TESTIMONY

Before the

United States
House of Representatives

Committee on Financial Services

The California Energy Crisis: Impacts, Causes and Remedies

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At 10:00 AM

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Summary

High electricity prices have dominated the headlines in many areas of the United States over the last twelve months – most noteworthy is California. Although some economic impact of rising electricity prices is unavoidable, the focus should be on managing that impact in the short-term, but encouraging supply additions in the long-term. This is an extremely precarious balance, though. The recent high prices of electricity have caused developers to announce 370,000 megawatts of new electricity generating capacity in the United States between now and 2006. This is a 49% addition to existing generating capacity in the United States and clearly indicates that the competitive markets for electricity are working. In California, the comparable number is 45%. The short-term desire to control prices could derail the new supply additions in certain areas of the United States. This could support higher electricity prices in the intermediate term.

In our opinion, the most critical action state and federal legislators and regulators can take is to ensure the development of a competitive market for electricity. Avoid the temptation to cap electricity prices in the near-term. Actions to ensure the enforcement of current law should be more than adequate to control price spikes. Importantly, avoiding the near-term temptation to cap electricity prices will deliver a much larger and longer-term benefit to consumers – the economic benefit associated with the development of excess generating capacity in the United States that will drive prices sustainably lower.

California is among more than 20 states in the United States that have legislatively begun to deregulate the electric power industry. However, California is different in several critical ways and the problems with deregulation appear most acute there. Although many of the characteristics of California deregulation were flawed, we believe one of the major shortcomings was deregulating supply when electricity supply was so short as to be bordering on inadequate. Significant amounts of new generating supply must be added in all regions of the United States, including California. However, we firmly believe that the development of new generating resources and the encouragement of a fully competitive electricity market will correct the shortcomings of the fledgling deregulation efforts of California and other areas of the United States.

HOW THE ELECTRICITY MARKETS WORK

Electricity and other energy sources remain the life-blood of the United States economy. The United States electricity markets have traditionally been regulated, largely on the basis of cost-plus and return-on-investment regimes. Vertically integrated companies generated, transmitted and distributed electricity to consumers in their franchised region, recovering reasonably incurred costs and having the opportunity to earn a “reasonable” return on invested capital. Over 100 investor-owned electricity companies, commonly known as electric utilities, operated in the country. Both state and federal authorities are charged with overseeing the industry. The historic regulatory regime, based on asset investment as a method to grow earnings, encouraged the addition of generating capacity, among other things. Dating back to the mid-1980s, the industry operated with a 35% capacity reserve margin (or with 35% more supply than peak electricity demand required). However, the regulatory regime did not maximize efficiency or minimize costs. As a mature and asset intensive industry, the generation of electricity is ripe for competition, in order to exploit these inefficiencies. Demand for electricity is currently expected to grow about 2.5% annually over the next few years.

The Public Utility Regulatory Policies Act of 1978 and the 1992 Energy Policy Act both encouraged the idea of a competitive electricity generation industry. In both laws, wholesale generators without the desire to sell electricity to retail consumers were permitted to enter the industry and construct and operate electricity generation facilities. Electric utilities purchased the electricity under long-term contracts from the unregulated wholesale generators. However, consumers indirectly financed these generators as their wholesale prices were passed on, dollar for dollar, to consumers. This spawned the idea of a fully competitive generation market, with the idea of passing the risks of excess supply and high costs from the consumer to the industry participants.

Over 20 states have passed legislation to adopt a more competitive industry structure for the electricity industry. This includes California, but also other states like Pennsylvania, Massachusetts, Illinois and Rhode Island. The deregulation movement in these states has generally included the recovery of previously incurred regulatory costs, the elimination of regulation of generation resources, and the eventual introduction of competition to consumers of electricity. However, many consumers (residential, commercial and industrial) still receive relatively fixed-price electricity as a result of the transition from a regulated monopoly to a competitive generation business, which is taking several years. Ideally, deregulation of electricity would occur in a period of excess supply rather than a period of shortage of supply. In deregulating any commodity, the economic forces of supply and demand will take over and efficiently determine prices. The UK electricity market was deregulated in a period of excess supply and prices have declined precipitously.

The wholesale spot market for electricity is largely deregulated, with over 370,000 megawatts of new generation proposed to be built over the next five years. By comparison, about 760,000 megawatts of generating capacity is installed in the United States currently. About half of the existing capacity is coal-fired. The new capacity

(370,000 MW) suggests that a 49% addition to generating capacity is possible over the next five years, most of which is likely to be natural gas fired generating capacity. By comparison, at a demand growth rate of 2.5% annually, the necessary capacity additions over the next five years would be 93,000 megawatts. The current announced backlog of generation development is a 400% increase over the required amount.

THE CALIFORNIA ENERGY CRISIS

As stated above, California is among more than 20 states in the US that have legislatively begun to deregulate the electric power industry. However, California is different in several critical ways. California fixed retail prices for several years, but allowed the deregulated wholesale market for power to move with the competitive forces. Further, regulators in the state forced the divestiture of some generating assets by the incumbent electric utilities. This divestiture forced the incumbents to purchase competitively priced wholesale power in the open market and to sell the power at fixed retail prices. Beginning in the summer of 2000, wholesale electricity prices were well above the retail prices the incumbent utilities were permitted to charge, creating a significant loss on certain sales by the incumbents. California regulators also implicitly forced the retail electric companies to buy in the spot market or risk clear 20/20 hindsight by regulators of long-dated contractual obligations.

Electricity supply nationwide is currently short. This is the result of a lack of new investment in the industry, largely as a result of the uncertainty of deregulation. As a result of this shortage, electricity prices in the spot market have been rising. This coupled with very poor hydroelectric conditions in the Northwest (almost 50% of electricity generation in the Northwest is hydro-powered) has left the western portion of the United States with very short electricity capacity and higher than normal electricity prices. As California has for several years been a net importer of electricity, the regional shortage is particularly acute for California. The state of California currently has an electricity capacity reserve margin of less than 3%.

Although many of the characteristics of California deregulation were flawed, we believe one of the major shortcomings was deregulating supply when supply was so short as to be bordering on inadequate. Many other examples of deregulated markets suggest the theoretic outlook for deregulation for the electricity markets in California and elsewhere is very strong. However, significant amounts of new generating supply must be added in all regions of the United States. Absent state or federal funding for electricity generation resources, we believe the new capacity is best built and financed by the private sector. With a need of between 100,000 and 200,000 megawatts of generating capacity nationwide and a cost of about $700,000 per megawatt of capacity, the total cost of the new capacity is between $70 and $140 billion.

IMPACT OF CALIFORNIA

Beginning with the 1992 Energy Policy Act, the industry has been encouraged to pursue competition as a method to squeeze out these efficiencies. California was one of the first electricity markets to move towards a more competitive industry structure. The near-term impact of the current electricity crisis on California may slow the economy. However, as we are quite convinced that excess supply will develop in the entire United States, including California, we believe the appropriate course of action is to allow the competitive markets to take their course.

High prices in competitive industries attract capital to those industries. The high prices temporarily generate high returns for industry participants. However, as new supply is added to take advantage of the high prices and high returns, the new supply reduces prices and profit margins. This is particularly true in commodity industries like electric power. As we stated above, the high prices that have existed in the United States over the last 12-18 months have caused over 370,000 megawatts of new generation to be proposed. If even half of this new capacity is built, electricity prices will decline significantly over the next few years. Our forecast suggests net additions between now and 2005 to approximate 220,000 megawatts.

In California, almost 17,000 megawatts of new electricity generating supply has been announced to be operating by 2003. Another 8,000 megawatts of electricity generating capacity is expected to be added between 2003 and 2006. Between now and 2006, this suggests an addition of 45% to existing generating resources. Importantly, a 31% addition to existing capacity is possible by 2003. The new additions, coupled with a return to more normal hydroelectric conditions should reduce electricity prices materially in 2002 and 2003.

ASSESSMENT OF THE CALIFORNIA CRISIS

In our opinion, the most critical action state and federal legislators and regulators can take is to ensure the development of a competitive market for electricity. Avoid the temptation to cap electricity prices in the near-term. Actions to ensure the enforcement of current law should be more than adequate to control price spikes. Importantly, avoiding the near-term temptation to cap electricity prices will deliver a much larger and longer term benefit to consumers – the economic benefit associated with the development of excess generating capacity in the United States. Ironically, the excess electricity supply we expect will benefit consumers both economically and environmentally. Economically, prices will be lower as a result of excess generating supply, providing a tangible benefit to consumers. Environmentally, the new generating resources are significantly cleaner and more efficient than existing electricity generating facilities. Combined, this will provide a cleaner environment and lower electricity prices.

We believe it is important to recall that the last time excess generating capacity was "enjoyed" in the United States (during the 1980s), consumers financed the excess supply through higher prices. This was a result of regulation. Avoiding price caps and allowing the development of excess generating supply and an efficient competitive market for electricity in the United States will hand consumers the benefit originally promised to them in electricity deregulation – significantly lower prices.

Beyond avoiding price caps and encouraging the development of new generating capacity, we believe there are two other important items for regulators and legislators to consider. This is to encourage the development of new transmission investments and to encourage a diversity of generating resources.

On electricity transmission, we believe solving bottlenecks and other transmission constraints will also aid in the development of a competitive electricity market. However, at relatively low returns, investor-owned companies are not encouraged to make investments in the electric transmission business currently. Part of this is a result of the high returns in the short generation market, but another contributing factor is the relatively low return offered for transmission investments. Considering the relatively higher investment permitted for natural gas transmission development and expansion, we believe electricity transmission ought to be encouraged with higher returns.

About 50% of the electricity generating resources in the United States use coal as a boiler fuel. Approximately another 18% is nuclear and another 18% is natural gas. The balance is oil, wind, solar and other renewables. Considering the 370,000 megawatts of proposed new capacity in the United States, over 95% of the capacity is natural gas driven. The consideration of nuclear, coal and other resources will be important over time to maintain fuel diversity and to avoid any fuel specific shocks to the price of electricity.

APPENDIX

1. **US Electricity Supply & Demand Update** (dated June 5, 2001)
2. **Restructuring of the US Electric Generation Sector** (dated June 8, 2001)
3. **Electricity Supply & Demand in the US** (dated March 8, 2001)

Equity Research
Americas

Deutsche Banc Alex. Brown

US
Utilities

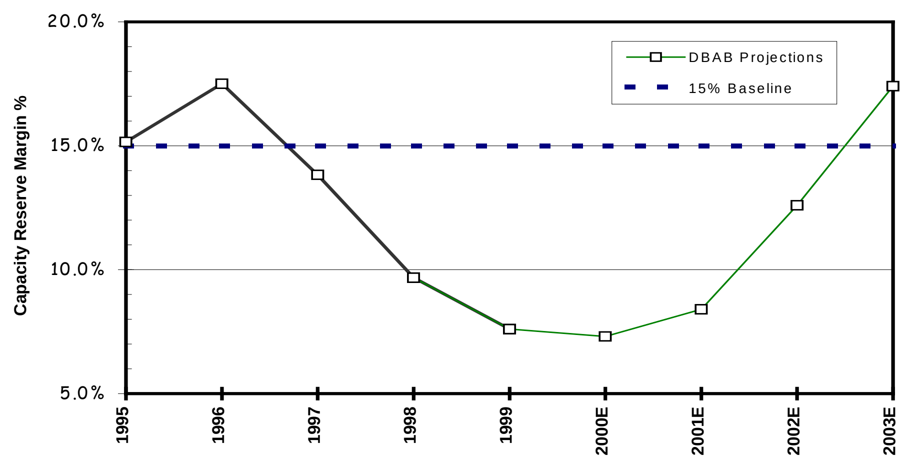
Deutsche Bank

June 5, 2001

U.S. Electricity Supply & Demand Update:

Capacity Shortage Still Evident, But Additions Continue – Suggests Near-Term Outperformance by Generators

U.S. Capacity Reserve Margins 1995 - 2003



Source: Deutsche Banc Alex. Brown, NERC, RDI Consulting

- Based on our most recent analysis of planned electricity supply additions, we still believe that nearly every U.S. region will experience tight capacity margins for electricity supply this summer.
- We expect about 35,000 megawatts of new generating capacity to come on line in the U.S. by mid-June. However, even factoring in this capacity, we still expect regional capacity margins to hold at historically low levels this year, providing rising prices for generators in the wholesale markets.
- The regions where we see the most difficult supply situations this summer include California, the Northwest, New York City, and parts of the Midwest and the Northeast. Texas and New England are the only regions showing close to adequate capacity.
- Overall, we expect power generators and marketers throughout the country to see strong year-over-year earnings comparisons in 2001, both from new capacity additions as well as improved margins and higher pricing. With the addition of more new supply in 2002, we expect to see electricity prices moderate in 2002.
- The companies we expect to benefit from this opportunity in the near term include Calpine Corp., Reliant Resources, UtiliCorp United, Allegheny Energy, Exelon Corp. and Orion Power Holdings. Other potential benefactors include Duke Energy, Mirant Corp. and NRG Energy.

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Executive Summary

Comprehensive work on supply and demand in any industry requires constant updating and review. Although we continue to believe our March 8 report on electricity supply and demand in the United States (*The March to a Commodity Drum*) is the most comprehensive, it needs to be updated regularly to remain useful. As such, we have been updating the figures monthly and watching the development of new supply additions during the first and second quarter. We believe that capacity added for the summer of 2001 will be a strong indicator of the industry's commitment to new capacity and the effectiveness of high prices to act as a catalyst for new supply additions.

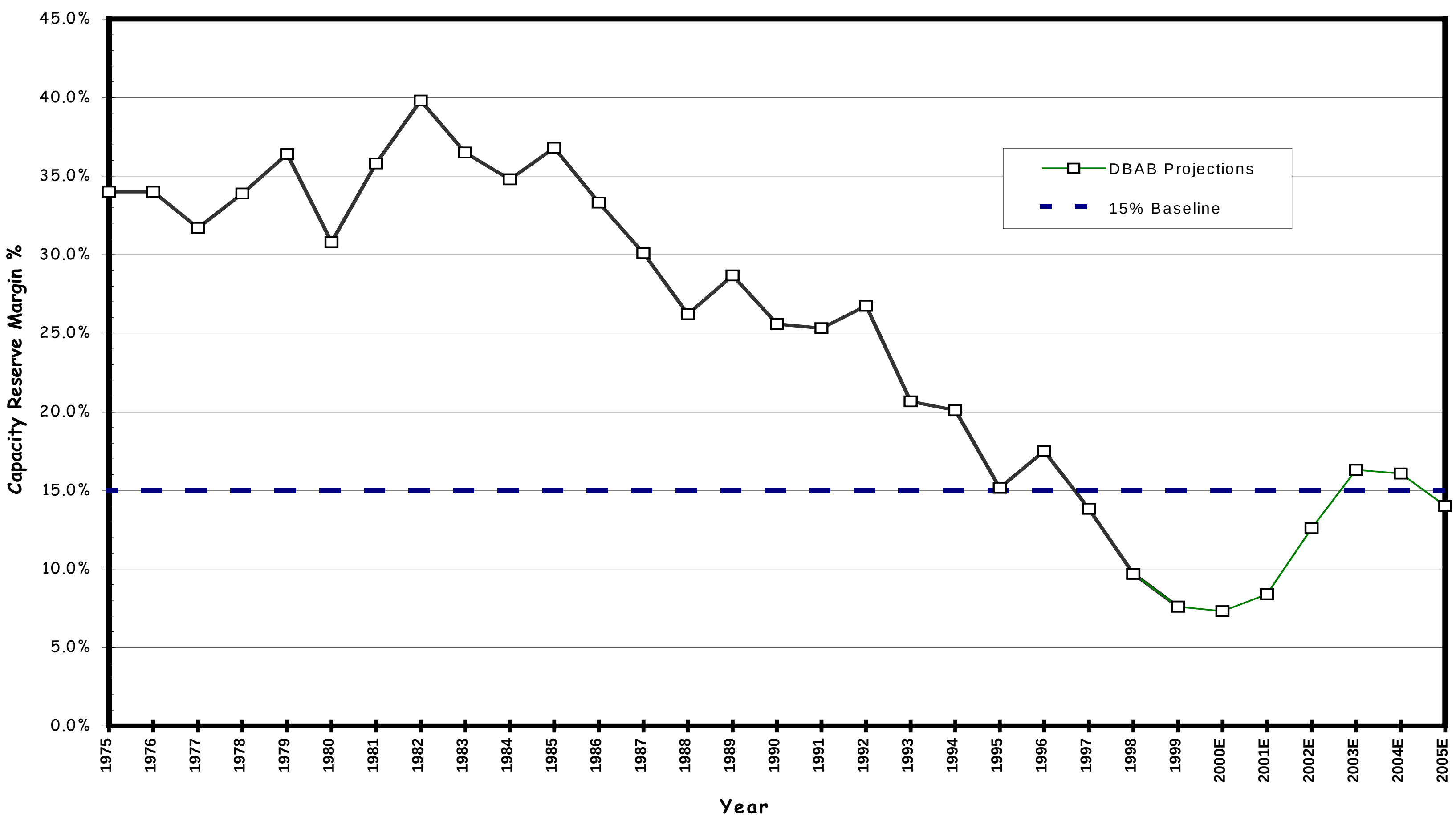
Based on our most recent analysis of planned electricity supply additions for 2001 and 2002, we still believe that nearly every region of the United States will be short electricity generating capacity during the summer of 2001. We expect 35,000 megawatts of new generating capacity to be available to meet the summer peak demand, relative to year-end 2000. However, this will still leave the U.S. with a capacity reserve margin of 8.4%. This is only slightly over the 7.0% reserve margin we saw in 2000. We continue to assume adequate capacity of a reserve margin of 15%. Admittedly, as we stressed in our March 8 report, a regional review of supply and demand is far more useful than any national average.

The regions where we see the most difficult supply situations this summer include California, the Northwest, New York City, and parts of the Midwest and the Northeast. California will almost certainly face periods of rolling blackouts this summer due to the lack of generation investment in the state over the last decade, and as a result of the low hydroelectric production levels in the Northwest, stemming from low water levels. New York City also faces a very tight summer due to the lack of supply additions and the growing level of demand. The two areas of the United States with the lowest capacity reserve margins this summer are California (-0.3%) and the Mid-Continent Area power Pool – MAPP (0.9%). The two regions with the highest estimated capacity margins are in Texas (16.0%) and New England (13.0%).

The shortage of electricity generating supply during the summer of 2001, coupled with the rising prices of electricity and the increasing output of new generating resources will drive earnings for the generators in the second and third quarters. We expect electricity prices and profit margins to be strong in 2001 but begin to moderate for the first time in the last three years during 2002. First quarter 2001 profits supported our forecast, with almost every one of the companies in the electric generation sector beating our expectation for earnings growth. We expect similar activity in the second and third quarters —particularly in light of the relatively easy earnings comparisons. The companies we expect to benefit from this opportunity in the near term include Calpine Corp. (CPN), Reliant Resources (RRI), UtiliCorp United (UCU), Allegheny Energy (AYE), Exelon Corp. (EXC) and Orion Power Holdings (ORN). Other potential benefactors include Duke Energy (DUK), Mirant Corp. (MIR) and NRG Energy (NRG).

Figure 1:

U.S. Capacity Reserve Margins 1975 - 2005



Source: Deutsche Banc Alex. Brown, NERC, RDI Consulting

The National Outlook for Supply & Demand

The capacity reserve margin that we expect for the summer of 2001 for the United States as a whole is 8.4%. This is based on about 795,000 megawatts of total generating capacity and about 3% peak demand growth over the summer of 2001. Chart 1 (front cover) shows the capacity reserve margin for 1995 to 2003. We believe the reserve margins will improve to almost 13% by the summer of 2002. Recall that the reserve margin in 2000 was 7.0%. We continue to assume adequate capacity at margin levels approaching 15%. Our national forecast assumes the addition of 45,000 megawatts of new generating capacity in 2001 and about 60,000 megawatts in 2002. About 35,000 megawatts of the total 45,000 megawatts expected during 2001 are planned to be available to meet the summer peak demand (commercially available by June 15 in this analysis).

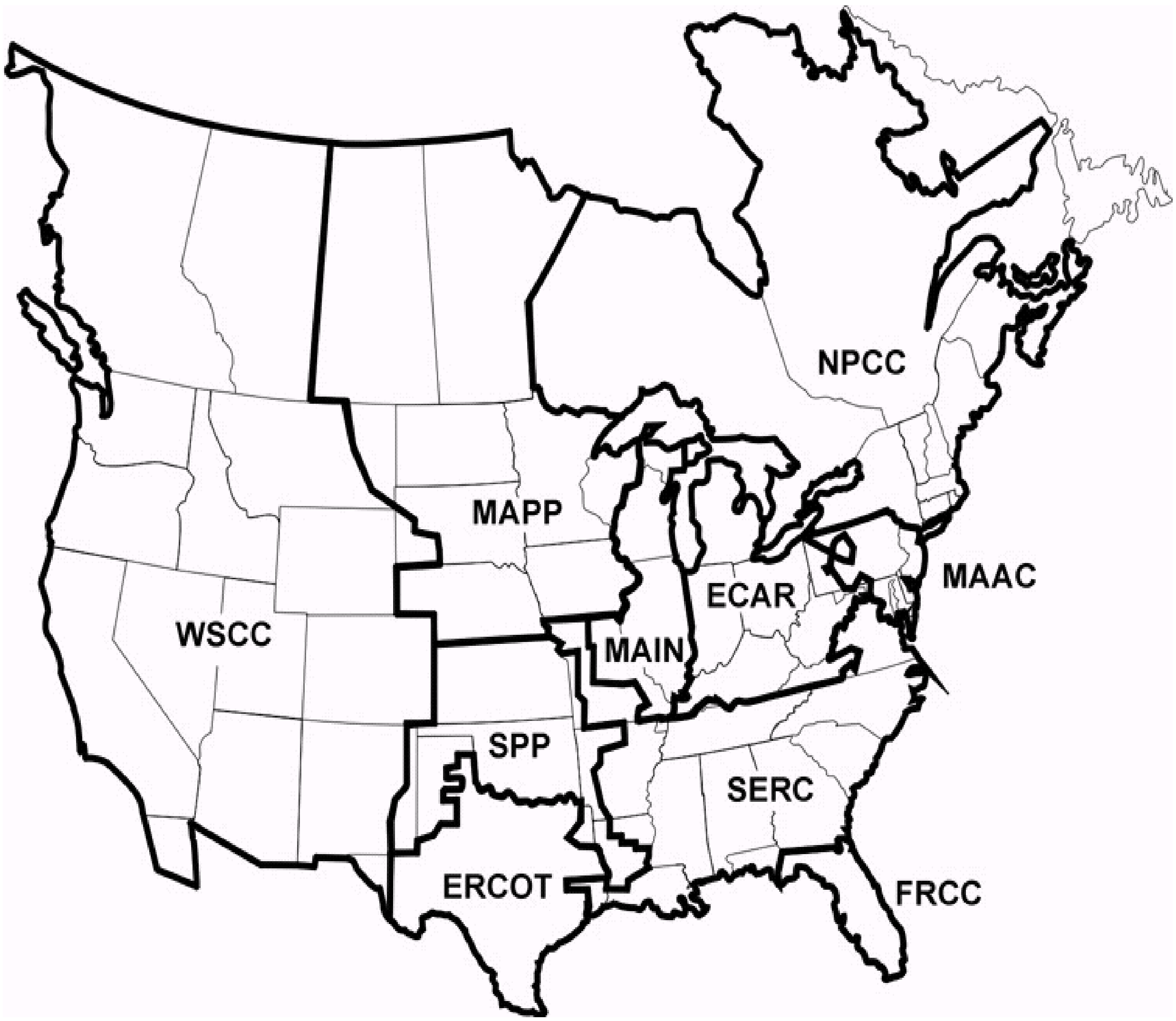
The roughly 100,000 additional megawatts that should be available by the summer of 2002 (45,0000 MW in 2001 plus 55,000 MW by June of 2002) highlight our concern about moderating electricity prices. Although these moderating prices will be good for consumers and should reduce some of the political risk in the electric power industry, they will also serve to highlight the commodity-nature of the electric power sector. Admittedly, the new generation units to be added over the next several years should keep earnings growing in the intermediate term. However, moderating commodity prices are likely to eliminate the upside surprise potential for quarterly and annual earnings in the electric power sector by late 2002.

Figure 2 shows the eleven regions that the North American Electric Reliability Council (NERC) divides the United States into. This is important since we review the same regions when developing our supply and demand forecast. We continue to emphasize that a regional review of supply and demand is far more useful than any national average.

Figure 3 shows the top 20 developers based on U.S. capacity additions in 2001. This list is headed by Strong Buy-rated Calpine Corp., with significantly more expected 2001 additions than any other developer. The middle column of the table displays the 2001 additions for each company as a percentage of total additions scheduled for this year. The far right column calculates the 2001 capacity additions as a percentage of year-end 2000 operating capacity for each developer (U.S. capacity only). The two largest developers based on this metric are Calpine and Reliant Resources.

Figure 2: **Map of NERC Regions**

North American Electric Reliability Council (NERC) Regions



ECAR
East Central Area Reliability Coor. Agreemt.
ERCOT
Electric Reliability Council of Texas
FRCC
Florida Reliability Coordinating Council
MAAC
Mid-Atlantic Area Council
MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool
NPCC
Northeast Power Coordinating Council
SERC
Southeastern Electric Reliability Council
SPP
Southwest Power Pool
WSCC
Western Systems Coordinating Council

Source: Deutsche Banc Alex. Brown estimates and company information

Figure 3: **Top 20 Developers – 2001 U.S. Generation Additions**

	COMPANY	MW*	% of 2001 Total	% of Company's 2000 Capacity**
1	Calpine Corp.	6,010	11.1%	102.8%
2	International Power plc	3,360	6.2%	NM
3	Reliant Resources	2,770	5.1%	28.9%
4	Duke Energy	2,673	4.9%	12.4%
5	PG&E Corp.	2,047	3.8%	16.5%
6	Southern Company	1,775	3.3%	5.3%
7	Progress Energy	1,345	2.5%	7.3%
8	Dynegy	1,342	2.5%	17.6%
9	Constellation Energy	1,299	2.4%	14.5%
10	Exelon Corp.	1,275	2.4%	6.7%
11	AES Corp.	1,247	2.3%	11.4%
12	Panda Energy	1,147	2.1%	NM
13	Public Service Ent. Group	1,049	1.9%	9.3%
14	Great River Energy	954	1.8%	NM
15	FPL Group	940	1.7%	4.6%
16	American Electric Power	931	1.7%	2.4%
17	Xcel Energy	845	1.6%	3.2%
18	TVA	700	1.3%	2.5%
19	DPL Inc.	680	1.3%	19.6%
20	Ameren Corp.	600	1.1%	4.9%
	TOP 20 TOTAL*	**32,989**	**61.0%**	
	2001 U.S. TOTAL*	**54,120**		

** Actual additons announced. Not probability weighted.*
*** Only includes capacity operating in U.S.*

Source: Deutsche Banc Alex. Brown, RDI Consulting

A Regional Review of 2001 Electricity Supply & Demand in the U.S.

Figure 4 shows the summer time capacity reserve margins for the eleven regions of the US. (including subregions for the West and Southeast). As stated above, we expect the national average margin to be 8.4% in the summer of 2001. Importantly, this is based on our forecast of demand growth (about 3% nationally) and the 35,000 megawatts of new generating capacity that should be available by June 15, 2001. We assume adequate capacity exists at reserve margin levels of 15% or over. These numbers are slightly different than our March 8 report as we are only including supply that will be available to meet summer time peak demand in the calculation. In our March 8 report, we included all capacity additions for 2001 in the annual capacity margin calculations – admittedly a little bit of an apples and oranges comparison. We view the numbers in this report as a more accurate reflection of the summer time capacity position in the eleven NERC regions of the US. As in the March 8 report, we have made a probability weighting of planned capacity additions based on the status of the individual projects. For 2001, we included 100% of projects listed as under construction, 50% of projects in advanced development and 0% of projects in early development.

Figure 4: **Summer 2001 CRM's**

NERC Region	2001 CRM
ECAR	7.2%
ERCOT	16.0%
FRCC	3.3%
MAAC	8.3%
MAIN	8.0%
MAPP	0.9%
NEPOOL	13.0%
NY	9.9%
SERC	3.6%
Entergy*	3.3%
Southern*	4.0%
TVA*	3.9%
VACAR*	1.2%
SPP	12.6%
WSCC	13.2%
AZ-NV-NM**	3.7%
California**	-0.3%
Northwest**	31.2%
Rocky Mts**	13.3%
US TOTAL	**8.4%**

* SERC subregion.

** WSCC subregion.

Source: Deutsche Banc Alex. Brown, NERC, RDI Consulting

Reviewing the regional reserve margins, it is noteworthy that only three of the eleven regions are expected to have double digit reserve margins in 2001. These three regions are Texas, New England and the central Southwest (SPP). The significant supply additions made in these three regions over the last two years have bolstered the supply situation. The other eight regions of the U.S. are expected to have reserve margins that are below 10% during the summer of 2001. It is important to note that while the WSCC appears to have a double-digit reserve margin, this number is misleading since it includes substantial hydro capacity in the West that is currently unavailable due to a lack of rainfall.

The regions with the lowest reserve margins are California (-0.3%) and the Mid-Continent Area Power Pool – MAPP (0.9%). The California region shortage is well publicized. Importantly, California's status as a net importer of power is how a negative capacity margin can persist. The MAPP region (located in the upper Midwest – North and South Dakota, etc.) is unique inasmuch as it is a winter peaking region. This suggests that the highest demand for electricity occurs in the winter rather than in the summer, like the other regions of the U.S. This allows the MAPP region to purchase power from other regions during peak demand. However, new resources will have to eventually be added to the MAPP region or transmission will have to show material improvement.

Figure 5 shows the capacity additions planned for each region by June 15 of this year. The largest additions (shown as a percent of installed regional capacity) are in Texas and the central Midwest (MAIN). This is, on average, an almost 10% addition to installed capacity. As the central Midwest region still only has an 8% reserve margin for the summer of 2001, it is very evident how short the region was in 2000.

The smallest planned capacity additions during the first half of 2001 are in New York City and the Western U.S. (including California). As shown in Figure 5, those two combined regions should add less than 2,500 MW of new electricity generating capacity in the first six months of 2001. The total capacity additions for all regions by June 15 is expected to be 35,000 MW. Our forecast for the full year 2001 continues to be about 45,000 MW.

Appendix A provides a plant-by-plant detail of capacity additions expected in 2001, sorted by NERC region.

Appendix B provides detailed summaries of the five-year outlook for electricity supply additions for each region. The appendix also includes a summary table of our expected supply additions, for the **full year,** from 2001 to 2005.

Figure 5: **Summer 2001 Capacity Additions by Region**

NERC Region	MW	% Installed Capacity*
ECAR	3,285	3.0%
ERCOT	7,984	12.5%
FRCC	2,079	5.3%
MAAC	1,064	1.8%
MAIN	4,621	8.4%
MAPP	835	2.5%
NEPOOL	1,964	7.7%
NY	500	1.4%
SERC	8,842	5.6%
Entergy	2,359	8.6%
Southern	3,312	7.5%
TVA	1,145	3.7%
VACAR	1,606	2.9%
SPP	2,546	5.7%
WSCC	1,907	1.4%
AZ-NV-NM	561	2.6%
California	696	1.3%
Northwest	346	0.7%
Rocky Mts	304	3.4%
Total	**35,207**	**4.6%**

* Percent of 2000 installed capacity for each region.

Source: Deutsche Banc Alex. Brown, NERC, RDI Consulting

The Hints for 2002 in the United States

Figure 6 shows the electricity generating additions that we expect in 2002 prior to the summer time peak. As shown in the table, we expect 55,000 megawatts of new capacity during the first six months of 2002 and a total of over 60,000 MW of new generating capacity for the full year. Again, this data has been probability weighted based on what we think will actually come into commercial operation. Outside of New York and the upper Midwest, almost every region of the U.S. gets a major injection of new capacity in time for the summer of 2002. This heightens our confidence in lower electricity prices and profit margins in 2002. Our 2002 forecast remains premised upon a 3% demand growth rate. As we stated above, we are more concerned with our demand forecast being too high rather than too low, primarily due to the slowed U.S. economy. Therefore, we remain confident in our 2002 outlook for moderating power prices.

Figure 6: **Summer 2002 Capacity Additions**

NERC Region	MW
ECAR	7,550
ERCOT	4,813
FRCC	5,835
MAAC	2,697
MAIN	5,668
MAPP	534
NEPOOL	3,874
NY	119
SERC	16,241
Entergy*	6,779
Southern*	5,429
TVA*	1,448
VACAR*	2,585
SPP	1,460
WSCC	5,279
AZ-NV-NM**	2,918
California**	1,099
Northwest**	665
Rocky Mts**	597
Total	**54,070**

* SERC subregion.

** WSCC subregion.

Source: Deutsche Banc Alex. Brown, RDI Consulting

Figure 7 shows the resulting capacity reserve margins for 2002, based on the supply additions prior to the summer of 2002 and the continuation of 3% demand growth. The biggest change in capacity reserve margins from 2001 to 2002 is in New England (13% to 25%), though most regions appear to show a marked improvement over the 2001 margins.

Figure 7: **Summer 2002 CRM's**

NERC Region	2002 CRM
ECAR	11.3%
ERCOT	20.3%
FRCC	12.6%
MAAC	10.8%
MAIN	13.6%
MAPP	-0.7%
NEPOOL	25.3%
NY	8.1%
SERC	4.3%
Entergy	18.4%
Southern	12.7%
TVA	4.4%
VACAR	1.9%
SPP	13.3%
WSCC	15.8%
AZ-NM-NV	16.3%
California	2.2%
Northwest	31.2%
Rocky Mts	17.6%
US TOTAL	**12.6%**

Source: Deutsche Banc Alex. Brown, NERC, RDI Consulting

California: A Tough 2001 But a Better 2002!

We believe that the most noteworthy change from 2001 to 2002 will be the materialization of a far less dire shortage situation in California. Although 2001 is likely to have blackouts at peak demand times, we expect that the return to more normal hydro conditions, coupled with supply additions of as much as 5,000 megawatts, will materially improve the supply situation.

The most important but unpredictable development in California will be the advancement of a solution to the regulatory and political issues in the state. Recall that the utility subsidiary of PG&E Corporation is in bankruptcy, and the utility subsidiary of Edison International is not far behind (particularly in light of the slow action by regulators and legislators on the proposed memorandum of understanding between California Governor Davis and the utility subsidiary of Edison International). Without approval of this MOU, the utility subsidiary of Edison International is far more likely to follow Pacific Gas & Electric into bankruptcy.

New York: A Better 2003!

The supply situation is likely to remain tight in New York City in both 2001 and 2002. As New York State is a net exporter of power and far less reliant on hydroelectric resources, the situation is less dire than California. However, few new supply additions are scheduled to be added in New York City before 2003. We expect the City to avert material or widespread (supply-led) blackouts or outages during the summer of 2001. We should point out that infrastructure-led outages (transformer or transmission problems) occurred during the summers of 1999 and 2000. Therefore, some service interruption appears likely during 2001.

Investment Outlook: Great in 2001, More Selective in 2002!

The shortage of electricity generating supply during the summer of 2001, coupled with the rising prices of electricity and the increasing output of new generating resources will drive earnings for the generators in the second and third quarters. We expect electricity prices and profit margins to be strong in 2001 but to begin to moderate for the first time in the last three years during 2002. First-quarter 2001 profits supported our forecast, with almost every one of the companies in the electric generation sector beating our expectation for earnings growth. We expect similar activity in the second and third quarters – particularly in light of the relatively easy earnings comparisons. The companies we expect to benefit from this opportunity in the near term include Calpine Corporation (CPN), Reliant Resources (RRI), UtiliCorp United (UCU), Allegheny Energy (AYE), Exelon Corporation (EXC) and Orion Power Holdings (ORN). Other potential benefactors include Duke Energy (DUK), Mirant Corporation (MIR) and NRG Energy (NRG).

Appendix A: Plant Detail of U.S. Capacity Additions in 2001

Figure 8: **U.S. Generation Additions – 2001**

U.S. Planned Generation Additions -- 2001

(Sorted by NERC Region)

Holding Company	Plant	MW	Location	State	NERC	Subregion	Fuel
AES Corp.	Georgetown	20	Unavailable	IN	ECAR	ECARSR	Natural Gas
Allegheny Energy, Inc.	Westmoreland (Alensu)	88	Unavailable	PA	ECAR	ECARSR	Natural Gas
Atlantic Renewable Energy Corporation	Mill Run Windpower	8	Unavailable	PA	ECAR	ECARSR	Wind
Central Vermont Public Service Corp.	Gauley River	80	Summersville	WV	ECAR	ECARSR	Water
Cinergy Corp.	Ashtabula (TRCISO)	14	Ashtabula	OH	ECAR	ECARSR	Natural Gas
Cinergy Corp.	Henry	68	Unavailable	IN	ECAR	ECARSR	Natural Gas
CMS Energy Corp.	Dearborn Industrial Generation LLC	550	Dearborn	MI	ECAR	ECARSR	Natural Gas
Constellation Energy Group, Inc.	Ceredo	185	Ceredo	WV	ECAR	ECARSR	Natural Gas
Constellation Energy Group, Inc.	Wolf Hills	250	Bristol	VA	ECAR	ECARSR	Natural Gas
Constellation Energy Group, Inc.	Wayne County [Constellation]	300	Unavailable	WV	ECAR	ECARSR	Natural Gas
DPL, Inc.	Darby Generating Station	160	Darby	OH	ECAR	ECARSR	Natural Gas
DPL, Inc.	Chester Township	200	Chester	IN	ECAR	ECARSR	Natural Gas
DPL, Inc.	Darby Generating Station	160	Darby	OH	ECAR	ECARSR	Natural Gas
DPL, Inc.	Undisclosed Site [Phase IIII]	160	Unavailable	NA	ECAR	ECARSR	Natural Gas
DTE Energy Co.	Georgetown	60	Unavailable	IN	ECAR	ECARSR	Natural Gas
Duke Energy Corp.	Henry	68	Unavailable	IN	ECAR	ECARSR	Natural Gas
Dynegy, Inc.	Riverside	560	Louisa	KY	ECAR	ECARSR	Natural Gas
E.ON AG	Brown (KUC)	133	Burgin	KY	ECAR	ECARSR	Natural Gas
East Kentucky Power Coop, Inc.	J.K. Smith (SMITH GENERATING FA	80	Winchester	KY	ECAR	ECARSR	Natural Gas
Energy Developments, Ltd.	Model Landfill Project	4	Columbus	OH	ECAR	ECARSR	Landfill Gas
Energy Developments, Ltd.	Ottawa Landfill	3	Sandusky	OH	ECAR	ECARSR	Landfill Gas
Energy Developments, Ltd.	Lorain Landfill	8	Oberlin	OH	ECAR	ECARSR	Landfill Gas
Energy Developments, Ltd.	Carbon Limestone Landfill	14	Youngstown	OH	ECAR	ECARSR	Landfill Gas
FirstEnergy Corporation	Perry (CEI)	25	North Perry	OH	ECAR	ECARSR	Uranium
FirstEnergy Corporation	West Lorain	425	Lorain	OH	ECAR	ECARSR	Natural Gas
Goldman Sachs Group, Inc.	Ceredo	315	Ceredo	WV	ECAR	ECARSR	Natural Gas
Mirant Corp.	Zeeland (SOUENE)	300	Zeeland	MI	ECAR	ECARSR	Natural Gas
NiSource Inc	Whiting Refinery (PRIENE)	545	Whiting	IN	ECAR	ECARSR	Natural Gas
NiSource Inc	Indiana Harbor Works (Ltv Steel)	50	East Chicago	IN	ECAR	ECARSR	Natural Gas
PG&E National Energy Group Inc	Bowling Green (USGECO)	45	Bowling Green	OH	ECAR	ECARSR	Natural Gas
PG&E National Energy Group Inc	Napoleon	45	Napoleon	OH	ECAR	ECARSR	Natural Gas
PG&E National Energy Group Inc	Galion	45	Galion	OH	ECAR	ECARSR	Natural Gas
SPARKenergy.com, Inc.	Putnam Energy Center	500	Warren	IN	ECAR	ECARSR	Natural Gas
Trigen Energy Corp.	Ashtabula (TRCISO)	14	Ashtabula	OH	ECAR	ECARSR	Natural Gas
Zilkha Renewable Energy	Mill Run Windpower	8	Unavailable	PA	ECAR	ECARSR	Wind
American Electric Power Company Inc	Sweeny Cogeneration Facility	61	Old Ocean	TX	ERCOT	ERCOTS	Natural Gas
American Electric Power Company Inc	Eastex Cogeneration Facility	440	Longview	TX	ERCOT	ERCOTS	Natural Gas
American Electric Power Company Inc	Trent Mesa	130	Unavailable	TX	ERCOT	ERCOTS	Wind
Austin Energy	Sandhill Power Project	183	Austin	TX	ERCOT	ERCOTS	Natural Gas
Calpine Corp.	Channel Energy Center	18	Houston	TX	ERCOT	ERCOTS	Natural Gas
Calpine Corp.	Channel Energy Center	542	Houston	TX	ERCOT	ERCOTS	Natural Gas
Calpine Corp.	Lost Pines I	250	Unavailable	TX	ERCOT	ERCOTS	Natural Gas
Calpine Corp.	Magic Valley Power Plant	700	Edinburg	TX	ERCOT	ERCOTS	Natural Gas
Calpine Corp.	Baytown Power Plant	700	Baytown	TX	ERCOT	ERCOTS	Natural Gas
Calpine Corp.	Baytown Power Plant	100	Baytown	TX	ERCOT	ERCOTS	Natural Gas
Cielo Wind Power, L.L.C.	Hueco Mountain Wind Ranch	2	El Paso	TX	ERCOT	ERCOTS	Wind
Constellation Energy Group, Inc.	Indian Mesa Wind Farm	14	Unavailable	TX	ERCOT	ERCOTS	Wind
Energy Developments, Ltd.	Tessman Road Landfill	5	San Antonio	TX	ERCOT	ERCOTS	Landfill Gas
Energy Developments, Ltd.	Whispering Pines Landfill	3	Houston	TX	ERCOT	ERCOTS	Landfill Gas
Energy Developments, Ltd.	Hutchins Landfill	3	Dallas	TX	ERCOT	ERCOTS	Landfill Gas
Enron Corporation	Enron Indian Mesa I	26	Unavailable	TX	ERCOT	ERCOTS	Wind
Enron Corporation	Iraan Wind Farm (Clear Sky)	135	Iraan	TX	ERCOT	ERCOTS	Wind
Enron Sandhill Lp	Sandhill Power Project	17	Austin	TX	ERCOT	ERCOTS	Natural Gas
Exelon Corp.	Laporte Energy Plant	160	La Porte	TX	ERCOT	ERCOTS	
FPL Group, Inc.	King Mountain	278	Unavailable	TX	ERCOT	ERCOTS	Wind
FPL Group, Inc.	Woodward Mountain (West Texas)	160	Odessa	TX	ERCOT	ERCOTS	Wind

(cont. on next page)

Source: Deutsche Banc Alex. Brown estimates and company information

Figure 9: **U.S. Generation Additions - 2001 (cont.)**

Garland Power & Light System	Ray Olinger	85	Nevada	TX	ERCOT	ERCOTS	Natural Gas
General Electric Co.	Sweeny Cogeneration Facility	61	Old Ocean	TX	ERCOT	ERCOTS	Natural Gas
GenTex Power Corporation	Lost Pines I	250	Unavailable	TX	ERCOT	ERCOTS	Natural Gas
Goldman Sachs Group, Inc.	Indian Mesa Wind Farm	28	Unavailable	TX	ERCOT	ERCOTS	Wind
Groupe Suez Lyonnaise des Eaux	Ennis-Tractebel #1	337	Ennis	TX	ERCOT	ERCOTS	Natural Gas
Lyondell Chemical Co.	Equistar Channelview	111	Channelview	TX	ERCOT	ERCOTS	Natural Gas
Millennium Chemicals, Inc.	Equistar Channelview	80	Channelview	TX	ERCOT	ERCOTS	Natural Gas
Mitsubishi Corp.	Tenaska Gateway Generating Station	246	Henderson	TX	ERCOT	ERCOTS	Natural Gas
Mitsubishi Corp.	Tenaska Gateway Generating Station	33	Henderson	TX	ERCOT	ERCOTS	Natural Gas
National Power plc	Midlothian Project	550	Midlothian	TX	ERCOT	ERCOTS	Natural Gas
National Power plc	Midlothian Project	550	Midlothian	TX	ERCOT	ERCOTS	Natural Gas
National Power plc	San Marcos (AMNAPO)	1,100	San Marcos	TX	ERCOT	ERCOTS	Natural Gas
Not Applicable	Indian Mesa Wind Farm	41	Unavailable	TX	ERCOT	ERCOTS	Wind
Not Applicable	Ennis-Tractebel #1	2	Ennis	TX	ERCOT	ERCOTS	Natural Gas
Occidental Petroleum Corp.	Equistar Channelview	80	Channelview	TX	ERCOT	ERCOTS	Natural Gas
Panda Energy International Inc	Panda Guadalupe Power Plant	500	New Braunfels	TX	ERCOT	ERCOTS	Natural Gas
Panda Energy International Inc	Odessa/Ector Power Partners	500	Odessa	TX	ERCOT	ERCOTS	Natural Gas
Private Investors	Ennis-Tractebel #1	4	Ennis	TX	ERCOT	ERCOTS	Natural Gas
Public Service Enterprise Group, Inc.	Panda Guadalupe Power Plant	500	New Braunfels	TX	ERCOT	ERCOTS	Natural Gas
Public Service Enterprise Group, Inc.	Odessa/Ector Power Partners	500	Odessa	TX	ERCOT	ERCOTS	Natural Gas
Reliant Energy, Inc.	Channelview	781	Houston	TX	ERCOT	ERCOTS	Natural Gas
Royal Dutch Petroleum Co.	Tenaska Gateway Generating Station	152	Henderson	TX	ERCOT	ERCOTS	Natural Gas
Royal Dutch Petroleum Co.	Tenaska Gateway Generating Station	20	Henderson	TX	ERCOT	ERCOTS	Natural Gas
Shell Transport & Trading Co. plc	Tenaska Gateway Generating Station	14	Henderson	TX	ERCOT	ERCOTS	Natural Gas
Shell Transport & Trading Co. plc	Tenaska Gateway Generating Station	102	Henderson	TX	ERCOT	ERCOTS	Natural Gas
Southern Company	SEI Texas Bosque County Peaking Pl	248	Whitney	TX	ERCOT	ERCOTS	
Tenaska, Inc.	Tenaska Gateway Generating Station	245	Henderson	TX	ERCOT	ERCOTS	Natural Gas
Tenaska, Inc.	Tenaska Gateway Generating Station	33	Henderson	TX	ERCOT	ERCOTS	Natural Gas
Texas Wind Power Company	Big Mesa Wind Ranch	77	Unavailable	TX	ERCOT	ERCOTS	Wind
Texas Wind Power Company	King Mountain Wind Ranch	77	McCamey	TX	ERCOT	ERCOTS	Wind
Texas Wind Power Company	King Mountain Wind Ranch	3	McCamey	TX	ERCOT	ERCOTS	Wind
Texas Wind Power Company	King Mountain Wind Ranch	200	McCamey	TX	ERCOT	ERCOTS	Wind
Calpine Corp.	Auburndale Power Partners Lim	100	Auburndale	FL	FRCC	FRCCSR	Natural Gas
Florida Municipal Power Agency	Cane Island Power Park	30	Intercession City	FL	FRCC	FRCCSR	Natural Gas
Jacksonville Electric Authority	Brandy Branch Generating Station	340	Baldwin	FL	FRCC	FRCCSR	Natural Gas
Jacksonville Electric Authority	Brandy Branch Generating Station	170	Baldwin	FL	FRCC	FRCCSR	Natural Gas
Kissimmee Utility Authority	Cane Island Power Park	220	Intercession City	FL	FRCC	FRCCSR	Natural Gas
Lakeland Electric & Water Utilities	McIntosh-Fl	249	Lakeland	FL	FRCC	FRCCSR	Natural Gas
Lakeland Electric & Water Utilities	McIntosh-Fl	-249	Lakeland	FL	FRCC	FRCCSR	Natural Gas
Lakeland Electric & Water Utilities	McIntosh-Fl	369	Lakeland	FL	FRCC	FRCCSR	Natural Gas
Progress Energy, Inc.	Crystal River	100	Crystal River	FL	FRCC	FRCCSR	Coal
Reliant Energy, Inc.	Reliant Energy Osceola	464	Kissimmee	FL	FRCC	FRCCSR	Natural Gas
AES Corp.	Commonwealth Chesapeake Project	41	Unavailable	VA	MAAC	PJM	Oil Light
AES Corp.	Ironwood Project	700	Lebanon	PA	MAAC	PJM	Natural Gas
Atlantic Renewable Energy Corporation	Somerset Wind Project	9	Somerset	PA	MAAC	PJM	Wind
Cayuga Energy, Inc.	Scranton Plant (PEIPOW)	23	Scranton	PA	MAAC	PJM	Natural Gas
Conectiv	Wilmington	111	Wilmington	DE	MAAC	PJM	Natural Gas
Conectiv	Wilmington	111	Wilmington	DE	MAAC	PJM	Natural Gas
Conectiv	Wilmington	111	Wilmington	DE	MAAC	PJM	Natural Gas
Constellation Energy Group, Inc.	Rockland Township	250	Rockland	PA	MAAC	PJM	Natural Gas
El Paso Corp.	Linden Cogen Plant [Eastcoast Pwr]	83	Linden	NJ	MAAC	PJM	Natural Gas
Enron Corporation	Linden Cogen Plant [Eastcoast Pwr]	87	Linden	NJ	MAAC	PJM	Natural Gas
Exelon Corp.	Muddy Run	104	Unavailable	PA	MAAC	PJM	Water
Mosbacher Power Partners, L.P.	Commonwealth Chesapeake Project	41	Unavailable	VA	MAAC	PJM	Oil Light
Not Applicable	Dover [Kraft Foods Cogeneration]	14	Dover	DE	MAAC	PJM	Natural Gas
Private Investors	Commonwealth Chesapeake Project	41	Unavailable	VA	MAAC	PJM	Oil Light
Southern Union Co.	Scranton Plant (PEIPOW)	23	Scranton	PA	MAAC	PJM	Natural Gas
TECO Energy, Inc.	Commonwealth Chesapeake Project	41	Unavailable	VA	MAAC	PJM	Oil Light
Xcel Energy, Inc.	Dover [Kraft Foods Cogeneration]	74	Dover	DE	MAAC	PJM	Natural Gas

