 1998. The company will have to acquire access to significant natural gas reserves at below market cost in order to maintain its current margins, however.

Mirant Corporation (BBB) was spun off in a 2000-2001 IPO from Southern Energy, which was incorporated in 1993. Mirant has a total capacity of 20,000 MW, of which 70% is located in North America (particularly the Mid-Atlantic region and California), 15% in Asia (primarily the Philippines), and the remainder in Europe and the Caribbean. 15% of the company's 4-year forecasted cash flows are expected to come from California. 28% are expected to come from regions of the world with significant credit risk. Revenues are diversified by both geography and fuel type. The company is constructing an additional 9,000 MW of capacity, and owns significant natural gas production facilities in the U.S. Moderate expansion is predicted for Mirant.

NRG Energy Inc. (BBB-) was incorporated in 1992 and has a total capacity of 25,059 MW, including plants under construction. The plants are divided between coal, natural gas, and oil, providing diversification of fuel type. The company is somewhat diversified geographically. Its largest presence is in the Northeast U.S., with 28% of its total capacity. 24% is located in the rest of the U.S. 8% of its capacity is located in Australia, and 5% in Europe. NRG has a good operating record, with an average availability of 92% from 1997-2000. Moderate expansion is predicted for NRG.

Orion Power Holdings (B+) held its IPO in November of 2000. The company has a relatively small total capacity of 5,396 MW, most of which is located in Ohio, Pennsylvania, and New York. The company has announced projects that will double its capacity, all located in the Northeast U.S. Currently, half of its capacity is coal or oil (PA, Ohio), and half is hydroelectric (New York). The company currently has some natural gas-fired plants under construction. Orion currently trades at a relatively high multiple of its projected earnings.

Reliant Resources Inc. (BBB+) is the IPP half of the former parent company Reliant Energy. (The other half owns the gas and electric transmission systems.) The newly-formed company has a total capacity of 12,707 MW, one-third of which is located in California and Nevada, and another third of which is located in the Pennsylvania-New Jersey-Maryland market. The remainder of its U.S. generation capacity is located in Florida, Illinois, and Texas. 27% of the company's capacity is located in the Netherlands. RRI has announced plans to become a provider of retail power services to the Texas market when the market opens to retail competition in 2002. The company also trades and markets power and natural gas. Reliant is expected to show moderate expansion. Because the company is newly independent, it has no track record as a stand-alone firm. Reliant will also require significant injections of cash in the near term, which it plans on acquiring by issuing equity.