(cont. on next page)

Source: Deutsche Banc Alex. Brown estimates and company information

Figure 10: **U.S. Generation Additions - 2001 (cont.)**

Duke Energy Corp.	Audrain	640	Vandalia	MO	MAIN	EMO	Natural Gas
University of Missouri	University of Missouri-Columbia	26	Columbia	MO	MAIN	EMO	Natural Gas
Calpine Corp.	Cook County	30	Chicago	IL	MAIN	NI	Natural Gas
Constellation Energy Group, Inc.	Chicago (Conpow)	300	Chicago	IL	MAIN	NI	Natural Gas
Dominion Energy Inc	Elwood	114	Elwood	IL	MAIN	NI	Natural Gas
Duke Energy Corp.	Lee Generating Station	640	Unavailable	IL	MAIN	NI	Natural Gas
Exelon Corp.	La Salle	50	Seneca	IL	MAIN	NI	Uranium
MidAmerican Energy Holdings Co.	Cordova Energy	537	Cordova	IL	MAIN	NI	Natural Gas
Peoples Energy Corp.	Elwood	636	Elwood	IL	MAIN	NI	Natural Gas
Reliant Energy, Inc.	Shelby	81	Shelby Ct	IL	MAIN	NI	Natural Gas
Reliant Energy, Inc.	Reliant Energy Aurora LP	873	Aurora	IL	MAIN	NI	Natural Gas
Wisconsin Energy Corp.	Cook County	270	Chicago	IL	MAIN	NI	Natural Gas
AES Corp.	AESMedina Valley	1	Mossville	IL	MAIN	SCI	Natural Gas
AES Corp.	AESMedina Valley	44	Mossville	IL	MAIN	SCI	Natural Gas
Ameren Corp.	Patoka	117	Kinmundy	IL	MAIN	SCI	Natural Gas
Ameren Corp.	Grand Tower	-186	Grand Tower	IL	MAIN	SCI	Coal
Ameren Corp.	Grand Tower	23	Grand Tower	IL	MAIN	SCI	Natural Gas
Ameren Corp.	Grand Tower	550	Grand Tower	IL	MAIN	SCI	Natural Gas
Ameren Corp.	Grand Tower	-186	Grand Tower	IL	MAIN	SCI	Coal
Ameren Corp.	Patoka	117	Kinmundy	IL	MAIN	SCI	Natural Gas
Ameren Corp.	Pinckneyville	144	Pinckneyville	IL	MAIN	SCI	Natural Gas
Alliant Energy Corp.	Amherst Digester	0	Amherst	WI	MAIN	WUM	Proc Gas
Calpine Corp.	Rockgen Energy Center	510	Cambridge	WI	MAIN	WUM	Natural Gas
FPL Group, Inc.	Iowa County Wisconsin Wind Farm	26	Eden	WI	MAIN	WUM	Wind
FPL Group, Inc.	West Bend Wind Project	30	West Bend	WI	MAIN	WUM	Wind
ALLETE	Potlatch Cloquet Cogen	24	Cloquet	MN	MAPP	MAPPSR	Steam
Alliant Energy Corp.	Top Deck Holstein	0	Westgate	IA	MAPP	MAPPSR	Proc Gas
Atlantic Renewable Energy Corporation	Top Of Iowa Wind Farm	40	Unavailable	IA	MAPP	MAPPSR	Wind
Dairyland Power Coop	Elk Mound Station	80	Eau Claire	WI	MAPP	MAPPSR	Natural Gas
East River Electric Power Coop, Inc.	Prairiewinds	3	Chamberlain	SD	MAPP	MAPPSR	Wind
enXco	Chandler Wind Turbine	4	Chandler	MN	MAPP	MAPPSR	Wind
Great River Energy	Great River Energy - Pleasant Valley	280	Unavailable	MN	MAPP	MAPPSR	Natural Gas
Great River Energy	Lakefield Junction Generation Facility	550	Trimont	MN	MAPP	MAPPSR	Natural Gas
Great River Energy	Great River Energy - Pleasant Valley	124	Unavailable	MN	MAPP	MAPPSR	Natural Gas
Northern Alternative Energy	Pipestone Wind	131	Unavailable	MN	MAPP	MAPPSR	Wind
Northern Alternative Energy	Salem	100	Salem	IA	MAPP	MAPPSR	Natural Gas
Xcel Energy, Inc.	Black Dog	-75	Minneapolis	MN	MAPP	MAPPSR	Coal
Zilkha Renewable Energy	Top Of Iowa Wind Farm	40	Unavailable	IA	MAPP	MAPPSR	Wind
Calpine Corp.	Westbrook Power Plant	540	Westbrook	ME	NPCC	NEPOOL	Natural Gas
El Paso Corp.	Milford [EPPSCO]	167	Milford	CT	NPCC	NEPOOL	Natural Gas
Endless Energy	Little Equinox	5	Unavailable	VT	NPCC	NEPOOL	Wind
Exelon Corp.	West Medway	269	Medway	MA	NPCC	NEPOOL	Natural Gas
Marubeni Corp.	West Medway	81	Medway	MA	NPCC	NEPOOL	Natural Gas
National Power plc	Blackstone (AMNAPO)	580	Blackstone	MA	NPCC	NEPOOL	Natural Gas
National Power plc	Bellingham	580	Bellingham	MA	NPCC	NEPOOL	Natural Gas
PG&E National Energy Group Inc	Millennium Power Partners, LP	12	Charlton	MA	NPCC	NEPOOL	Natural Gas
PG&E National Energy Group Inc	Millennium Power Partners, LP	348	Charlton	MA	NPCC	NEPOOL	Natural Gas
PG&E National Energy Group Inc	Lake Road	792	Killingly	CT	NPCC	NEPOOL	Natural Gas
Power Development Co.	Milford [EPPSCO]	105	Milford	CT	NPCC	NEPOOL	Natural Gas
PPL Corp.	Wallingford	200	Wallingford	CT	NPCC	NEPOOL	Natural Gas
Private Investors	West Medway	6	Medway	MA	NPCC	NEPOOL	Natural Gas
VIVENDI	West Medway	184	Medway	MA	NPCC	NEPOOL	Natural Gas
Adirondack Hydro Development Corp.	Northumberland	10	Unavailable	NY	NPCC	NYPP	Water
Atlantic Renewable Energy Corp.	Canastota	30	Canastota	NY	NPCC	NYPP	Wind
Atlantic Renewable Energy Corp.	Flat Rock (ATRE)	25	Unavailable	NY	NPCC	NYPP	Wind
Calpine Corp.	Lockport Energy Assoc. L/P L	5	Lockport	NY	NPCC	NYPP	Natural Gas
CES Acquisition Corp.	Lockport Energy Assoc. L/P L	10	Lockport	NY	NPCC	NYPP	Natural Gas
Enron Corporation	Far Rockaway (ENRNA)	60	Far Rockaway	NY	NPCC	NYPP	Oil Light
Fortistar Capital, Inc.	Lockport Energy Assoc. L/P L	3	Lockport	NY	NPCC	NYPP	Natural Gas
Harbert Management Corp.	Lockport Energy Assoc. L/P L	9	Lockport	NY	NPCC	NYPP	Natural Gas
International Wind Corp.	Flat Rock (ATRE)	25	Unavailable	NY	NPCC	NYPP	Wind
Jamestown Board of Public Utilities	Carlson	43	Jamestown	NY	NPCC	NYPP	Natural Gas

(cont. on next page)

Source: Deutsche Banc Alex. Brown estimates and company information

Figure 11: **U.S. Generation Additions - 2001 (cont.)**

New York Power Authority	Pilgrim State Hospital	44	Islip	NY	NPCC	NYPP	Natural Gas
New York Power Authority	23rd Street	80	Brooklyn	NY	NPCC	NYPP	Natural Gas
New York Power Authority	Harlem Rail	80	New York	NY	NPCC	NYPP	Natural Gas
New York Power Authority	Hell Gate	80	New York	NY	NPCC	NYPP	Natural Gas
New York Power Authority	River Street (NYPA)	44	Brooklyn	NY	NPCC	NYPP	Natural Gas
New York Power Authority	Vernon Boulevard	80	New York	NY	NPCC	NYPP	Natural Gas
New York Power Authority	Virginia Avenue	44	Staten Island	NY	NPCC	NYPP	Natural Gas
NYC Energy Group, L.P.	Nisa Electrical Generation	80	Brooklyn	NY	NPCC	NYPP	Natural Gas
Tomen Corp.	Lockport Energy Assoc. L/P L	8	Lockport	NY	NPCC	NYPP	Natural Gas
UtiliCorp United, Inc.	Lockport Energy Assoc. L/P L	10	Lockport	NY	NPCC	NYPP	Natural Gas
Associated Electric Coop, Inc.	St Francis	130	Malden	MO	SERC	ENTR	Natural Gas
Calpine Corp.	Pine Bluff Energy Center	176	Pine Bluff	AR	SERC	ENTR	Natural Gas
Cleco Corp.	Perryville Power Station	85	Monroe	LA	SERC	ENTR	Natural Gas
Duke Energy Corp.	Hinds Energy Facility	500	Jackson	MS	SERC	ENTR	Natural Gas
Duke Energy Corp.	St Francis	130	Malden	MO	SERC	ENTR	Natural Gas
Dynegy, Inc.	Calcasieu Generation Project	165	Lake Charles	LA	SERC	ENTR	Natural Gas
Entergy Corp.	Warren Power Project [Entergy]	300	Vicksburg	MS	SERC	ENTR	Natural Gas
Mirant Corp.	Perryville Power Station	85	Monroe	LA	SERC	ENTR	Natural Gas
Not Applicable	Sterlington	7	Sterlington	LA	SERC	ENTR	Natural Gas
Not Applicable	Big Cajun 1	19	New Roads	LA	SERC	ENTR	Natural Gas
Not Applicable	Sterlington	11	Sterlington	LA	SERC	ENTR	Natural Gas
Not Applicable	Big Cajun 1	19	New Roads	LA	SERC	ENTR	Natural Gas
PG&E National Energy Group Inc	Attala Energy Center	510	Kosciusko	MS	SERC	ENTR	Natural Gas
Praxair, Inc.	Praxair Cogen	3	Sulphur	LA	SERC	ENTR	Other
Reliant Energy, Inc.	Conroe Landfill	2	Conroe	TX	SERC	ENTR	Landfill Gas
Royal Dutch Petroleum Co.	Pine Bluff Energy Center	26	Pine Bluff	AR	SERC	ENTR	Natural Gas
Shell Transport & Trading Co. plc	Pine Bluff Energy Center	18	Pine Bluff	AR	SERC	ENTR	Natural Gas
Xcel Energy, Inc.	Sterlington	37	Sterlington	LA	SERC	ENTR	Natural Gas
Xcel Energy, Inc.	Big Cajun 1	101	New Roads	LA	SERC	ENTR	Natural Gas
Xcel Energy, Inc.	Sterlington	56	Sterlington	LA	SERC	ENTR	Natural Gas
Xcel Energy, Inc.	Big Cajun 1	101	New Roads	LA	SERC	ENTR	Natural Gas
Alabama Electric Coop, Inc.	McWilliams	500	Gantt	AL	SERC	STHRN	Natural Gas
Calpine Corp.	Hog Bayou Energy Center	110	Mobile	AL	SERC	STHRN	Natural Gas
CES Acquisition Corp.	Tenaska Georgia	117	Franklin	GA	SERC	STHRN	Natural Gas
Dynegy, Inc.	Heard County Power Plant	500	Franklin	GA	SERC	STHRN	Natural Gas
Dynegy, Inc.	Tenaska Georgia	117	Franklin	GA	SERC	STHRN	Natural Gas
E.ON AG	Monroe	450	Unavailable	GA	SERC	STHRN	Natural Gas
Progress Energy, Inc.	Monroe [CPLC]	160	Monroe	GA	SERC	STHRN	Natural Gas
Resource Technology Corp.	Columbus Landfill	2	Columbus	GA	SERC	STHRN	Landfill Gas
Royal Dutch Petroleum Co.	Hog Bayou Energy Center	66	Mobile	AL	SERC	STHRN	Natural Gas
Shell Transport & Trading Co. plc	Hog Bayou Energy Center	44	Mobile	AL	SERC	STHRN	Natural Gas
Southern Company	Victor J. Daniel	990	Escatawpa	MS	SERC	STHRN	Natural Gas
Southern Company	Barry (ALAP)	537	Bucks	AL	SERC	STHRN	Natural Gas
Southern Company	Theodore Cogen	207	Theodore	AL	SERC	STHRN	Natural Gas
Tenaska, Inc.	Tenaska Georgia	234	Franklin	GA	SERC	STHRN	Natural Gas
Energy Developments, Ltd.	Middlepoint Landfill	5	Unavailable	TN	SERC	TVA	Landfill Gas
Groupe Suez Lyonnaise des Eaux	Red Hills Generation Facility	432	Chester	MS	SERC	TVA	Coal
Not Applicable	Red Hills Generation Facility	3	Chester	MS	SERC	TVA	Coal
Private Investors	Red Hills Generation Facility	5	Chester	MS	SERC	TVA	Coal
Tennessee Valley Authority	Haywood County	700	Unavailable	TN	SERC	TVA	Natural Gas
Calpine Corp.	Broad River Energy Center	350	Gaffney	SC	SERC	VACAR	Natural Gas
Dominion Energy Inc	Caroline County [Virginia Electric]	320	Unavailable	VA	SERC	VACAR	Natural Gas
FPL Group, Inc.	Doswell Combined Cycle Facilit	171	Ashland	VA	SERC	VACAR	Natural Gas
Progress Energy, Inc.	Hamlet	620	Hamlet	NC	SERC	VACAR	Natural Gas
Progress Energy, Inc.	Rowan	465	Salisbury	NC	SERC	VACAR	Natural Gas
Calpine Corp.	Aries	183	Pleasant Hill	MO	SPP	N	Natural Gas
Empire District Electric Co.	Stateline (EMDE)	301	Unavailable	MO	SPP	N	Natural Gas
Empire District Electric Co.	Stateline (EMDE)	-91	Unavailable	MO	SPP	N	Natural Gas
FPL Group, Inc.	Gray County	110	Montezuma	KS	SPP	N	Wind
Kansas City Power & Light Co.	Hawthorn	540	Kansas City	MO	SPP	N	Coal
UtiliCorp United, Inc.	Aries	189	Pleasant Hill	MO	SPP	N	Natural Gas
Western Resources, Inc.	Gordon Evans	151	Colwich	KS	SPP	N	Natural Gas

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Source: Deutsche Banc Alex. Brown estimates and company information

Figure 12: **U.S. Generation Additions - 2001 (cont.)**

Western Resources, Inc.	Stateline (EMDE)	-61	Unavailable	MO	SPP	N	Natural Gas
Western Resources, Inc.	Stateline (EMDE)	201	Unavailable	MO	SPP	N	Natural Gas
American Electric Power Company Inc	Northeastern	300	Oologah	OK	SPP	S	Natural Gas
Arkansas Electric Coop Corp.	Fulton [AEC]	153	Fulton	AR	SPP	S	Natural Gas
Cielo Wind Power, L.L.C.	White Deer Wind Farm	80	White Deer	TX	SPP	S	Wind
Duke Energy Corp.	McClain Energy Facility	385	Newcastle	OK	SPP	S	Natural Gas
E.I. DuPont de Nemours & Co., Inc.	Sabine River Works (COGLPO)	147	Orange	TX	SPP	S	Natural Gas
Not Applicable	Sabine River Works (COGLPO)	97	Orange	TX	SPP	S	Natural Gas
Oklahoma Municipal Power Authority	McClain Energy Facility	115	Newcastle	OK	SPP	S	Natural Gas
Oneok Inc	ONEOK - Logan County Peaking Faci	300	Unavailable	OK	SPP	S	Natural Gas
Xcel Energy, Inc.	Sabine River Works (COGLPO)	176	Orange	TX	SPP	S	Natural Gas
Calpine Corp.	South Point Power Plant	500	Bullhead City	AZ	WSCC	AZNMNV	Natural Gas
Duke Energy Corp.	Griffith Energy Project	40	Kingman	AZ	WSCC	AZNMNV	Natural Gas
Duke Energy Corp.	Griffith Energy Project	270	Kingman	AZ	WSCC	AZNMNV	Natural Gas
Phelps Dodge Corp.	Chino Mines Co.	50	Hurley	NM	WSCC	AZNMNV	Natural Gas
Pinnacle West Capital Corp.	Glendale Airport-Aps	0	Glendale	AZ	WSCC	AZNMNV	Solar
Pinnacle West Capital Corp.	Embry Riddle Solar (APS)	0	Prescott	AZ	WSCC	AZNMNV	Solar
Pinnacle West Capital Corp.	Gilbert Solar Facility	0	Gilbert	AZ	WSCC	AZNMNV	Solar
Pinnacle West Capital Corp.	Solar	0	Unavailable	AZ	WSCC	AZNMNV	Solar
PPL Corp.	Griffith Energy Project	270	Kingman	AZ	WSCC	AZNMNV	Natural Gas
PPL Corp.	Griffith Energy Project	40	Kingman	AZ	WSCC	AZNMNV	Natural Gas
Reliant Energy, Inc.	Desert Basin	70	Casa Grande	AZ	WSCC	AZNMNV	Natural Gas
Reliant Energy, Inc.	Desert Basin	490	Casa Grande	AZ	WSCC	AZNMNV	Natural Gas
Williams Companies, Inc.	Las Vegas	62	Unavailable	NV	WSCC	AZNMNV	Natural Gas
A. Ahlstrom Corp.	Chino Correctional Facility	176	Chino	CA	WSCC	CAMX	Natural Gas
AES Corp.	Huntington Beach	440	Huntington Beacl	CA	WSCC	CAMX	Natural Gas
Alameda County	Santa Rita Jail Solar	1	Dublin	CA	WSCC	CAMX	Solar
Alliance Power Inc.	Alliance Century Peaker	40	Colton	CA	WSCC	CAMX	Natural Gas
Alliance Power Inc.	Alliance Drews Peaker	40	Colton	CA	WSCC	CAMX	Natural Gas
Auberry Energy, Inc.	Auberry Energy Inc.	8	Auberry	CA	WSCC	CAMX	Biomass
Bechtel Group, Inc.	Indigo Energy Facility	68	Palm Springs	CA	WSCC	CAMX	Natural Gas
Bechtel Group, Inc.	Larkspur Energy Facility	45	San Diego	CA	WSCC	CAMX	Natural Gas
Calpine Corp.	Los Medanos Energy Center	510	Pittsburg	CA	WSCC	CAMX	Natural Gas
Calpine Corp.	Sutter Power Plant	500	Yuba City	CA	WSCC	CAMX	Natural Gas
Calpine Corp.	Gilroy (Calpine)	135	Gilroy	CA	WSCC	CAMX	Natural Gas
Calpine Corp.	King City	50	King City	CA	WSCC	CAMX	Natural Gas
DG Power	El Cajon Peaker	49	El Cajon	CA	WSCC	CAMX	Natural Gas
DG Power	Escondido (DG Power)	49	Escondido	CA	WSCC	CAMX	Natural Gas
DG Power	Midway Peaker	49	Unavailable	CA	WSCC	CAMX	Natural Gas
DG Power	Mission Peaker	49	Unavailable	CA	WSCC	CAMX	Natural Gas
DG Power	Panoche Peaker	49	Unavailable	CA	WSCC	CAMX	Natural Gas
DG Power	SDG&E Border Substation Peaker	49	San Diego	CA	WSCC	CAMX	Natural Gas
DG Power	Vaca-Dixon Peaker (DG Power)	49	Unavailable	CA	WSCC	CAMX	Natural Gas
Edison International	Wilmington Peaker	9	Unavailable	CA	WSCC	CAMX	Natural Gas
Edison International	Sunrise Power Project	320	Fellows	CA	WSCC	CAMX	Natural Gas
El Paso Corp.	United Golden Gate	51	South San Franci	CA	WSCC	CAMX	Natural Gas
Electricityprovider Inc	Lancaster (Ep)	200	Lancaster	CA	WSCC	CAMX	Natural Gas
Fresno Cogeneration Partners LP	Fresno Peaker	23	Fresno	CA	WSCC	CAMX	Natural Gas
Indeck Energy Services, Inc.	Wilmington Peaker	17	Unavailable	CA	WSCC	CAMX	Natural Gas
Los Angeles Dept. of Water & Power	LADWP Headquarters Fuel Cell Plant	0	Los Angeles	CA	WSCC	CAMX	Other
Los Angeles Dept. of Water & Power	LADWP Headquarters Fuel Cell Plant	0	Los Angeles	CA	WSCC	CAMX	Other
Megaenergy	Tulare County Peakers	96	Unavailable	CA	WSCC	CAMX	Natural Gas
Neutrogena Corporation	Neutrogena Solar	0	Los Angeles	CA	WSCC	CAMX	Solar
Not Applicable	Wilmington Peaker	0	Unavailable	CA	WSCC	CAMX	Natural Gas
Not Applicable	Contra Costa County 2	50	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Kern County Peaker	50	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Kings County Peaker	50	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Monterey County Peaker	50	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	San Bernardino County Peaker	90	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Santa Clara County Peaker	100	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Sutter County Peaker	50	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Hanford Energy Park	45	Hanford	CA	WSCC	CAMX	Natural Gas

(cont. on next page)

Source: Deutsche Banc Alex. Brown estimates and company information

Figure 13: **U.S. Generation Additions - 2001 (cont.)**

Not Applicable	Contra Costa County Peaker	100	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Fresno County Peaker	100	Fresno	CA	WSCC	CAMX	Other
Not Applicable	Los Angeles 1 Peaker	50	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Los Angeles 2 Peaker	50	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Los Angeles 3 Peaker	100	Unavailable	CA	WSCC	CAMX	Other
Not Applicable	Madera Power Plant	2	Firebaugh	CA	WSCC	CAMX	Biomass
Not Applicable	Red Bluff Peaker	8	Red Bluff	CA	WSCC	CAMX	Natural Gas
Not Applicable	Chowchilla Peaker	8	Chowchilla	CA	WSCC	CAMX	Natural Gas
Not Applicable	Round Mountain Oil Field Peaker	7	Unavailable	CA	WSCC	CAMX	Other
Panda Energy International Inc	Solano County Peaker	147	Unavailable	CA	WSCC	CAMX	Natural Gas
PG&E National Energy Group Inc	La Paloma	250	Mc Kittrick	CA	WSCC	CAMX	Natural Gas
Public Service Enterprise Group, Inc.	Wilmington Peaker	4	Unavailable	CA	WSCC	CAMX	Natural Gas
Public Service Enterprise Group, Inc.	Hanford Energy Park	45	Hanford	CA	WSCC	CAMX	Natural Gas
RAMCO Inc	Chula Vista Peaker	46	Chula Vista	CA	WSCC	CAMX	Natural Gas
RAMCO Inc	Escondido Peaker (RAMCO)	46	Escondido	CA	WSCC	CAMX	Natural Gas
Royal Dutch Petroleum Co.	Indigo Energy Facility	41	Palm Springs	CA	WSCC	CAMX	Natural Gas
Royal Dutch Petroleum Co.	Larkspur Energy Facility	27	San Diego	CA	WSCC	CAMX	Natural Gas
Sacramento Municipal Utility District	Proctor & Gamble	44	Sacramento	CA	WSCC	CAMX	Natural Gas
SeaWest WindPower, Inc.	San Gorgonio	44	Unavailable	CA	WSCC	CAMX	Wind
Shell Transport & Trading Co. plc	Indigo Energy Facility	27	Palm Springs	CA	WSCC	CAMX	Natural Gas
Shell Transport & Trading Co. plc	Larkspur Energy Facility	18	San Diego	CA	WSCC	CAMX	Natural Gas
Stockton Sierra Cogen	Stockton Peaker	20	Stockton	CA	WSCC	CAMX	Natural Gas
Volkar/Coombs Partners	Madera Power Plant	14	Firebaugh	CA	WSCC	CAMX	Biomass
Wellhead Power LLC	Gates Peaker	50	Unavailable	CA	WSCC	CAMX	Natural Gas
Wellhead Power LLC	Los Banos Peaker	45	Los Banos	CA	WSCC	CAMX	Natural Gas
Xcel Energy, Inc.	Madera Power Plant	9	Firebaugh	CA	WSCC	CAMX	Biomass
Xcel Energy, Inc.	Red Bluff Peaker	41	Red Bluff	CA	WSCC	CAMX	Natural Gas
Xcel Energy, Inc.	Chowchilla Peaker	41	Chowchilla	CA	WSCC	CAMX	Natural Gas
Xcel Energy, Inc.	Round Mountain Oil Field Peaker	36	Unavailable	CA	WSCC	CAMX	Other
Avista Corp.	Rathdrum (Cogentrix)	130	Rathdrum	ID	WSCC	NWPA	Natural Gas
Avista Corp.	Rathdrum (Cogentrix)	5	Rathdrum	ID	WSCC	NWPA	Natural Gas
Benton Public Utilities District	Finley	27	Finley	WA	WSCC	NWPA	Natural Gas
Cogentrix Energy, Inc.	Rathdrum (Cogentrix)	130	Rathdrum	ID	WSCC	NWPA	Natural Gas
Cogentrix Energy, Inc.	Rathdrum (Cogentrix)	5	Rathdrum	ID	WSCC	NWPA	Natural Gas
Columbia River Peoples Utility District	Columbia Peaking Facility	25	Rainier	WA	WSCC	NWPA	Natural Gas
FPL Group, Inc.	Stateline Wind Project	100	Helix	OR	WSCC	NWPA	Wind
FPL Group, Inc.	Stateline Wind Project	200	Helix	OR	WSCC	NWPA	Wind
Kansai Electric Power Company	Naniwa	180	Unavailable	NV	WSCC	NWPA	Natural Gas
Klamath Falls, City of	Klamath Cogen Project	464	Klamath Falls	OR	WSCC	NWPA	Natural Gas
Montana Rail Link, Inc.	Sappington Junction Peaker	10	Butte	MT	WSCC	NWPA	Gasoline
Montana Rail Link, Inc.	Trident Peaker	10	Three Forks	MT	WSCC	NWPA	Gasoline
Morgan Stanley Dean Witter & Co.	Naniwa	180	Unavailable	NV	WSCC	NWPA	Natural Gas
Northwest Aluminum Co.	Sherman County Wind Farm	25	Unavailable	OR	WSCC	NWPA	Wind
Northwest Regional Power Of Goldendale	Goldendale Diesel Generator Farm	29	Goldendale	WA	WSCC	NWPA	Gasoline
NorthWestern Corp.	Montana First Megawatts	80	Unavailable	MT	WSCC	NWPA	Natural Gas
Quantum Dynamics Group, Inc.	Quantum Dynamics Group Inc	3	Fernley	NV	WSCC	NWPA	Natural Gas
Scottish Power plc	Gadsby	100	Salt Lake City	UT	WSCC	NWPA	Natural Gas
Scottish Power plc	West Valley City	160	West Valley City	UT	WSCC	NWPA	Natural Gas
SeaWest WindPower, Inc.	Condon Wind Project	25	Unavailable	OR	WSCC	NWPA	Wind
SeaWest WindPower, Inc.	Blackfeet I Wind Power Project	22	Unavailable	MT	WSCC	NWPA	Wind
Black Hills Corp.	Neil Simpson 2	40	Gillette	WY	WSCC	RMPA	Natural Gas
Black Hills Corp.	Valmont [CO]	40	Boulder	CO	WSCC	RMPA	Natural Gas
Energy Unlimited, Inc.	Ponnequin Wind Plant	2	Unavailable	CO	WSCC	RMPA	Wind
North American Power Group	Two Elks Plant	50	Wright	WY	WSCC	RMPA	Natural Gas
North American Power Group	DIA Power Project	150	Denver	CO	WSCC	RMPA	Natural Gas
Terra Moya Aqua, Inc.	Simpson Ridge	10	Medicine Bow	WY	WSCC	RMPA	Wind
Tri-State G & T Association, Inc.	Limon (TSGT)	140	Limon	CO	WSCC	RMPA	Natural Gas
Xcel Energy, Inc.	Fort St. Vrain	214	Platteville	CO	WSCC	RMPA	Natural Gas
Xcel Energy, Inc.	Ponnequin Wind Plant	8	Unavailable	CO	WSCC	RMPA	Wind
Xcel Energy, Inc.	Peetz	25	Peetz	CO	WSCC	RMPA	Wind
		54,120					

Source: Deutsche Banc Alex. Brown estimates and company information

Appendix B: U.S. Regional Capacity Outlook Detail

Figure 14: **MW Additions per Year – Probability Weighted**

NERC Region	2000	2001	2002	2003	2004	2005	Total
ECAR	4,192	4,563	8,623	11,944	3,965	1,571	34,858
ERCOT	4,167	10,077	5,087	4,632	2,543	600	27,106
FRCC	1,024	2,438	6,090	5,123	1,493	(257)	15,911
MAAC	725	1,675	3,202	3,123	1,535	443	10,703
MAIN	3,124	4,647	5,631	5,351	496	352	19,601
MAPP	361	782	558	88	1,524	375	3,688
NEPOOL	1,552	3,594	4,092	2,932	250	0	12,420
NY	189	543	119	5,505	2,505	85	8,946
SERC							
Entergy*	1,221	2,479	8,746	4,457	926	500	18,329
Southern*	2,955	4,672	5,429	5,622	880	0	19,558
TVA*	1,138	1,145	2,548	1,453	775	883	7,942
VACAR*	2,719	1,766	3,005	714	2,370	0	10,574
SPP	2,157	3,126	3,060	3,962	882	1,321	14,508
WSCC							
AZ-NV-NM**	620	1,705	3,368	6,487	2,078	730	14,988
California**	57	2,661	3,434	5,327	2,801	975	15,255
Northwest**	22	1,323	1,714	2,221	3,680	990	9,950
Rocky Mts**	431	492	1,077	540	293	250	3,083
Total	26,654	47,688	65,783	69,481	28,996	8,818	**247,420**

* SERC subregion.

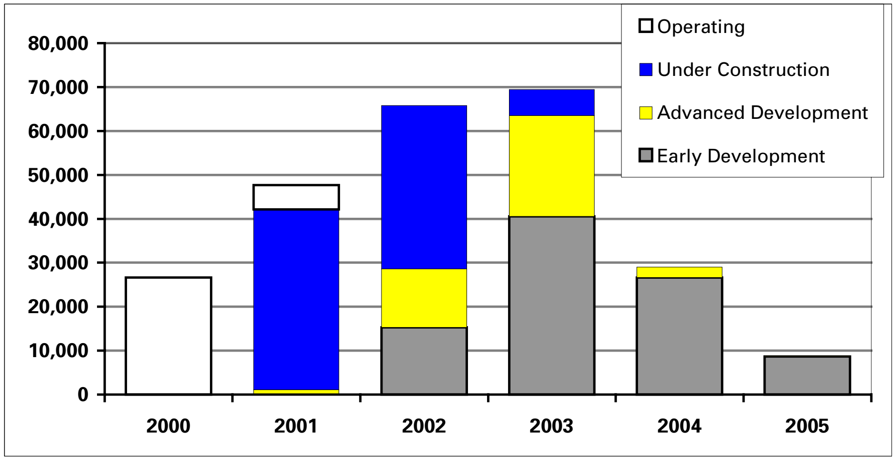
** WSCC subregion.

Source: Deutsche Banc Alex. Brown, RDI Consulting

Figure 15: **Capacity Outlook – United States**

United States

Capacity Additions by Year (MW's)



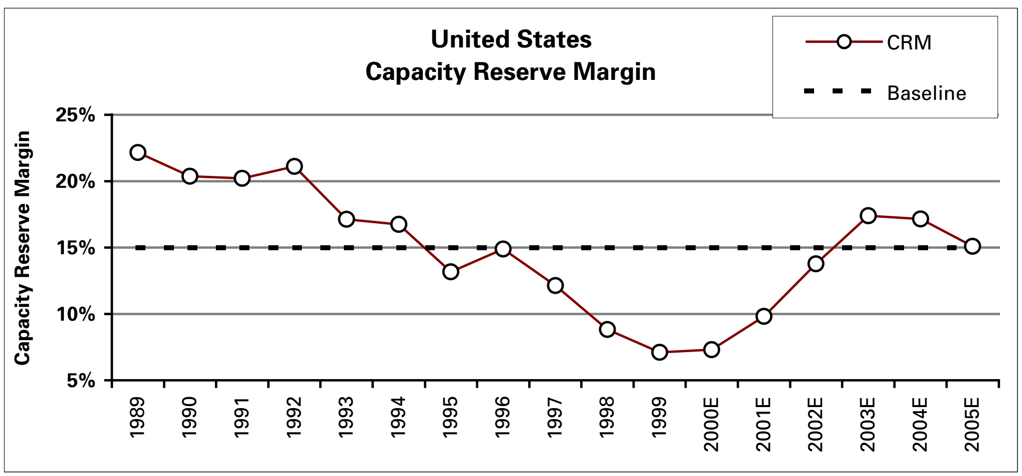
Capacity Additions

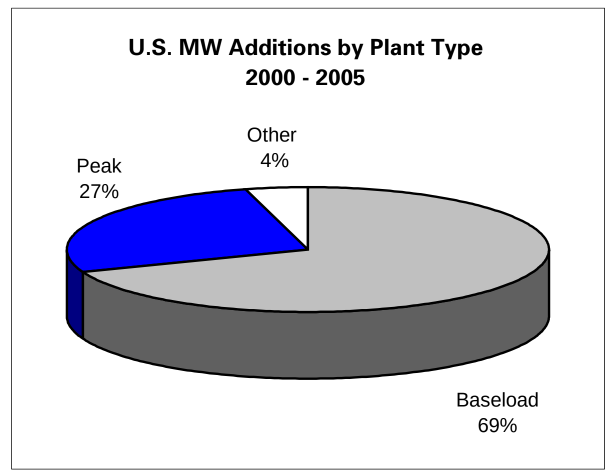
Year	MW
2000	26,654
2001	47,688
2002	65,783
2003	69,481
2004	28,996
2005	8,818
Total	***247,420***

TOP FIVE BUILDERS IN U.S.*

Company	MW*
1) Calpine Corp.	30,856
2) Duke Energy	18,697
3) Cogentrix	12,700
4) PG&E Corp.	12,395
5) Panda Energy	12,246

* Actual additions announced & completed 2000 to 2005; Not probability weighted.



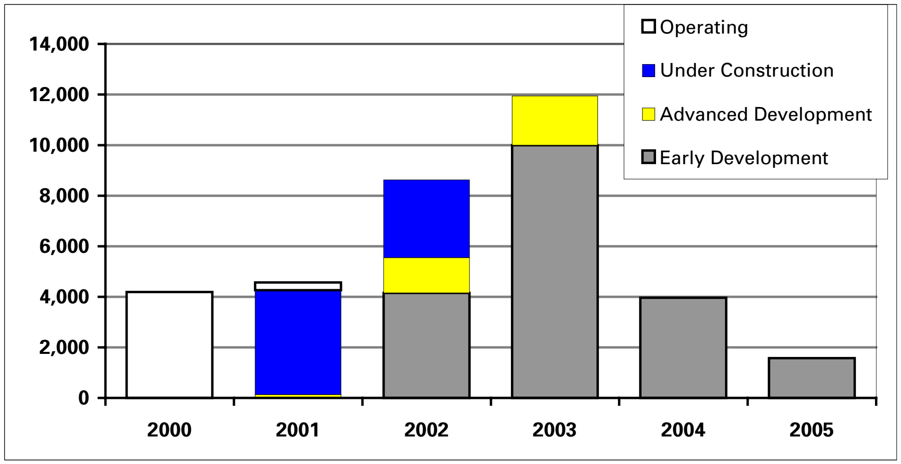


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 16: **Capacity Outlook – ECAR**

ECAR - East Central Area Reliability Coordination Agreement

Capacity Additions by Year (MW's)



Capacity Additions	
Year	MW
2000	4,192
2001	4,563
2002	8,623
2003	11,944
2004	3,965
2005	1,571
Total	*34,858*

TOP FIVE BUILDERS IN ECAR*	
Company	MW*
1) Cogentrix	6,300
2) Duke Energy	5,728
3) Public Ser Enter Grp	4,473
4) Dynegy Inc.	2,806
5) Mirant Corp.	2,380

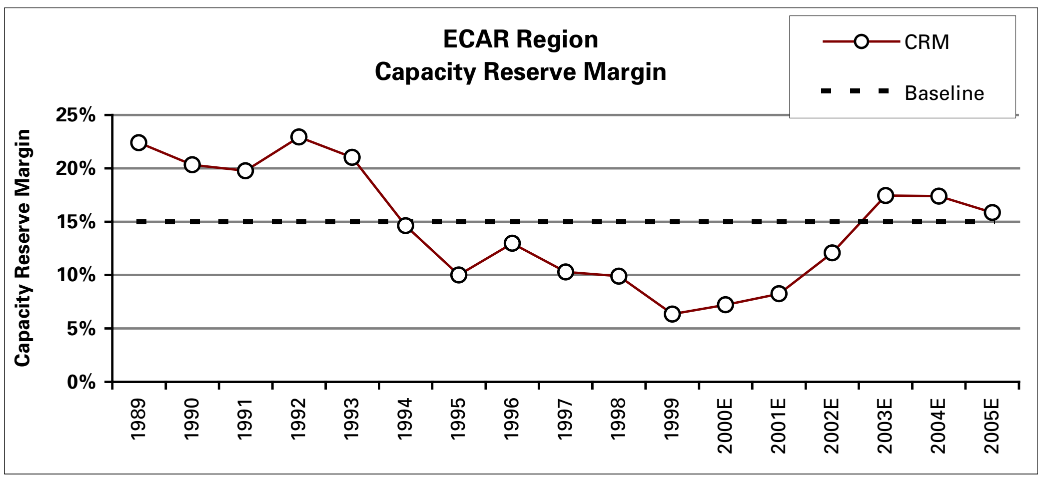
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

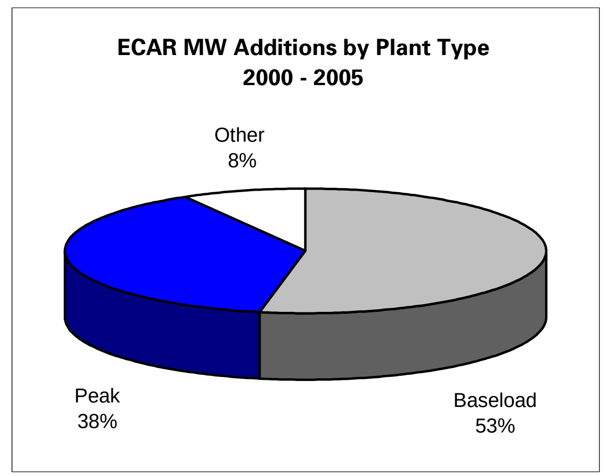
States w/in ECAR

IN, OH, KY, PA
WV, MI, VA

DEREG STATUS

OH, PA - Retail choice begun
WV, MI, VA - Legis. enacted; retail choice pending
IN, KY - Investigatiing



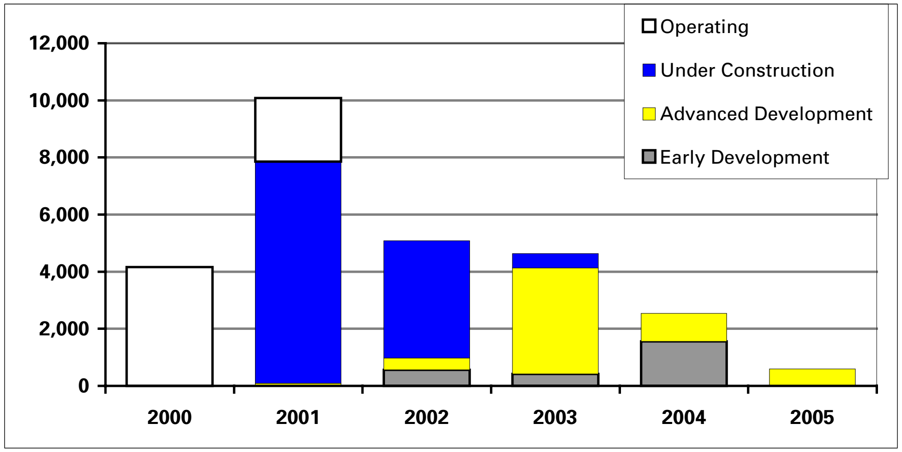


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 17: **Capacity Outlook - ERCOT**

ERCOT - Electric Reliability Council of Texas

Capacity Additions by Year (MW's)



Capacity Additions

Year	MW
2000	4,167
2001	10,077
2002	5,087
2003	4,632
2004	2,543
2005	600
Total	***27,106***

TOP FIVE BUILDERS IN ERCOT*

Company	MW*
1) Calpine Corp.	5,743
2) International Power	4,991
3) Group Suez Lyonnaise	1,923
4) Newport Generation	1,600
5) Pandas Energy	1,510

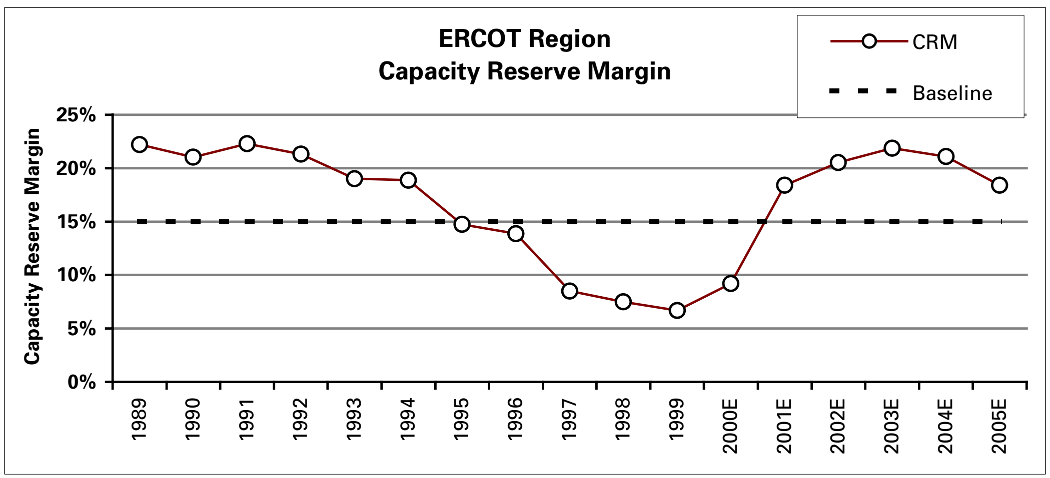
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

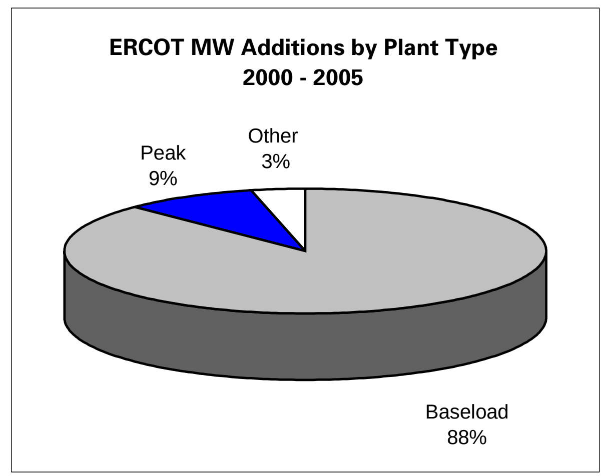
States w/in ERCOT

Texas

TEXAS DEREG STATUS

Legislation enacted; choice beginning Jan. '02



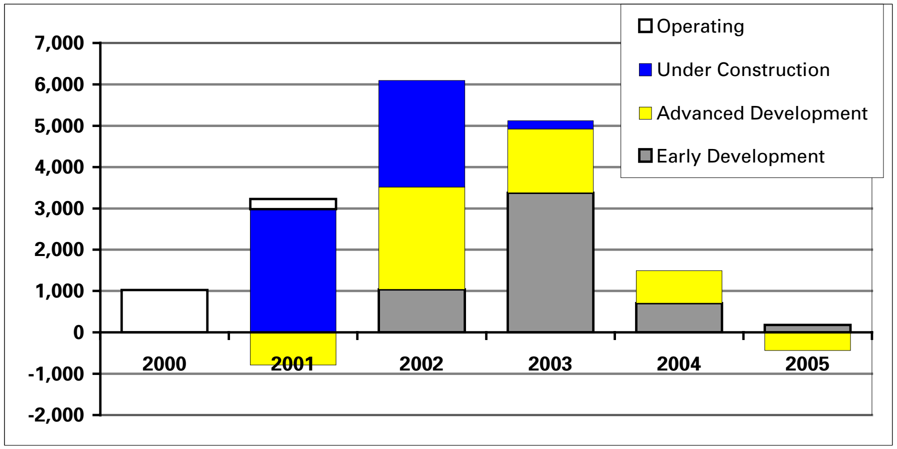


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 18: **Capacity Outlook - FRCC**

FRCC - Florida Reliability Coordinating Council

Capacity Additions by Year (MW's)



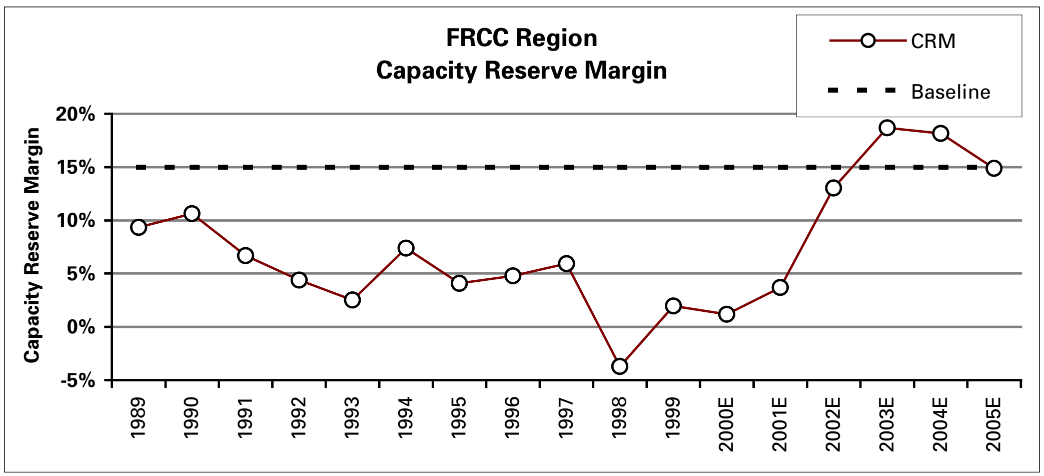
Capacity Additions	
Year	**MW**
2000	1,024
2001	2,438
2002	6,090
2003	5,123
2004	1,493
2005	-257
Total	***15,911***

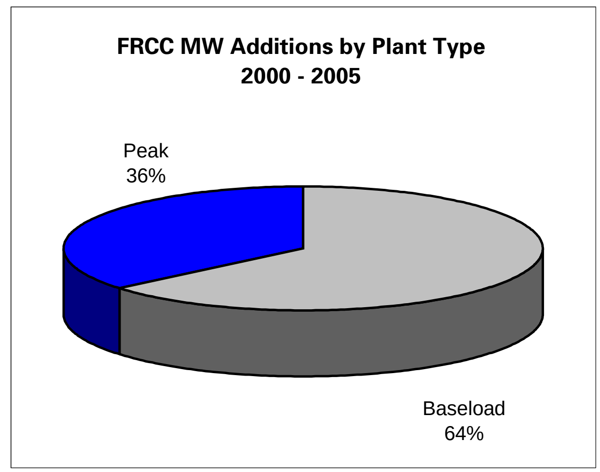
TOP FIVE BUILDERS IN FRCC	
Company	MW*
1) FPL Group	2,981
2) Panda Energy	2,000
3) Calpine Corp.	1,720
4) TECO Energy	1,708
5) El Paso Energy	1,020

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in FRCC
Florida

FLORIDA DEREG STATUS
Investigating



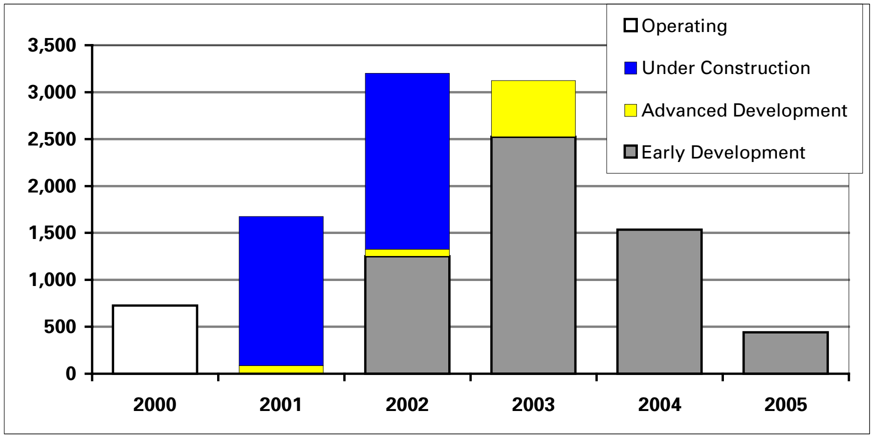


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 19: **Capacity Outlook - MAAC**

MAAC - Mid-Atlantic Area Council

Capacity Additions by Year (MW's)



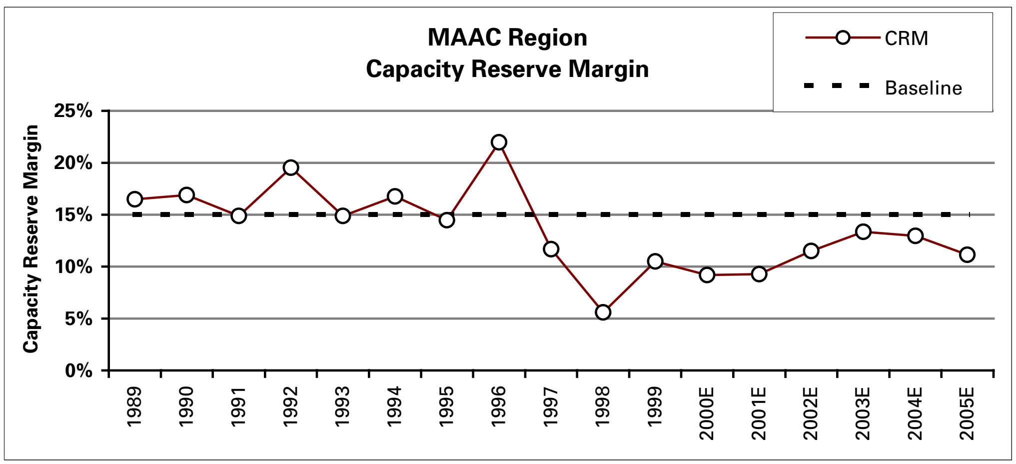
Capacity Additions	
Year	MW
2000	725
2001	1,675
2002	3,202
2003	3,123
2004	1,535
2005	443
Total	***10,703***

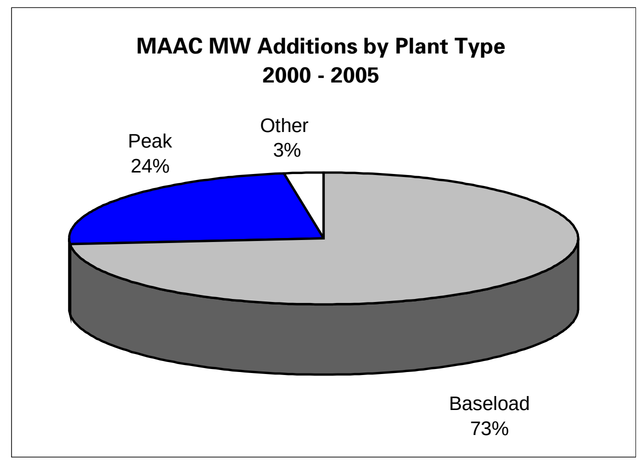
TOP FIVE BUILDERS IN MAAC	
Company	MW*
1) Public Service Enterprise Group	2,057
2) PG&E Corp.	1,900
3) AES Corp.	1,605
4) PPL	1,500
5) Reliant Energy	1,334

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in MAAC
DE, MD, NJ, PA

DEREG STATUS
NJ, PA - Retail choice begun
DE, MD - Legislation enacted; retail choice pending



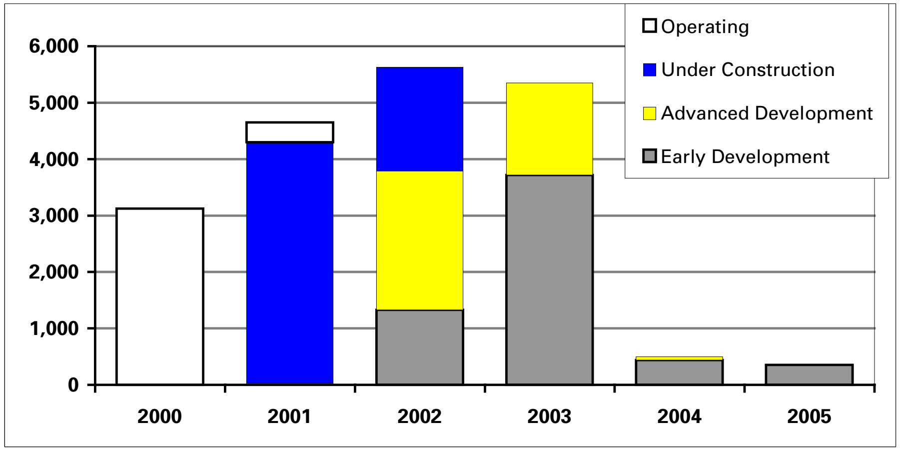


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 20: **Capacity Outlook - MAIN**

MAIN - Mid-America Interconnected Network

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	3,124
2001	4,647
2002	5,631
2003	5,351
2004	496
2005	352
Total	***19,601***

TOP FIVE BUILDERS IN MAIN	
Company	MW*
1) Calpine Corp.	2,464
2) Amren Corp.	2,101
3) Panda Energy	2,070
4) NRG Energy	1,950
5) MidAmerican Energy	1,637

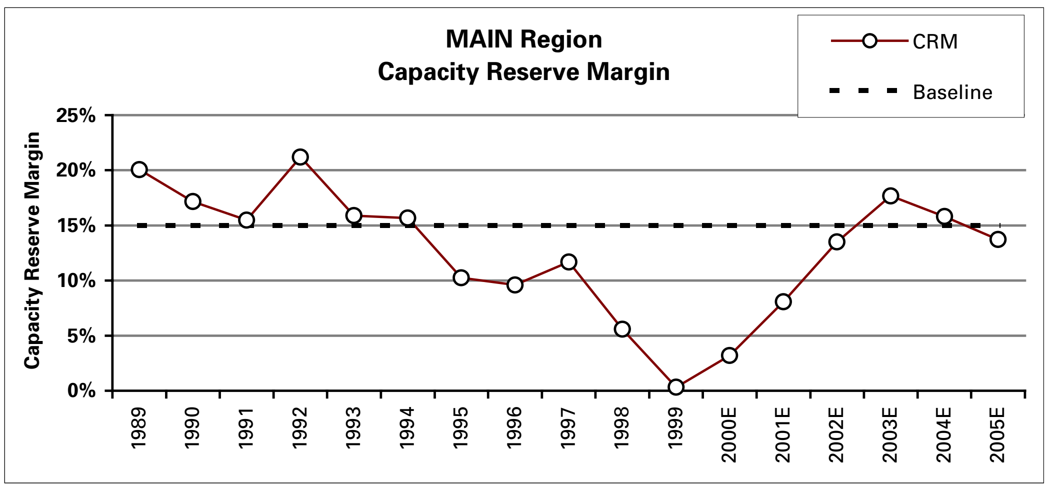
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

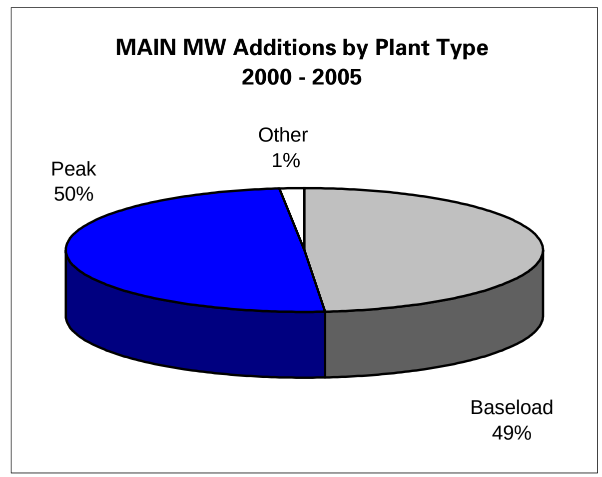
States w/in MAIN

WI, IL, MO

DEREG STATUS

IL - Retail choice begun
MO, WI - Investigating



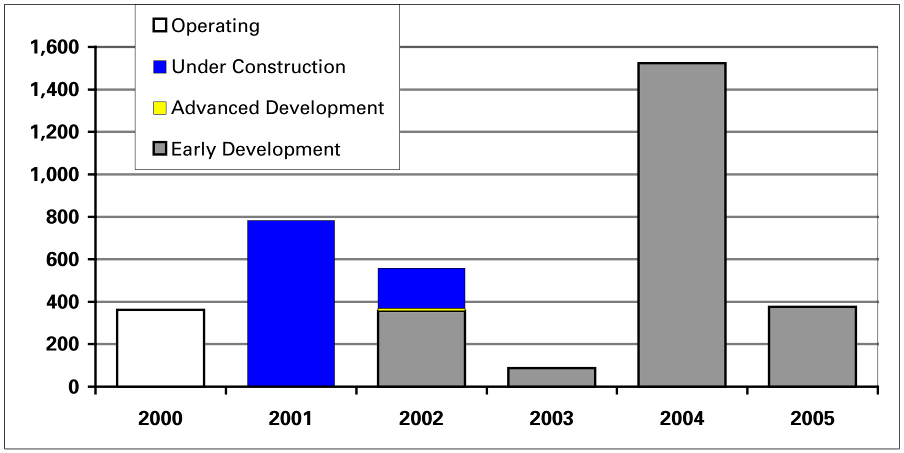


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 21: **Capacity Outlook - MAPP**

MAPP - Mid-Continent Area Power Pool

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	361
2001	782
2002	558
2003	88
2004	1,524
2005	375
Total	***3,688***

TOP FIVE BUILDERS IN MAPP

Company	MW*
1) Clipper Windpower LLC	3000
2) Great River Energy	984
3) Northern Alternative	681
4) Tenaska Inc.	600
5) Xcel Energy	114

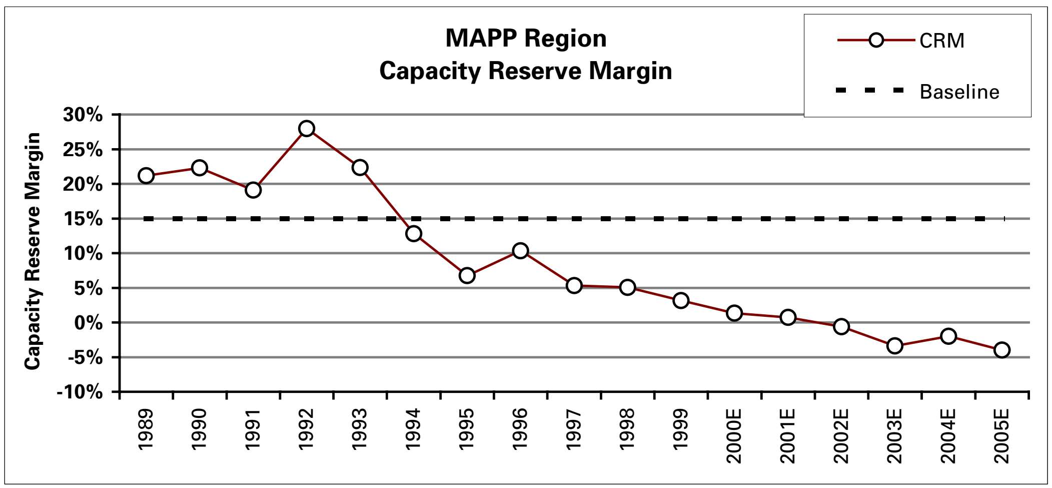
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

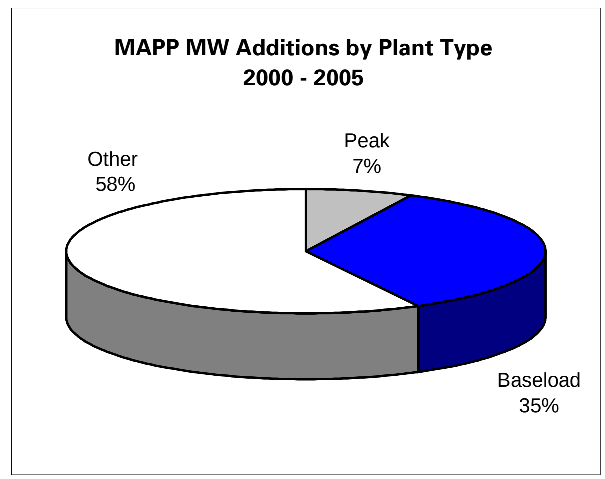
States w/in MAPP

ND, SD, NE, MN, WI, IA

DEREG STATUS

MN, IA, ND, WI - Investigating
NE, SD - No activity



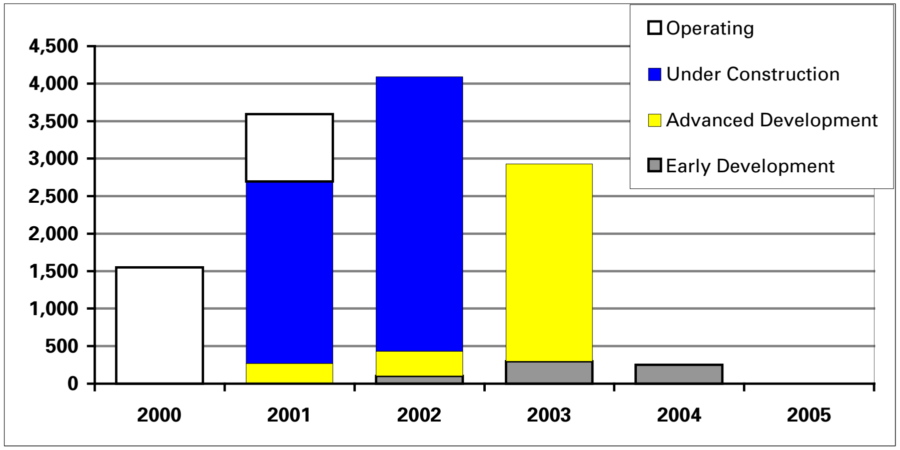


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 22: **Capacity Outlook - NEPOOL**

NEPOOL - New England Power Pool (subregion of NPCC)

Capacity Additions by Year (MW's)



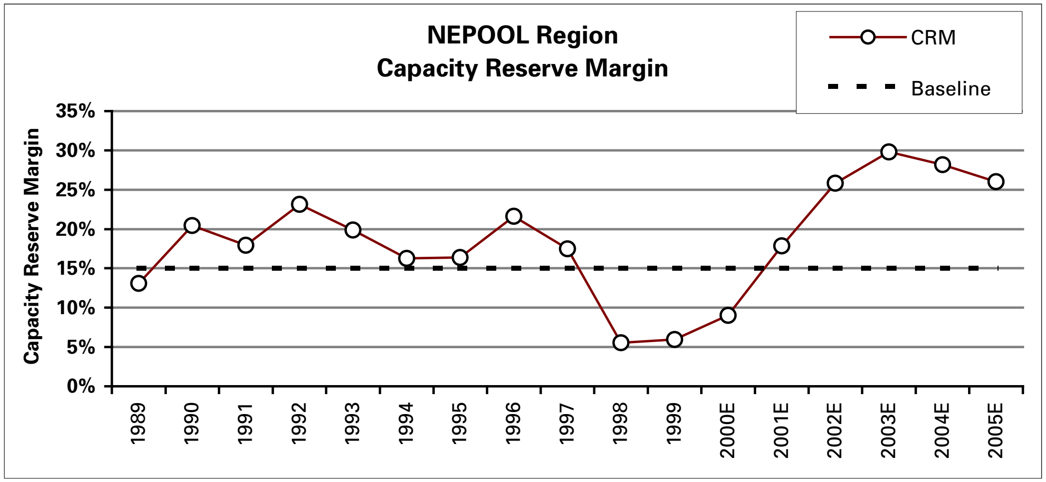
Capacity Additions	
Year	**MW**
2000	1,552
2001	3,594
2002	4,092
2003	2,932
2004	250
2005	0
Total	*12,420*

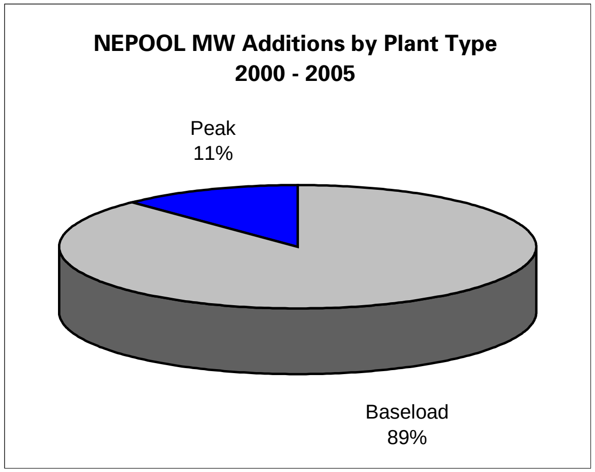
TOP FIVE BUILDERS IN NEPOOL	
Company	MW*
1) FPL Group	1,950
2) Calpine Corp	1,597
3) Excelon Corp	1,224
4) International Power	1,160
5) PG&E Corp.	1,152

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NEPOOL
CT, MA, NH, ME
VT, RI

DEREG STATUS
CT, MA, NH, ME, RI - Retail choice begun
NH - Legis. enacted; retail choice pending
VT - Investigating



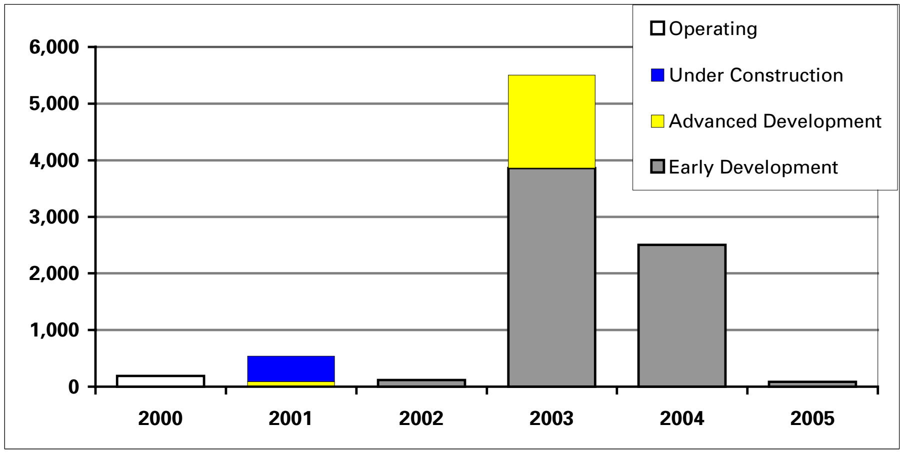


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 23: **Capacity Outlook - NYPP**

NYPP - New York Power Pool (subregion of NPCC)

Capacity Additions by Year (MW's)



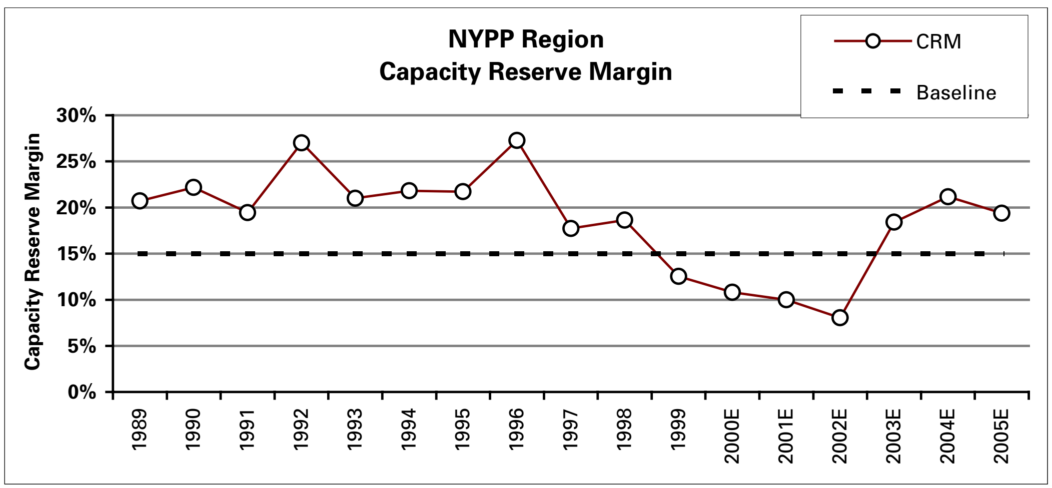
Capacity Additions	
Year	MW
2000	189
2001	543
2002	119
2003	5,505
2004	2,505
2005	85
Total	***8,946***

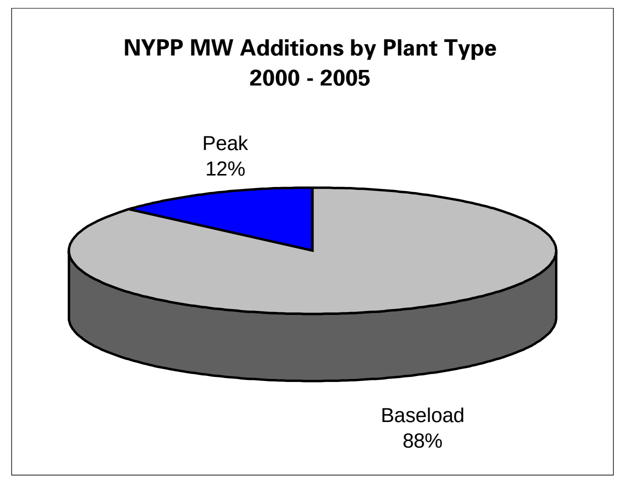
TOP FIVE BUILDERS IN NYPP	
Company	MW*
1) International Power	1,640
2) KeySpan	1,186
3) PG&E Corp.	1,092
4) ABB Energy Ventures	1,075
5) SCS Energy, LLC	1,000

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NYPP
New York

DEREG STATUS
NY - Restructuring order issued, but not enacted.



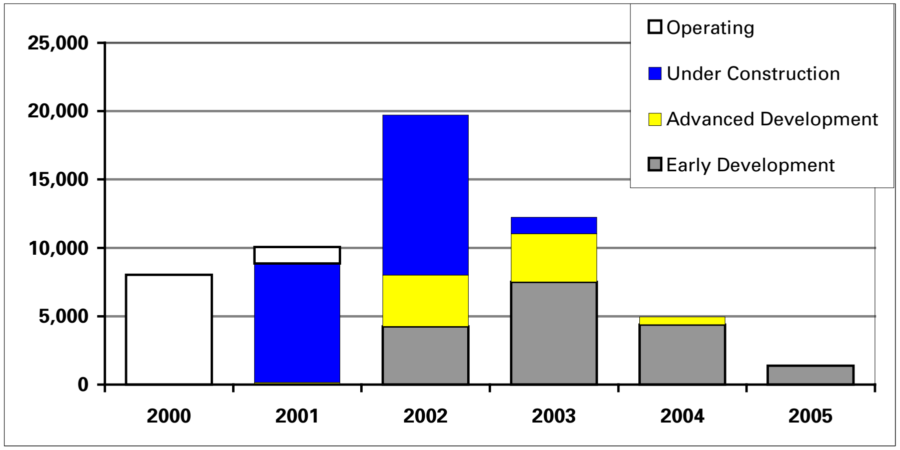


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 24: **Capacity Outlook - SERC**

SERC - Southeastern Electric Reliability Council

Capacity Additions by Year (MW's)



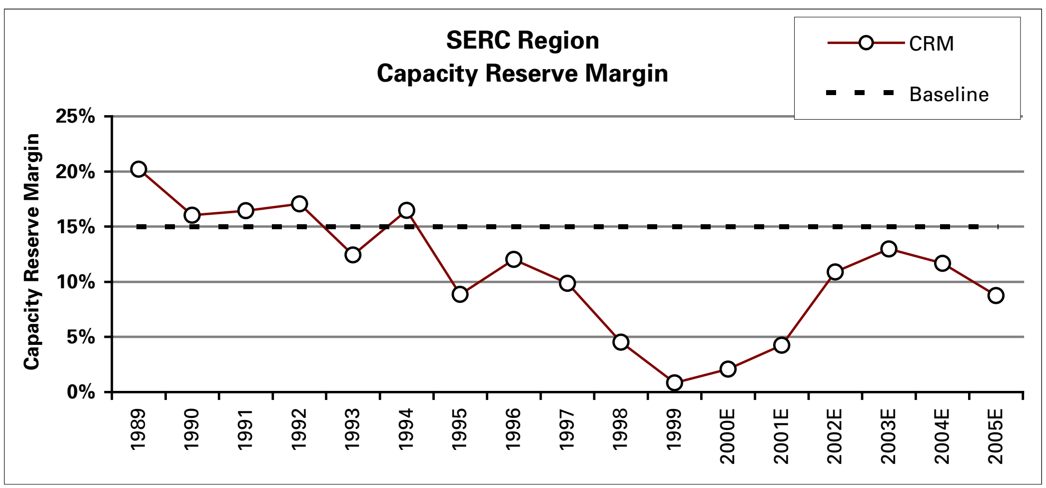
Capacity Additions	
Year	**MW**
2000	8,033
2001	10,062
2002	19,727
2003	12,245
2004	4,951
2005	1,383
Total	***56,401***

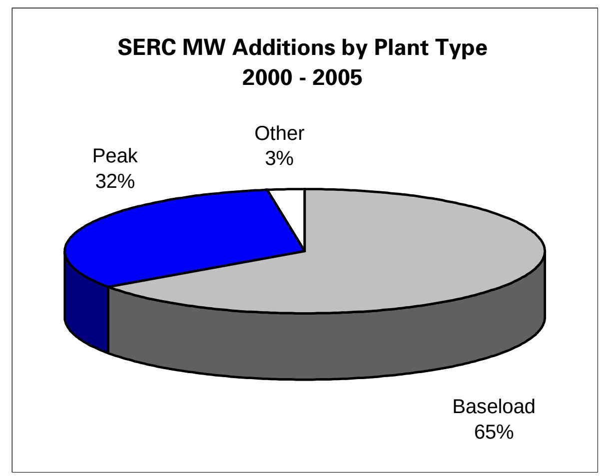
TOP FIVE BUILDERS IN SERC	
Company	MW*
1) Calpine Corp.	8,330
2) Southern Company	6,513
3) Tenaska Inc.	5,590
4) TVA	4,364
5) Duke Energy	4,330

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SERC
LA, AR, MO, TX, MS
AL, GA, KY, TN, VA
NC, SC

DEREG STATUS
TX, AR, VA - Legis. enacted; choice pending
SC - Legislation pending.
LA, MS, MO, KY, NC - Investigating
AL, GA, TN - No activity.



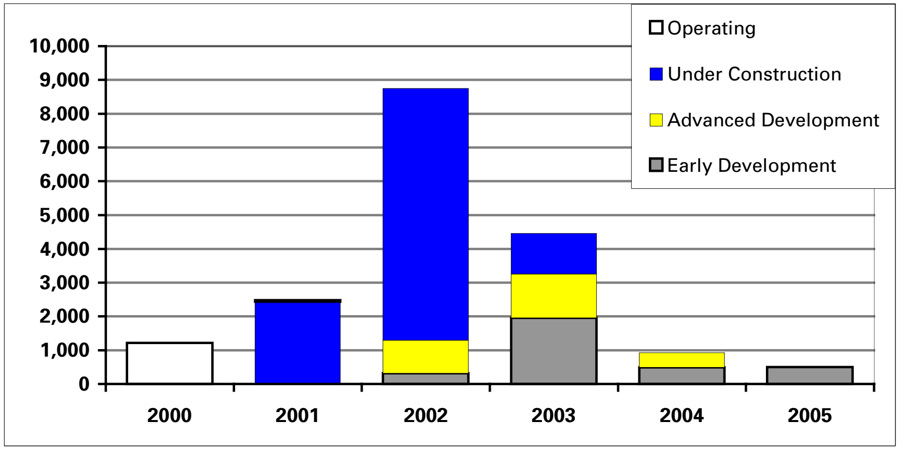


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 25: **Capacity Outlook - Entergy**

ENTR - Entergy (subregion of SERC)

Capacity Additions by Year (MW's)



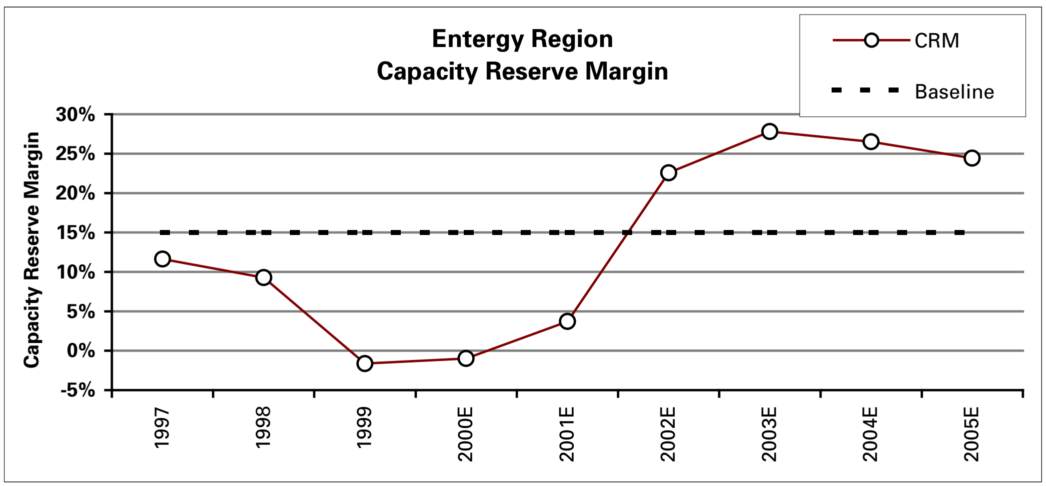
Capacity Additions	
Year	MW
2000	1,221
2001	2,479
2002	8,746
2003	4,457
2004	926
2005	500
Total	***18,329***

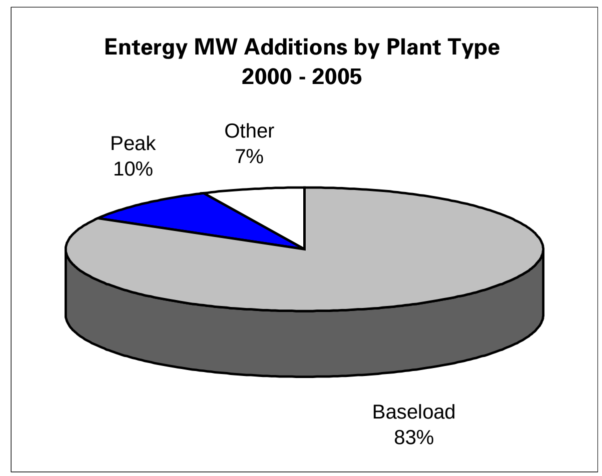
TOP FIVE BUILDERS IN ENTERGY	
Company	MW*
1) TECO Energy	2,309
2) Calpine Corp.	2,150
3) Ls Power	2,100
4) Cogentrix	2,035
5) Duke Energy	1,870

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in ENTR
LA, AR, MO, TX, MS

DEREG STATUS
TX, AR - Legis. enacted; retail choice pending
LA, MS, MO - Investigating



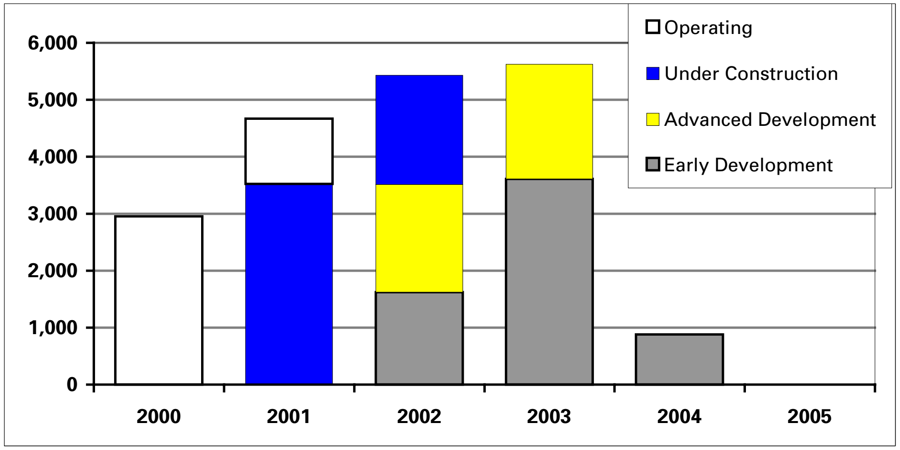


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 26: **Capacity Outlook - Southern**

SOU - Southern (subregion of SERC)

Capacity Additions by Year (MW's)



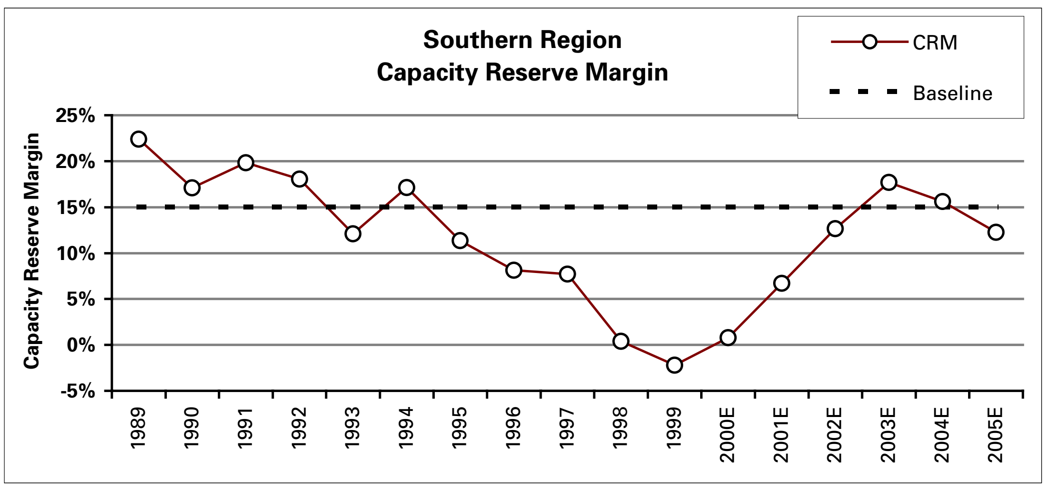
Capacity Additions	
Year	MW
2000	2,955
2001	4,672
2002	5,429
2003	5,622
2004	880
2005	0
Total	***19,558***

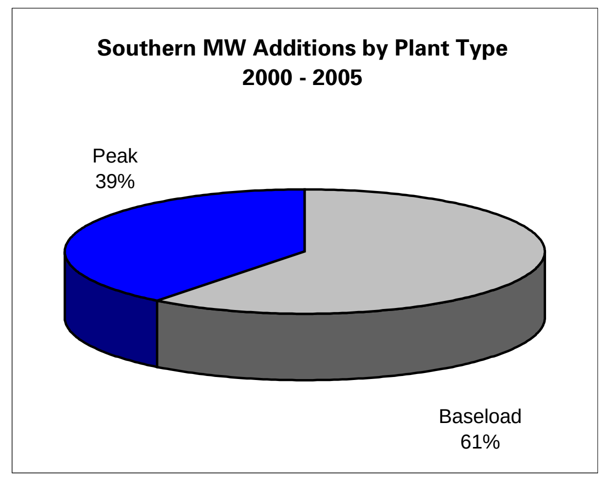
TOP FIVE BUILDERS IN SOUTHERN	
Company	MW*
1) Southern Company	6,513
2) Tenaska, Inc.	2,674
3) Duke Energy	2,460
4) Calpine Corp.	1,850
5) Oglethorpe Power Corp.	1,640

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SOU
AL, GA

DEREG STATUS
AL, GA - No activity



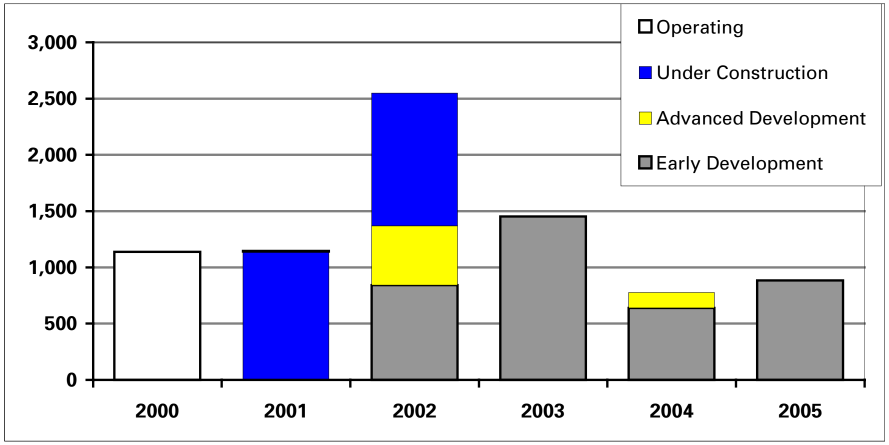


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 27: **Capacity Outlook - TVA**

TVA - Tennessee Valley Authority (subregion of SERC)

Capacity Additions by Year (MW's)



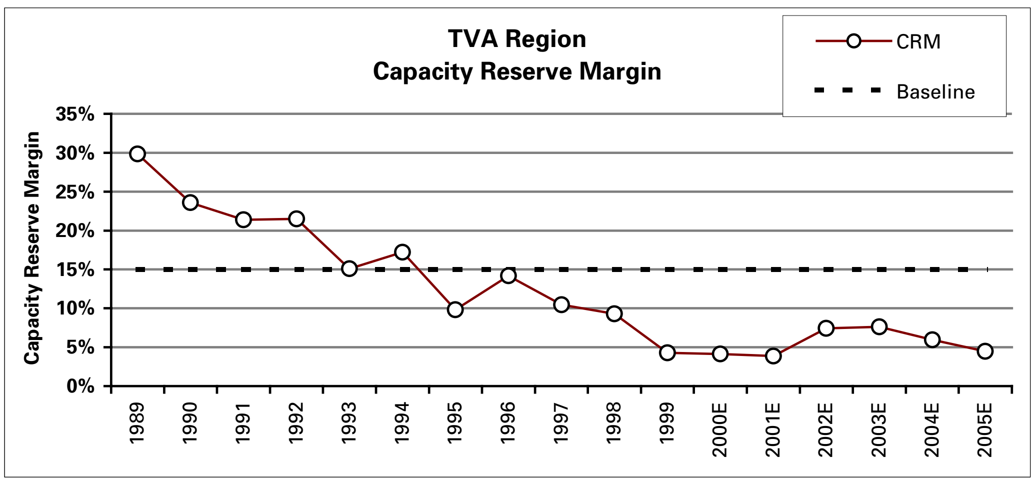
Capacity Additions Year	MW
2000	1,138
2001	1,145
2002	2,548
2003	1,453
2004	775
2005	883
Total	***7,942***

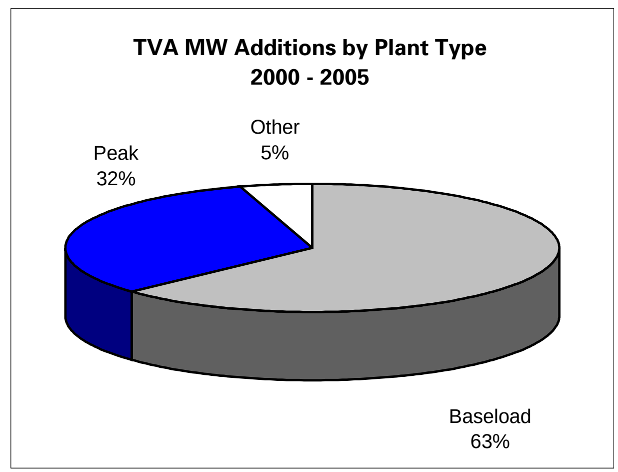
TOP FIVE BUILDERS IN TVA	
Company	MW*
1) Calpine Corp.	2,930
2) Tennessee Valley Authority	2,164
3) Panda Energy	1,300
4) Cogentrix	800
5) Enron Corp.	510

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in TVA
KY, TN, MS, AL

DEREG STATUS
MS, KY - Investigating
TN, AL - No activity



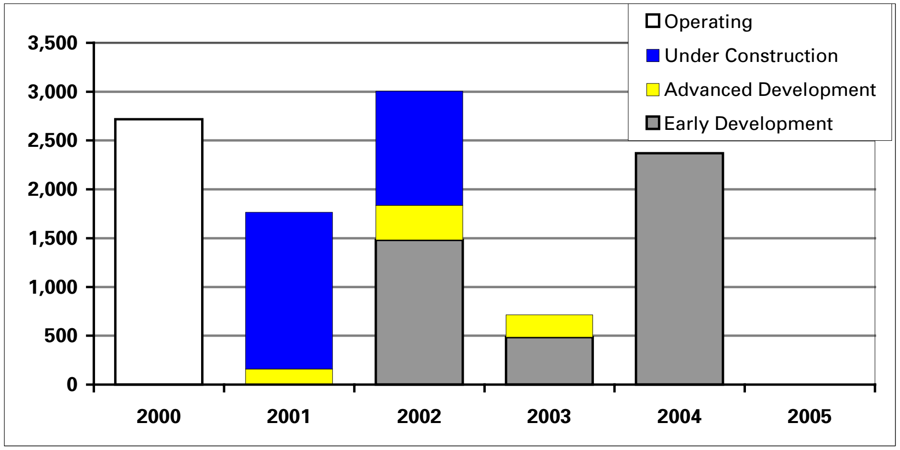


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 28: **Capacity Outlook - VACAR**

VACAR - Virginia-Carolinas (subregion of SERC)

Capacity Additions by Year (MW's)



Capacity Additions	
Year	MW
2000	2,719
2001	1,766
2002	3,005
2003	714
2004	2,370
2005	0
Total	***10,574***

TOP FIVE BUILDERS IN VACAR	
Company	MW*
1) Progress Energy, Inc.	3,044
2) Calpine Corp.	1,400
3) Group Suez Lyonnaise	1,375
4) South Carolina PSA	1,370
5) Dominion Resources	921

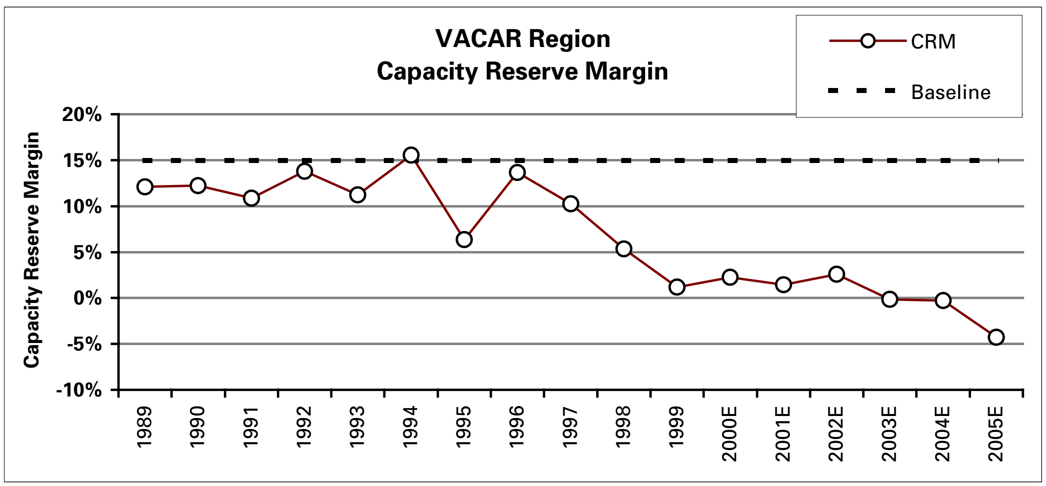
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

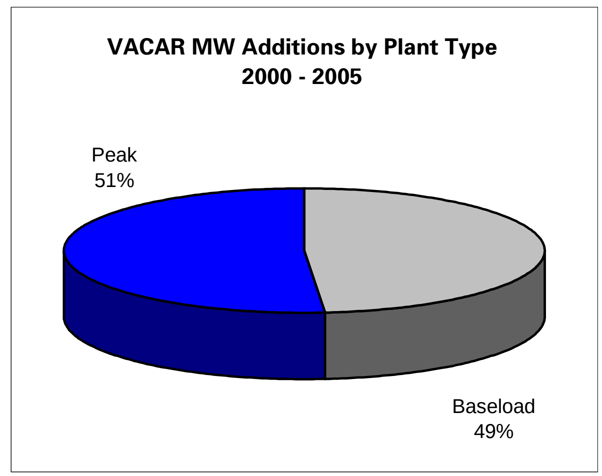
States w/in VACAR

VA, NC, SC

DEREG STATUS

VA - Legis. enacted; retail choice pending
SC - Legislation pending
NC - Investigating



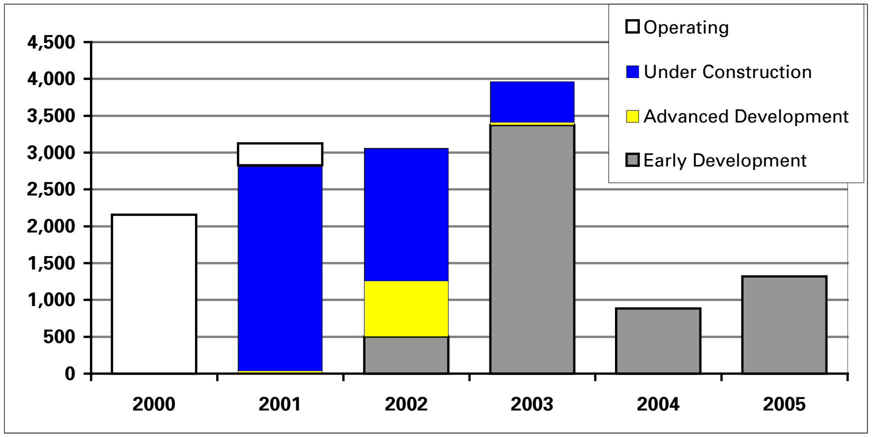


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 29: **Capacity Outlook - SPP**

SPP - Southwest Power Pool

Capacity Additions by Year (MW's)



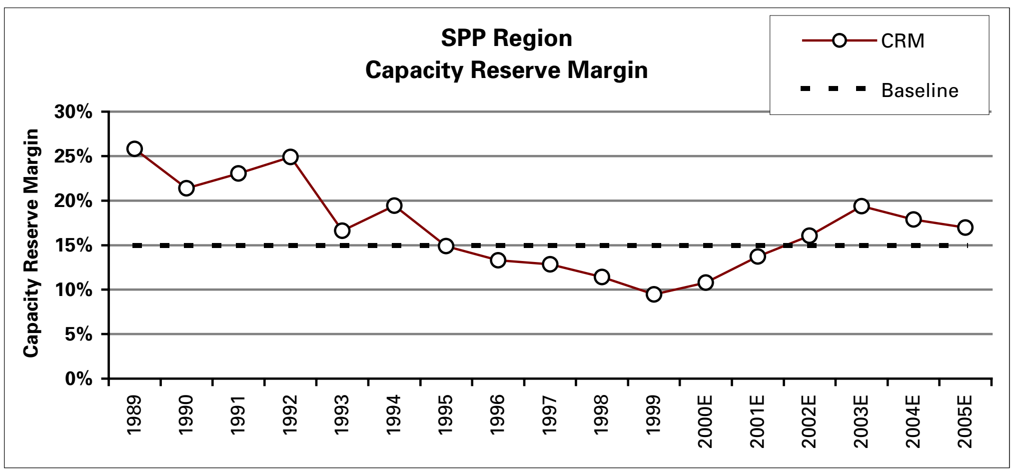
Capacity Additions	
Year	**MW**
2000	2,157
2001	3,126
2002	3,060
2003	3,962
2004	882
2005	1,321
Total	***14,508***

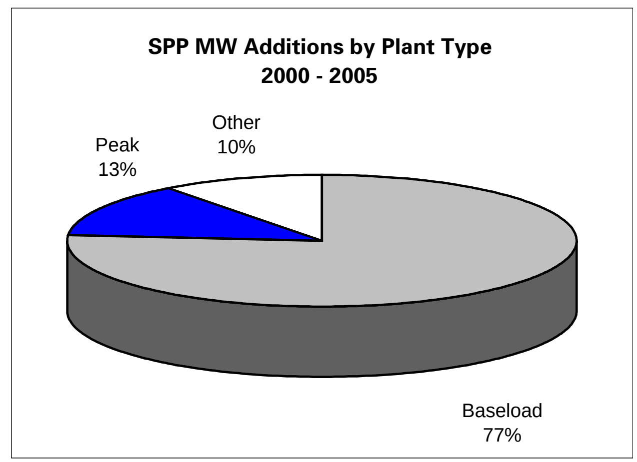
TOP FIVE BUILDERS IN SPP	
Company	MW*
1) Energetix	1,885
2) Calpine Corp.	1,669
3) Kansas City P&L	1,608
4) Smith Cogeneration	1,200
4) American Electric Power	1,200

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SPP
KS, OK, MO, AR, TX NM

DEREG STATUS
TX, NM, AR - Legis. enacted; Retail choice pending
OK - Legislation pending
MO - Investigating
KS - No activity



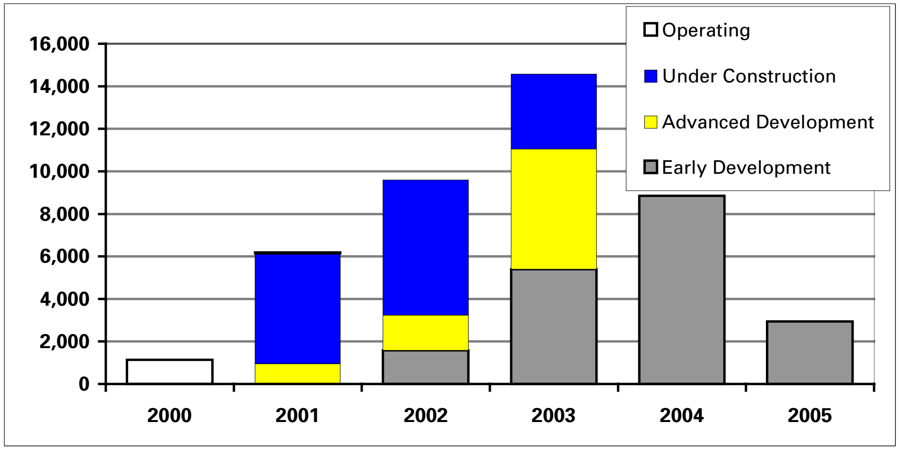


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 30: **Capacity Outlook - WSCC**

WSCC - Western Systems Coordinating Council

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	1,130
2001	6,181
2002	9,594
2003	14,575
2004	8,851
2005	2,945
Total	***43,276***

TOP FIVE BUILDERS IN WSCC	
Company	MW*
2) Calpine Corp.	6,706
2) Duke Energy	5,834
3) PG&E Corp.	4,235
4) Reliant Energy	2,623
5) AES Corp.	2,155

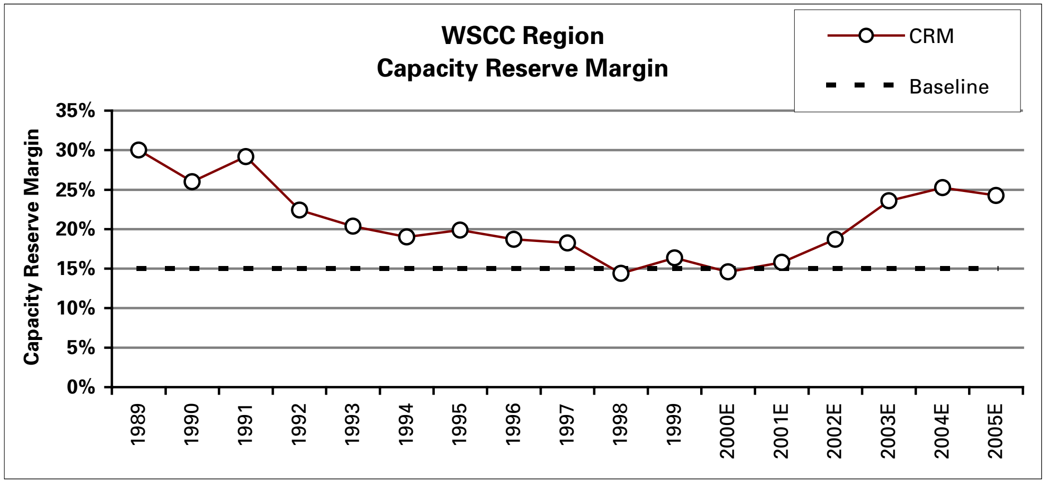
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

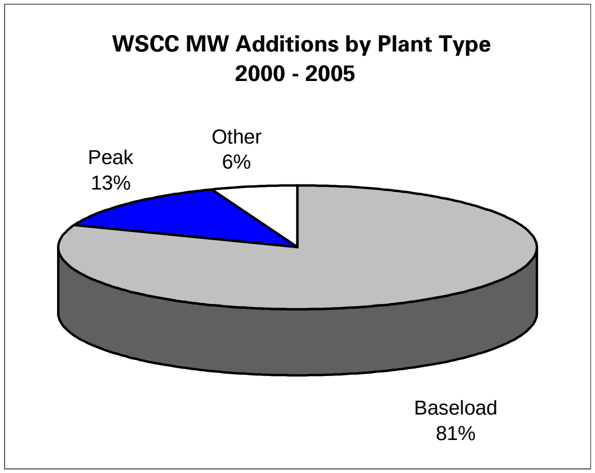
States w/in WSCC

AZ, NM, NV, CA, MT
WA, OR, ID, UT, CO
WY

DEREG STATUS

CA - Retail choice begun.
AZ, NM, OR, MT - Legis. enacted; choice pending
NV - Deregulation postponed.
UT, WA, WY, CO - Investigating
ID - No activity.