Figure 5. Relative performance of IPP stocks from 9/21/00 to 9/21/01

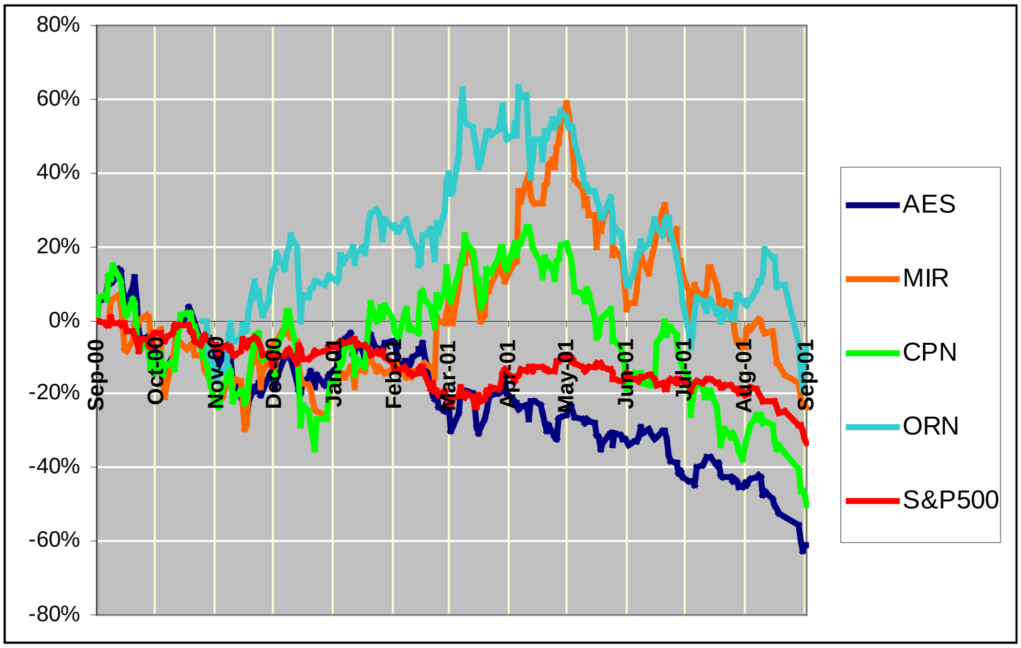


Table 4. Independent Power Producing Companies

Company	Price	52-week High	52-week Low	Market Capitalization	LTM EPS	Price/ Earnings	2002 Proj. EPS	2002 Proj. P/E	Price/ Book	ROE	Long term growth	PEG
AES	$ 29.00	$ 72.81	$ 26.60	15.4 BB	$ 1.15	25.20	$ 2.40	12.08	$ 2.70	$ 0.11	$ 0.30	0.84
Calpine	$ 29.05	$ 58.04	$ 27.80	8.86 BB	$ 1.49	19.50	$ 2.30	12.63	$ 3.60	$ 0.23	$ 0.40	0.7
Mirant	$ 25.25	$ 47.20	$ 20.56	8.6 BB	$ 1.39	18.17	$ 2.35	10.74	$ 2.20	$ 0.12	$ 0.23	0.89
NRG	$ 16.99	$ 37.70	$ 16.40	3.37 BB	$ 1.15	14.77	$ 1.65	10.30	$ 1.70	$ 0.13	$ 0.25	0.59
Reliant	$ 18.28	$ 37.50	$ 17.20	5.47 BB	$ 1.47	12.44	$ 2.00	9.14	$ 1.80	$ 0.11	$ 0.25	0.49
Orion	$ 21.90	$ 34.00	$ 16.31	2.27 BB	$ 0.55	39.82	$ 1.57	13.95	$ 1.70	$ 0.05	$ 0.25	1.59

Note: Market prices as of September 14, 2001

Table 5. Investment Opinions and Target Prices

Firm	12 mo. Target Price	Percent Increase	Rating	Comments
Calpine	$ 56.41	94%	Buy	Very aggressive expansion plans especially in low capacity areas including California. Exposure to California (23% of capacity) but low exposure to bankrupt utilities. Excellent operating history- efficient capital spending.
Mirant	$ 49.75	97%	Buy	Attractive forward 2000 P/E multiple around 10.74. Exposure to California (15% of cashflow). Already written off receivables due to bankrupt facilities. Significant exposure in Asian markets which have double digit GDP growth. Strong natural gas reserves to power generation of electricity.
NRG	$ 22.55	33%	Hold	Diversified plants- capital spending to upgrade retiring capacity. Exposure 28% in northeast, which has capacity to meet demand. (Slower capacity growth) Strong operating history, good management.
Reliant	$ 25.33	39%	Hold	Significant exposure to Texas and increased expansion plans in Texas. Texas is already an overcapacity area and does not transmit outside of ERCOT region. Uncertainty with deregulation in plans in Texas and increased competition due to overcapacity. Plans to issue equity in the near term.
Orion	$ 21.90	0%	Sell	Significant exposure (90%) to New York Metro Area. Loss of demand from WTC attacks. Only public for one year. Selling pressure once shares go off lockup expiration. Short operating history and lack of strong management track record.
AES	$ 20.30	-30%	Sell	Significant international risk- international exposure in Middle East. Hydroelectric power exposure in Brazil- severe drought conditions triggered government regulations. A significant amount of retiring capacity will require increased capital spending.

Sources:

1. Standard & Poor's Ratings Direct. Company Analysis.
2. Business Browser OneSource Corporate Analysis.
3. Exposure to market segments taken from company 10K's.

Important Disclaimer

Please read this document before reading this report.

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