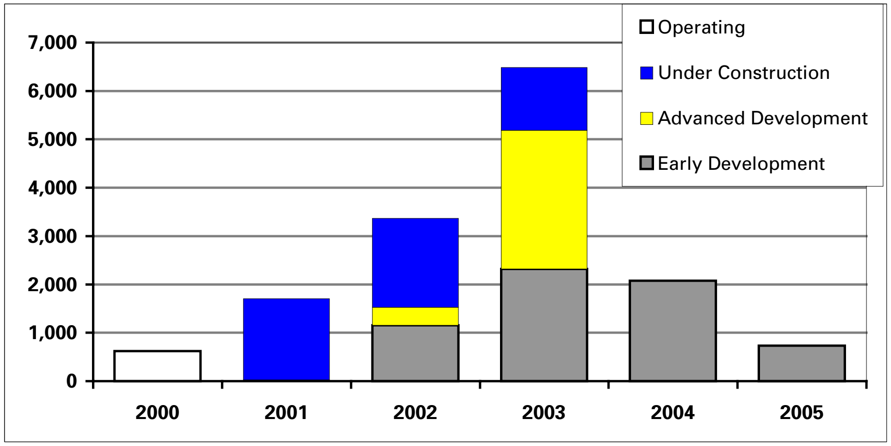


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 31: **Capacity Outlook – AZ-NM-NV**

AZ-NM-NV Region (subregion of WSCC)

Capacity Additions by Year (MW's)



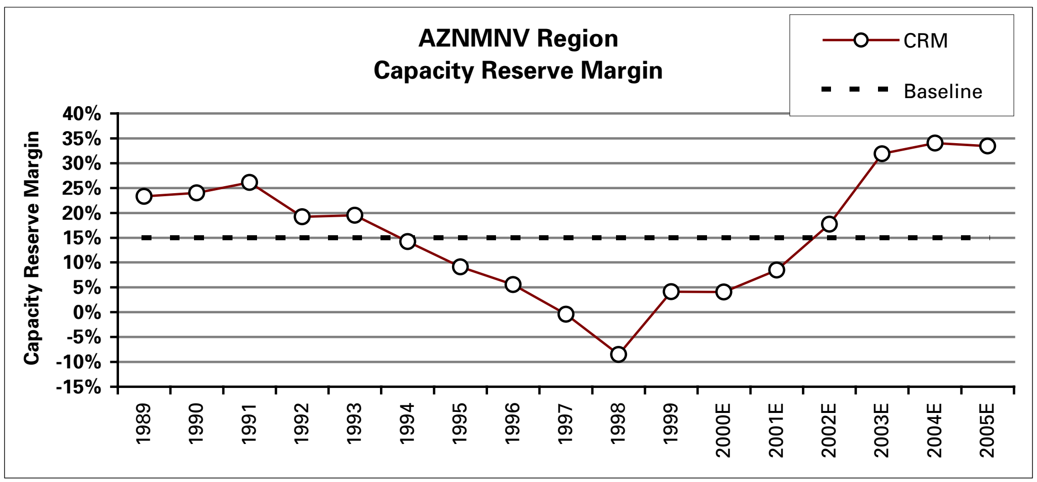
Capacity Additions	
Year	MW
2000	620
2001	1,705
2002	3,368
2003	6,487
2004	2,078
2005	730
Total	***14,988***

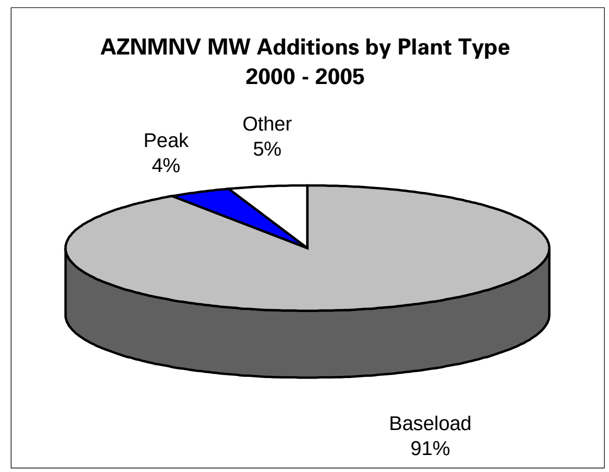
TOP FIVE BUILDERS IN AZ-NM-NV	
Company	MW*
1) Reliant Energy	2,622
2) Duke Energy	2,580
3) Sempra Energy	1,540
4) Southwestern Power	1,500
5) Panda Energy/TECO	1,150

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in AZNMNV
AZ, NM, NV

DEREG STATUS
AZ, NM - Legis. enacted; choice pending
NV - Legis. enacted, but dereg postponed.



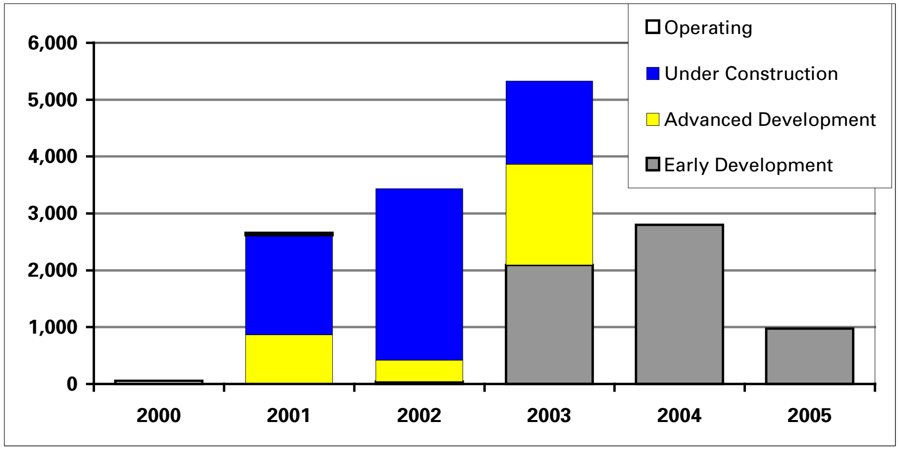


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 32: **Capacity Outlook - California**

CALIFORNIA (subregion of WSCC)

Capacity Additions by Year (MW's)



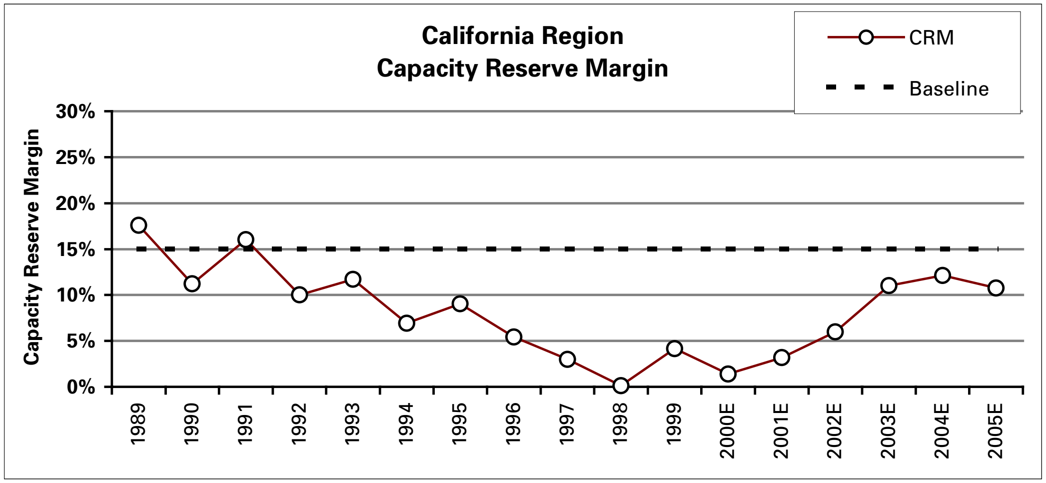
Capacity Additions	
Year	**MW**
2000	57
2001	2,661
2002	3,434
2003	5,327
2004	2,801
2005	975
Total	***15,255***

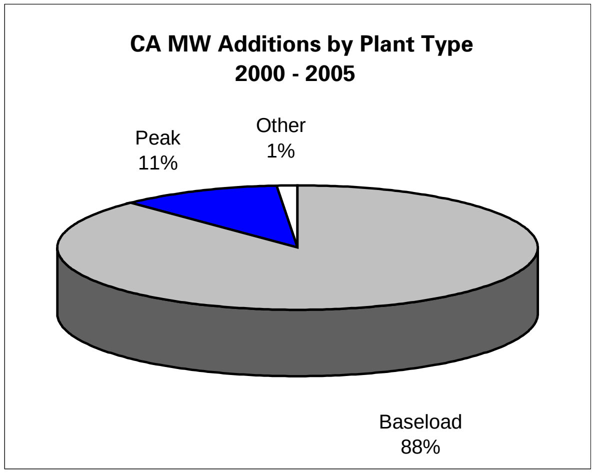
TOP FIVE BUILDERS IN CALIFORNIA	
Company	MW*
1) Calpine Corp.	4,956
2) Duke Energy	2,260
3) AES Corp.	2,155
4) PG&E Corp.	1,510
5) Enron Corp.	1,250

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

CALIFORNIA DEREG STATUS

-Retail choice began March '98
-First state to allow choice
-Current CA electricity crisis should not reverse deregulation in the state



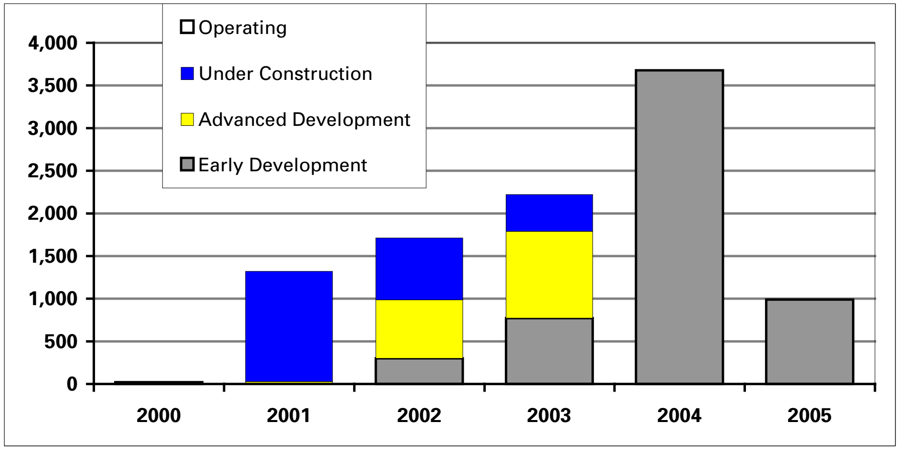


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 33: **Capacity Outlook - NWPA**

NWPA - Northwest Power Authority (subregion of WSCC)

Capacity Additions by Year (MW's)



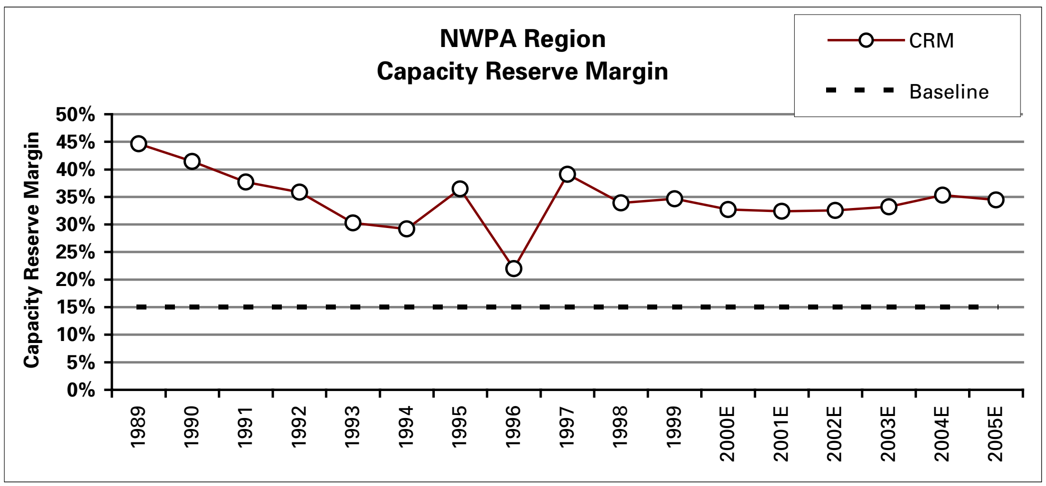
Capacity Additions	
Year	**MW**
2000	22
2001	1,323
2002	1,714
2003	2,221
2004	3,680
2005	990
Total	***9,950***

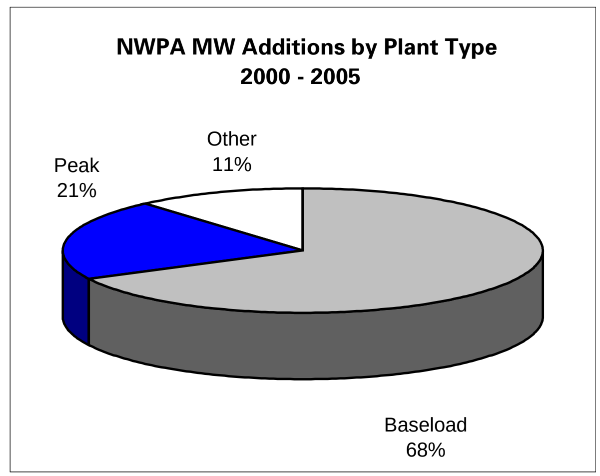
TOP FIVE BUILDERS IN NWPA	
Company	MW*
1) Cogentrix Energy	1,965
2) Newport Northwest	1,300
2) Newport Generation	1,300
4) PPL Corp.	1,100
5) Duke Energy	994

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NWPA
MT, WA, NV, OR, WY ID, UT

DEREG STATUS
OR, MT, AZ - Legis. enacted; choice pending
UT, WA, WY - Investigating
ID - No activity



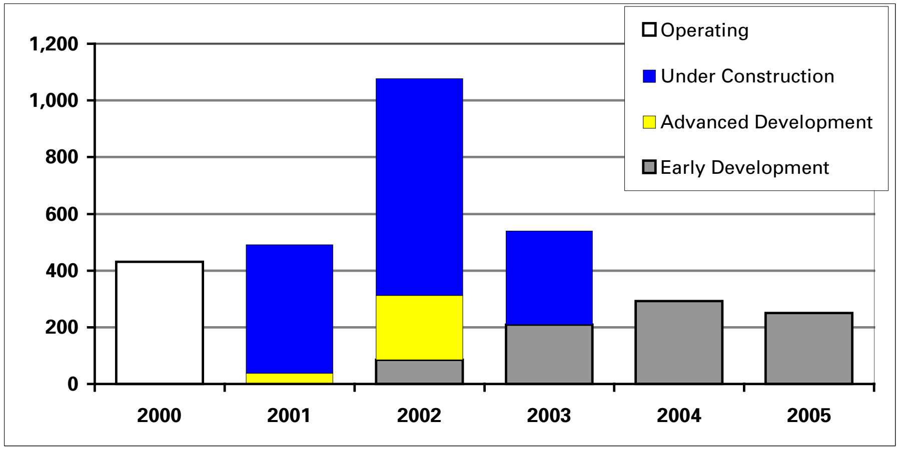


Source: Deutsche Banc Alex. Brown estimates and company information

Figure 34: **Capacity Outlook - RMPA**

RMPA - Rocky Mountain Power Authority (subregion of WSCC)

Capacity Additions by Year (MW's)



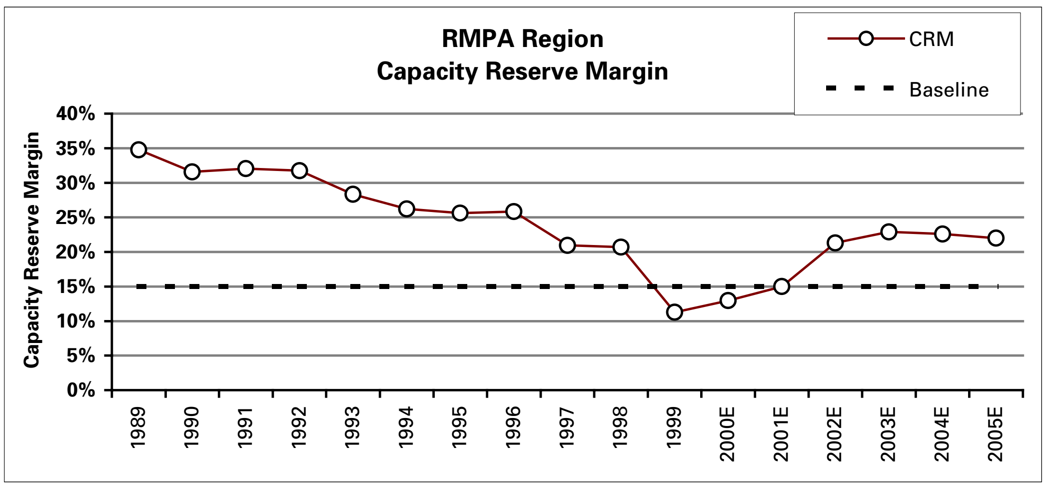
Capacity Additions	
Year	**MW**
2000	431
2001	492
2002	1,077
2003	540
2004	293
2005	250
Total	***3,083***

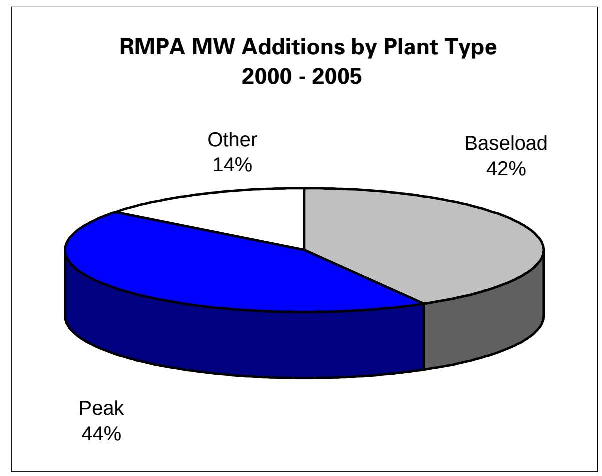
TOP FIVE BUILDERS IN RMPA	
Company	MW*
1) Calpine Corp.	921
2) North American Power	800
3) El Paso Corp.	565
4) Enron Corp.	402
5) Black Hills Corp.	356

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in RMPA
CO, WY

DEREG STATUS
CO, WY - Investigating





Source: Deutsche Banc Alex. Brown estimates and company information

Additional Information Available upon Request

Disclosure Checklist			
Company	**Ticker**	**Price (6/5/01)**	**Disclosure**
Calpine Corp.	CPN	$43.30	O#
Reliant Resources	RRI	30.56	O&#
Utilicorp United	UCU	35.14	&
Allegheny Energy	AYE	50.96	O
Exelon Corp.	EXC	65.44	O
Orion Power Holdings	ORN	26.53	O#
Duke Energy	DUK	42.50	O

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* Deutsche Banc Alex. Brown Inc. maintains a net primary market in the common stock.

++ An author or the immediate family member of an author of comments on this company has a beneficial position in the common stock.

O The stock is optionable.

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% Within the past three years, Deutsche Banc Alex. Brown Inc. has participated in a private resale of securities made pursuant to Rule 144A under the Securities Act of 1933.

& The company has a convertible issue outstanding.

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June 8, 2001

Restructuring of the U.S. Electric Generation Sector

Expect Trend to Continue Despite California's Troubles

- Despite California's difficulties in deregulating the electric generation business, deregulation is working in 24 states in the U.S. We do not subscribe to the view of a sustained national or regional retreat from competition or the prospect of re-regulation.
- California's energy crisis is driven by a lack of generation supply and a failed deregulation framework.
- The pace of change may slow in some states in the near term, but may produce a more deliberate, comprehensive process toward restructuring at the state and federal level.
- A number of catalysts should help advance the restructuring process, which provides new opportunities for investors.
- We are bullish on the prospects for the generation sector, which we rate Buy.
- Recommend generators such as AES Corp (AES) and Calpine Corp (CPN), which are rated Strong Buy. In addition, we recommend Buy-rated Allegheny Energy (AYE), Exelon Corporation (EXC), Orion Power Holdings (ORN), Reliant Resources (RRI) and UtiliCorp United (UCU).

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Introduction

Despite the glaring failure of California's process to deregulate the electric generation business, deregulation is working elsewhere in the U.S. We do not subscribe to the view of a sustained national or regional retreat from competition or the prospect of re-regulation. The situation in California may slow the pace of change in some states, but may actually transform the transition to a more deliberate, comprehensive process toward restructuring at the state and federal level. The process of deregulation has been under way over the last decade, and we believe that a number of factors will serve as catalysts to continue the process. The addition of new generating supply, the movement toward the creation of regional transmission organizations, the Bush Administration's efforts to create a national energy policy, and an engaged, fully staffed Federal Energy Regulatory Commission (FERC) will contribute to this process.

California has clearly identified a number of pressing issues that must be addressed on a regional and national level. We believe Congress is poised to act this summer on several legislative initiatives in response to the energy crisis in California and the Western U.S. We do not expect this to include price caps though. At the state level, deregulation in 24 states continues relatively smoothly. No other region of the country is experiencing the same difficulties as California for a variety of reasons. We continue to think that California is an anomaly, driven by a lack of generating supply and a failed deregulation framework.

This report is designed to identify and briefly describe the characteristics of California's deregulation scheme that led to its failure. We explain how deregulation is working elsewhere and provide specific examples of the success in Pennsylvania and Texas. We attempt to address questions about other regions of concern, particularly New York City, which will also face a tight supply of power this summer. We believe that industry restructuring will continue to provide additional opportunities for investors. We are enthusiastic about the prospects in the near to intermediate term, especially for the wholesale generators, given the shortage of electricity nationally in the U.S. and the concern for price stability in a volatile pricing environment. Thus, our outlook continues to be bullish for the generation sector, which we rate Buy. We continue to recommend generators such as AES Corp (AES) and Calpine Corp (CPN), which are rated Strong Buy. In addition, we recommend Buy-rated Allegheny Energy (AYE), Exelon Corporation (EXC), Orion Power Holdings (ORN), Reliant Resources (RRI) and UtiliCorp United (UCU).

Why Deregulate? Advantages and Beneficiaries of Restructuring

Federal Overview

Why deregulate electric generation? The genesis of deregulation came from the passage of the Energy Policy Act of 1992, which had two primary components pertaining to this industry. First, the EPA of 1992 created a new class of power companies called "exempt wholesale generators" under the Public Utility Holding Company Act of 1935 (PUHCA). PUHCA imposes certain investment, financing, capitalization, ownership and other limitations and imposes significantly more onerous reporting requirements, subjecting utility companies to considerably more regulatory oversight. Currently, 19 utilities are subject to PUHCA, while 118 are exempt wholesale generators. The wholesale market, which includes sales between other generators or third parties that sell the power to the ultimate customer or end-user, is regulated by the Federal Energy Regulatory Commission (FERC), much like the federal government oversees interstate commerce. The retail market, which includes sales to residential, commercial, industrial customers, is regulated by state authorities.

The second major component of major importance called for non-discriminatory access to utility transmission lines. Transmission lines were originally built to serve the native load of the local utility, which were operated and controlled by the incumbent utilities. Building upon the congressional mandate for access to transmission, FERC issued a series of orders in 1996. FERC issued Order 888, which opened transmission access to non-utilities in a move to establish wholesale competition. In a related action, Order 889 required utilities to share information about available transmission capacity and create electronic systems to facilitate that process. Another important feature of Order 888 is that FERC affirmed that utilities would be entitled to recover "legitimate, prudent and verifiable" stranded costs in order to transition the industry to a competitive one. Stranded costs refer to those generation-related costs incurred under regulation, which would be uneconomic in a competitive market. Examples include (above market) purchased power contracts with non-utility generators, deferred taxes, and other regulatory assets. The recovery of stranded costs, both the mechanism to calculate and recoup these costs, had been a challenging issue to address in promoting competition. By affirming recovery, a significant barrier to deregulation was mitigated and states began to take up efforts to restructure the generation business.

State Overview

The main proponents of change at the state level have typically been large industrial customers in states where the cost of electricity was significantly higher than the national average. The cry for lower electricity prices sparked the restructuring of a cost-based, rate-regulated industry to transition to a competitive market over a certain period of time. Generally speaking, during the "transition period" electric utilities would be permitted to recover most of their stranded costs, and customers would benefit from rate reductions. In addition, it entailed the functional separation of the generation from the transmission and distribution business, and in some cases actually called for forced divestitures to value the assets at market prices and create new entrants into the market. In many cases, however, it resulted in the transfer of the generation assets to an unregulated subsidiary and rules of conduct for transactions between affiliate companies. It usually included rate reductions, sometimes in part funded by the securitization of a non-bypassable competitive transition charge, and fixed rates for a defined number of years. Thus, the term “deregulation” is somewhat of a misnomer, as various elements of the business were dictated by the regulatory agreement reached by each company. The legacy generation industry will not be truly deregulated for a couple of years. We prefer the term industry “restructuring,” since it is more representative of what has actually occurred.

Benefits of Deregulation

The FERC orders granted open access to transmission, which facilitated development of the wholesale market and access to lower-cost power. This also increased competition because it served to reward the lowest-cost producer. It also lowered barriers to entry, encouraging new participants. It also increased the flexibility for investing and financing and reduced the reporting requirements and degree of regulatory oversight. At the state level, deregulation has meant rate reductions to customers. For the utilities, it has affirmed recovery of stranded costs, provided a greater number of corporate strategic options and created an opportunity for new investments, products, markets, etc.

Because each state is regulated by a separate regulatory body and has adopted different approaches to deregulation, the outcomes have varied by state. Overall, these changes created a variety of opportunities for various participants. It provided a chance for sellers to monetize the generation assets through divestiture and re-deploy the capital. For the buyers, it created an opportunity to optimize the assets through portfolio management and the leverage provided by trading and marketing skills. The acquisition of these unregulated assets provided additional opportunities for growth, since they are not subject to rate caps or an authorized return on equity, as well as new products and services. It also sparked a round of consolidation as companies sought to realize economies of scale or to gain size and scale. Ultimately, it led to a more competitive market that rewards companies with a low-cost advantage. But most significantly, it spawned the emergence of the wholesale energy merchant company, and provided an opportunity for utilities to become national in scope. Unfortunately, the benefits of deregulation envisioned have not materialized as expected as a result of the shortage of generating capacity in the United States. However, as this is rectified through new investment we expect the benefits to emerge.

California: The Restructuring Anomaly.

What Went Wrong and Why It Is Unique

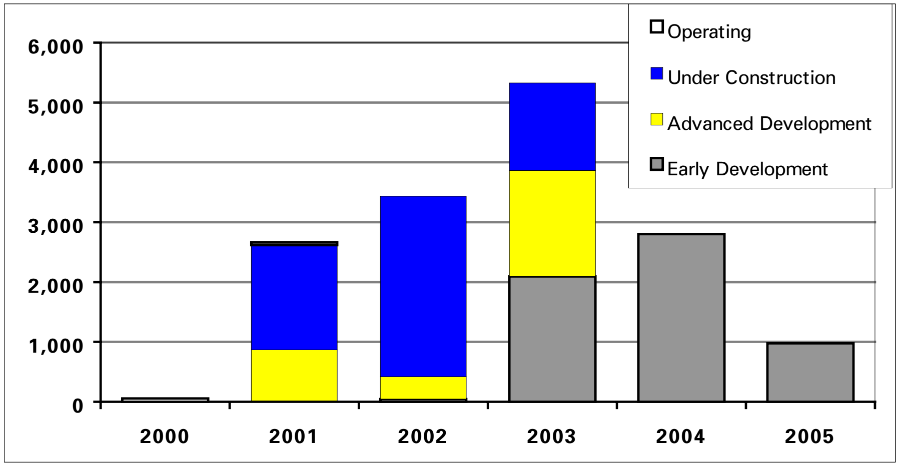
Much has already been written about the problems now facing California and its two investor-owned utilities, Southern California Edison (SCE), a subsidiary of Edison International (EIX), and PCG Corp's (PCG) utility subsidiary, Pacific Gas & Electric (PG&E). Thus, we do not intend to dwell at length on them here. We view the problems as the result of (1) inadequate power supply compounded by (2) a flawed deregulation framework.

Inadequate Supply of Generation

The heart of the problem is that no new power plants have been built in California over the last decade, leaving California to rely on imports for about 25% of their power consumed. This amount of imported power is far greater than any other regional power pool and thus is unique to California. The combination of stringent environmental restrictions, a difficult siting process and questionable public planning resulted in very little new capacity additions. Shown below in Figure 1 is the capacity reserve margin for the California region and the expected capacity additions this year through 2005. As you can see, California has steadily been drawing down on its reserve of power without adding new supply. Contrast the dire situation in California to that of the country, which is shown in Figure 2 on the following page. On average, the nation is short power, but not nearly to the same degree as in California.

Figure 1: **California (Sub-region of WSCC)**

Capacity Additions by Year (MW's)



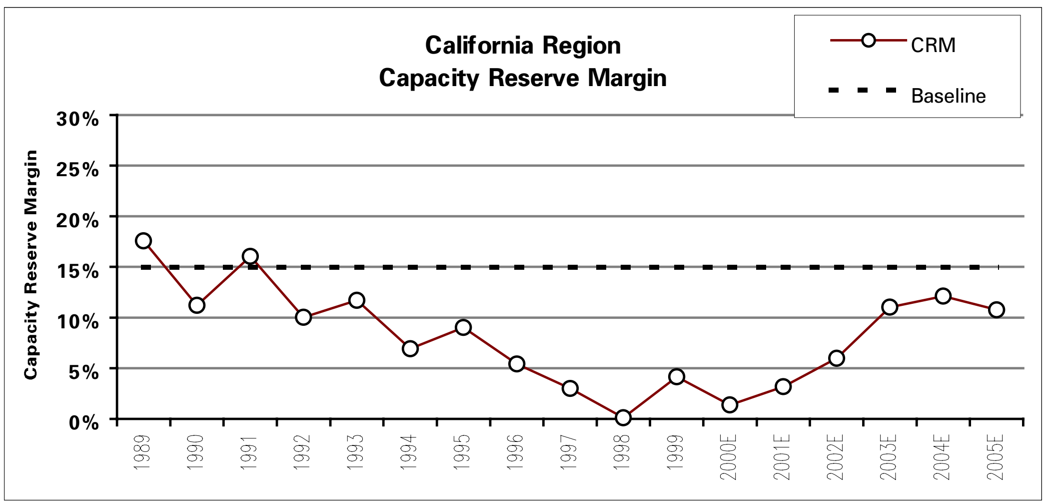
Capacity Additions	
Year	MW
2000	57
2001	2,661
2002	3,434
2003	5,327
2004	2,801
2005	975
Total	***15,255***

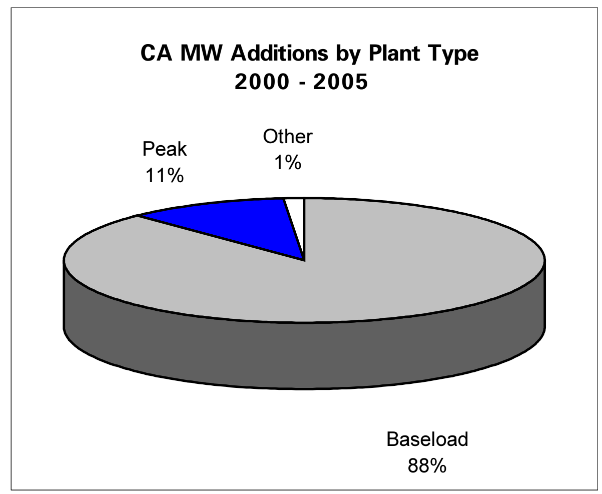
TOP FIVE BUILDERS IN CALIFORNIA	
Company	MW*
1) Calpine Corp.	4,956
2) Duke Energy	2,260
3) AES Corp.	2,155
4) PG&E Corp.	1,510
5) Enron Corp.	1,250

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

CALIFORNIA DEREG STATUS

-Retail choice began March '98
-First state to allow choice
-Current CA electricity crisis should not reverse deregulation in the state

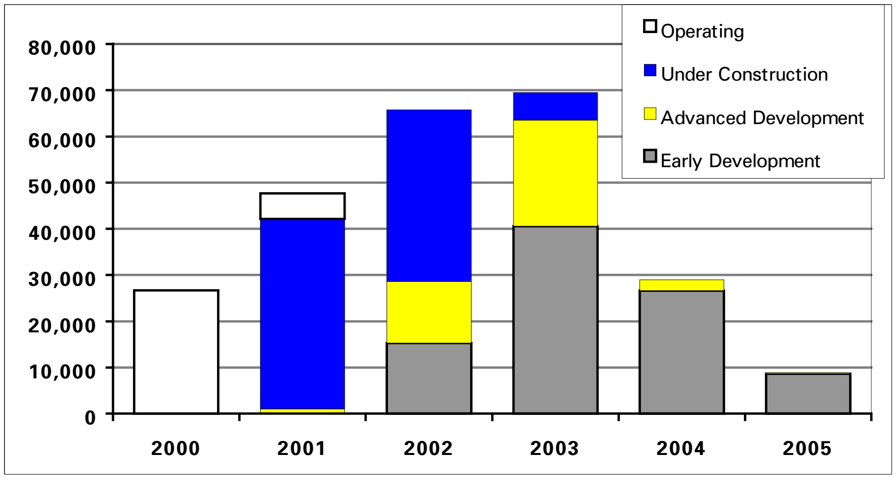




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 2: **United States**

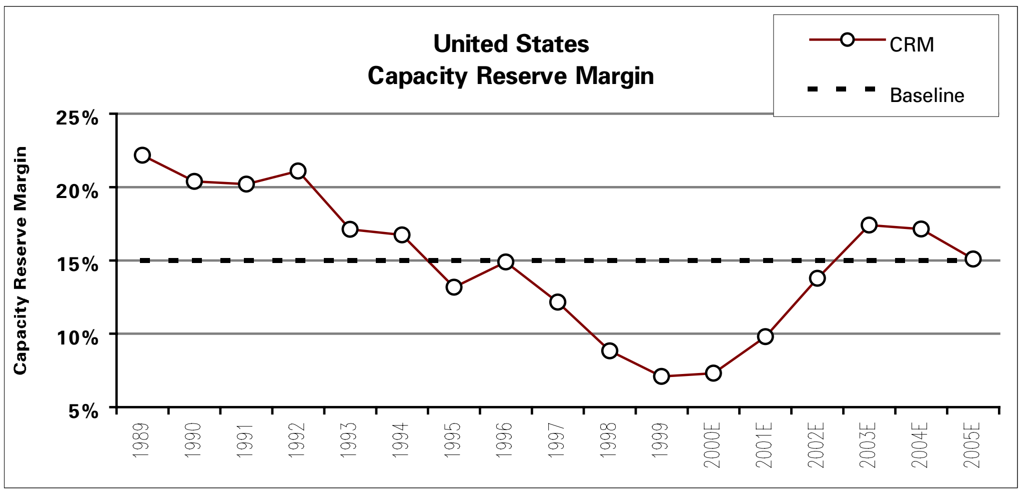
Capacity Additions by Year (MW's)

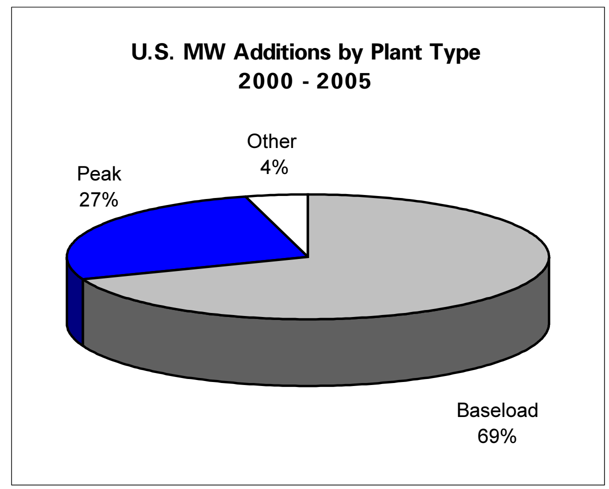


Capacity Additions	
Year	**MW**
2000	26,654
2001	47,688
2002	65,783
2003	69,481
2004	28,996
2005	8,818
Total	***247,420***

TOP FIVE BUILDERS IN U.S.*	
Company	MW*
1) Calpine Corp.	30,856
2) Duke Energy	18,697
3) Cogentrix	12,700
4) PG&E Corp.	12,395
5) Panda Energy	12,246

* Actual additions announced & completed 2000 to 2005; Not probability weighted.





Source: Deutsche Banc Alex. Brown estimates and company information

Furthermore, the ability to import power was limited this year due to reduced availability of hydroelectric power in the Northwest. As the state's population and economy grew over the last decade, the state's reliance on this imported power grew as well, which compounded the problem.

Flawed Deregulation Framework

The problems experienced today by the two state utilities are rooted in the its 1996 plan to deregulate the generation segment. In summary, the California Public Utility Commission (PUC), with the authority of enabling state legislation, forced the divestiture of the utilities' generation. In addition, the PUC fixed the retail rates the utilities could charge customers, creating a natural short position in a tight supply environment. Neither utility was able to pass on the cost of higher purchased power to customers. This situation was exacerbated by the absence of long-term power supply contracts, which exposed the utilities to the volatile prices in the day ahead and real time market, which increased according to the laws of supply and demand. The poor design of the California Independent System Operator (ISO) and the Power Exchange (PX) also contributed to the situation. The net effect is that the utilities incurred escalating purchased power costs as the price of power sky-rocketed and revenues remained constant under a fixed rate cap. Further complicating the situation has been the reluctance by politicians and regulators to quickly enact a comprehensive, long-term solution once the situation became apparent. This ultimately led to a financial, not operational, crisis for both utilities.

As we stand today, both companies have recorded huge write-offs associated with the unrecovered, deferred purchased power costs. PCG's utility has filed for bankruptcy under Chapter 11 and has yet to submit its plan for reorganization to the bankruptcy court. On April 9, EIX's subsidiary signed a memorandum of understanding with California Governor Gray Davis for the state to purchase EIX's transmission assets in exchange for recovery of deferred purchased power costs. No definitive action necessary to satisfy the terms of the MOU has been taken by either the PUC or the state legislature at this time. We continue to point out that the MOU does not eliminate the threat of bankruptcy for SCE. The California Department of Water Resources (CDWR) has been purchasing electricity on behalf of the two utilities since January 17, when Gov. Davis issued an executive order. For these reasons, we continue to see the experience in California as an isolated situation and do not expect it to be replicated in other states. We continue to believe that elsewhere deregulation will continue to advance, as evidenced by the activity at the state level described below.

Deregulation IS Working!

Current Status of Deregulation

Deregulation in states that have enacted a form of restructuring *is* working, despite the frequent headlines regarding the crisis in California. Currently, 24 states, plus Washington D.C., have enacted some form of restructuring solution and appear committed to moving forward as planned. As you can see from Figure 3, the country seems to be broken down into two primary groupings, those that have adopted and are implementing restructuring and those that are not currently pursuing it. A handful of states are in the exploratory stage and may eventually consider restructuring. This appears to be driven by regional disparities in the cost of generation. The states listed in groups 1 and 2 represent about 61% of U.S. electricity sales. In these states, deregulation is well under way. As you can see in the table, the other states are clustered in groups 3, 4 and 5.

Pullback in Select Regions

In reaction to the considerably higher power prices in the Western U.S. and California's troubled utilities, a few states in the West have pulled back from the restructuring process. The Northwest, which is also sensitive to the reduced availability of hydro-electric power, has also experienced higher power prices. The recent actions of regulators and politicians in Montana and Nevada in particular have injected a level of concern over the risk of re-regulation. We think that their actions are a knee-jerk reaction in an effort to assert some degree of control over the situation. The desire to retain generation is a bit myopic, in our opinion, since similar results can be accomplished through contractual arrangements. Nonetheless, the Nevada legislature halted the generation asset sale of the states's major IOU, Sierra Pacific Resources (SRP). Sierra Pacific has incurred losses from unrecovered purchased energy costs in the first quarter, but has since been authorized to recover all wholesale purchased power and fuel costs through rates on a deferred recovery mechanism. In Montana, the legislature pushed back the transition period until 2007 from 2002, and the Montana Public Service Commission (PSC) has asserted that it can continue to monitor the rates charged to default customers during this period by Montana Power (MTP). The company has experienced difficulties in contracting for long-term power from PPL Montana, a subsidiary of PPL Corp (PPL), who purchased generation assets from MTP. The PSC wants MTP to demonstrate that customers will not pay higher rates than before deregulation went into effect. Given the increase in power prices, this could have the effect of placing it in the same position as the California utilities. No final action has been taken by the PSC.

Figure 3:

Competition and Restructuring in the Electric Power Industry

The Pace of Evaluation at the State Level

F A S T E R < - > S L O W E R									
Group 1 [5]				**Group 2**	**Group 3**	**Group 4**	**Group 5**	**Group 6**
Arkansas	'03	Nevada (2)	'04	Oregon (2)	*Federal Legislation*	Colorado	Alaska	Hawaii
Arizona (2)	'01	New Hampshire (2)	'01	Vermont	Indiana	Kansas	Florida	South Dakota
California (1,2)	'98	**New Jersey (1, 2)**	'99	West Virginia	North Carolina	Kentucky	Idaho	
Connecticut (1)	'00	New Mexico	'07		Alabama	Minnesota	Nebraska	
Delaware	'01	**New York (2,3)**	'99		Georgia	North Dakota	Tennessee	
District of Columbia	'01	**Ohio**	'01		Iowa	Utah		
Illinois (1)	'00	Oklahoma			Louisiana	Wisconsin		
Maine (2)	'00	**Pennsylvania (1,2)**	'99		Mississippi	Wyoming		
Maryland	'00	**Rhode Island (1,2)**	'98		Missouri			
Massachusetts (1,2)	'98	Texas (1,2)	'02		South Carolina			
Michigan (1)	'02	Virginia	'02		Washington			
Montana (1,2)	'07							
58% [4]				**3%** [4]	**21%** [4]	**10%** [4]	**10%** [4]	**1%** [4]

Group 1: Legislative restructuring solution approved (Bold indicates competition has been implemented)
Group 2: Regulatory restructuring solution or specific guidelines approved.
Group 3: Significant debate and rapidly approaching regulatory or legislative solution.
Group 4: Advanced discussions of restructuring and initial debate.
Group 5: Preliminary discussions of restructuring.
Group 6: Little or no substantive discussions of restructuring.

Notes:
(1) Asset securitization permitted under legislation passed by state legislature.
(2) Some companies have agreed to sell some portion (or all) of their generating assets.
(3) Regulatory-led restructuring plan approved for each company in NY; legislation unlikely to be passed.
(4) Percent of total US electricity sales represented in each group.
(5) Figures to the right of state name and footnotes is the year full customer choice is expected to be implemented.

Source: Deutsche Banc Alex. Brown estimates and company information

Examples of Other State Restructuring: Pennsylvania and Texas

Other States Are Not Like California!

While the specific details of restructuring vary by state, and even differ among the utilities in each state, we thought it would be helpful to provide some concrete examples of the approaches adopted by other states. These states were selected to illustrate the various methods employed as well as to indicate the different time horizons to implement and complete the transition to competition. Again, we hope that by comparing and contrasting these states with California on the issues of (I) generation supply and (II) restructuring framework, we can illustrate why the financial crisis that occurred in California is the extreme case of state level restructuring. Where it is not proceeding as anticipated, regulators are making adjustments as necessary. We think that an actively engaged, pragmatically minded commission is crucial to institute any necessary refinements and to instill confidence in the market.

Pennsylvania

Generation Supply Situation and Market Structure

Pennsylvania does not find itself in a predicament like that of California because of a much better regional supply outlook and a better designed market structure. Pennsylvania is included in the Mid-Atlantic Area Council (MAAC) region, one of the power pools as defined by the North American Reliability Council (NERC). Power supply in MAAC is below the 15% capacity reserve margin (CRM) target, although it should be adequate in 2001 and is expected to increase gradually over time. Our current estimated CRM for 2001 is 9.3%. As of June 15, 1,064 MW of generation will have been added this year and an additional 611 MW are expected by year-end. The announced probability-weighted backlog from 2001 to 2005 for the region is 9,978 MW. Thus, the CRM for 2002 should increase to about 11.5% and 13.3% in 2003. Please see the Appendix for additional information about the supply outlook in the MAAC region.

Pennsylvania is part of the PJM power pool (Pennsylvania-Jersey-Maryland), which is one of the better-designed regional power pools. The table below cites a number of factors that differentiate the PJM ISO from the California ISO. Note the relatively lower use of hydro and natural gas-fired generation and better transmission access in PJM.

Figure 4:

PJM-ISO	Cal-ISO
Congestion Mgmt: Location Marginal Pricing	Congestion Management: Price
Capacity Market	No Capacity Market
PJM is the Scheduling Coordinator	Scheduling Coordinator are part of ISO
Bilaterals can self-schedule	Schedule coordinators are private
PJM schedules generation by Eco dispatch	Schedule coordinators compete with PX
PX, ICAP and Transmission under ISO	Several markets under different entities
Little or no transmission constraints	Transmission constraints limit import
2% hydro capacity; not susceptible to water levels	Hydro capacity decreased 23%
9% gas fired; less dependent on natural gas prices	45% gas fired generation
$1,000/mWh cap; consistent with neighboring pools	$250/mWh cap in 2000; drove power out of state
Forward contracts	No forward contracts; purchase through PX

Source: DBAB & Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning

Deregulation Legislation and Settlement Agreements

Pennsylvania was one of the first states to pass restructuring legislation in December 1996 with the Customer Choice Act. The Pennsylvania Public Utility Commission (PUC) implemented the particular elements of restructuring through company-specific settlement agreements, each with different terms. Broadly speaking, however, the basic components included:

- no forced divestiture of generation
- recovery of stranded costs through wires charges
- phase-in of retail competition with full competition by January 1, 2001
- capped distribution rates

It is interesting to compare the various restructuring agreements, which set the utilities on paths toward very different strategic and financial outcomes. A very brief overview is provided below:

Figure 5: **Pennsylvania Utilities**

Utility	Parent	Generation Divestiture	Distribution Rate Cap Expires	CTC Expires	PoLR Obligation
Peco Energy	Exelon (EXC)	No	6/30/2005	12/31/10	Until 12/31/10
PP&L	PPL Inc (PPL)	No	2004	2009	2009
Duquesne Light	DQE, Inc (DQE)	Yes	1/1/2002	12/31/05	Transferred to buyer (ORN)
Metropolitan Edison	GPU, Inc (GPU)	Yes	2010	2010	2010; Phased out through auction
Pennsylvania Electric	GPU, Inc (GPU)	Yes	2010	2009	2009; Phased out through auction

Source: Deutsche Banc Alex. Brown estimates and company information

At the heart of the issue is whether or not the utilities retained their generation and how they handled the obligation to serve those customers that do not select an alternative supplier. This obligation is known in Pennsylvania as the Provide of Last Resort (PoLR), and is referred to as default service or standard offer service in other states. The Pennsylvania PUC did not require generation divestiture. PECO Energy, PP&L and Allegheny Energy elected to retain their generation, which was subsequently transferred to an unregulated subsidiary. In contrast, DQE and GPU opted to sell off their generation. But the difference in the agreements reached by DQE and GPU highlight the crucial element of risk management: the PoLR. DQE sold its assets to Orion Power, but has renegotiated a long-term purchased power agreement through December 2004. Under the agreement, DQE effectively transferred the PoLR obligation to Orion. That means that during this time, ORN bears the risk of meeting 100% of the demand from those existing DQE customers that do not choose an alternate energy supplier. Orion has built a 500 MW peaking plant nearby to meet the peak demand of the DQE contract, which should act an “insurance policy” this summer.

GPU also decided to divest its generation, but reached a different settlement agreement. GPU’s plan instituted a competitive bidding process for GPU’s PoLR in blocks. So far, the process has resulted in a failed auction. The first auction for 20% in June 2000 yielded no bidder, and the second auction for 40% in June 2001 had the same outcome. GPU is supposed to auction 60% in 2002 and 80% in 2003. GPU has had to incur the expense of purchasing that power in the open market, which has proved costly. GPU has petitioned the PUC for a rate increase. On April 25, an Administrative Law Judge (ALJ) for Pennsylvania regulators recommended a $317 million rate increase. On May 24, the Pennsylvania PUC approved the merger of FirstEnergy Corp. (FE) and GPU, but postponed a decision on GPU's request to raise rates. The commission voted 4-1 to convene a collaborative meeting on the rate request. A final decision from the PUC is expected no later than July 13. FE has previously stated that GPU's rate relief plan is critical to the merger's closure. Due to GPU's obligation to provide power to retail customers at capped rates below the wholesale price, it lost $47 million in 2000 and is estimated to lose approximately $250 million in 2001. Thus, a lack of a reasonable rate plan could threaten GPU's financial stability, which in turn could pose a risk to the merger. Given the ALJ's recommendation in April and the PUC's recent move to empower the interested parties to negotiate the rate relief, we believe that the ultimate outcome will be favorable for GPU and, accordingly, the merger with FE. A rate deferral mechanism, rather than a rate increase, remains a possibility.

In contrast to GPU’s auction process, PECO has been able to fulfill its settlement requirements. First, PECO’s energy delivery business has contracted for supply for non-switching customers from Generation under a long-term purchased power agreement at a price equal to its fixed rates. In order to encourage customer switching, the PUC established a shopping credit forced the utility to sell blocks of capacity to alternative energy suppliers. Effective January 1, 2001, PECO agreed to assign 20% of its non-shopping residential customers to competitive default service provided by a competitive energy supplier. PECO signed a bilateral contract with New Power Company (NPW) for 22% of that load to New Power through January

2004. PECO also contracted with Green Mountain Energy Company for 50,000 residential customers under the same terms as the New Power contract.

Pennsylvania took a phased approach to the implementation of retail competition. Starting January 1, 1999 one-third of the peak load in each customer class was eligible to choose an alternate supplier. The second one-third of capacity could choose January 2, 1999. By January 1, 2000 all customers had the ability to choose.

Texas

Generation Supply Situation and Market Structure

Texas is probably one bookend to the regional supply outlook while California is the other bookend. Because of a dramatically easier siting and permitting process in Texas, the state has the largest backlog of projects entering commercial operations this year and next. As a result, it is likely to be the first region to reach a glut of capacity in excess of a 15% capacity reserve margin target. Texas is part of the Electric Reliability Council Of Texas (ERCOT) region, one of the power regions as defined by the North American Electric Reliability Council. Our current estimated CRM for 2001 is 18.4%. As of June 15, we expect 7,984 MW of generation will have been added and an additional 2,093 MW are expected by yearend. The announced backlog from 2001 to 2005 for the region is 22,939 MW (probability-weighted). Thus, the CRM for 2002 should increase to about 20.5% and 21.9% in 2003. As a result of the new capacity and current inability to export power, prices are expected to decline and remain relatively stable. Please see the Appendix for additional information about the supply outlook in the ERCOT region.

Deregulation Legislation and Settlement Agreements

The state of Texas, led by the Public Utility Commission under Chairman Pat Wood, devised a multi-year restructuring plan. Texas regulators have reiterated their commitment to move forward with the state's restructuring process. The main elements include:

- Deferred true up of stranded costs in 2004
- Phase-in of retail choice with pilot programs
- Price to beat adjustments include fuel and purchased energy costs, subject to adjustment twice a year
- No forced divestiture of generation, but partial sale of generation establishes fair market value of assets
- 40% switching threshold necessary to move to market based rates

One of the features of the approach taken in Texas is that the process is very dynamic, with decisions being made and implemented over time. One of the more creative tactics used by the PUC was the ability to assign the Provider of

Last Resort (PoLR) obligation to a retail electric provider in a particular territory if there are no applications. It may not necessarily be the incumbent utility. The PUC has also orchestrated the auction of 15% of capacity to new suppliers. The retail energy provider of the incumbent may not participate in that auction, which should serve to encourage new entrants and attract other utilities into what was previously the "home turf" of the incumbent. An interesting twist in Texas is that the PUC recently determined the utilities have a negative stranded cost (i.e., stranded benefit)! This is the result of increased non-gas fired generation asset values in the current market environment. This will create more "headroom" under the price to beat (PTB), which should also help to attract new suppliers. The actual true-up of stranded costs is not until 2004. A generic ruling on the PTB was issued earlier this year, which allowed for an adjustment to for purchased energy costs (including fuel) no more that twice a year. The final PTB will be set at the end of the year. Another unusual aspect is the way the regulated generation will be valued. For example, Reliant Energy will spin out 19% of the regulated generation (genco) to create a market value in 2002. Reliant Resources, the unregulated wholesale business, will have an option to bid on the regulated genco in 2004.

A pilot program for 5% of customers has been delayed from June 1 to July 6 to provide additional time for refinements to the information system infrastructure. Full competition is slated to start January 1, 2002 for all customers.

Is New York the Next California?

One of the most frequently asked question following the "outbreak" of the California power "epidemic" is: "Who's next?" Much attention has been focused on New York, particularly the New York City market, given some similarities to California. The most obvious parallel is the tight power supply. While the two regions may share some similarities, New York is not like California for a number of reasons, which we explore in further detail. Although New York may see power outages this summer, we do not expect another utility to face the same financial woes as those by EIX or PCG.

Tight Power Supply Suggests Similarities

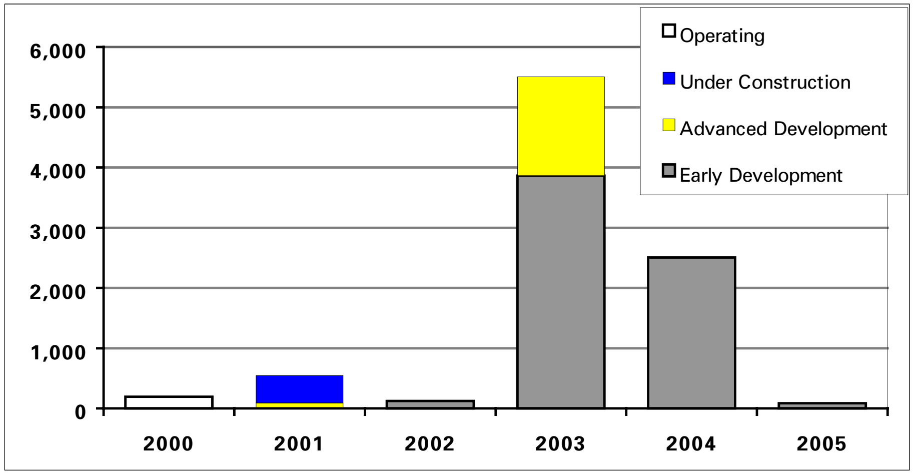
The New York City region is supply-constrained due to a lack of new capacity additions. Similar to California, the permitting and siting of new power plants has proven to be extremely difficult due to local opposition and resistance from environmental groups. The area has also experienced strong economic growth, which has fueled the growth in demand. The projected peak New York City demand is 10,535 MW and is supplied by 8,236 MW currently in service in the area. About 5,100 MW of capacity can be imported into the region. 80% of the generating capacity needed to serve New York City must be located within the city's "load pocket." The outlook for New York State is more encouraging, given the greater availability of capacity and ability to import power, if necessary. Our most recent survey of the available capacity for the state for this year and through 2005 is shown in the table below.

Efforts to add new supply are under way, but progressing slowly. An additional 400 MW in 44 MW installments from the New York Power Authority (NYPA) are expected to be in service at various points through out the summer, starting in mid-June. In addition, about 100 MW from the East Coast Power project (Enron: ENE and El Paso: EPG) and Hudson Avenue Unit 10 (Consolidated Edison- ED) are also expected to come on-line. Plans for new supply this summer should help but not completely avoid trouble, especially during periods of hot weather. If all of the projected power is added as expected, this would yield about 8,700 MW against the projected peak of 10,535 MW. In other words, New York City will be short about 1,835 MW, before power imports. Consolidated Edison has spent nearly all of the $483 million budgeted to upgrade its infrastructure to avoid the problems it experienced in 1999, but any number of factors could disrupt the fragile, heavily taxed system. This does not account for any unplanned outages or disruptions, such as the transmission meltdown at Con Ed in 1999 and the shut down of the 1,000 MW Indian Point nuclear plant unit 2 in 2000.

Another fundamental characteristic of the region is that like California, the ability to import power into the region is limited. New York imports about 5,130 MW. Some capacity is available from the north from the New England Power Pool (NEPOOL) and some from the south from the Pennsylvania-New Jersey-Maryland (PJM) power pool. Because it is not as dependent on hydro-electric power as in Northwest, the area is less vulnerable to fluctuations in rainfall/snowpack. This season, however, is expected to experience average water conditions.

Figure 6: **New York Power Pool (Sub-Region of NPCC)**

Capacity Additions by Year (MW's)



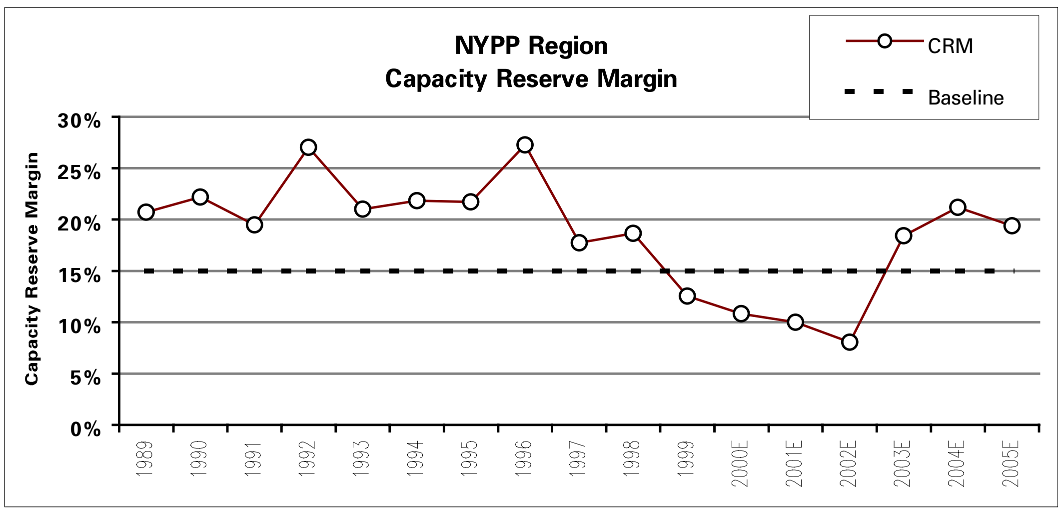
Capacity Additions Year	MW
2000	189
2001	543
2002	119
2003	5,505
2004	2,505
2005	85
Total	***8,946***

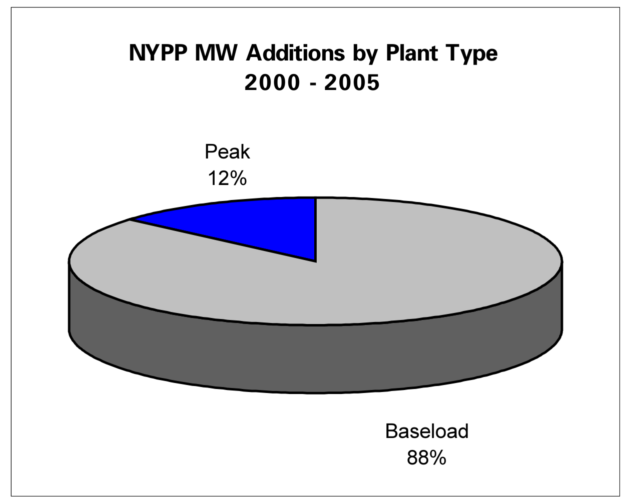
TOP FIVE BUILDERS IN NYPP Company	MW*
1) International Power	1,640
2) KeySpan	1,186
3) PG&E Corp.	1,092
4) ABB Energy Ventures	1,075
5) SCS Energy, LLC	1,000

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NYPP
New York

DEREG STATUS
NY - Restructuring order issued, but not enacted.





Source: Deutsche Banc Alex. Brown estimates and company information

Different Deregulation Framework

Another parallel with California is that Consolidated Edison has divested most of its generation under New York restructuring. Currently, its owned generation supplies about 25% of its utility load, with about 20% supplied under contract by Non-Utility Generators (NUGs). Con Ed has secured about 5% of its demand through firm contracts for certain periods. The result is that the company purchases about 50% of its load through the New York Independent System Operator (NY ISO), which operates a day ahead and real time market much like California. Con Ed *is* permitted to enter into bilateral contracts to reduce its reliance on the day ahead or real time market. At this point, we believe that Con Ed has entered into some long-term contracts, but because it is the largest buyer, the company has not disclosed the counter-parties, amounts or terms of the contracts. While Con Ed has some incentives to manage it's purchased power expenses through hedging, an important difference is that Con Ed *is* allowed to pass on its purchased power costs, which include the cost of natural gas. Con Ed's purchases are subject to a "prudence review" by the New York Public Service Commission (PSC). This arrangement was tested last summer as electricity prices rose in spite of cool weather predominantly as a result of higher natural gas prices and the Indian Point 2 nuclear unit outage. The PSC withstood the hand waving conducted by politicians and recovered those costs. Con Ed's arrangement remains intact for this summer. Thus, ED will not be subject to the same situation that EIX and PCG's utility subsidiaries have been.

That being said, the marketplace is somewhat different. The New York ISO has instituted a $1,000/mWh cap, which is the same as the New England ISO and the PJM market, which should avoid the situation in California where power was driven out of state to regions that did not have a price cap.

Figure 7: **Comparison of New York ISO vs. California ISO**

NY-ISO	Cal-ISO
Congestion Mgmt: Locational Pricing	Congestion Management: Price
Capacity Market	No Capacity Market
Bilaterals can self-schedule	Schedule coordinators are private
PJM schedules generation by Eco dispatch	Schedule coordinators compete with PX
PX, ICAP and Transmission under ISO	Several markets under different entities
Moderate transmission constraints, severe in NYC	Transmission constraints limit import
17% hydroelectric; not as susceptible to water levels	25% hydro capacity; more dependent on rainfall
28% gas fired; less dependent on natural gas prices	45% gas fired generation
$1,000/mWh cap; consistent with neighboring pools	$250/mWh cap in 2000; drove power out of state
Forward contracts allowed	No forward contracts; purchase through PX

Source: DBAB, Consolidated Edison & Pennsylvania Public Utility Commission

The NY ISO had proposed an Automated Mitigation Procedure (AMP), which was designed to act as a "circuit breaker." The plan intended to allow the ISO to more actively and quickly review and question the bidding behavior of generators. The process has been automated through a computer system that is designed to pick up unusual or large movements in bids. It would be triggered only if the energy price exceeds $150/mWh and only in the day ahead market (not the real time market). It would potentially allow a bid to be replaced by a "reference price" which is based on trailing 90-day average of accepted bids. The idea is to impose discipline into the bidding process. This system, however, is less than perfect. Since a bid price in July would reference prices from April and May, which are "shoulder months" it would not necessarily provide a meaningful price for comparison. However, it is intended over the course of the summer to keep the average-weighted price down as well as incent generators to bid at such a level that they are not knocked out of the dispatch queue because they submitted egregious bid prices. Mirant Corp (MIR) has successfully challenged the AMP at FERC on the grounds that the NY ISO does not have the authority to implement these changes. According to Mirant, that authority resides with FERC. FERC agreed with Mirant's petition. The New York ISO has requested the FERC rehear their petition on an expedited basis, but no action has been taken by FERC at this time.

The New York Public Service Commission, working in concert with Con Ed, have made preparations to shed load through demand reduction programs. The Emergency Demand Response Program is expected to shave 50-75 MW of peak load by this summer. More importantly, the New York Public Service Commission is an informed, educated and actively engaged body that has been working with the utilities. Also, the deregulation under the PSC happened under Governor Pataki's watch, and thus, he has more political capital invested in keeping Con Ed financially healthy and keeping the market functional. Nonetheless, supply is expected to be tight this summer even assuming normal weather and we would not be surprised if there was a political reaction to higher prices.

Other Regions, Reasons for Concern

Based on our recently updated Electricity Supply & Demand Outlook report, we expect several regions to be tight power supplies this summer. These regions include California, New York City, the Northwest, the Northeast and parts of the Midwest. We feel that although the expected CRM is less than the 15% target, supply will be adequate to avoid rolling blackouts as in California. In those regions, a perceived risk of power shortages begs the question, what's the worst that can happen here? Conceptually, the greatest risk is for those participants that are short capacity. This could be the result of being physically short capacity through divestiture or load growth outstripping native supply, or being contractually short power due to inadequate hedging and risk management practices. The natural short resulting from divestiture is limited to a handful of utilities that do not have buy-back agreements with the buyers of their generation or other purchased-power agreements. We have discussed how GPU found itself exposed to the wholesale market and could not pass on those costs until recently. But by and large, this risk is not widespread. (See table in the Appendix for a list of those states that forced divestiture). In most other states, the utilities retain the ability to pass on energy costs, including both the cost of gas and purchased power. In many states, this has been addressed pretty satisfactorily with an adjustment mechanism- monthly, quarterly, semi-annually, or an automatic trigger to avoid significant deferrals like those accumulated in California. In other states, the utilities must still file with the state commission for a rate increase. We have seen regulators in a handful of states respond to requests for rate increases to reflect the higher price of natural gas and electricity. Recovery may be spread out over a period of time to mitigate the immediate impact to ratepayers. Only in Arizona, California, Connecticut, Maryland, Montana, New Mexico, Oregon, Pennsylvania, Utah and Washington are the utilities not allowed to pass on the cost of fuel and/or purchased power automatically. Please refer to the status of rate caps and fuel adjustment clauses by state in the Appendix .

Catalysts to Advance Deregulation

We acknowledge that the pace of change may slow in some states as a result of California, but wholeheartedly believe that a number of factors should continue the restructuring of the industry. The most significant drivers include the addition of new generating capacity, the formation of regional transmission organizations, as well as other federal and state initiatives. We are encouraged by the recent policy proposal drafted by the Bush Administration and the adoption of a long-term, comprehensive approach to industry reform. Despite the recent change in Senate leadership, we are optimistic that Congress will take legislative action this summer and later this fall in order to address some of the more pressing energy policy issue confronting the Western U.S. and the country as a whole.

New Supply Additions Will Help . . .

Large Announced Project Backlog

As we have discussed previously, we believe the situations in California and New York can be explained primarily as matter of inadequate generating supply and the lack of new plant construction near the source of electricity demand. We contend that as new supply is added to these areas as well as elsewhere across the country, prices will ease and the increasing abundance of power will foster the movement toward competition in currently regulated states. In the interim, however, the industry has responded with a growing backlog of generation projects to meet the electricity shortage. Nationally, the probability-weighted backlog of announced projects through 2005 stands at 220,766 MW. We expect about 35,000 megawatts (MW) of new generating capacity to come on line in the U.S. by June 15. (Please refer to the Appendix for a complete listing of Supply & Demand tables by region). This backlog has been encouraged in part by high electricity prices, which have attracted investment in infrastructure facilities.

States Encourage Supply Additions

Due to the inability to store electricity and the inherent fluctuations in weather patterns, it is impossible to completely eradicate price volatility from the marketplace. However, the extreme volatility should moderate as new supply is built. Lower price volatility makes the decision easier for politicians and regulators to advance deregulation. We have seen some recent state attempts to facilitate new construction for this purpose. As a direct response to the California crisis, the state of Washington's legislature enacted a bill to facilitate the construction of new generation. In late May, the Minnesota legislature approved and Governor Ventura signed an energy bill aimed to streamline the approval process for new generation and the routing of transmission lines. The bill also expedited the siting process for plants between 50 to 80 MW, natural gas-fired plants, and transmission lines under five miles long. Another provision lifted the requirement to obtain a certificate of need to upgrade existing facilities, as long as the increase in output was 100 MW or less or no more than 10% of existing capacity. In early April, New

Mexico Governor Johnson signed SB 452, which requires the New Mexico Regulation Commission to rule on plant and transmission line siting applications within six months of filing, or else the filing is automatically approved. These actions should help in the intermediate to long-term. The high prices and volatility, however, have tested regulators' will to withstand political pressure despite the prospects for it to continue in the near term.

New Supply Helps…Despite Challenges

Refunds and Price Caps

The situation in California has led to the call for price caps in the state and throughout the Western United States. Advocates for price caps claim that the FERC is not upholding its obligation to enforce "just and reasonable" rates under the Federal Power Act (FPA). We continue to argue against price caps and suggest that California continue to aggressively pursue the signing of bilateral agreements to reduce the significance of prices in the spot market. We think the price increases approved by the CPUC will help to reduce demand, which has yet to make its full impact felt. The demand response in Sempra Energy's (SRE) California utility's service territory, where prices have been passed through to consumers, was about 9%. EIX and PCG customers are only just now receiving their May bills, which contain the 30% rate increase. We would expect a similar response from EIX and PCG's customers. Reports have indicated that demand has been reduced by about 10% through a combination of conservation efforts, the 10% rate increase in January, the expectation of higher rates (retroactive to March 27), and a downturn in the regionally-based technology sector.

To date, FERC has not implemented a hard cap and has not ordered onerous refunds to customers. The commission has chosen to evaluate only the power sold during Stage 3 emergencies in California. In reviewing electricity power sales for the months of January, February, March and April, the FERC ordered refunds that represent a fraction of the total transactional value of bulk power sold through the California ISO. The parties named could either refund the amount or justify to the FERC the prices charged for the power based on fuel prices, operating costs and other related expenses.

On April 25, the Federal Energy Regulatory Commission announced a peak price mitigation plan for electricity prices in California. Ostensibly, the FERC rejected price caps for electricity prices again. The plan implements cost-based pricing at times that the California Independent System Operator (ISO) declares a Stage I emergency (supply reserve dips below 7.5%). We note that during the very hot summer in 2000, a Stage I emergency was declared for a total of about 201 hours, or about 7% of the time. Therefore, we do not expect a material impact from the cost-based pricing in 2001. Admittedly, the risk is a substantially greater number of Stage I emergencies in 2001. The Western Systems Coordinating Council recently indicated that reserves ought to be tight but adequate in every region of the West except California.

Windfall Profits Tax

On May 7, the California State Senate passed a bill establishing a "wind fall profits" tax in the state of California for companies selling electricity. The legislation would effectively cap electricity prices over $80 per megawatt hour, but did exempt certain companies from the tax. Although the tax is unlikely to be implemented and become law, the legislation now moves to the State Assembly for further consideration. Another version of the bill is in the State Assembly. Discussions of similar laws have not had a majority of support among legislators recently, but the support in the Senate was strong. We do not expect the proposed legislation to be enacted into law. The law as currently written would provide a major disincentive to BOTH the development of new generating assets as well as the operation of high cost existing assets. This would further exacerbate the shortage of generating capacity in the state -- at a time when the shortage is likely to seem most acute. For these reasons, we view the legislation as unlikely to advance. However, we expect the threat of the legislation to be used by legislators in discussions and negotiations with generators. For similar political reasons, Governor Davis has expressed his support for the legislation.

Transmission and The Emergence of RTOs: The Missing Link

The industry has responded to declining capacity reserve margins by building generation closer to the load centers in the absence of compelling incentives to build transmission. The issue of limited transmission capability and bottlenecks in California and New York highlight a significant issue confronting the country as a whole: the need to upgrade and expand the nation's transmission network to facilitate the transfer of power across regions. The prospect of siting new transmission lines, however, touches on the thorny issues of states' rights and eminent domain of federal authorities and requires the close coordination of federal, state and local entities. In addition, the need for new transmission lines also begs for the resolution of appropriate ratemaking mechanisms and the establishment of enticing incentives for investment. The upcoming Regional Transmission Organization (RTO) deadline and congressional attention on the matter suggest that some constructive reforms will occur. Ultimately, enhanced ability to move power should bolster competition and increase reliability.

Grid Not Designed for Present Utilization

Never has the demand for reliable power been so great as today given the increasing dependence on technology throughout our economy. This growth in demand for capacity and for reliable power has stressed the current transmission system, which was not designed to wheel power between regions. The country is divided into three main power regions, or grids, which have limited interconnections and are prone to congestion in certain areas. The U.S. is sub-divided into the Western grid, the Eastern grid and ERCOT, the Electric Reliability Council of Texas. Both the Western and Eastern grids have interconnections with portions of Canada.

Complicated, Lengthy Approval and Siting Process Inhibits Construction

Difficulty in obtaining siting permits from multiple jurisdictions has thwarted new construction of transmission. As an example, consider that American Electric Power (AEP) first proposed a 57 mile, 765-kV transmission line in 1991. This line would connect the area near Tazewell in Southwestern Virginia to Northern Ohio. On June 1, 2001 the Virginia State Corporation Commission approved AEP's request, citing the need to reinforce AEP's grid in Southwestern Virginia since the previous upgrade occurred in 1973 despite growing demand on the system. The proposal has been under consideration for nearly ten years due to local opposition and the number of approvals required. The planned line crosses 11 miles of federal land, requiring approval from the U.S. Forest Service, the National Park Service and the Arm Corps of Engineers. To date no indication of the expected review of the application by these federal entities is available.

Economic Incentives for Construction Are Absent

Recently, there has been little economic incentive for the construction of new transmission. The most recent allowed return on equity on transmission assets is 11.2%. The FERC has proposed to increase the return by 200 basis points under certain conditions. While this action is an encouraging sign of FERC's recognition of and willingness to craft economic incentives, the aggressive timeline makes it unlikely that the construction timeframe could be met. Significantly stronger incentives need to be devised.

FERC Order 2000

In December 1999, the FERC issued Order 2000, which strongly encouraged all public utilities that own, operate or control interstate electric transmission to participate in a Regional Transmission Organization (RTO). The FERC did not mandate what form the RTO would take. Either an Independent System Operator (ISO), Transco or hybrid model is acceptable, so long as they fulfill the filing requirements. The minimum characteristics focused on independence (from market participants, i.e., generators) and the ability to provide reliable, non-discriminatory efficiently priced transmission. This is the foundation for a competitive bulk power market. The for-profit transco model would necessitate relinquishing operational control (ownership). However, given the tax implications (i.e., capital gains) associated with the sale of transmission assets to another entity, the transco model could be prohibitive. We are hopeful that legislative action may alleviate these tax burdens, since we believe the for-profit transmission company is the most vibrant model. The RTOs are required to be operational by December 15, 2001. FERC is planning a "RTO Seams" technical conference in June or July to discuss the interaction of sales between the RTOs.

Anticipate Constructive Legislative Solutions

The pending deadline for RTO participation should help focus attention on several outstanding issues that could be resolved through companion legislation. Already, a number of bills have been introduced which contain elements pertaining to tax reform. Specifically, the Electric Power Industry Modernization Act (H.R. 1459) and National Energy Security Act of 2001 (S 389) contain provisions to address Private Use Relief, Transmission Tax Relief, and Contributions in Aid of Construction issues. We are cautiously optimistic that the enabling legislation can be passed this year.

Bush Administration Plan Further the Development of RTOs

With the RTO deadline looming come year-end and news about the current energy crisis in California, this issue has received increased attention by national political leaders. The Bush Administration, under Vice President Cheney's leadership, recently released its recommendations for a comprehensive national energy policy. The National Energy Policy proposal devotes significant attention to the issue of transmission. The major policy recommendations are listed below:

- Encourages FERC to use its existing authority to promote competition and encourage investment in transmission facilities.

- Directs the Secretary of Energy to examine the benefits of creating a national grid, identify transmission bottlenecks, and suggest measures to remove such bottlenecks by December 31, 2001.

- Encourage the use of incentive rate-making proposals.

- Directs federal utilities to consider whether transmission expansions are necessary, such as the Bonneville Power Administration (BPA).

- In consultation with the appropriate federal, state, and local government authorities, directs the Secretary of Energy to develop legislation to grant authority in order to obtain rights-of-way for electricity transmission lines in order to create a national grid.

- Recommends that the Secretary of Energy and FERC work to improve the reliability of the interstate transmission system and develop legislation to provide for enforcement by self-regulatory organization subject to FERC oversight.

- Suggested exploration of ways to relieve the bottleneck at the "Path 15" transmission line in Southern California.

These recommendations are conceptual and lack sufficient detail to form the basis of any investment decision, but we think the tack taken is encouraging, if not ambitious. The Administration is moving at a rapid pace to create a national grid. This is likely to encounter resistance, but would not be unlike the authority the FERC exercised in the natural gas pipeline industry. The most urgent issue of relieving congestion on Path 15 is likely to garner the most attention and support.

Components of The Bush Administration Plan Support Federal Deregulation Initiatives

Proposal Highlights

On May 17, President Bush's National Energy Policy was unveiled, an important step to stimulate energy supply while enhancing efficiency. It specifically called for the development of a comprehensive national energy program. In essence, these proposals aim to reduce regulatory uncertainty (e.g., EPA regulation, nuclear waste disposal, etc.) and encourage investment to increase power supply and reliability. In addition to its provisions for transmission, the report called for the following:

- Ease regulatory barriers to building power plants;
- Streamline the re-licensing process for certain types of power plants;
- Increase power supply from neighboring Canada and Mexico;
- Utilize a variety of fuel sources to generate reliable and affordable electricity;
- Promote conservation by employing technologies to tap renewable energy sources;
- Bolster efficiency;
- Repeal the Public Utility Holding Company Act (PUHCA) and the Public Utilities Regulatory Policies Act (PURPA);
- Establish a flexible, market-based program to reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power plants

Among the recommendations, the proposal to repeal PUHCA and PURPA could have the most significant impact on the industry. Overall, the report did not contain many surprises and is consistent with the Administration's economically sensible, market-based approach. We continue to believe that supply-side biased energy policy is currently the correct solution, in light of the supply shortage. However, demand-side considerations should be included in any longer-term goals of the policy. The energy policy as released is positive for the generators and potentially for companies in the energy transmission business.

Congressional Action Expected

The change to a Democratically controlled Senate has also shuffled the committee leadership positions. Senator Murkowski (R-AK) has relinquished his chairmanship of the Senate Energy Committee to Senator Jeff Bingaman

(D-NM). The new Committee leadership does not automatically or dramatically alter the committee's policy focus, but it may affect the scope and speed of implementation. Already the Democrats have announced that they will shift the Congressional priorities to issues such as Education. Under a Republican led Senate, we expected the Energy Policy proposal to be a priority issue. On a conference call hosted by Deutsche Banc Alex. Brown on May 25, Senator Bingaman indicated that he would prefer that the FERC take action to uphold the "just and reasonable" rate doctrine of the Federal Power Act before Congress stepped in to legislate price caps. We believe supply-side initiatives are still more likely than price caps. We expect Congress to prod the Federal Energy Regulatory Commission into more closely scrutinizing whether wholesale electricity rates are "just and reasonable" as prescribed in the Federal Power Act. Aside from the issue of price caps, several bills have been introduced, and more are expected, to address urgent matters regarding California and the Western U.S. as well as long-term issues consistent with the Bush Administration's plan. Thus, we expect some activity at the federal level this year.

Full FERC Membership Provides Horsepower and Willpower for Action

The U.S. Senate recently approved President Bush's two nominees to the Federal Energy Regulatory Commission (FERC). The two recent appointees are Patrick Wood, formerly a state regulator in Texas, and Nora Mead Brownell, formerly a state regulator in Pennsylvania. Wood will serve a five-year term ending June 30, 2005, while Brownell completes an existing term that is renewed through June 30, 2006. In addition to the three existing commissioners, the appointments to the two vacant chairs will complete the staffing of this important agency before the critical summer-time season. When combined with the other competitive market-oriented commissioners on the FERC, we believe the five commissioners will continue to firmly endorse a market-oriented approach to solving the shortage of generating capacity in the United States. We believe the appointments are positive.

The current Chairman, Curt Hebert, has repeatedly stated that he is against price caps. Pat Wood is rumored to replace Mr. Hebert as the Chairman. If that were to occur, Mr. Wood's track record in Texas and his political ties to President Bush suggest to us that he will take an even-handed approach. Either way, we view the leadership at FERC as pro-restructuring.

Outlook for Future State Deregulation Remains Promising

By now, we aim to have demonstrated that deregulation is continuing, despite some recent tests, and have identified a number of catalysts that will advance the process. We feel that more knowledgeable regulators and an informed populace about the pitfalls of deregulation will emphasize and encourage new generation supply, which will help develop a mature wholesale market. In light of the passage of comprehensive restructuring legislation in the near term, we expect to see piece meal legislation designed to encourage the construction of new supply and improve reliability. Previously, we illustrated how a handful of states were proactively responding to California by encouraging new supply and transmission. Politicians and regulators appear preoccupied with improving reliability and strengthening the wholesale market, as well as open access to transmission. We feel that in a couple of years, we will continue to see additional states move to restructure. We think the most likely states to adopt restructuring next are Indiana, West Virginia, and Florida. Consider the following:

Indiana: The 2000 legislative session considered a restructuring proposal, but did not adopt one. Legislation was introduced again in January 2001, but was not taken up. The major investor owned utilities (IOUs) were able to reach consensus to support a bill, which is a crucial starting point for drafting legislation. Indiana is surrounded by deregulated states, and its membership in the Alliance RTO may be a catalyst.

West Virginia: Specific language to enable the implementation of a regulatory-driven restructuring plan was not passed during the short 2001 session, but may be revisited in 2002. This primarily requires changes in tax laws, since the bulk of the more significant items have been addressed. The legislation would have enabled the transfer of generation to an unregulated affiliate, which in today's climate, appeared to be too politically risky to vote on.

Florida: Gov. Jeb Bush created the Energy 2020 Study Commission to propose a state energy plan. In January 2001, the energy study commission approved a recommendation to restructure the wholesale power industry, which included the removal of statutory barriers for new market entrants and the creation of Exempt Wholesale Generator status of IOU affiliates. We think that the need for new capacity will drive this process. The 2000 capacity reserve margin was about 1.2%, and is expected to be 3.7% in 2001 and 13.0% in 2002. The study group will issue a plan on retail competition by the end of 2001.

Retail Competition Will Follow

As the country adds new generation supply, it will continue to develop the wholesale market. This trend should lay the groundwork for the development of a more vibrant retail market. When trying to assess the success of deregulation, undue emphasis is placed on the level of customer switching. While this a metric that is relatively easy to compile and compare, it is only one facet of the overall health of a "competitive market." Retail competition has already been implemented in Arizona, California, Connecticut, the District of Columbia, Illinois, Maine, Maryland, Massachusetts, New Jersey, New York, Ohio, Pennsylvania and a pilot program in Texas is just beginning. Full competition in Texas should start January 1, 2002. Additional states are expected to introduce customer choice in 2002, including Michigan and Virginia.

Bearing in mind the potential implications from adopting retail choice, six states delayed its implementation until the market place is more developed and stable. Arkansas, Oklahoma, New Mexico, and West Virginia, which were scheduled to start competition in 2002, as well as Montana and Nevada, where competition was slated for 2004, have recently taken steps to delay the onset of competition.

Arkansas delayed competition from January 1, 2002 until October 31, 2003 at the earliest. On 2/20/01, Gov. Huckabee signed into law a bill that amends the Electric Consumers Choice Act passed in April of 1999. The Public Service Commission is authorized to push back the date another two years (until 10/1/05) once it has determined that "effective market structures" exist. An effective market involves participation in a FERC-approved regional transmission entity and sufficiently available generation and transmission capacity. Many company-specific issues such as rate unbundling, market power, transition costs, etc. have not yet been addressed.

In April of this year, the **Oklahoma** legislature approved and forwarded a bill to delay the start of competition to Governor Keating, who signed the bill. Competition was originally slated to start July 2002, but has been delayed indefinitely pending additional restructuring legislation. The new law calls for the creation of an advisory committee, a transmission study report by December 31, 2001 and a final restructuring study report by December 31, 2002. Thus, competition is not likely to be implemented before 2003.

New Mexico Governor Gary Johnson signed SB 266 on March 8, 2001, which effectively delayed competition until 7/1/07 for residential and small commercial customers. All other customers will be eligible 7/1/08.

Enabling legislation in **West Virginia** was not adopted in the 2001 short session, and may be taken up in 2002. As a result, the start of customer choice has been pushed back until at least mid-2002, assuming the legislature acts in the early part of the year.

Montana decided to postpone competition from mid 2002 for another five years, given the volatility in the Western power markets. The state, however, passed legislation in May to exempt new generation and related delivery facilities from property taxes for 10 years if the owner offers power contracts to sell 50% of the new output of the facilities at a cost-based rate for 20 years (12% maximum ROE). The Public Service Commission has not yet adopted permanent company-specific restructuring plans.

In response to events in California, **Nevada** lawmakers voted in April to postpone competition indefinitely and cease deregulation. Governor Guinn signed AB 369, specifically stopping the pending sale of Sierra Pacific Resources' (SRP) generation assets. The generation auction was a condition of its merger between Nevada Power and Sierra Pacific Power. The asset sales are prohibited until July 1, 2003. The new law also reinstated deferred energy accounting for Sierra Pacific. Recently, the legislature has approved a new bill permitting large users (1 MW+) the option to shop starting 4/1/02. This would pertain to more sophisticated buyers, including commercial, industrial and government customers, whose contracts would be subject to PUC approval.

We are not put off by these actions, as we believe the retail market will grow in importance over the years. In the interim, we continue to focus on the generators who are capitalizing on opportunities in the wholesale market.

The Industry's Response: Increasingly Differentiated Strategies

The result of the various components and timing of each state's efforts to restructure has been the increasingly divergent strategies of investor-owned utilities. Naturally, these strategies have yielded different investment profiles of utilities ranging from growth vs. income, as well as various levels of risk and the diversification of businesses, markets and customers.

Choosing Their Stripes

We have subdivided the Electric Power sector in to the Generation and Distribution sectors, but even now our division may warrant further segmentation. Some companies remain integrated, others focused exclusively on generation and still others focused exclusively on transmission and distribution (T&D). Some states forced divestiture (New York, California). Others have focused on aggressively increasing their generation portfolio.

Sparked Rounds of Consolidation

We have also witnessed a significant amount of consolidation between T&D companies with limited growth opportunities. Other utilities have combined to increase scale and scope and gain access to complementary skills and assets. The pace of transactions has slowed considerably. There were 23 deals announced in 1999, 8 in 2000 and two in 2001. In fact, we have seen two mergers called off this year. Please refer to the Appendix for a table of announced and completed M&A transactions. PUHCA repeal could re-ignite another round of transactions since it would help reduce the lengthy review process, increase the number of investment options and lift the restriction about maintaining "contiguous" operations. It may also encourage foreign investment.

Emergence of Wholesale Merchant Energy Players

The uneven restructuring of the industry has also afforded regional companies to develop a national presence through a combination of physical assets purchased through divestitures and contractual ownership through negotiated agreements. The emergence of merchant generators has shifted the cost burden and risk of new generation to the private sector, and altered the financing strategy of new projects. The ability and need for power companies to better manage their costs has resulted in an increase in bulk wholesale power sales over time. This has increased liquidity and strengthened the wholesale markets. It has led to the development of risk management skills, structured products, weather guarantees, tolling arrangements and other innovations. The volatility of energy prices has created new market opportunities as demand for energy services and co-generation has increased.

Taking Off the Training Wheels: The Equity Carve-Out

One of the most dramatic trends currently shaping the industry has been the trend to spin out the rapidly growing, unregulated businesses in pursuit of a higher valuation and thus the creation of a more efficient means of accessing the capital markets to fund this backlog of generation projects. We have seen traditional utilities that, through the deregulation process, have participated in the unregulated wholesale market. Recent examples include Southern Company's (SO) complete spin out on April 2, 2001 of Southern Energy, which was subsequently named Mirant Corp (MIR). Similarly, Ecel Energy (XEL) issued 20% of the shares of NRG Energy (NRG) on June 6, 2000. UtiliCorp United (UCU) completed the spin out of 20% of Aquila (ILA) on April 24, 2001. The most recent transaction was the May 1 partial IPO of Reliant Energy (REI)'s wholesale business, Reliant Resources (RRI). Constellation Energy (CEG) has filed a plan to separate its unregulated wholesale business from the traditional utility and expects to complete the transaction in the fourth quarter.

Figure 8:

Rating	Company	Ticker	06/06/01 Price	2001E	P/E	5 year Growth	PEG	2002E	P/E	'02/'01	PEG
Strong Buy	AES Corp.	AES	$ 42.54	$ 1.85	23.0	30%	0.77	$ 2.40	17.7	30%	0.59
Strong Buy	Calpine Corp.	CPN	$ 42.90	$ 1.90	22.6	40%	0.56	$ 2.45	17.5	29%	0.44
Not Rated	NRG Energy (1)	NRG	$ 25.94	$ 1.36	19.1	25%	0.76	$ 1.67	15.5	23%	0.62
Not Rated	Mirant Corp. (1)	MIR	$ 36.32	$ 1.90	19.1	25%	0.76	$ 2.33	15.6	23%	0.62
Buy	Orion Power Holdings	ORN	$ 26.68	$ 1.20	22.2	25%	0.89	$ 1.55	17.2	29%	0.69
Buy	Reliant Resources	RRI	$ 30.35	$ 1.60	19.0	25%	0.76	$ 1.95	15.6	22%	0.62
Not Rated	Aquila (1)	ILA	$ 28.75	$ 1.25	23.0	25%	0.92	$ 1.55	18.5	24%	0.74
	Average				*21.1*						
	Median				*22.2*						

(1) Estimates from First Call

Source: Deutsche Banc Alex. Brown estimates and company information

Investment Conclusions

- Fundamentals look strong given the shortage of generating capacity, earnings growth and visibility: Focus on Generation.
- Near-term opportunity in the NYC market. We have recommended companies such as Orion Power (ORN) that have leverage to the New York City energy market.
- Favor unregulated names: CPN, AES, EXC, CEG, ORN, PEG, RRI, REI.
- Monitor those that may take steps to unlock value: DUK, CIN, AYE, PPL, PEG.
- Intermediate term: focus on wholesale generators with the commercial skills to manage their business in an excess supply environment (i.e., risk management).
- Eventually, as the market deregulates completely, having some access to the end customer will prove to be more relevant.

Appendix

Deregulation Background Information

- Divestiture table
- Consolidation trend- M&A table
- Pass Through of Purchased Energy Costs by State

Electricity Supply & Demand Outlook by Region

Figure 9: **M&A Activity (From DBAB and company information)**

Electric Power Industry: Domestic Mergers & Acquisitions

Announced Date	Announced and Pending	-- Terms -- 1-for-1	Other
2/20/2001	Energy East Corp. - RGS Energy	- -	RGS = $39.50 per share; 55% cash/45% stock proration
2/12/2001	Potomac Electric - Conectiv	- -	CIV = $25 per share; 50/50 cash/stock
11/9/2000	PNM - Western Resources	- -	WR = $4.4B in stock & debt assumpt. for utility operations
9/5/2000	National Grid Group - Niagara Mohawk	- -	NMK = $19 per share in cash or stock
8/8/2000	FirstEnergy - GPU Inc.	- -	GPU = $36.50 per share, 50% cash, 50% stock
6/30/2000	NS Power - Bangor Hydro-Electric	- -	BGR = $26.50 per share in cash

Terms changed from original offer

Announced Date	Completed	Closing Date	*Participants*
10/5/1999	DTE Energy	5/31/2001	DTE Energy - MCN Energy Group
7/17/2000	AES Corp.	3/27/2001	AES Corp. - IPALCO Enterprises
2/28/2000	Powergen	12/12/2000	PowerGen - LG&E Energy
12/22/1999	GPU	4/27/2000	GPU - MYR Group
12/20/1999	Allegheny Energy	1/4/2000	Allegheny Energy - Mountaineer Gas
11/10/1999	Energy East	9/1/2000	Energy East - Berkshire Energy
11/8/1999	NiSource	11/1/2000	NiSource - Columbia Energy
10/25/1999	Berkshire Hathaway	3/14/2000	Berkshire Hathaway - MidAmerican Energy
9/23/1999	Exelon Corporation	10/20/2000	PECO Energy - Unicom Corp.
8/23/1999	Progress Energy Inc	11/30/2000	CP&L Energy - Florida Progress Corp
6/30/1999	Energy East	9/1/2000	Energy East - CTG Resources
6/28/1999	Wisconsin Energy	4/26/2000	Wisconsin Energy Corp. - WICOR Inc.
6/15/1999	Energy East	9/1/2000	Energy East - CMP Group
6/15/1999	Northeast Utilities	3/1/2000	Northeast Utilities - Yankee Energy System
6/14/1999	Vectren Corporation	3/31/2000	Indiana Energy - Sigcorp
6/14/1999	Dynegy	2/2/2000	Dynegy - Illinova Corp.
5/25/1999	Laurel Hill Capital Partners	4/7/2000	TNP Enterprises - *LBO By Laurel Hill Capital*
4/23/1999	Energy East	2/18/2000	Energy East - Connecticut Energy
3/25/1999	Exel Energy	8/21/2000	New Century Energies - Northern States Power
3/5/1999	Utilicorp United	12/31/2000	UtiliCorp United - St. Joseph L&P
2/22/1999	Dominion Energy	1/28/2000	Dominion Energy - Consolidated Natural Gas
2/17/1999	SCANA Corporation	2/10/2000	SCANA Corp. - P.S. Co. of N. Carolina
2/1/1999	National Grid Group	4/19/2000	New England Electric Sys. - Eastern Utitities Assoc.

Figure 10: **States with Divestitures**

State	Generation Divestiture
California	Mandatory
Connecticut	Mandatory
D.C.	Optional
Delaware	Optional
Illinois	Optional
Maine	Mandatory
Maryland	Optional
Massachusetts	Mandatory
New Hampshire	Mandatory
New Jersey	Optional
New York	Mandatory
Pennsylvania	Optional
Rhode Island	Mandatory

Source: Deutsche Banc Alex. Brown estimates and company information

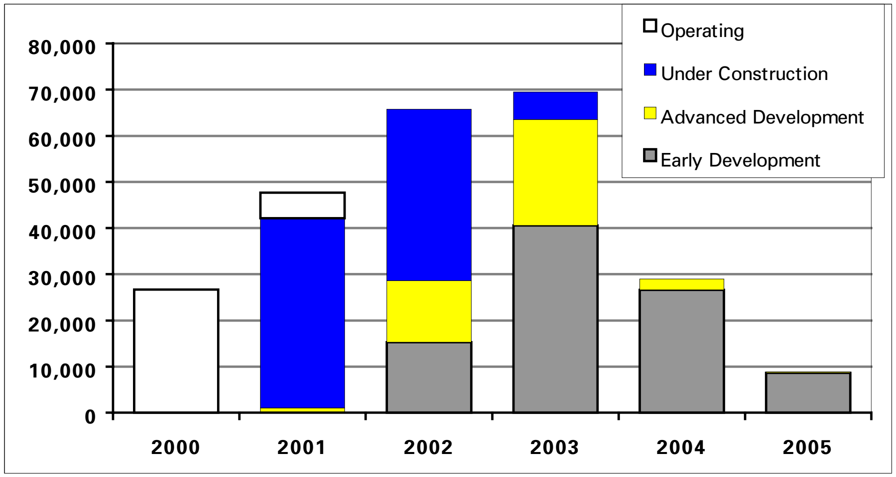
Figure 11: Purchased Energy Costs

State	Rate Cap	Cost Pass-Through	State	Rate Cap	Cost Pass-Through
AL		yes	MT	yes	
AR		yes	NC		yes
AZ	yes		ND		yes
CA	yes		NH	yes	
CO		yes	NJ	yes	
CT	yes		NM		
DC	yes		NV		yes
DE	yes	yes	NY		yes
FL		yes	OH	yes	
GA		yes	OK		yes
HI		yes	OR		
IA		yes	PA	yes	
ID		yes	RI		yes
IL	yes	yes	SC		yes
IN		yes	SD		yes
KS		yes	TN		yes
KY		yes	TX		yes
LA		yes	UT		
MA		yes	VA		yes
MD	yes		VT		
ME		yes	WA		
MI	yes		WI		yes
MN		yes	WV		yes
MO			WY		yes
MS		yes			

Source: Deutsche Banc Alex. Brown estimates and Regulatory Research Associates, Inc.

Figure 12: **United States**

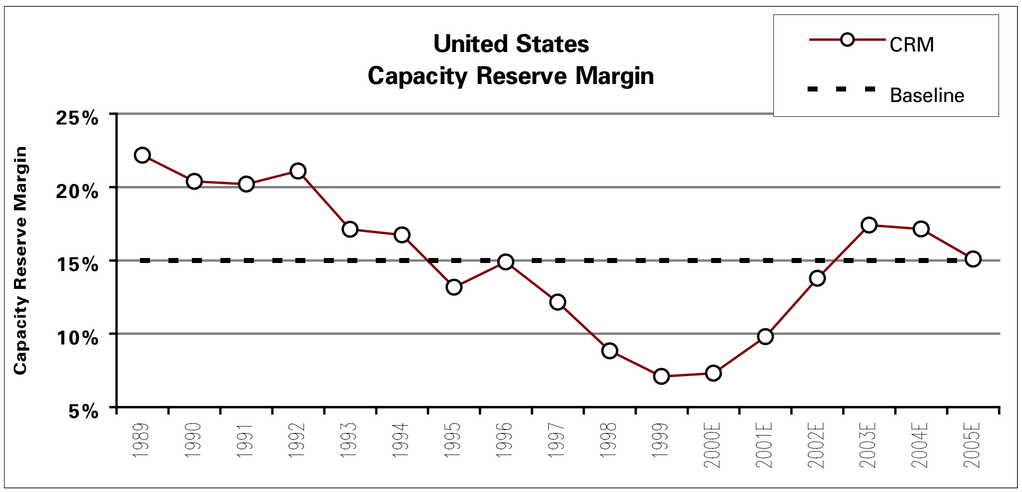
Capacity Additions by Year (MW's)

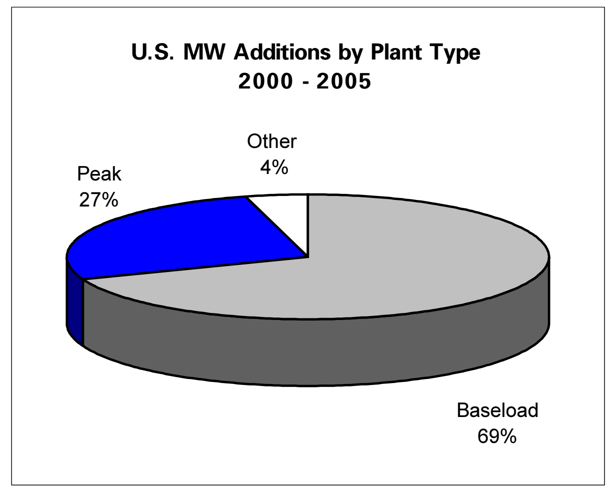


Capacity Additions	
Year	**MW**
2000	26,654
2001	47,688
2002	65,783
2003	69,481
2004	28,996
2005	8,818
Total	***247,420***

TOP FIVE BUILDERS IN U.S.*	
Company	MW*
1) Calpine Corp.	30,856
2) Duke Energy	18,697
3) Cogentrix	12,700
4) PG&E Corp.	12,395
5) Panda Energy	12,246

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

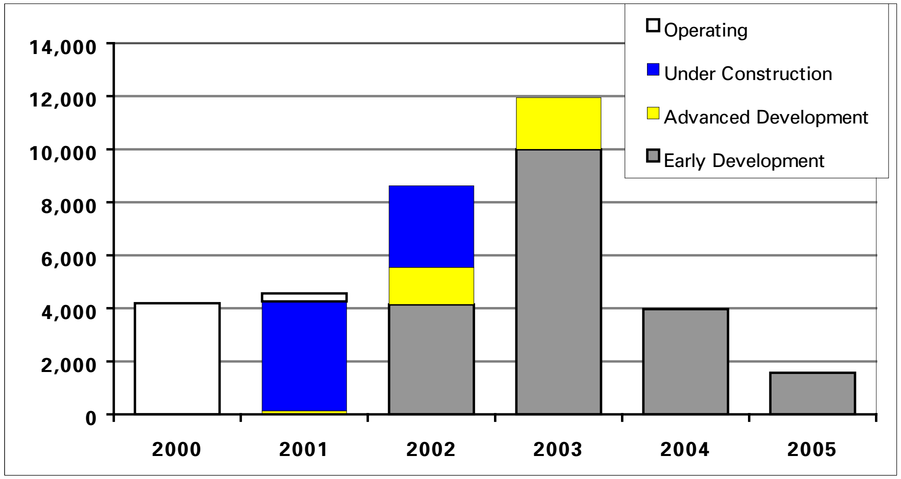




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 13: **ECAR**

Capacity Additions by Year (MW's)



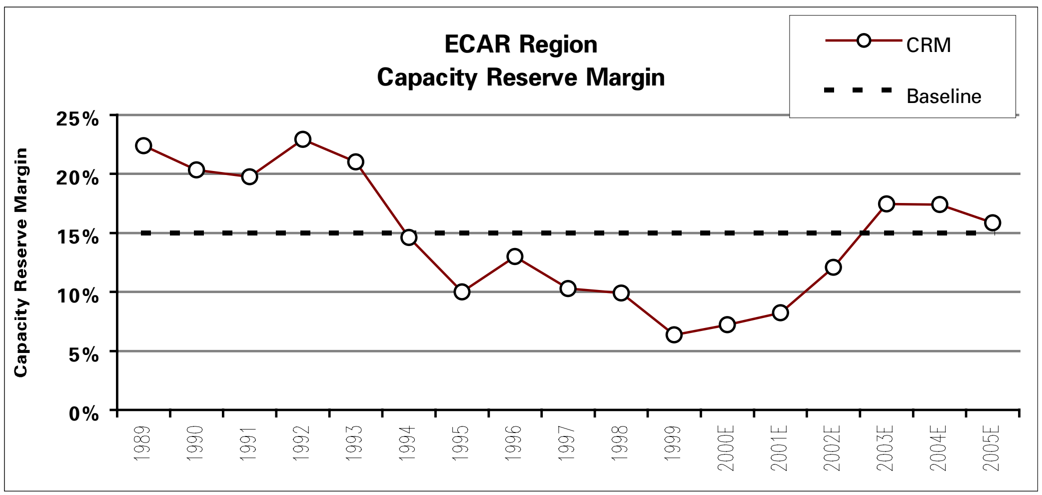
Capacity Additions	
Year	MW
2000	4,192
2001	4,563
2002	8,623
2003	11,944
2004	3,965
2005	1,571
Total	*34,858*

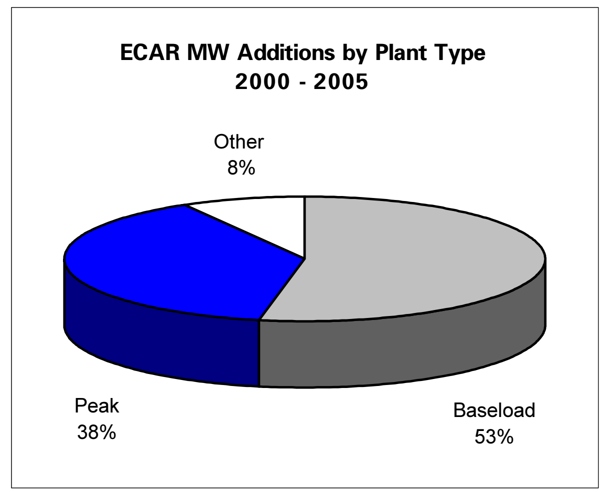
TOP FIVE BUILDERS IN ECAR*	
Company	MW*
1) Cogentrix	6,300
2) Duke Energy	5,728
3) Public Ser Enter Grp	4,473
4) Dynegy Inc.	2,806
5) Mirant Corp.	2,380

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in ECAR
IN, OH, KY, PA
WV, MI, VA

DEREG STATUS
OH, PA - Retail choice begun
WV, MI, VA - Legis. enacted; retail choice pending
IN, KY - Investigatiing

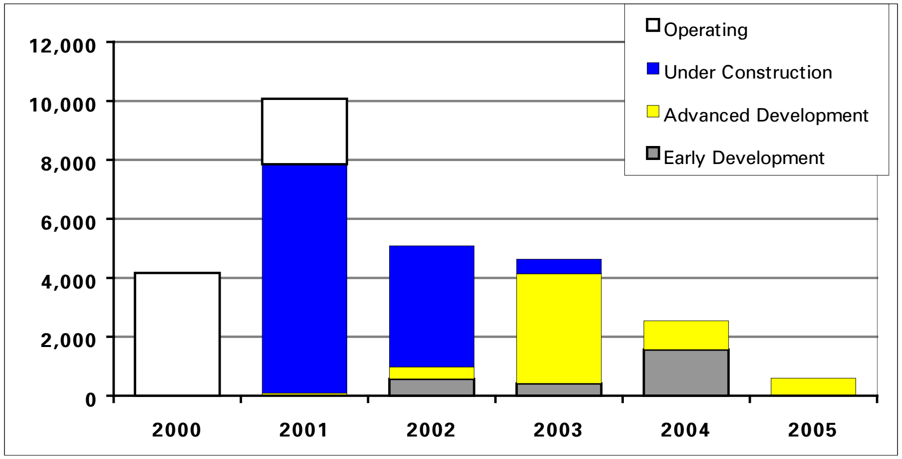




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 14: **ERCOT**

Capacity Additions by Year (MW's)



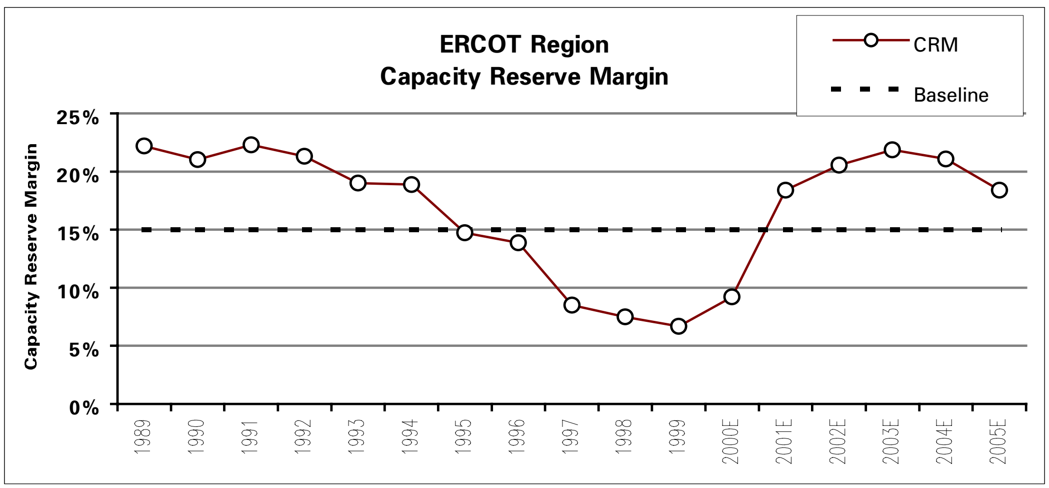
Capacity Additions	
Year	MW
2000	4,167
2001	10,077
2002	5,087
2003	4,632
2004	2,543
2005	600
Total	***27,106***

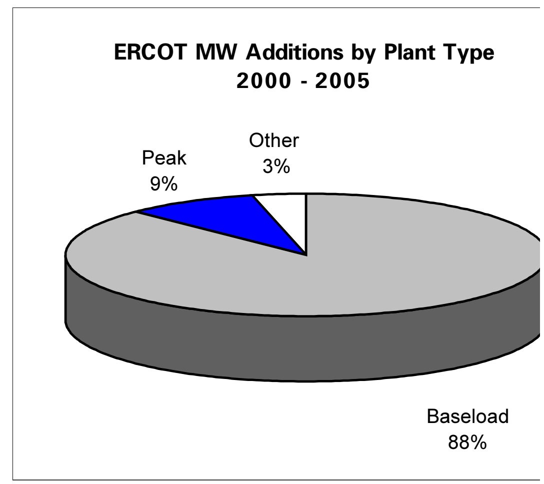
TOP FIVE BUILDERS IN ERCOT*	
Company	MW*
1) Calpine Corp.	5,743
2) International Power	4,991
3) Group Suez Lyonnaise	1,923
4) Newport Generation	1,600
5) Pandas Energy	1,510

* Actual additions announced & completed 2000 t 2005; Not probability weighted.

States w/in ERCOT
Texas

TEXAS DEREG STATUS
Legislation enacted; choice beginning Jan. '02

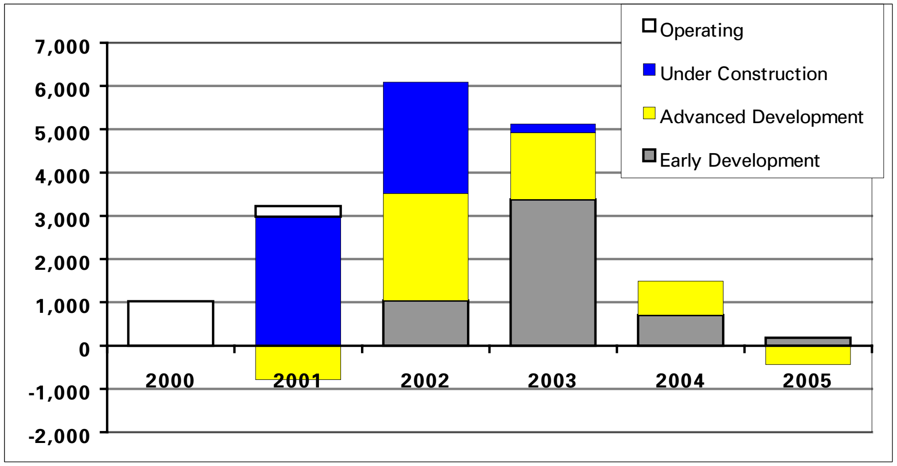




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 15: **FRCC: Florida Reliability Coordinating Council**

Capacity Additions by Year (MW's)



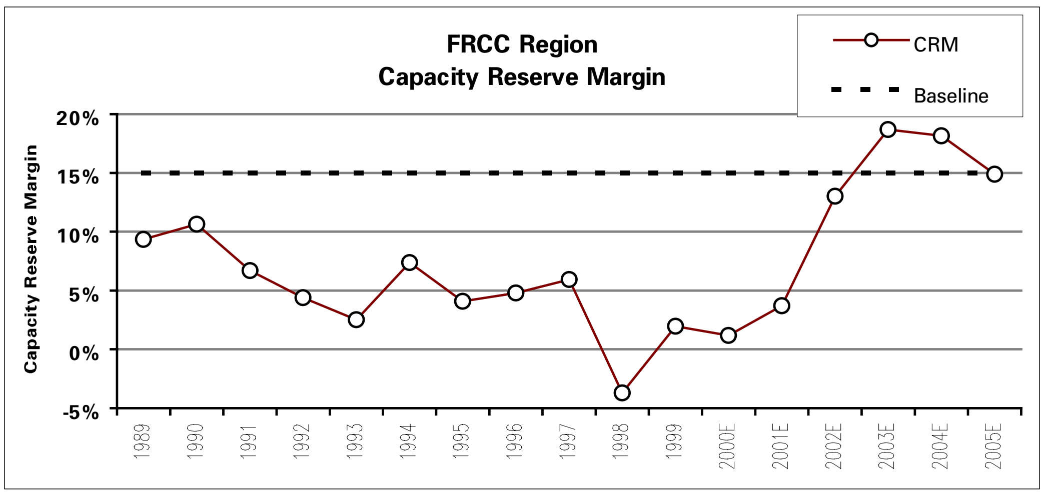
Capacity Additions	
Year	**MW**
2000	1,024
2001	2,438
2002	6,090
2003	5,123
2004	1,493
2005	-257
Total	***15,911***

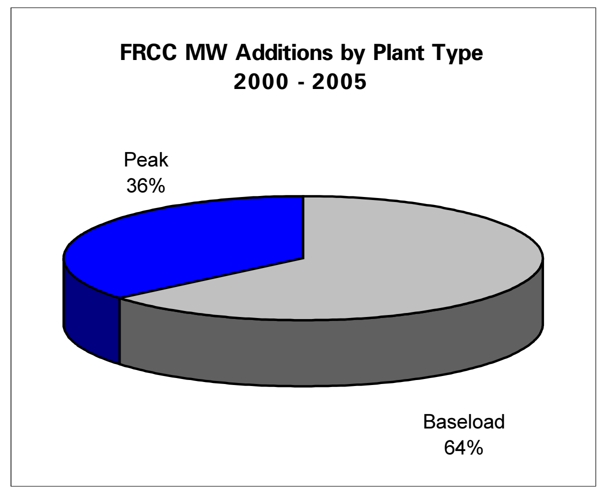
TOP FIVE BUILDERS IN FRCC	
Company	MW*
1) FPL Group	2,981
2) Panda Energy	2,000
3) Calpine Corp.	1,720
4) TECO Energy	1,708
5) El Paso Energy	1,020

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in FRCC
Florida

FLORIDA DEREG STATUS
Investigating

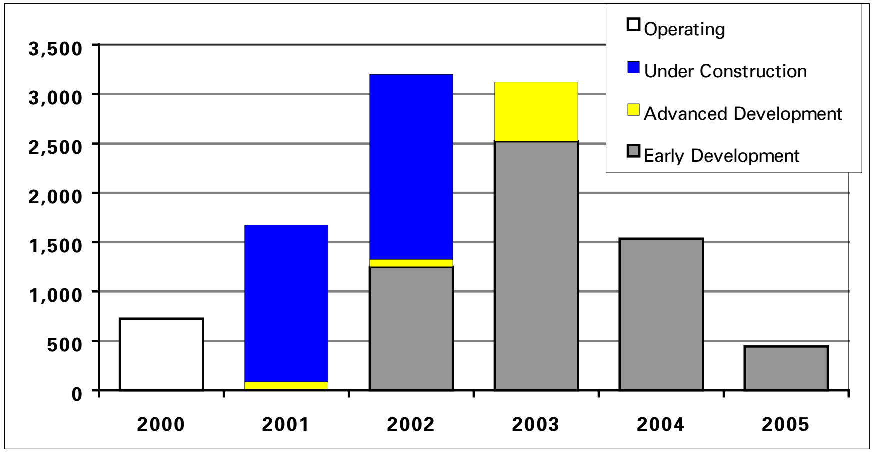




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 16: **MAAC**

Capacity Additions by Year (MW's)



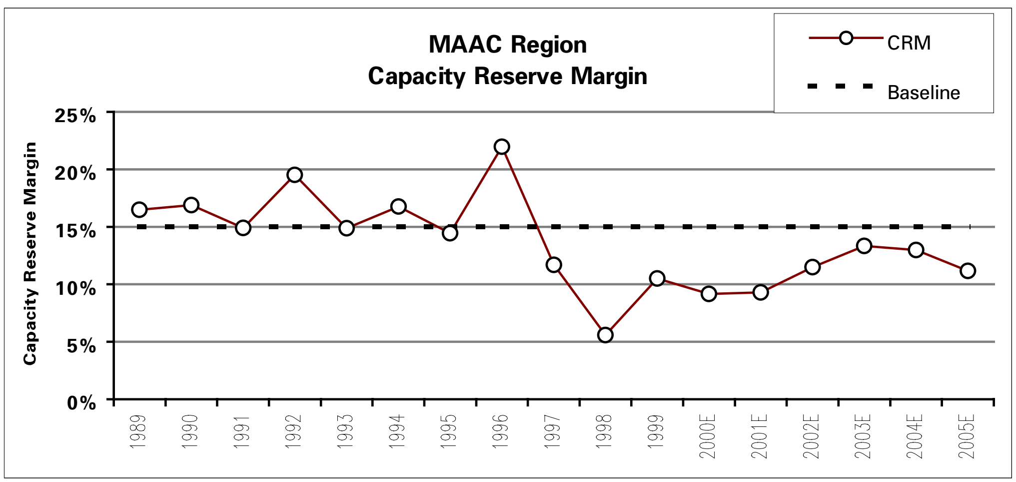
Capacity Additions	
Year	**MW**
2000	725
2001	1,675
2002	3,202
2003	3,123
2004	1,535
2005	443
Total	***10,703***

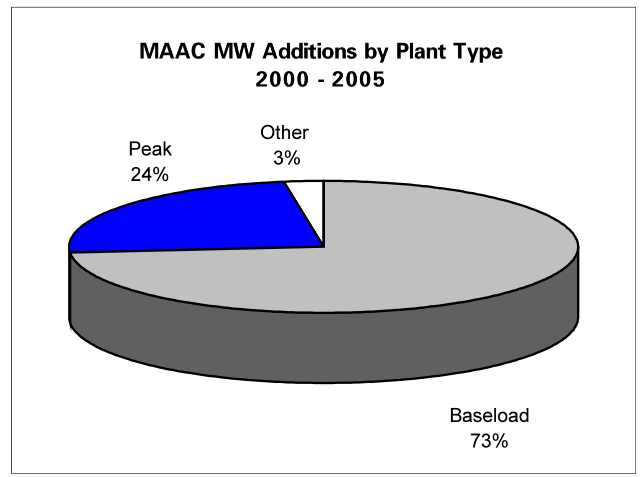
TOP FIVE BUILDERS IN MAAC	
Company	MW*
1) Public Service Enterprise Group	2,057
2) PG&E Corp.	1,900
3) AES Corp.	1,605
4) PPL	1,500
5) Reliant Energy	1,334

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in MAAC
DE, MD, NJ, PA

DEREG STATUS
NJ, PA - Retail choice begun
DE, MD - Legislation enacted; retail choice pending

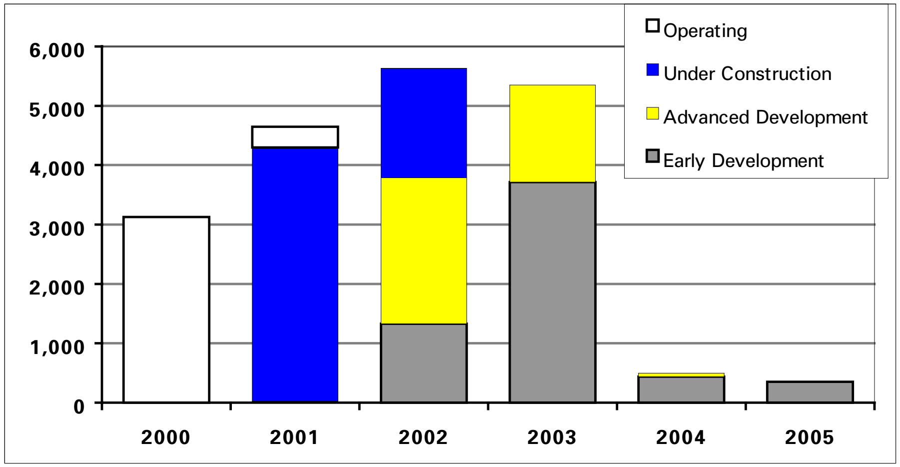




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 17: **MAIN**

Capacity Additions by Year (MW's)



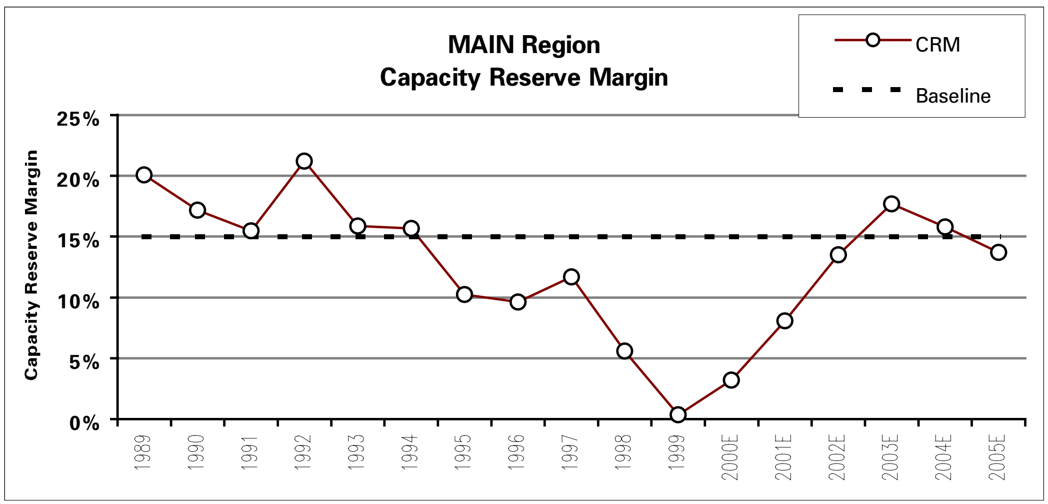
Capacity Additions	
Year	MW
2000	3,124
2001	4,647
2002	5,631
2003	5,351
2004	496
2005	352
Total	***19,601***

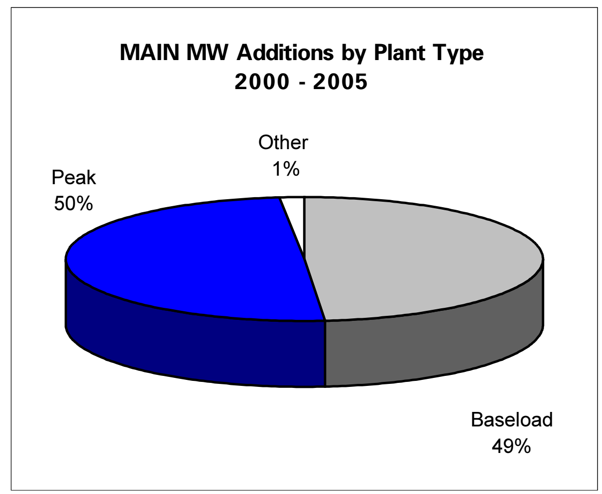
TOP FIVE BUILDERS IN MAIN	
Company	MW*
1) Calpine Corp.	2,464
2) Amren Corp.	2,101
3) Panda Energy	2,070
4) NRG Energy	1,950
5) MidAmerican Energy	1,637

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in MAIN
WI, IL, MO

DEREG STATUS
IL - Retail choice begun
MO, WI - Investigating

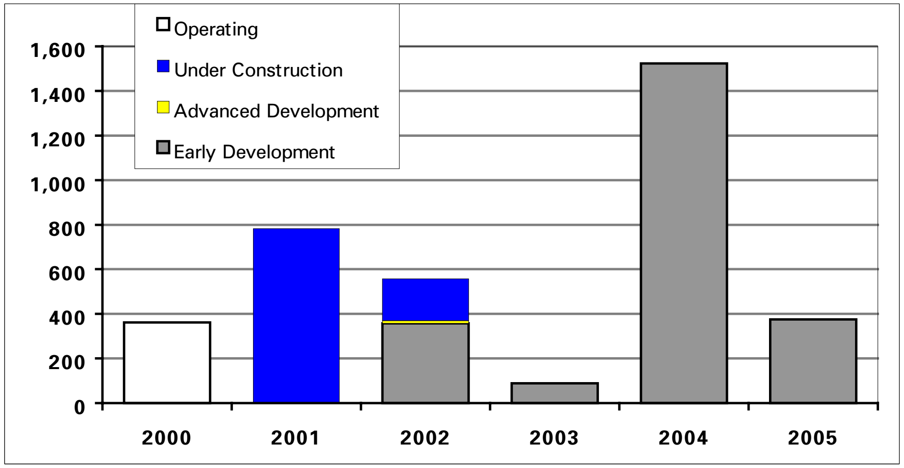




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 18: **MAAP**

Capacity Additions by Year (MW's)



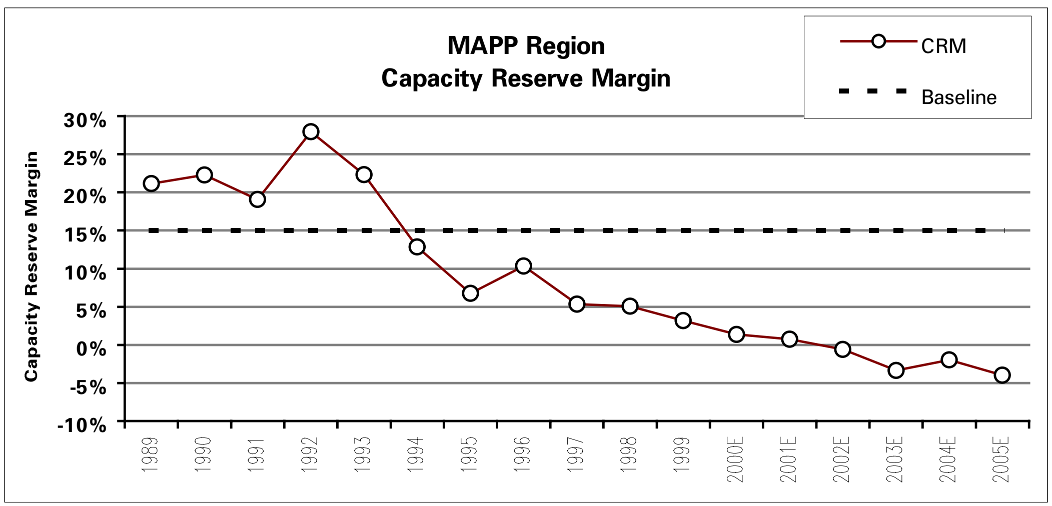
Capacity Additions	
Year	**MW**
2000	361
2001	782
2002	558
2003	88
2004	1,524
2005	375
Total	***3,688***

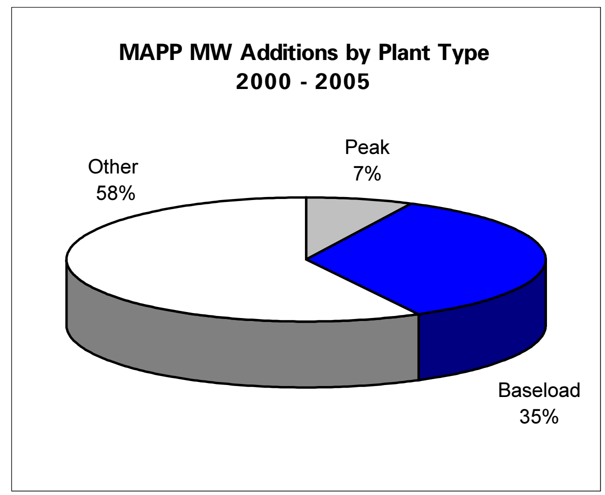
TOP FIVE BUILDERS IN MAPP	
Company	MW*
1) Clipper Windpower LLC	3000
2) Great River Energy	984
3) Northern Alternative	681
4) Tenaska Inc.	600
5) Xcel Energy	114

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in MAPP
ND, SD, NE, MN, WI, IA

DEREG STATUS
MN, IA, ND, WI - Investigating
NE, SD - No activity

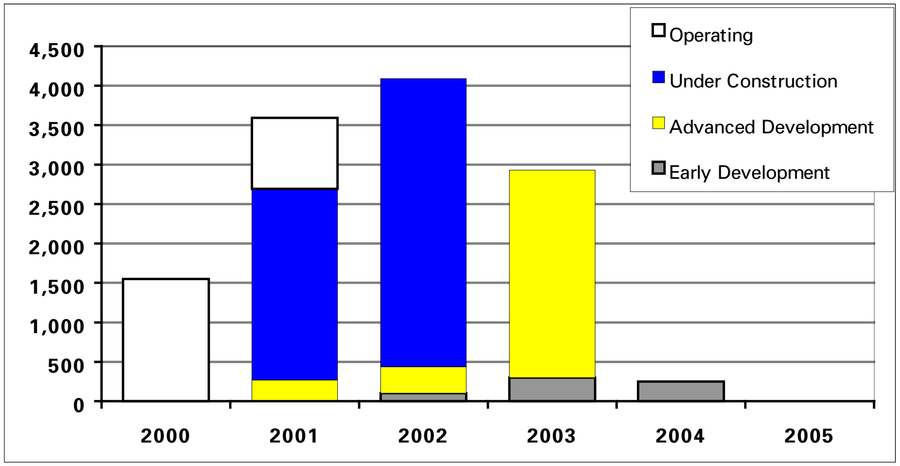




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 19: **NEPOOL**

Capacity Additions by Year (MW's)



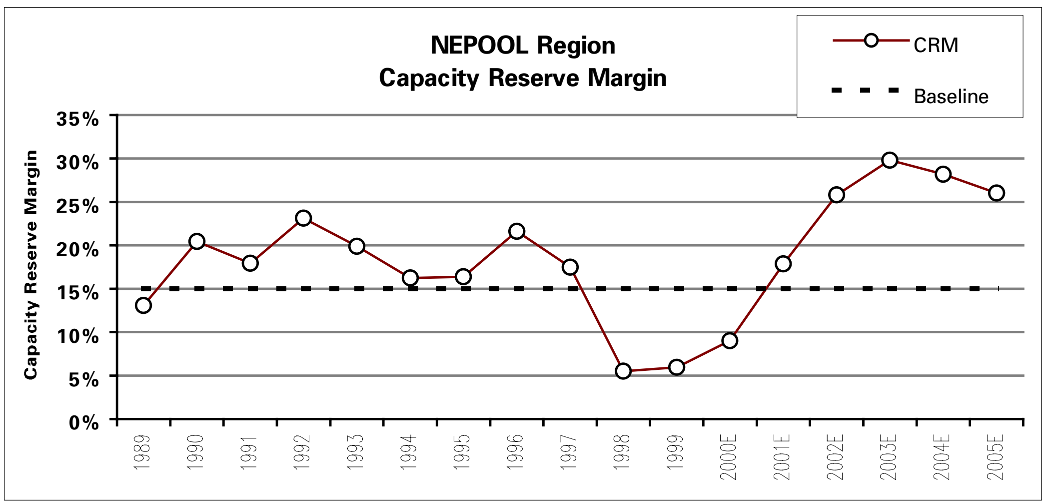
Capacity Additions	
Year	MW
2000	1,552
2001	3,594
2002	4,092
2003	2,932
2004	250
2005	0
Total	***12,420***

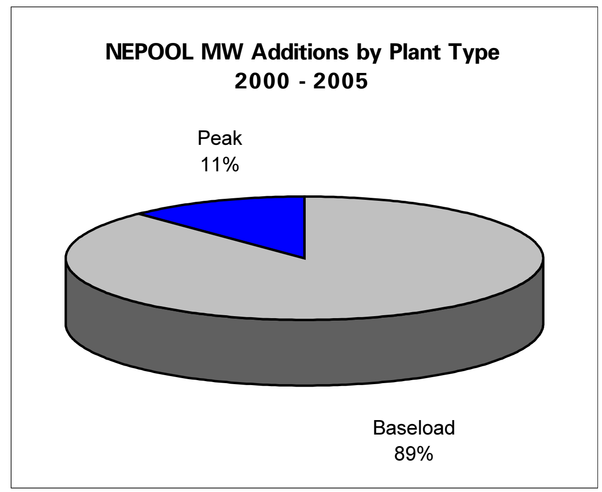
TOP FIVE BUILDERS IN NEPOOL	
Company	MW*
1) FPL Group	1,950
2) Calpine Corp	1,597
3) Excelon Corp	1,224
4) International Power	1,160
5) PG&E Corp.	1,152

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NEPOOL
CT, MA, NH, ME
VT, RI

DEREG STATUS
CT, MA, NH, ME, RI - Retail choice begun
NH - Legis. enacted; retail choice pending
VT - Investigating

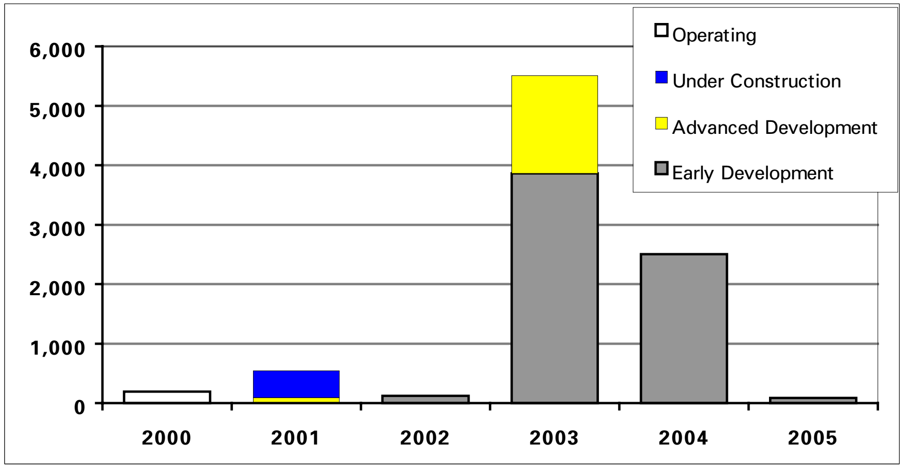




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 20: **NYPP**

Capacity Additions by Year (MW's)



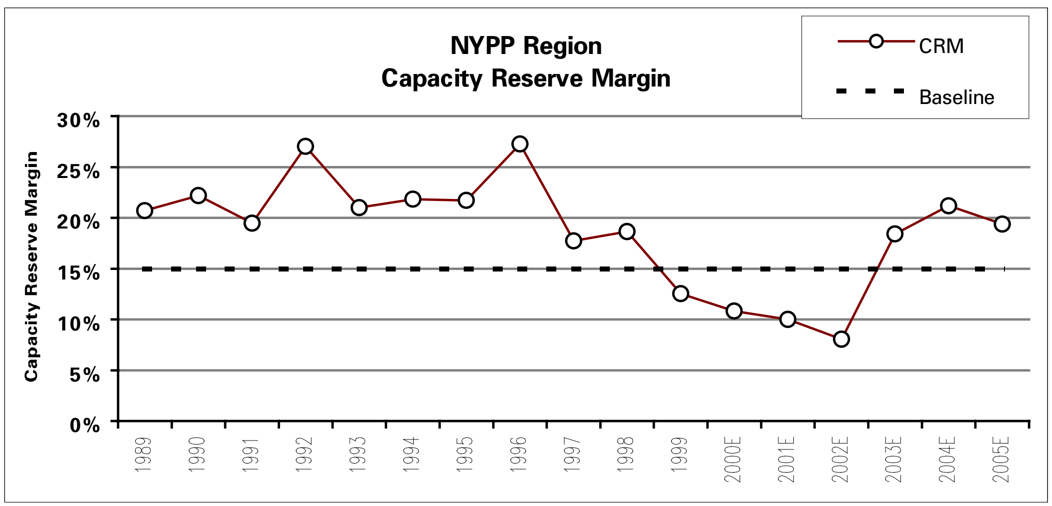
Capacity Additions	
Year	MW
2000	189
2001	543
2002	119
2003	5,505
2004	2,505
2005	85
Total	***8,946***

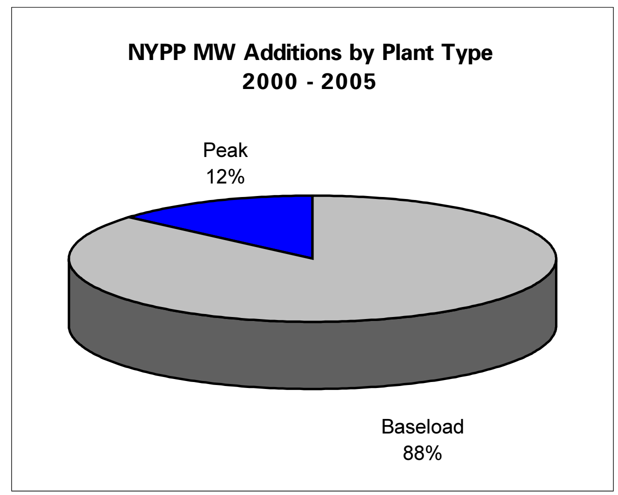
TOP FIVE BUILDERS IN NYPP	
Company	MW*
1) International Power	1,640
2) KeySpan	1,186
3) PG&E Corp.	1,092
4) ABB Energy Ventures	1,075
5) SCS Energy, LLC	1,000

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NYPP
New York

DEREG STATUS
NY - Restructuring order issued, but not enacted.

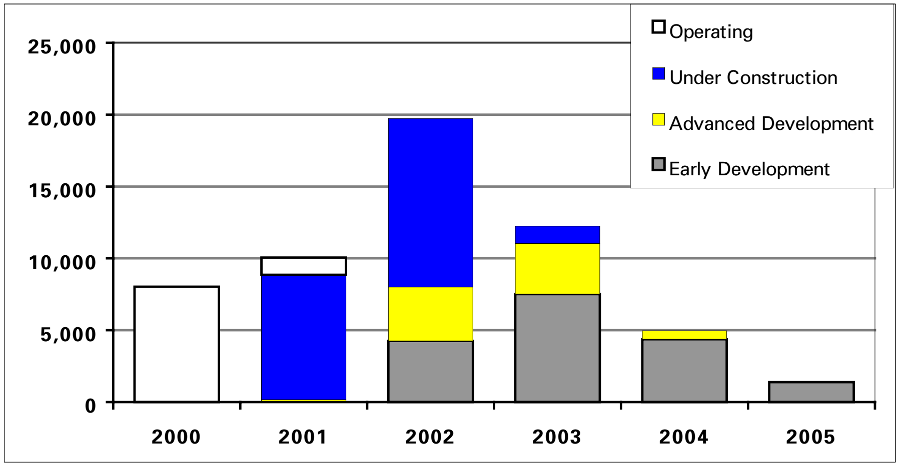




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 21: **SERC**

Capacity Additions by Year (MW's)



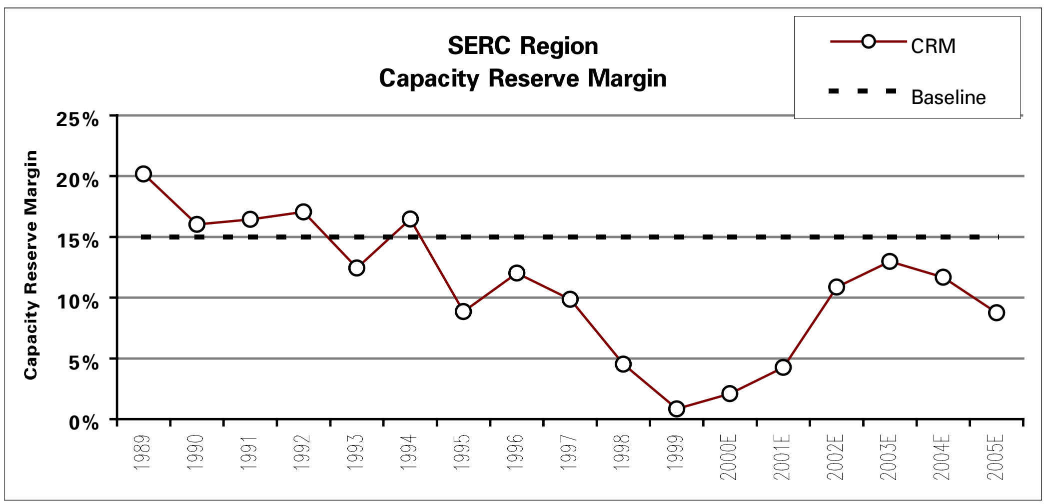
Capacity Additions	
Year	**MW**
2000	8,033
2001	10,062
2002	19,727
2003	12,245
2004	4,951
2005	1,383
Total	***56,401***

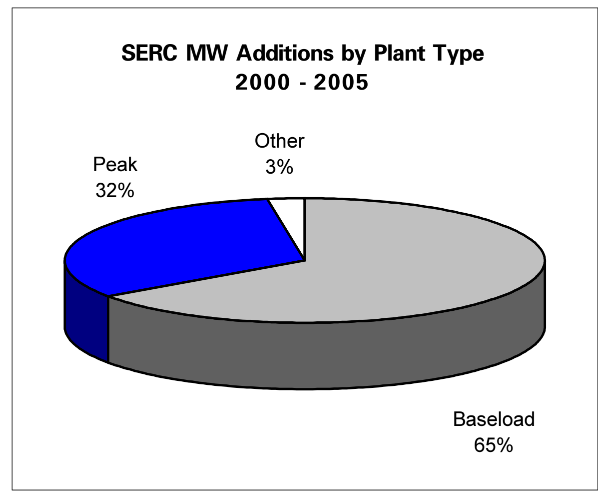
TOP FIVE BUILDERS IN SERC	
Company	MW*
1) Calpine Corp.	8,330
2) Southern Company	6,513
3) Tenaska Inc.	5,590
4) TVA	4,364
5) Duke Energy	4,330

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SERC
LA, AR, MO, TX, MS
AL, GA, KY, TN, VA
NC, SC

DEREG STATUS
TX, AR, VA - Legis. enacted; choice pending
SC - Legislation pending.
LA, MS, MO, KY, NC - Investigating
AL, GA, TN - No activity.

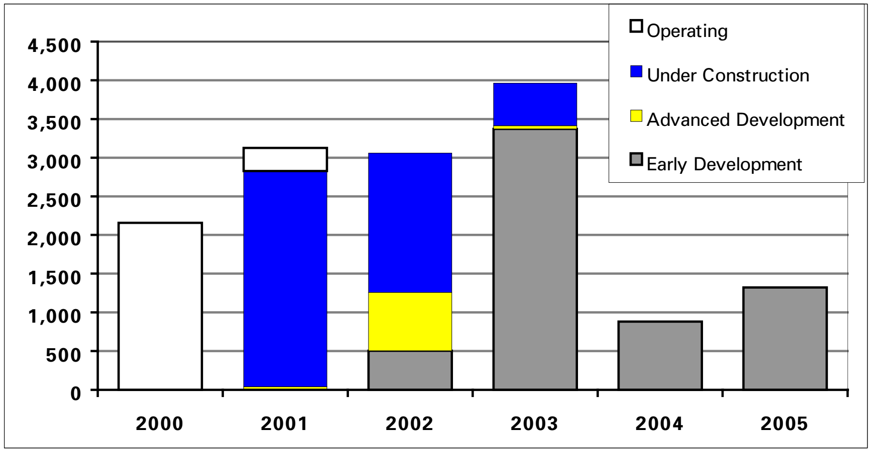




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 22: **SPP**

Capacity Additions by Year (MW's)



Capacity Additions Year	MW
2000	2,157
2001	3,126
2002	3,060
2003	3,962
2004	882
2005	1,321
Total	***14,508***

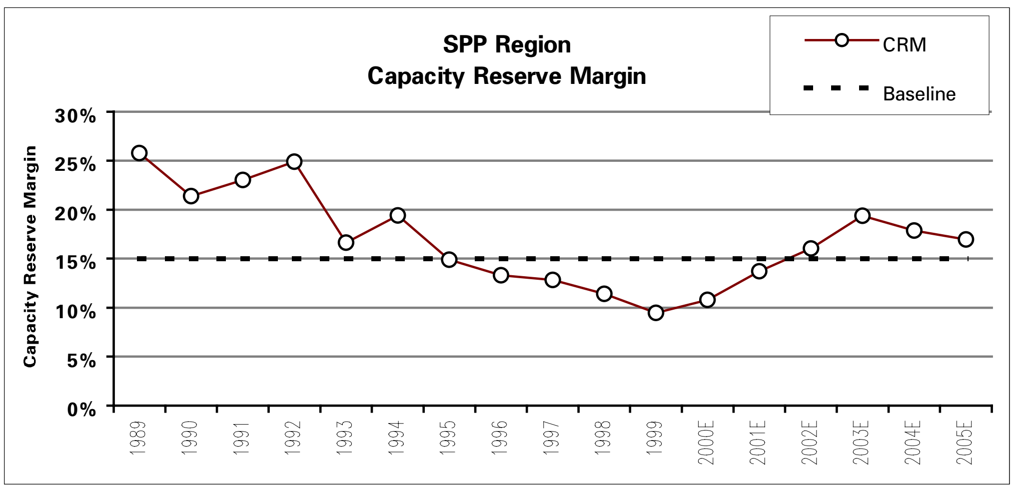
TOP FIVE BUILDERS IN SPP Company	MW*
1) Energetix	1,885
2) Calpine Corp.	1,669
3) Kansas City P&L	1,608
4) Smith Cogeneration	1,200
4) American Electric Power	1,200

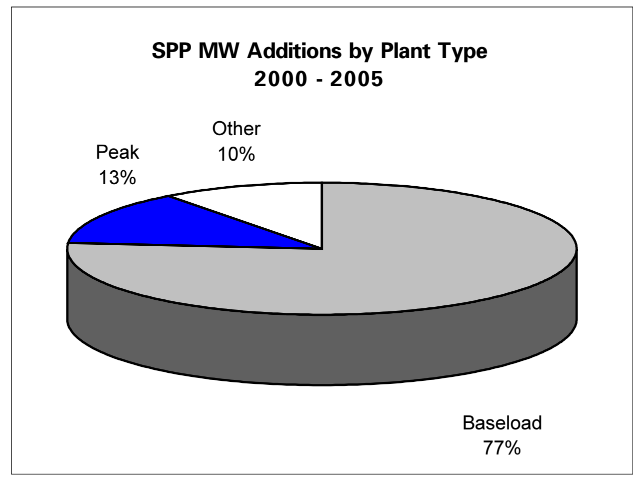
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SPP
KS, OK, MO, AR, TX NM

DEREG STATUS

TX, NM, AR - Legis. enacted; Retail choice pending
OK - Legislation pending
MO - Investigating
KS - No activity

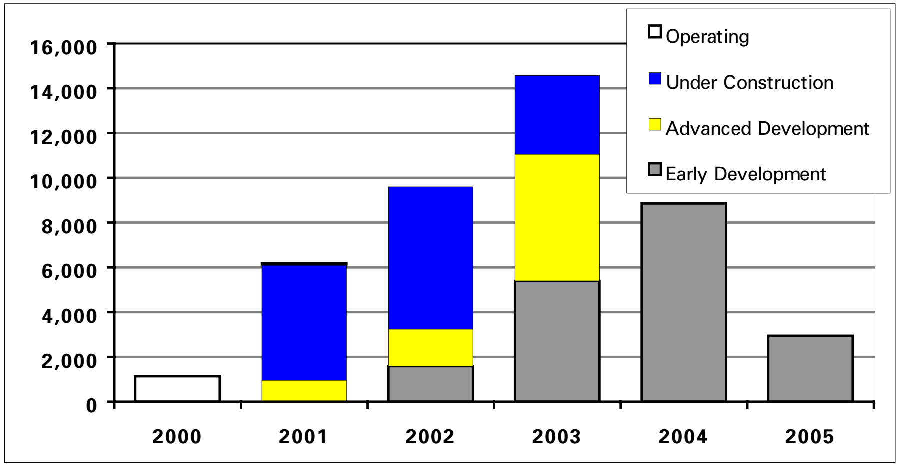




Source: Deutsche Banc Alex. Brown estimates and company information

Figure 23: **WSCC**

Capacity Additions by Year (MW's)



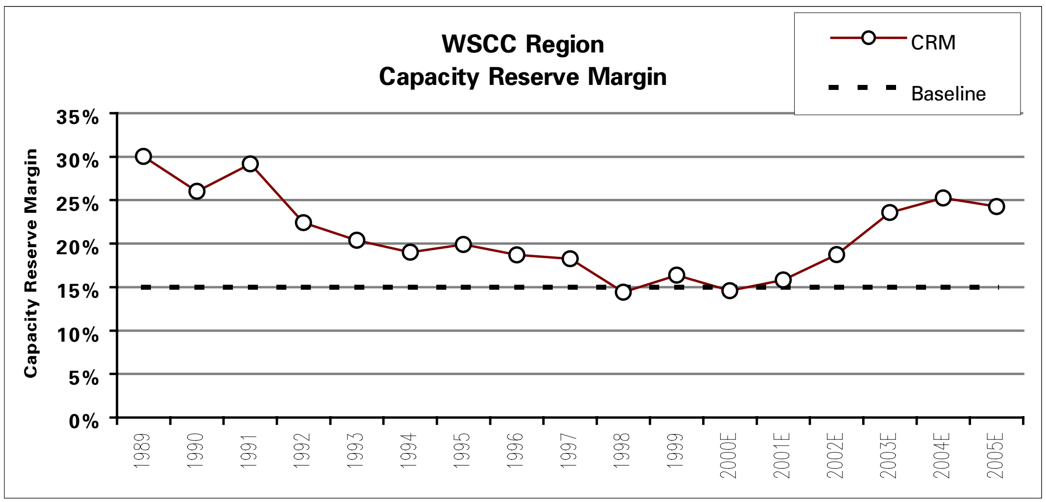
Capacity Additions	
Year	**MW**
2000	1,130
2001	6,181
2002	9,594
2003	14,575
2004	8,851
2005	2,945
Total	***43,276***

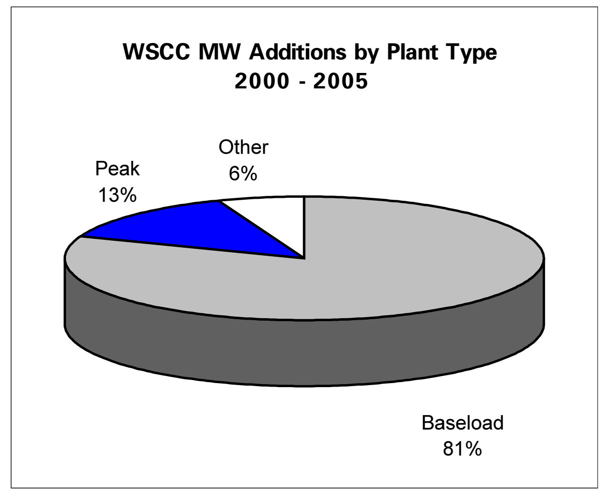
TOP FIVE BUILDERS IN WSCC	
Company	MW*
2) Calpine Corp.	6,706
2) Duke Energy	5,834
3) PG&E Corp.	4,235
4) Reliant Energy	2,623
5) AES Corp.	2,155

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in WSCC
AZ, NM, NV, CA, MT WA, OR, ID, UT, CO WY

DEREG STATUS
CA - Retail choice begun. AZ, NM, OR, MT - Legis. enacted; choice pending NV - Deregulation postponed. UT, WA, WY, CO - Investigating ID - No activity.





Source: Deutsche Banc Alex. Brown estimates and company information

Additional Information Available upon Request

Disclosure Checklist

Company	Ticker	Price (6/06/01)	Disclosure
AES Corp	AES	$42.47	
Calpine Corp	CPN	$43.76	#, ++, O
Allegheny Energy	AYE	$50.39	O
Constellation Energy	CEG	$43.20	@, O
Exelon Corp	EXC	$63.56	O
Orion Power Holdings	ORN	$26.25	#, O
Public Service Enterprise Group	PEG	$49.76	O
Reliant Energy	REI	$41.46	#, &, O
Reliant Resources	RRI	$30.80	
UtiliCorp United	UCU	$34.79	&
Edison International	EIX	$9.98	&, O
PG&E Corp	PCG	$11.07	#, O
PPL Inc.	PPL	$56.80	
DQE Inc	DQE	$22.85	
GPU Inc	GPU	$32.25	
TXU	TXU	$47.60	O
American Electric Power	AEP	$47.90	
Entergy Corp	ETR	$42.26	
New Power Company	NPW	$9.39	
Green Mountain Power	GMP	$15.51	
Consolidated Edison	ED	$38.35	
Mirant Corp	MIR	$37.58	
Sierra Pacific Resources	SRP	$16.10	
FirstEnergy	FE	$30.20	
Sempra Energy	SRE	$26.71	
Ecel Energy	XEL	$28.73	
NRG Energy	NRG	$26.28	
Aquila Energy	ILA	$29.30	
Southern Company	SO	$23.29	
Montana Power	MTP	$13.48	

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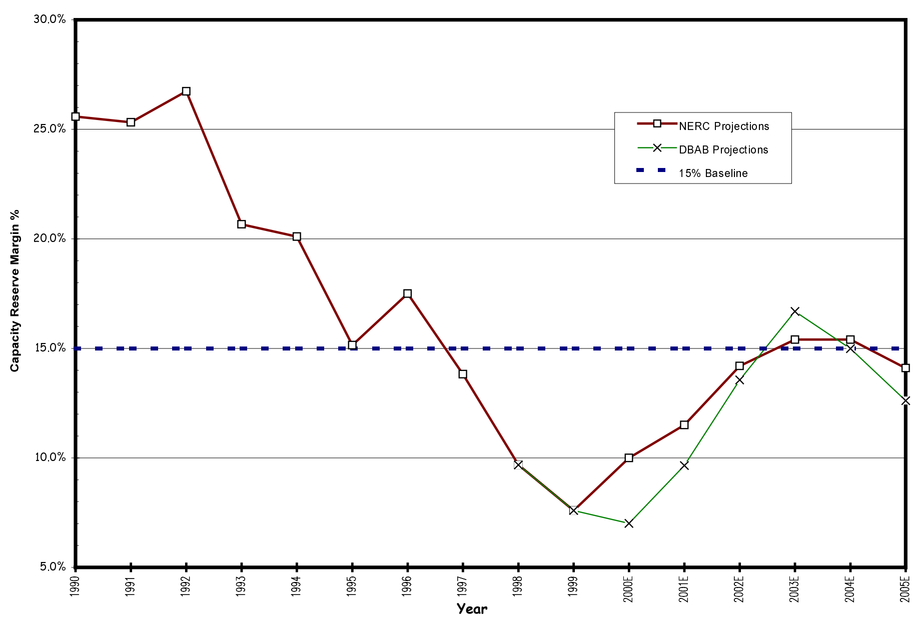
March 8, 2001

Electricity Supply & Demand in the U.S: The March to a Commodity Drum!

An Analysis of Regional Electricity Supply and Demand Dynamics

U.S. Capacity Reserve Margins 1990 - 2005



Source: Deutsche Banc Alex. Brown, RDI Consulting, NERC

- Our recent analysis of U.S. electricity supply and demand dynamics indicates that every region of the country will be short generating capacity in 2001.
- We expect about 45 GW of generating capacity to be added in 2001 and close to 60 GW in 2002. We assume demand growth of 3% annually.
- Profit margins in the electric generation sector are expected to be strong in 2001 and are likely to peak in 2002.
- The most interesting region at this time, in terms of likelihood of adequate or oversupply by 2002, is Texas.
- The analysis supports our generation thesis. Our favorite ideas in the sector are Calpine Corp., AES Corp., Reliant Energy and Exelon Corp. All four stocks are rated Strong Buy.

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Contents

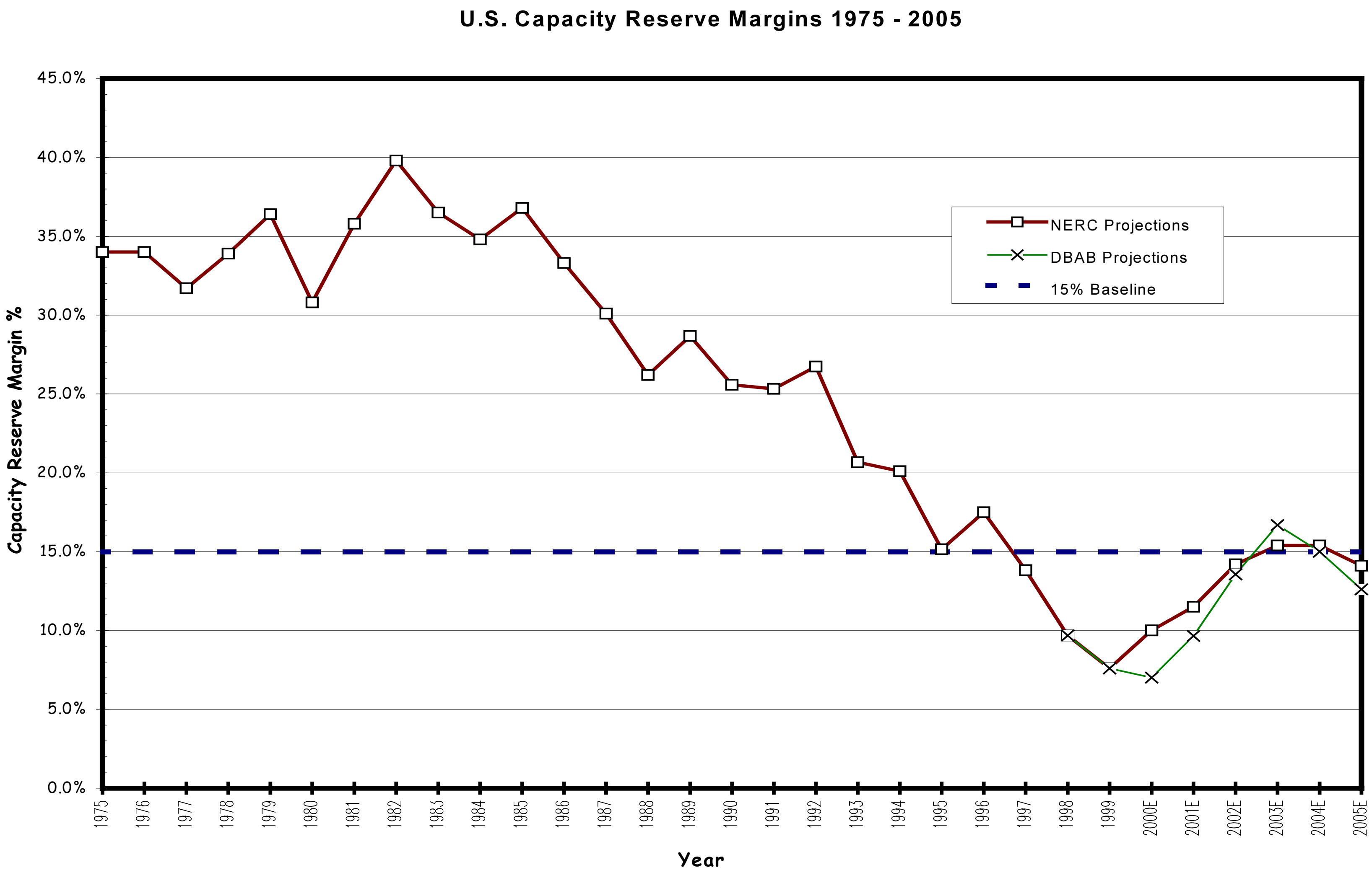
Executive Summary

The electricity supply and demand outlook for 2001 continues to appear challenging. We expect 45 gigawatts (GW) of generating capacity to be added in 2001, with about 70% of that capacity available to meet summer peak demand. In 2002, we expect closer to 60 GW of generation capacity additions. However, siting and permitting challenges continue, so we would not be surprised if the 2002 figure is lower than our forecast. In 2000, 24 GW of new generating capacity were added in the U.S. This compares with our forecast of 31 GW. Although siting and permitting is slowing the addition of generating capacity in the U.S. somewhat, we remain convinced that we will move from a short capacity position in the U.S. to a long capacity position over the next several years. In fact, we continue to believe that the industry will build to excess capacity by 2005. Currently, 350 GW of capacity additions have been announced. We believe about 200 GW are necessary to adequately meet 3% annual demand growth comfortably by 2005.

Profit margins in the generation sector are likely to peak in 2002, leaving only capacity additions to drive earnings growth. Although the rising profit margins in 2001 continue to support our generation focused investment thesis in the electric power industry, we continue to emphasize that the generation opportunity is a finite one. The summer of 2001 and the second and third quarters of 2001 still look very promising from an earnings growth perspective. Every region of the U.S. will be short generating capacity in 2001. In 2002, the only region that appears to be moving towards adequate capacity and lower margins is Texas. Figure 1 shows U.S. capacity reserve margins from 1975. This chart also includes our capacity reserve margin projections through 2005, as well as projections by the North American Electric Reliability Council (NERC). Relative to our capacity addition forecast, NERC is more conservative. Table 1 displays estimated capacity reserve margins for every region of the United States for 2001 and 2002 using our supply growth estimates. Overall, the supply and demand analysis for 2001 and early 2002 continues to support our investment thesis on the generators in the US. Our favorite ideas in the sector are AES Corporation, Calpine Corporation, Reliant Energy and Exelon Corporation. These four stocks are Strong Buy rated.

The regional capacity outlook is more important in the electricity sector than the national outlook. The regions closest to adequate capacity include Texas and New England. In New England, though, the variable cost of a lot of the generation is very high, particularly at peak. The steepness of the variable cost curve in the region makes us relatively more comfortable with the capacity position in New England. The variable cost curve in Texas is very flat, which makes the region more susceptible to wholesale price pressure. The regions shortest generating capacity include California, the upper Midwest (MAPP), the Midwest (MAIN), the Southeast (SERC), Florida and New York.

Figure 1



Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Table 1: **Capacity Reserve Margin Estimates – 2001 & 2002**

NERC Region	2001 CRM	2002 CRM
ECAR	8.4%	12.4%
ERCOT	17.2%	19.9%
FRCC	4.8%	12.7%
MAAC	9.0%	12.8%
MAIN	5.0%	9.5%
MAPP	0.7%	-1.1%
NPCC		
New England	19.5%	30.0%
New York	9.1%	7.6%
SERC		
Entergy	3.7%	23.5%
Southern	8.1%	12.9%
TVA	6.2%	7.4%
VACAR	1.2%	2.3%
SPP	13.6%	16.9%
WSCC		
AZ-NM-NV	8.2%	17.0%
California	2.7%	3.7%
Northwest	32.4%	32.4%
Rocky Mountains	14.2%	16.8%
US TOTAL	**9.7%**	**13.6%**

Source: Deutsche Banc Alex. Brown estimates, NERC, RDI Consulting

National Outlook for Electricity Generation Capacity Additions

Although the headline numbers continue to suggest a lot of electricity generating capacity will be entering commercial operation over the next five years, we continue to see challenges associated with siting and permitting slowing the process slightly in the very near-term. There have been approximately 350 gigawatts (GW) of generating capacity announced over the last few years. This compares with a base of installed generating capacity of approximately 750 GW. The average construction term is about 16 months for a combined cycle plant, once permits have been received. However, when we review the capacity additions in 2000, we originally expected 31 GW of new capacity, but only 24 GW were added. The challenges of permitting and siting for the plants appear to be the major obstacle. These challenges, coupled with the sheer amount of announced capacity additions, convinces us that all of the announced capacity will not be built. Based on these issues, we remain optimistic about the earnings growth for generators in 2001 and 2002. However, profit margins are likely to peak in early 2002.

Based on 3% annual demand growth, we see the need for about 200 GW of new generating capacity by year-end 2005. We are assuming 218 GW of capacity additions by yearend 2005. Notwithstanding our belief that less than 350 GW will be added by 2005, we continue to watch carefully for signs of excess construction activity in the United States. Our current forecast of generating capacity additions suggest adequate generating capacity in the United States by late 2003 or early 2004. We expect a 15% capacity reserve margin by 2004. However, we believe our forecast of capacity additions is more likely to be too low than too high. Therefore, the capacity reserve margin may be higher in 2005.

We continue to be confident that the question of excess generating capacity in the United States is a question of "when" not "if". Like many other asset-intensive, commodity businesses, we expect developers to add too much capacity to the U.S. generation market. Gross profit margins for U.S. generation companies are likely to peak in 2002. The decline from the peak will be determined by how fast additional generating capacity is added.

For 2001, we expect about 45 GW of new capacity to enter operation. About 75% of that capacity is expected to enter commercial operation before summer time, so it should be available to meet summer peak demand. In 2002, we expect closer to 60 GW to enter commercial operation. Although turbine-manufacturing capacity is the single biggest limitation to how fast capacity can be added, the slower than expected additions in 2000 have left more turbines available for future deployment. However, only a fraction of the 60 GW is currently under construction, so that level of addition in 2002 is far from assured. The 20 largest developers in the United States are shown in Table 2, along with the announced development plans for each company.

Table 2: **Top 20 Generation Developers – U.S.**

(Projects Announced & Completed 2000 - 2005)

Developer	MW *	% of 1999 Capacity
Calpine Corp.	30,764	4.2%
Duke Energy	18,017	2.5%
Panda Energy	12,903	1.8%
PG&E Corp.	12,283	1.7%
Cogentrix	11,500	1.6%
FPL Group Inc.	9,283	1.3%
International Power plc	8,052	1.1%
Tenaska, Inc.	8,000	1.1%
Public Service Entr. Grp.	7,606	1.0%
Mirant Corp.	7,572	1.0%
Southern Co.	7,470	1.0%
Constellation Energy	6,462	0.9%
Enron	6,155	0.8%
TECO Energy Inc.	5,983	0.8%
NRG Energy	5,406	0.7%
AES Corp.	4,814	0.7%
Dynegy Inc.	4,703	0.6%
Progress Energy Inc.	4,584	0.6%
Reliant Energy	4,383	0.6%
Dominion Resources	4,255	0.6%
Total	180,195	24.6%
1999 U.S. Installed Capacity	733,481	

** Actual additions announced; Not probability weighted.*

Source: Deutsche Banc Alex. Brown estimates, RDI Consulting, NERC

The majority of the 350 GW of proposed generation capacity is natural gas fired. Although this is the cleanest and most efficient generation using fossil fuels, the recent rise in natural gas prices has made investors and developers recalculate the economics of natural gas fired generation. We believe that natural gas fired capacity is clearly economic in the long term with sustainable natural gas prices below $5.50 per mmbtu. In the near-term, though, since natural gas fired capacity can be built faster than any other generating capacity, we expect approximately 100 GW of natural gas fired plants will be built no matter the price of natural gas. This is a result of the shortage of generating capacity that exists in the U.S. currently. Longer term, high gas prices will breed the economic deployment of new coal and nuclear driven electricity generating capacity.

Cost Comparisons for New Capacity

The new combined cycle combustion turbine electricity generating plants are extremely efficient, with a heat rate of about 6.2 (btu per mwh). At $5.00 per mmbtu natural gas, the variable cost of generating electricity is about $40 per megawatt hour (mwh) and the total cost is closer to $55 per mwh. This compares with coal-fired capacity, assuming $24 per ton of coal, of $33 per mwh variable cost and $58 per mwh total cost. A cost comparison for new nuclear is difficult to calculate, but appears to be over $60 per mwh. These figures continue to argue in favor of natural gas-fired generating capacity until long-term gas prices rise sustainably above $5.50 per mmbtu. Although gas may seasonally exceed that level over the next year or two, we believe the short lead times for gas fired generation argue in favor of the addition in the near term. Figure 2 shows our gas plant cost calculations.

A review of wholesale power markets suggest that power prices in 2001 and 2002 are likely to be above the $55 per megawatt hour level. This should encourage the addition of natural gas-fired capacity in many regions.

The high efficiency of natural gas fired plants, coupled with the relative speed that the assets can be built, continues to suggest that a lot of the new generating capacity will be natural gas fired. However, if about 40 GW of new gas-fired generating capacity is added annually and 60% of the capacity is baseloaded, natural gas consumption could rise by 7% annually, or about 1.4 trillion cubic feet annually. High gas prices have reduced some industrial uses for natural gas, so the total demand for gas may be tempered in 2001 — particularly when the impact of a slowing or recessionary economy are included. However, without significant increases in gas production, investors and developers should eventually worry about natural gas supply availability for a significant amount of new natural gas fired capacity.

Figure 2:

Power Plant Economics - Natural Gas Fired

	620	Megawatt (MW) Total Capacity with HRSG Duct Firing		
	350	MW plant with 270 MW HRSG uses	105,000	thousand cubic feet (mcf)/day
		of natural gas or	35,910,000	mcf/year at assumed capacity factor.
Assumptions:				
$	500	capital cost per kilowatt (kw)		
$	0.0051	variable operating cost per kilowatt hour (kwh)		
$	15.35	fixed operating cost per kw		
	95%	assumed annual capacity factor		
$	**5.00**	**assumed cost of gas per mcf**		
	2%	Assumed Property Tax Rate		
$	310,000,000	Total capital cost		
	8%	Assumed Cost of Debt		
	70%	Debt as a percent of total capital		
	30	year depreciation of asset		
$	10,333,333	annual depreciation expense		
	5,088,960	mwhs generated annually at assumed capacity factor		
$	40.38	Variable costs per megawatt hour		
$	179,550,000	fuel cost		
	25,953,696	variable costs		
	9,517,000	fixed operating costs		
	10,333,333	Depreciation		
	6,200,000	Property taxes		
$	231,554,029	Total Operating Costs		
$	17,360,000	Interest Costs		
$	**248,914,029**	**Pretax Costs**		
	$48.91	**Pretax Cost per mwh**		
Assumptions:				
	20%	Cost of Equity		
$	93,000,000	Equity Investment		
$	18,600,000	Equity Return		
	38%	Assumed Tax Rate		
$	30,000,000	Pretax Equity Return		
$	**278,914,029**	**After Tax and Return Cost**		
	$54.81	**After Tax and Return Cost per mwh**		

Source: Deutsche Banc Alex. Brown estimates and company information

Table 3:

U.S. COAL-FIRED GENERATION ADDITIONS

(Announced & Completed 2000 - 2005)

Holding Company	Plant	MW *	State	NERC	Plant Type	Primary Fuel	Operation Date	Status
AES Corp.	AES Warrior Run Inc.	180	MD	ECAR	Coal Boiler/Cog	Coal	2/10/2000	Operating
Royal Dutch Petroleum Co.	Delaware City [Motiva]	47	DE	MAAC	Comb Cycle	Coal	4/30/2000	Operating
Saudi Refining, Inc.	Delaware City [Motiva]	73	DE	MAAC	Comb Cycle	Coal	4/30/2000	Operating
Shell Transport & Trading Co. plc	Delaware City [Motiva]	31	DE	MAAC	Comb Cycle	Coal	4/30/2000	Operating
Texaco, Inc.	Delaware City [Motiva]	73	DE	MAAC	Comb Cycle	Coal	4/30/2000	Operating
Xcel Energy, Inc.	Black Dog	-75	MN	MAPP	Coal Boiler	Coal	1/1/2001	Operating
(Not Reported)	Red Hills Generation Facility	3	MS	SERC	Coal Boiler	Coal	5/15/2001	Under Constr
Groupe Suez Lyonnaise	Red Hills	432	MS	SERC	Coal Boiler	Coal	5/15/2001	Under Constr
Private Investors	Red Hills Generation Facility	5	MS	SERC	Coal Boiler	Coal	5/15/2001	Under Constr
Progress Energy, Inc.	Crystal River	100	FL	FRCC	Coal Boiler	Coal	10/1/2001	Under Constr
Marlow Power & Steam, Inc.	Seward Cogeneration	3	AK	ASCC	Coal Boiler/Cog	Coal	1/1/2002	Early Develop
Vectren Corp.	Mt Vernon (Posey)	42	IN	ECAR	Coal Boiler/Cog	Coal	6/1/2002	Early Develop
Reliant Energy, Inc.	Seward (HOUIND)	300	PA	MAAC	Coal Boiler	Syn Coal	6/1/2002	Early Develop
Enviropower	Petersburg	500	IN	ECAR	Coal Boiler	Waste Coal	1/1/2003	Early Develop
Enviropower	Perry (Kmp)	500	KY	ECAR	Coal Boiler	Coal	1/1/2003	Early Develop
Black Hills Corp.	Wygen No. 1	80	WY	WSCC	Coal Boiler	Coal	1/1/2003	Under Constr
Southern Illinois Power Coop	Marion (SIPC)	120	IL	MAIN	Coal Boiler	Coal	2/1/2003	Early Develop
Enviropower	Sullivan County	500	IN	ECAR	Coal Boiler	Waste Coal	6/1/2003	Early Develop
Global Energy, Ltd.	Kentucky Pioneer	520	KY	ECAR	Coal Boiler	Coal	6/1/2003	Early Develop
Enviropower	Franklin County	500	IL	MAIN	Coal Boiler	Waste Coal	6/1/2003	Early Develop
North American Power Group	Two Elks Plant	250	WY	WSCC	Coal Boiler	Waste Coal	6/1/2003	Early Develop
TECO Energy, Inc.	Gannon	-600	FL	FRCC	Coal Boiler	Coal	5/1/2004	Early Develop
TECO Energy, Inc.	Gannon	1,020	FL	FRCC	Comb Cycle	Coal	5/1/2004	Early Develop
Composite Power Corp.	Bearcreek	500	MT	WSCC	Coal Boiler	Coal	6/1/2004	Early Develop
UniSource Energy Corp.	Springerville	380	AZ	WSCC	Coal Boiler	Coal	6/1/2004	Early Develop
Corn Belt Energy Corp.	Elkhart [Corn Belt]	91	IL	MAIN	Coal Boiler	Coal	12/1/2004	Early Develop
Peabody Group	Thoroughbred Energy Center	1,500	KY	ECAR	Coal Boiler	Coal	1/1/2005	Early Develop
Wisconsin Energy Corp.	Port Washington	-320	WI	MAIN	Coal Boiler	Coal	1/1/2005	Early Develop
Wisconsin Energy Corp.	Port Washington	500	WI	MAIN	Comb Cycle	Coal	1/1/2005	Early Develop
TECO Energy, Inc.	Lake Charles (TECO)	670	LA	SPP	CC/Cogen	Coal	1/1/2005	Early Develop
Ls Power	Plum Point Energy Station	1,000	AR	SERC	Coal Boiler	Coal	6/1/2005	Early Develop
UniSource Energy Corp.	Springerville	380	AZ	WSCC	Coal Boiler	Coal	6/1/2005	Early Develop
		9,305						

** Negative megawatt values represent units being retired or refitted.*

Source: Deutsche Banc Alex. Brown estimates, RDI Consulting

Outlook for Coal

Of the total 350 GW of announced generating capacity additions, only 10 GW of the capacity is expected to be coal fired. Table 3 shows a listing of the announced coal fired facilities. If the historic volatility of natural gas remains, we expect additional coal-fired generation to be built. The Bush Administration is likely to fund a significant amount of research and development for clean-coal technology in its energy policy. This will not solve the near-term capacity issues in the United States, but will likely encourage the addition of coal-fired generating capacity over the next five years.

In the United States, about 51% of electricity is generated with coal-fired capacity. We expect this number to stagnate or decline in the near-term, but grow modestly over the ensuing several years. Several of the generators we communicate with are considering new coal-fired generation capacity. Importantly, the breakeven economics for a new greenfield coal-fired generating plant are about $5.50 per mmbtu of gas. This is not far from current natural gas prices. However, if a brownfield site can be utilized, the breakeven economics can decline closer to $4.00 per mmbtu. These observations hearten our belief that more coal-fired capacity is likely to be built in the United States.

Outlook for Nuclear

Nuclear capacity in the United States is operating better than at almost any time in its 30 year history. Consolidation has begun concentrating the plants in the hands of the best operators in the country, and we expect this trend to continue. With nuclear operating licenses being extended by the Nuclear Regulatory Commission (NRC), we expect the existing amount of nuclear generating capacity to operate for at least the next 10–15 years.

The question of new nuclear capacity is a challenging one. Unless the new capacity is constructed near an existing nuclear plant, we do not believe the psychology of the U.S. population would be in favor of new nuclear plants. Sustainably high fossil fuel prices or other energy crises could change this psychology, though. However, we are not convinced that any new nuclear generating capacity will be built in the next five years. We are more optimistic about new coal-fired capacity than nuclear capacity. However, we expect the Bush Administration to fund additional research for nuclear.

Demand Growth for Electricity

Our electricity demand forecast is about 3% annually. In many regions, growth has been materially higher in the past two years. However, we believe this was driven almost entirely by remarkably strong economic growth. The relationship between growth in GDP and growth in electricity demand remains strong — particularly during times when GDP growth is positive. A simple correlation coefficient between the two variables is about 0.80.

Although some have suggested that the rising concentration of technology and telecommunications related equipment will drive electricity demand growth faster than 3%, we have not found any quantitative data to support that position. Admittedly, given our positive investment thesis on the generation sector, we would be thrilled at faster demand growth. However, a narrow focus on technology-driven electricity demand growth ignores the realities of industrial demand for electricity, which has been impacted by the globalization of the industrial economy and the increasing concentration of service-based businesses in the U.S. economy. Therefore, we are hard pressed to see demand sustainably above 3% over the five year forecast horizon. In fact, we believe the 3% growth is more likely to be too high than too low.

Forecasting Methodology

Using new generation data provided by Resource Data International (RDI) and our demand growth estimates, we have made a forecast of capacity reserve margins for every region of the United States through 2005. We do not expect the entire 350 GW of announced generating capacity additions to be constructed. In our analysis of 2001 generating capacity additions, using February 2001 data, we assumed all plants under construction came on line as scheduled. Further, we assumed that peaking units in advanced development entered commercial operation as scheduled. For 2002 through 2005, we assumed all capacity under construction entered commercial operation as scheduled, while capacity in advanced development was reduced by 25% and capacity in early development was reduced by 50%. This probability weighting clearly underestimates the capacity that will be added in 2004 or 2005. However, our forecast suggests nationally the supply of electricity should reach adequacy by 2004, so the concern is less important. This methodology suggests 218 GW of capacity will be added by yearend 2005. Since the capacity additions in 2004 and 2005 are likely to be higher than our forecast, our five-year estimate (2001-2005) of capacity additions is more likely to be too low than too high.

Regional Outlook

Our current forecast of generating capacity additions suggests adequate generating capacity in the United States by 2004. We expect a 15% capacity reserve margin by 2004. A detailed summary of these additions is shown in Table 4. We show the largest additions by state in Table 5. However, it is far more important to review capacity additions on a regional basis. Our concerns for excess capacity are focused on Texas and the New England/Northeast regions of the United States. We are carefully monitoring both demand growth for electricity and supply additions to generating capacity. However, our concerns about Texas appear to be much more firmly based than the concerns about New England/Northeast.

Table 4: **MW Additions Per Year – Probability Weighted**

NERC Region	2000	2001	2002	2003	2004	2005	Total
ECAR	3,933	5,072	8,812	10,174	1,818	1,521	**31,330**
ERCOT	3,743	9,411	5,550	5,038	843	0	**24,585**
FRCC	1,036	2,928	5,385	4,711	347	180	**14,587**
MAAC	716	1,478	4,343	3,491	445	443	**10,916**
MAIN	1,063	4,754	4,696	5,664	393	452	**17,022**
MAPP	100	1,017	402	65	28	0	**1,612**
NEPOOL	1,552	4,188	5,469	1,561	250	0	**13,020**
NY	18	346	300	5,833	1,716	72	**8,285**
SERC	8,824	10,653	18,819	10,842	2,000	800	**51,938**
Entergy*	1,221	2,479	9,212	2,979	520	800	**17,211**
Southern*	3,635	4,740	4,832	5,181	0	0	**18,388**
TVA*	1,238	1,843	1,750	1,596	520	0	**6,947**
VACAR*	2,730	1,591	3,025	1,088	960	0	**9,394**
SPP	2,157	3,096	3,616	3,519	0	425	**12,813**
WSCC	1,104	5,751	7,719	12,577	4,660	1,595	**33,406**
AZ-NV-NM**	632	1,625	3,212	4,857	778	730	**11,834**
California**	0	2,445	2,295	5,535	1,175	375	**11,825**
Northwest**	22	1,294	1,619	1,679	2,708	490	**7,812**
Rocky Mts**	450	387	593	507	0	0	**1,937**
Total	**24,246**	**48,694**	**65,111**	**63,478**	**12,501**	**5,488**	**219,518**

* SERC subregion.

** WSCC subregion.

Source: Deutsche Banc Alex. Brown estimates, RDI Consulting

We believe it is valuable to review both total capacity additions and the current variable cost of generating capacity in each region. In New England, for example, the existing capacity is extremely expensive. This is particularly true at times of peak demand. Therefore, we are less convinced that a significant increase in generating capacity in New England will result in a collapse in wholesale prices for electricity. Conversely, in Texas the variable cost curve for all existing generation is relatively flat. Therefore, significant increases in generating capacity are likely to have a very negative impact on wholesale electricity prices in 2002 or 2003.

Table 5: **Top 10 States – US Generating Capacity Additions**

(Projects Announced & Completed - 2000 to 2005)

STATE	MW *	% of 1999 Capacity
Texas	31,746	4.3%
Illinois	20,450	2.8%
Florida	20,342	2.8%
California	17,441	2.4%
New York	14,996	2.0%
Arizona	14,477	2.0%
Alabama	13,371	1.8%
Ohio	12,840	1.8%
Georgia	12,251	1.7%
Indiana	12,247	1.7%
Total	170,161	23.2%
1999 U.S. Installed Capacity	733,481	

** Actual additions announced; Not probability weighted.*

Source: Source: Deutsche Banc Alex. Brown estimates, RDI Consulting, NERC

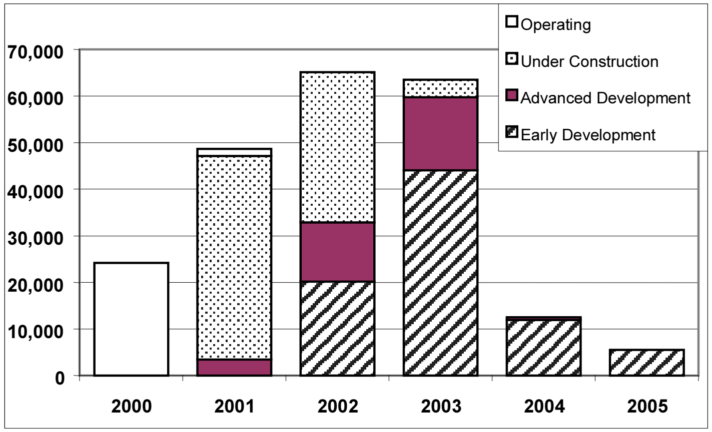
An analysis of each region of the United States follows. For each NERC region analyzed, we have included a snapshot of capacity additions and the capacity reserve margin. Further, we have included a variable cost and heat rate chart. These charts graph the variable cost and heat rate of every electricity generation plant in each region. The variable cost is important since it directly impacts pricing in each region at different levels of demand. Variable costs for electric power include fuel costs and variable operating expenses. The steeper the variable cost curve, the more tolerant the region will be to excessive capacity additions. This is a result of the displacement of inefficient and expensive capacity in a region. We overlay on the variable cost curve the heat rate for each generating plant in the region. Heat rate is defined as energy (measured by mmbtu) per kilowatt hour. It is essentially a fuel efficiency measure. However, since the output is in the denominator of the equation, the lower the heat rate the better. As is shown in all of the variable cost charts, the lowest variable cost plants also tend to have the lowest heat rates. Thus, as demand increases and less efficient plants are dispatched, this tends to drive up the variable cost.

The regional arrangement of the next several sections of this report mirrors the North American Electric Reliability Council (NERC) regions (see Figure 4, pg. 14). Analysis of the capacity outlook for each region, as well as the variable cost curve is shown in Figures 5 through 42. The Southeastern region and the Western region are divided into four sub-regions as a result of the overall size of these regions. A summary of the capacity outlook for the entire U.S. is shown in Figure 3 on page 13. A detailed regional breakdown of supply, demand and capacity reserve margins from 1989 to 2005 is shown in Appendix A on pages 74 and 75.

Figure 3:

United States

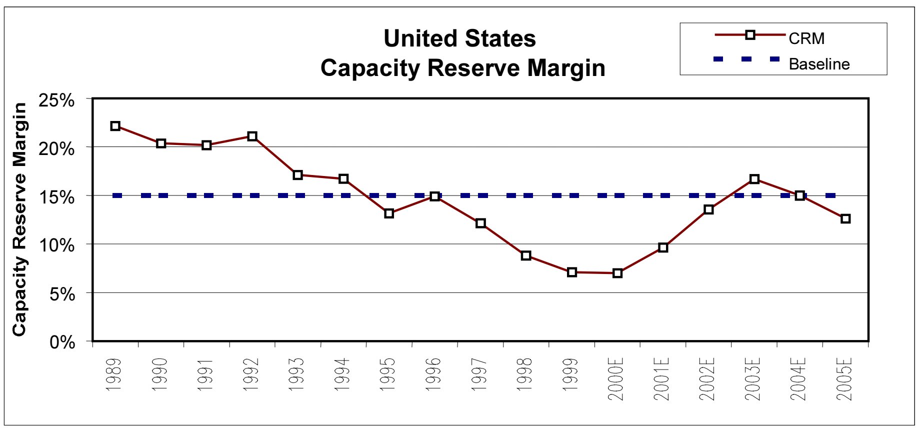
Capacity Additions by Year (MW's)

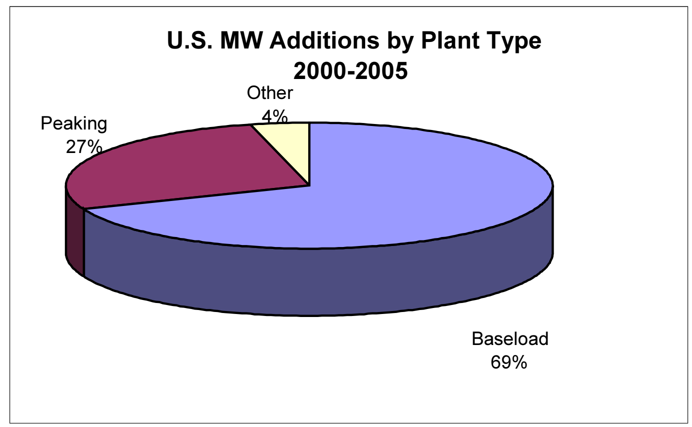


Capacity Additions	
Year	**MW**
2000	24,246
2001	48,695
2002	65,111
2003	63,478
2004	12,500
2005	5,488
Total	***219,518***

TOP FIVE BUILDERS IN U.S.	
Company	MW*
1) Calpine Corp.	30,764
2) Duke Energy	18,017
3) Panda Energy	12,903
4) PG&E Corp.	12,283
5) Cogentrix	11,500

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

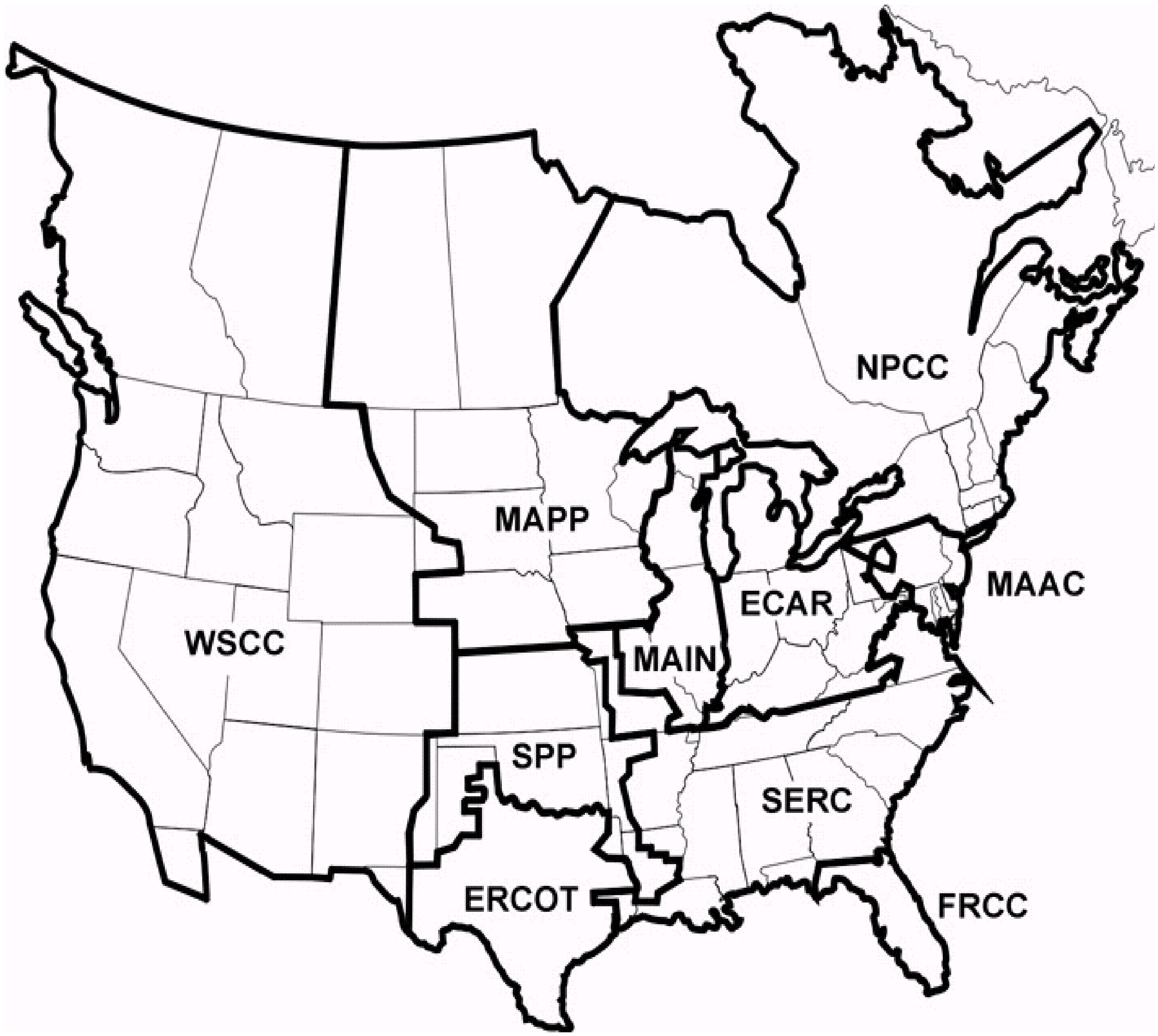




Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 4:

North American Electric Reliability Council (NERC) Regions



ECAR
East Central Area Reliability Coor. Agreemt.
ERCOT
Electric Reliability Council of Texas
FRCC
Florida Reliability Coordinating Council
MAAC
Mid-Atlantic Area Council
MAIN
Mid-America Interconnected Network
MAPP
Mid-Continent Area Power Pool
NPCC
Northeast Power Coordinating Council
SERC
Southeastern Electric Reliability Council
SPP
Southwest Power Pool
WSCC
Western Systems Coordinating Council

Source: NERC

U.S. NERC Regions

East Central Area Reliability Coordination Agreement (ECAR)

Total 2000 Capacity: 109,913 MW
Total Under Construction: 5,838 MW
Total Announced Additions (2000 – 2005): 31,329 MW

This NERC region comprises the Industrial Midwest and includes the states of Ohio, West Virginia, Michigan, Indiana and parts of Kentucky, Virginia and Pennsylvania. Capacity reserve margins have been below 10% since the mid-1990s. Supply reserves are likely to remain tight in the region through the end of 2001. About 5,000 MW of capacity are expected to be added in 2001, bringing the reserve margin at year-end to about 9%. Nearly all of this expected 2001 capacity is already under construction. For 2002 another 8,000 MW are slated to come on line. However, a large portion of this capacity is currently in the early development stage, so it is by no means assured to enter commercial operation. As we continue to believe a 15% reserve margin is necessary to allow sustainable price stability, we expect spot electricity prices to remain strong in the region through most of 2002, providing a good opportunity for power generators. Further, the ECAR region is quickly advancing towards deregulated status, which has spurred the rapid increase in capacity additions in the region. Under our capacity addition forecast, the reserve margin peaks in 2003 at about 17% and then begins declining. Our reserve margin estimates for the region are based on the assumption of 3.0% annual growth in electricity demand.

The ECAR region remains particularly short peaking capacity. Of the approximately 5,000 MW of generating capacity expected to enter commercial operation in 2001, about 3,700 MW are peaking facilities fired with natural gas. Further, most of the capacity currently under construction for 2001 will be in commercial operation by summer time. Only 700 MW of the 5,000 MW total will enter commercial operation after September 1.

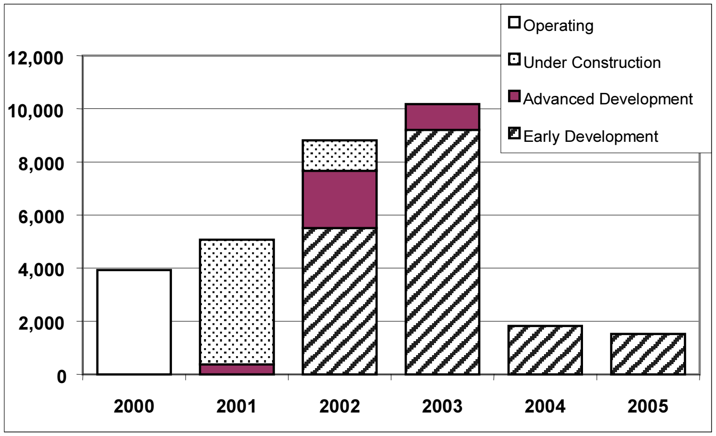
The most interesting characteristic of the ECAR region is the dominance of coal-fired capacity in the region. It is one of the few regions of the country where the spark spread (price difference between natural gas and electricity) can become negative despite the current shortage of capacity. Over 85% of the electricity generated in ECAR is generated using coal-fired capacity. Although most of the new capacity entering commercial operation is natural gas fired, the region is far more sensitive to coal prices than natural gas prices. Over time, the natural gas–fired additions should serve to flatten the variable cost curve shown in Figure 6. Using $5.00 per mmbtu natural gas, a new combined cycle combustion turbine would have variable costs of about $40 per megawatt hour and total costs of about $55 per megawatt hour.

Overall, the capacity outlook for the ECAR region of the United States appears short for 2001 and 2002. The capacity reserve margin should improve by 2003 to approximately adequate capacity if our assumption that about 9,000 MW of capacity will enter operation in 2003 is accurate. However, as more natural gas fired capacity enters operation, the region will become increasingly sensitive to changes in the price of natural gas.

Figure 5: **Capacity Outlook**

ECAR - East Central Area Reliability Coordination Agreement

Capacity Additions by Year (MW's)



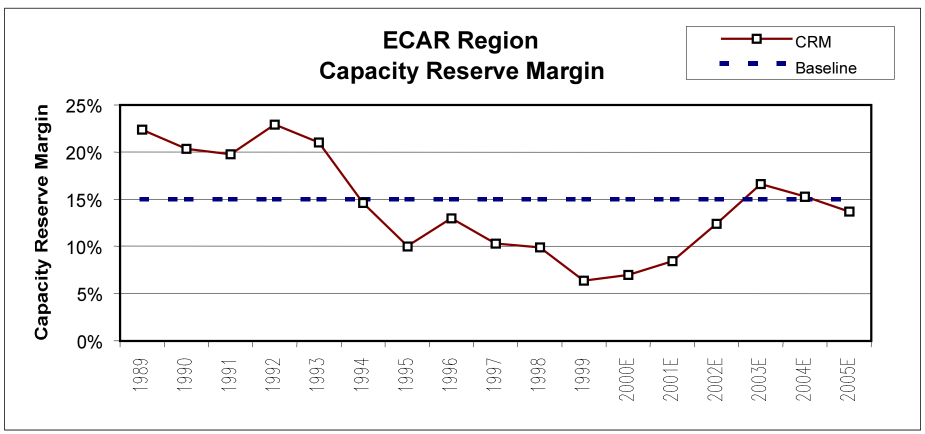
Capacity Additions	
Year	**MW**
2000	3,933
2001	5,072
2002	8,812
2003	10,174
2004	1,818
2005	1,521
Total	***31,329***

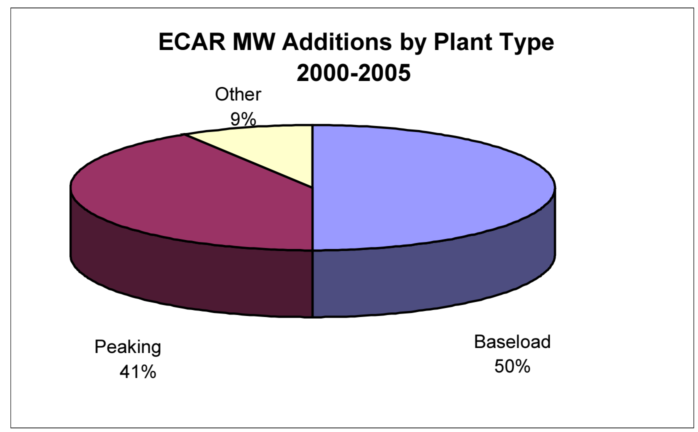
TOP FIVE BUILDERS IN ECAR*	
Company	MW*
1) Cogentrix	5,100
2) Duke Energy	4,508
3) Public Ser Enter Grp	3,070
4) Dynegy Inc.	2,476
5) DPL Inc.	2,440

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in ECAR
IN, OH, KY, PA
WV, MI, VA

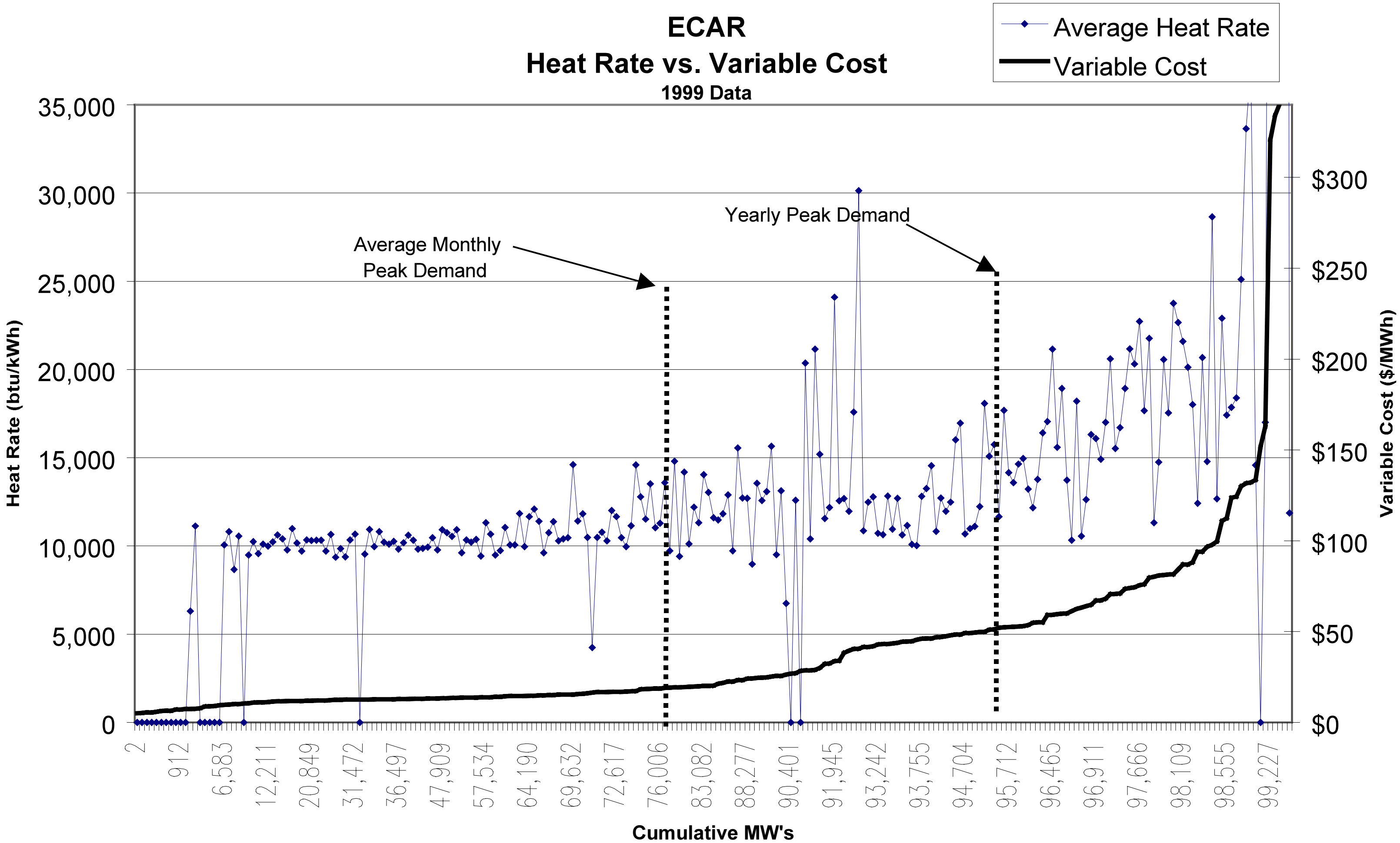
DEREG STATUS
OH, PA - Retail choice begun
WV, MI, VA - Legis. enacted; retail choice pending
IN, KY - Investigatiing





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 6:



Note: Chart excludes 3,782MW of hydro capacity in region.

Note: Chart excludes 4 plants totaling 368MW with an average heat rate of 431,278 btu/kWh and average variable cost of $5,164/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Electric Reliability Council of Texas (ERCOT)

Total 2000 Capacity: 63,247 MW
Total Under Construction: 12,155 MW
Total Announced Additions (2000 – 2005): 24,584 MW

This NERC region consists of the majority of the state of Texas. A lot of capacity is being added to this region as a result of the ease of siting power plants and the advanced status of deregulation. Deregulation legislation has been enacted in the state and retail choice is scheduled to begin in January of 2002. In advance of the opening up of this market, many power generators have announced plans to add generation in the state. Further, about 95% of the new plant additions from 2001 to 2005 are either under construction or in advanced development, raising the likelihood that most of the 20,841 MW of announced capacity will be brought on line. This would bring the capacity reserve margin for ERCOT to 17% by the end of 2001 and above 20% in 2003 and 2004. If this occurs, the region could experience a significant decline in power prices. Another issue for the region could be the fact that nearly all of the new plant additions are expected to be baseload facilities, which are intended to run year-round. This compares with peaking facilities that are only run during periods of peak demand. Lastly, as indicated in Figure 8, the region has a fairly flat variable cost curve which means that there are not a lot of high-cost plants that can be forced off the grid. The combination of these issues will make Texas the most interesting electricity region in the next 12 to 24 months.

The ERCOT region will be the region we will be watching most carefully during the summer of 2001. We will be watching for levels of spot market volatility. Although we believe the region will still be slightly short capacity in 2001, the prospect for adequate or excess capacity in 2002 appears probable. Our capacity reserve margin estimates are based on about 4% demand growth in Texas. Although the 17% capacity reserve margin for 2001 is above the 15% level we associate with adequate capacity, almost 2,000 MW of the capacity additions for the year will occur after August. Therefore, some of the new resources will not be available to meet the summer peak demand. Excluding these additions, the summer time reserve margin in Texas should be about 14% in 2001.

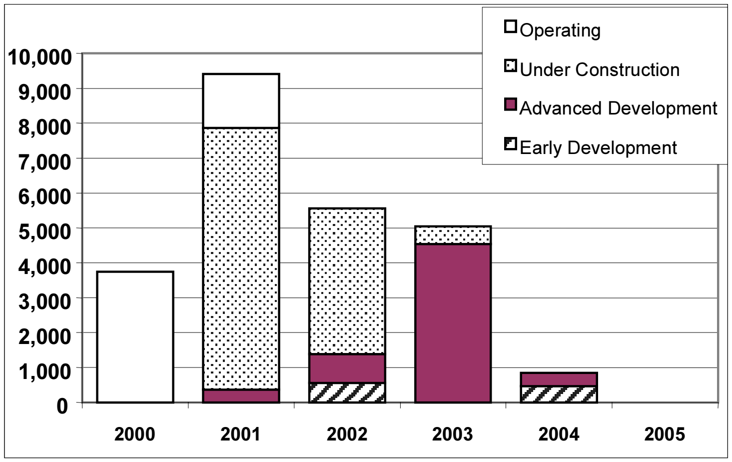
It is important to note that the state of Texas is somewhat unique in the United States. The ERCOT region is almost entirely physically cut off from the rest of the U.S. from an electricity point of view. Only three major electricity transmission lines run out of Texas. However, these lines have no additional capacity. This is important because if the region reaches excess capacity, the capacity will either have to be shut in or drive prices lower. We believe this is the only market that is so close to adequate generating capacity in the United States.

A detailed regional breakdown of supply, demand and capacity reserve margins from 1989 to 2005 is shown in Appendix A on pages 74 and 75.

Figure 7: **Capacity Outlook**

ERCOT - Electric Reliability Council of Texas

Capacity Additions by Year (MW's)



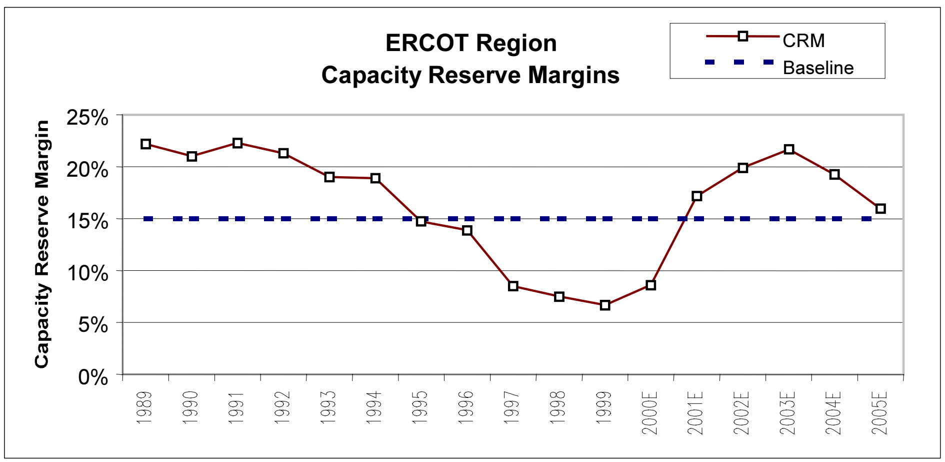
Capacity Additions	
Year	**MW**
2000	3,743
2001	9,411
2002	5,550
2003	5,038
2004	843
2005	0
Total	***24,584***

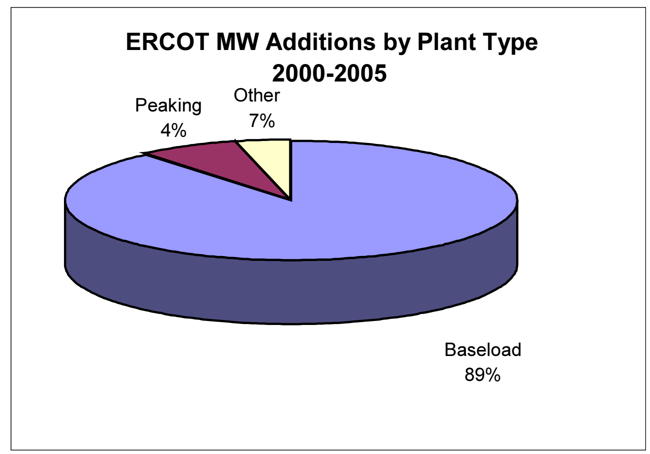
TOP FIVE BUILDERS IN ERCOT*	
Company	MW*
1) Calpine Corp.	4,743
2) International Power plc	4,441
3) Panda Energy	1,510
4) Cobisa Corp.	1,500
5) Public Service Enterprise	1,500

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in ERCOT
Texas

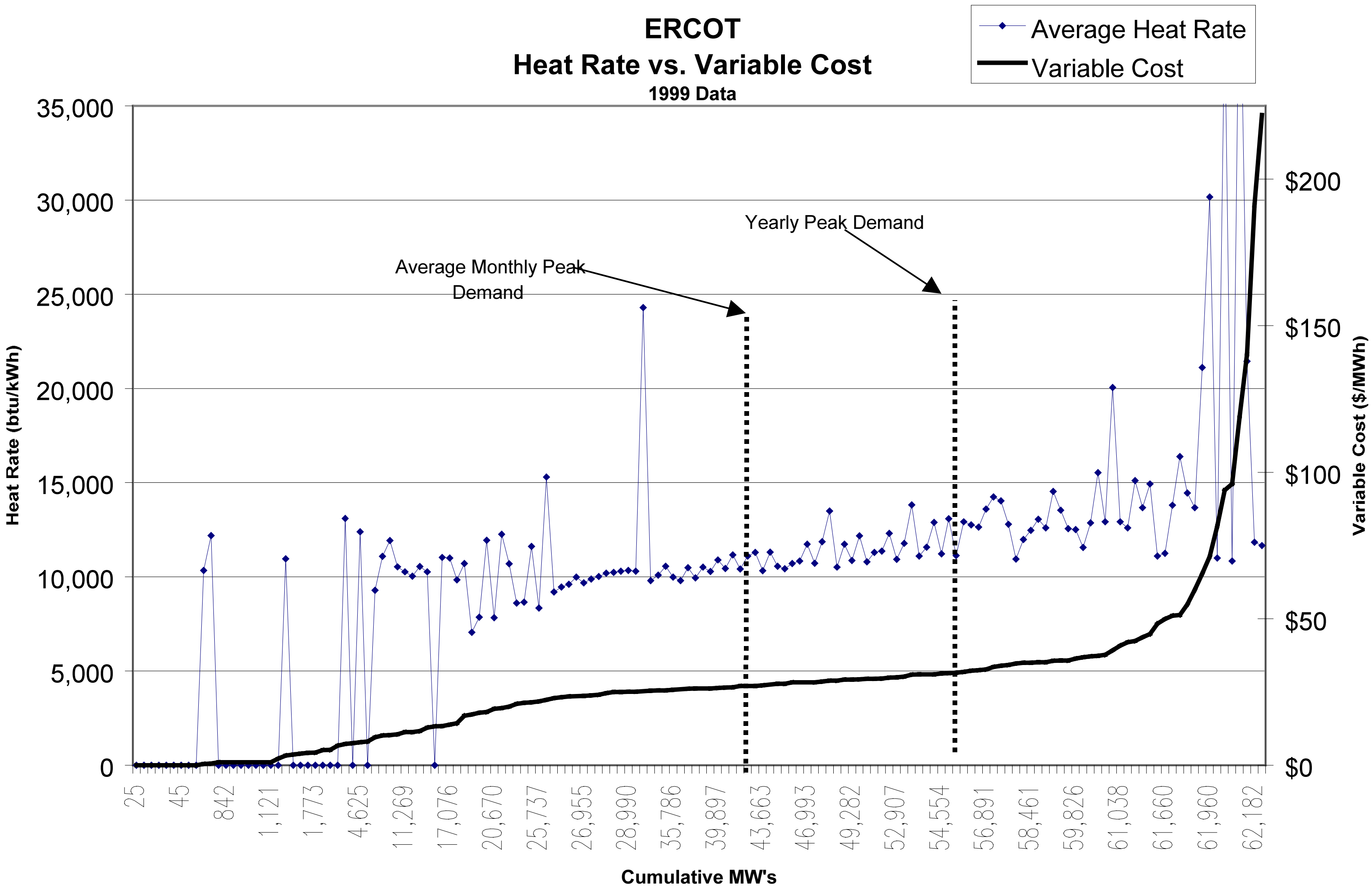
TEXAS DEREG STATUS
Legislation enacted; choice beginning Jan. '02





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 8:



Note: Chart excludes a 74MW plant with an average heat rate of 17,563 btu/kWh a and average variable cost of $771/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Florida Reliability Coordinating Council (FRCC)

Total 2000 Capacity: 39,279 MW
Total Under Construction: 7,041 MW
Total Announced Additions (2000 – 2005): 14,587 MW

This NERC region is comprised of the state of Florida, excluding a portion of the northwest panhandle of the state. The FRCC has experienced tight reserve margins over the last several years, as economic growth has outpaced generating capacity additions. Significant capacity growth has been hindered by regulations in the state that prohibit the construction of merchant plants. Approximately 7,000 MW of generating capacity are currently under construction in the state, with a total of about 3,000 MW slated to come on line by year-end 2001. The largest developer in this region is one of the state's incumbent utilities, FPL Group.

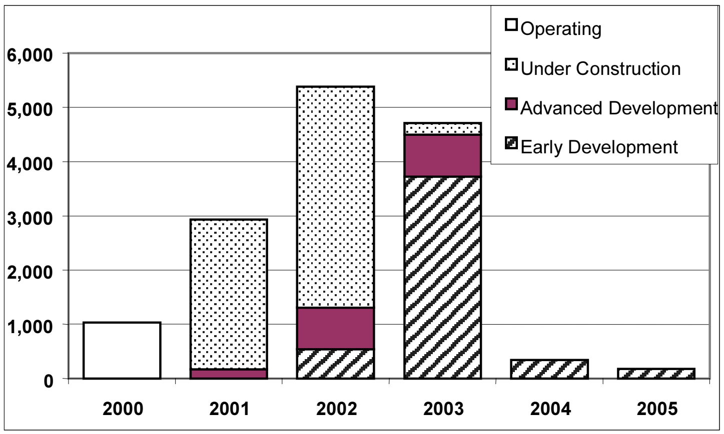
Even with the 2001 capacity additions, capacity reserve margins are expected to be below 5% at the end of the year. We do not expect to see a recovery of reserve margins to baseline levels (15%) until 2003. The reserve margin projections are based on a 3.5% annual growth rate in peak electricity demand for the region though 2005. Currently, FRCC is one of the shortest markets in the overall short-capacity Southeast.

Most of the supply we expect to be added in Florida is baseload capacity and natural gas fired. The relative steepness of the variable power production cost curve shown in Figure 10 suggests the new efficient capacity should not reduce prices immediately. Further, since the market in Florida is not deregulated, we do not expect a very negative reaction to spot prices. The prospect of the rapid occurrence of excess capacity is reduced as a result of the regulated nature of the Florida market. Our analysis does not assume any rapid change in regulation in Florida over the next five years.

Figure 9:

FRCC - Florida Reliability Coordinating Council

Capacity Additions by Year (MW's)



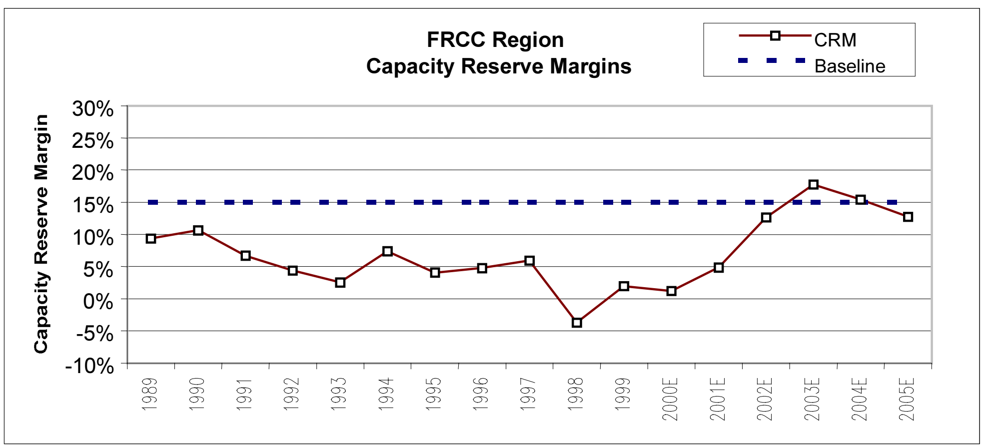
Capacity Additions	
Year	MW
2000	1,036
2001	2,928
2002	5,385
2003	4,711
2004	347
2005	180
Total	***14,587***

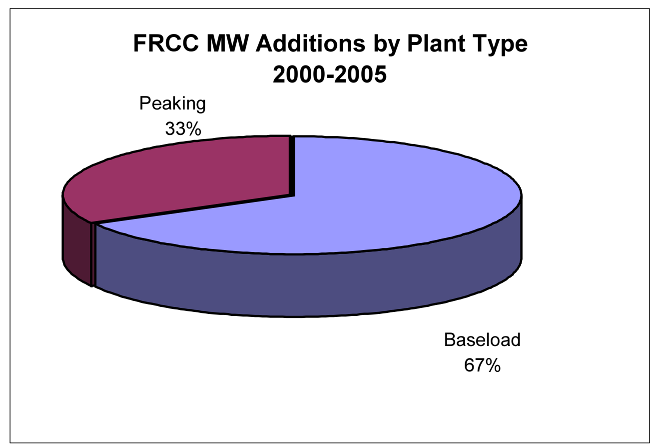
TOP FIVE BUILDERS IN FRCC	
Company	MW*
1) FPL Group	3,781
2) Panda Energy	2,000
3) Calpine Corp.	1,720
4) El Paso Energy	1,020
5) TECO Energy	975

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in FRCC
Florida

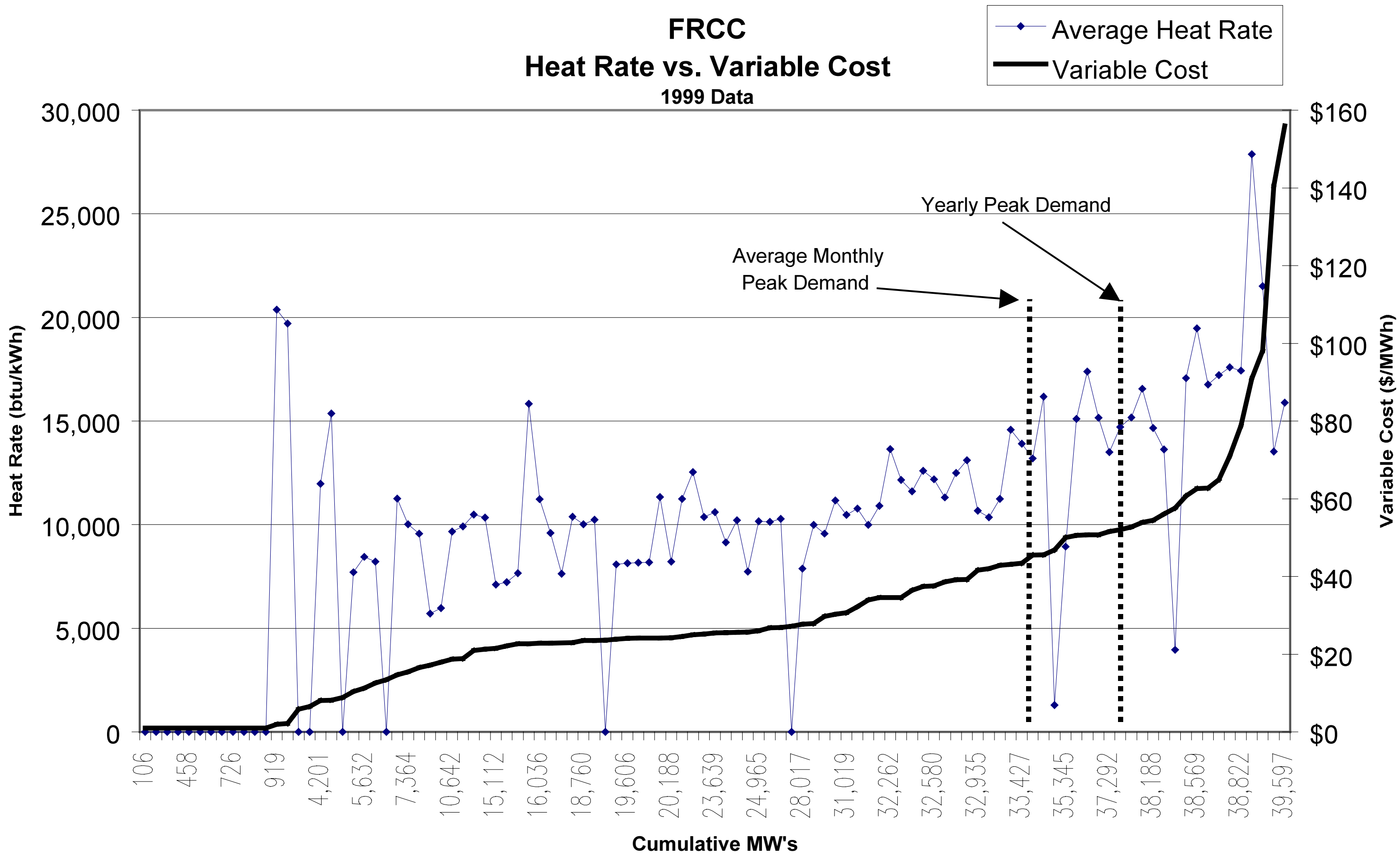
FLORIDA DEREG STATUS
Investigating





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 10:



Note: Chart includes all capacity in the region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Mid-Atlantic Area Council (MAAC)

Total 2000 Capacity: 58,419 MW
Total Under Construction: 3,281 MW
Total Announced Additions (2000 – 2005): 10,915 MW

This region is made up of New Jersey, Delaware, the District of Columbia and most of Pennsylvania and Maryland. Capacity reserve margins in the region dropped below 10% in 1998 and have recovered to the 10% level over the last two years. However, like most other regions of the United States, margins look to remain tight through 2001, which should bolster current pricing trends throughout the year. Only about 1,500 MW of capacity are projected to be added in 2001, which is about 2.8% of current installed capacity. In 2002 another 4,300 MW of capacity additions are planned, which should bring reserve margins to the 13% level. The reserve margin projections are based on a 2.8% annual growth rate in peak electricity demand for the region though 2005. All four states in the region have passed deregulation legislation, with retail choice already begun in New Jersey and Pennsylvania. Further, unlike California, the transition to a deregulated market appears to be running smoothly in the MAAC region. This is a result of the generation ownership by the incumbent suppliers.

In 2001, the new capacity is evenly divided between baseload and peaking facilities. However, most of the capacity is natural gas fired. Almost all of the capacity expected to enter commercial operation in 2001 is already under construction. Looking over the 2001 to 2005 period, though, most of the announced capacity additions are expected to be baseload. Reviewing the variable cost curve for plants in the region explains this.

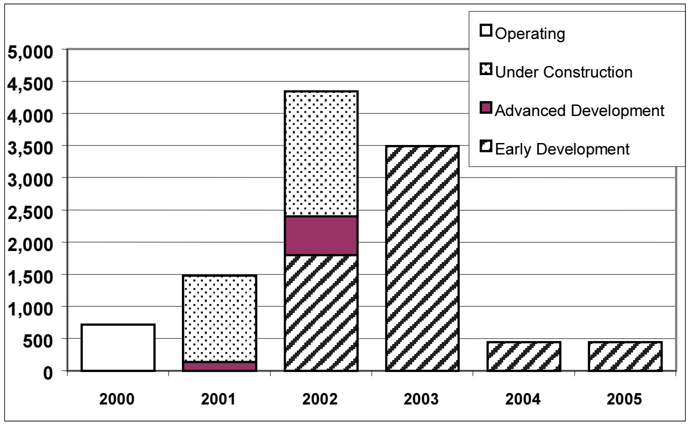
Figure 12 shows the variable cost curve for all of the generation in the mid-Atlantic region. At annual peak demand, variable costs are about $50 per megawatt hour. Assuming $5.00 per mmbtu natural gas, variable costs for a combined cycle plant are about $40 per megawatt hour. Further, total costs are only about $55 per megawatt hour. This, coupled with the high heat rate of a lot of the capacity in the mid-Atlantic region, convinces us that the region will attract a lot of generation development over the next four years.

A detailed regional breakdown of supply, demand and capacity reserve margins from 1989 to 2005 is shown in Appendix A on pages 74 and 75.

Figure 11: **Capacity Outlook**

MAAC - Mid-Atlantic Area Council

Capacity Additions by Year (MW's)



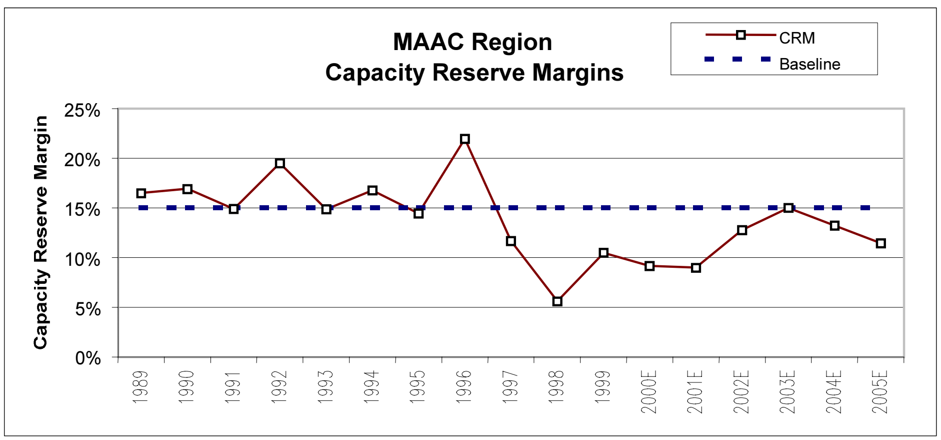
Capacity Additions	
Year	MW
2000	716
2001	1,478
2002	4,343
2003	3,491
2004	445
2005	443
Total	*10,915*

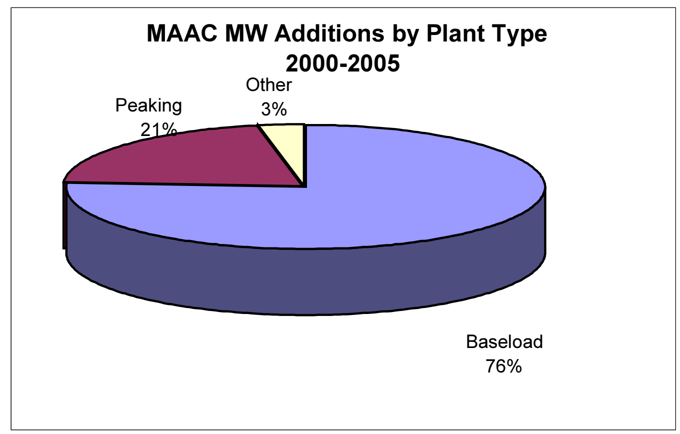
TOP FIVE BUILDERS IN MAAC	
Company	MW*
1) Public Service Enterprise Group	2,057
2) PG&E Corp.	1,900
3) AES Corp.	1,605
4) PPL	1,500
5) Dominion Resources	1,100

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in MAAC
DE, MD, NJ, PA

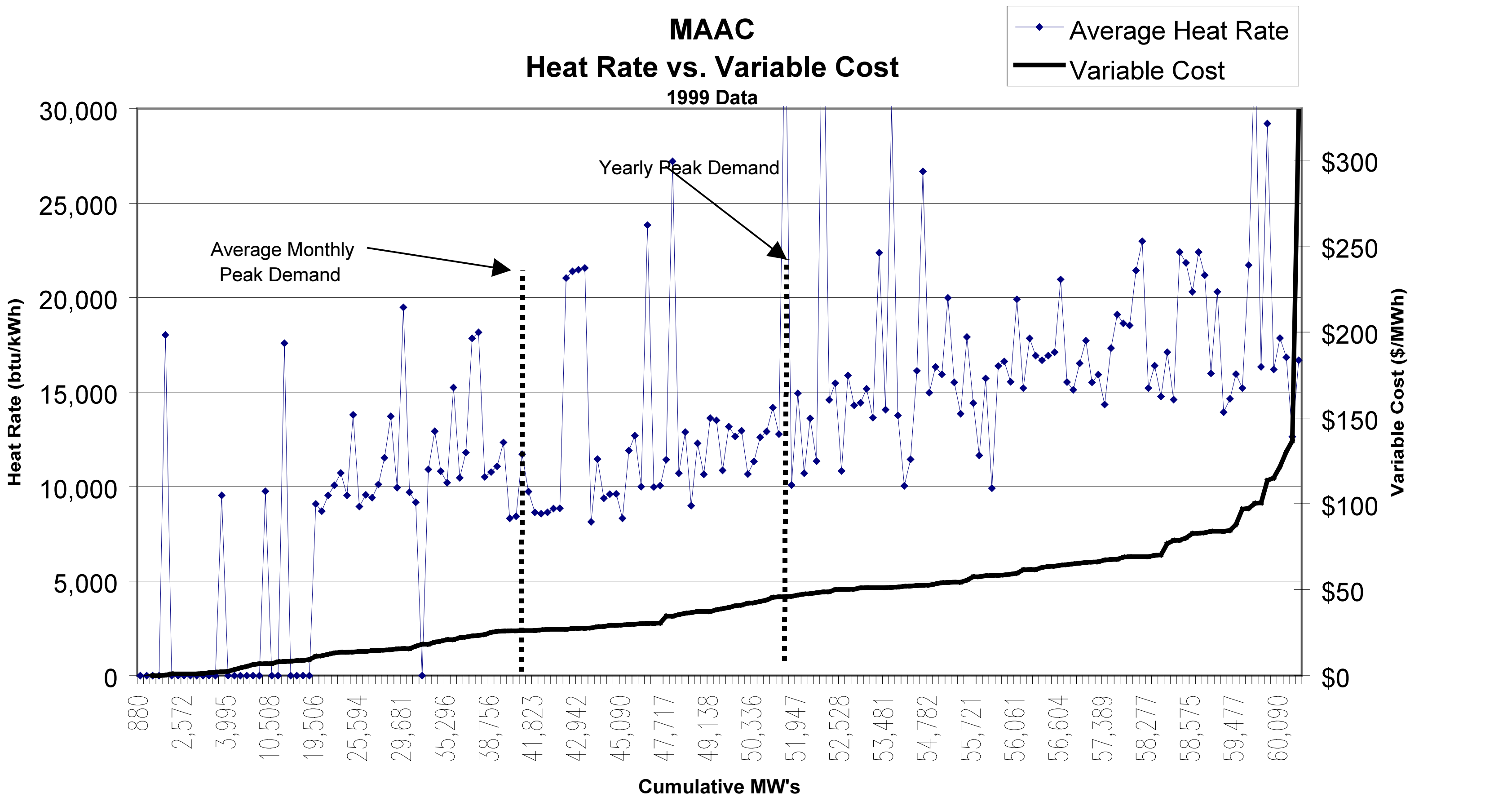
DEREG STATUS
NJ, PA - Retail choice begun
DE, MD - Legislation enacted; retail choice pending





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 12:



Note: Chart excludes 2 plants totaling 64MW with an average heat rate of 14,566 btu/kWh and average variable cost of $11,866/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Mid-America Interconnected Network (MAIN)

Total 2000 Capacity: 52,773 MW
Total Under Construction: 5,650 MW
Total Announced Additions (2000 – 2005): 17,022 MW

This NERC region is comprised of the state of Illinois and parts of Wisconsin and Missouri. Peak reserve margins in the region have declined sharply since 1992, from 25% in 1989 to 0% in 1999, as few capacity additions have been made over the last ten years. In 2001, approximately 4,700 MW are projected to come on line in the region, with the majority of this capacity already under construction. However, the reserve margin for the region is projected to still be well below 10% by the end of this year. Thus, we would expect pricing strength to continue in the region for the full year 2001. We do not expect to see a full recovery of reserve margins until the second half of 2002, when a total of 10,000 MW will have been added since 2001. Reserve margin projections for the region are based on the assumption of 3.0% annual peak demand growth through 2005. The capacity reserve margin in our forecast peaks at about 15% in 2003 and then declines through 2005. When considered in light of the steep variable cost curve for the region, we would not be surprised to see our capacity addition forecast exceeded in 2004 and 2005.

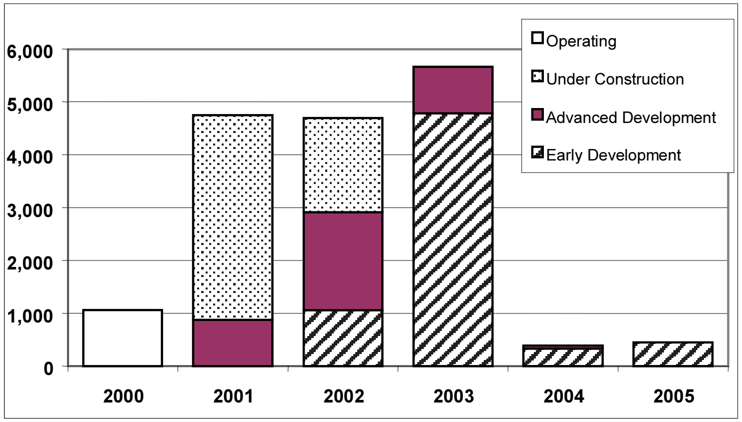
Most of the capacity expected to enter commercial operation is peaking capacity fired by natural gas. As variable costs rise rapidly in the region for existing generating capacity, we expect the peaking capacity to be very profitable during 2001 and 2002. This will make the region somewhat more sensitive to natural gas prices.

Figure 14 shows the variable cost curve for the main region. The steepness of the curve, particularly in the annual peak demand area, will breed additional generation development. At $5.00 per mmbtu natural gas, a new combined cycle combustion turbine would have variable costs of about $40 per megawatt hour and total costs of about $55 per megawatt hour.

Figure 13: **Capacity Outlook**

MAIN - Mid-America Interconnected Network

Capacity Additions by Year (MW's)



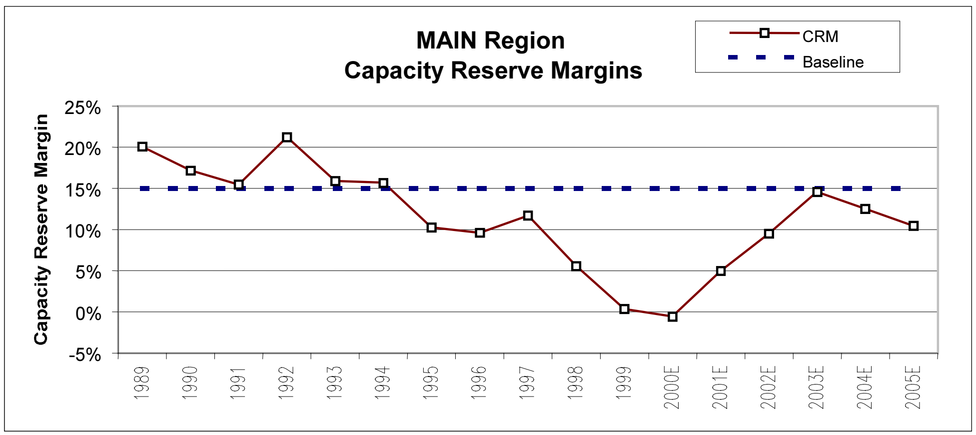
Capacity Additions	
Year	**MW**
2000	1,063
2001	4,754
2002	4,696
2003	5,664
2004	393
2005	452
Total	***17,022***

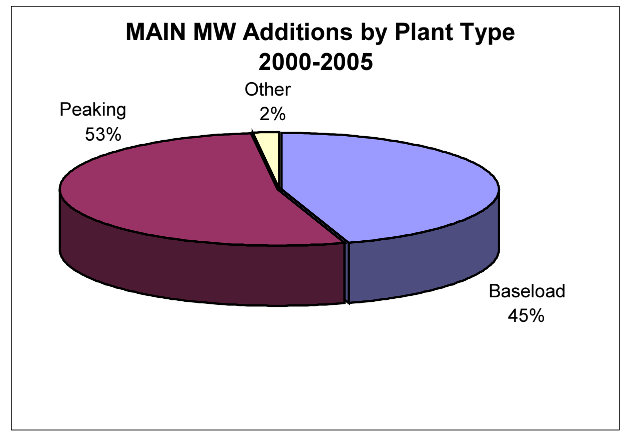
TOP FIVE BUILDERS IN MAIN	
Company	MW*
1) Calpine Corp.	2,533
2) Panda Energy	2,070
3) Ameren Corp.	1,919
4) Enron Corp.	1,763
5) ABB Energy	1,492

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in MAIN
WI, IL, MO

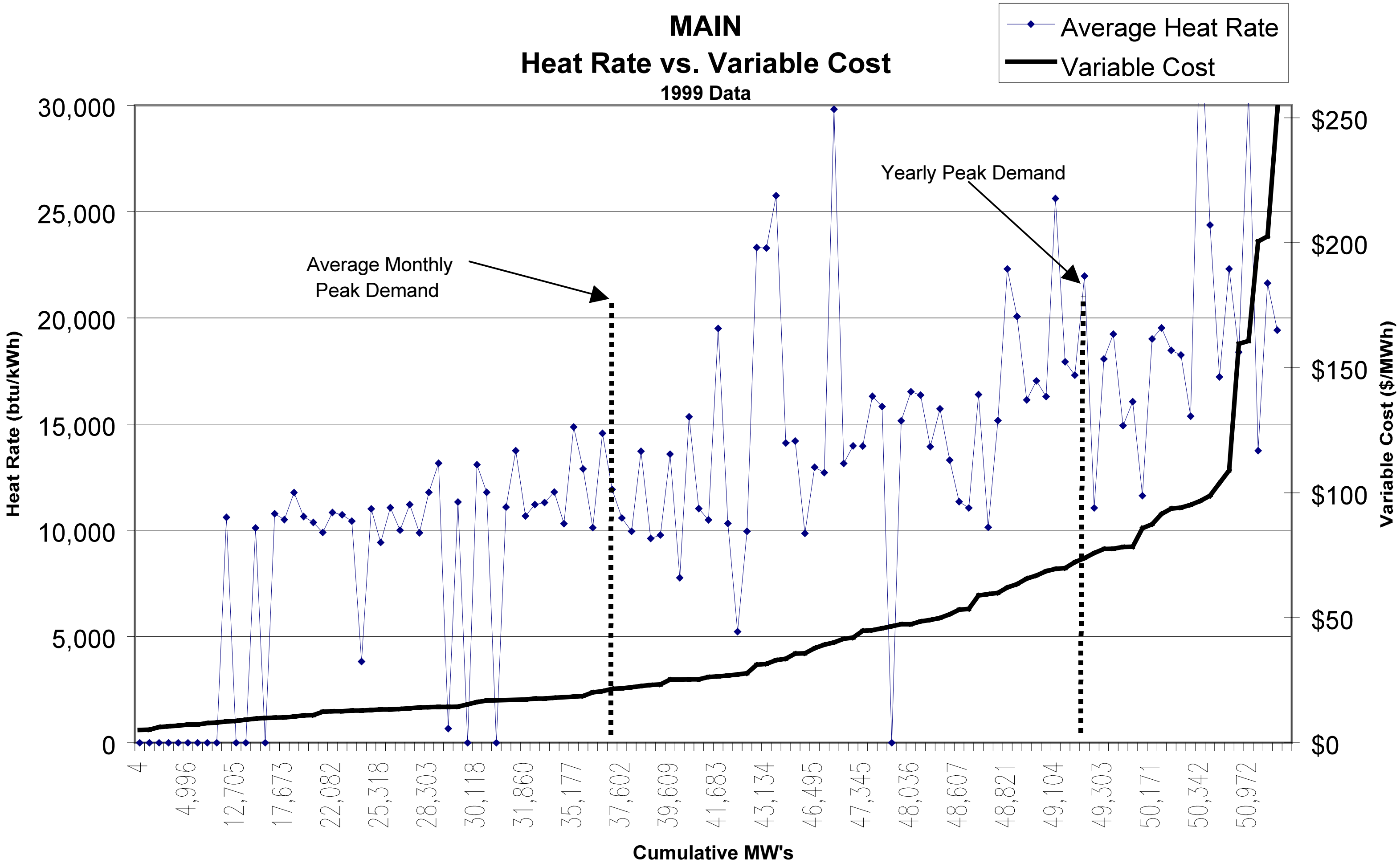
DEREG STATUS
IL - Retail choice begun
MO, WI - Investigating





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 14:



Note: Chart excludes 1,131MW of hydro capacity in region.
Note: Chart excludes one plant totaling 154MW with an average heat rate of 97,245 btu/kWh and average variable cost of $300/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Mid-Continent Area Power Pool (MAPP)

Total 2000 Capacity: 33,051 MW
Total Under Construction: 1,015 MW
Total Announced Additions (2000 – 2005): 1,612 MW

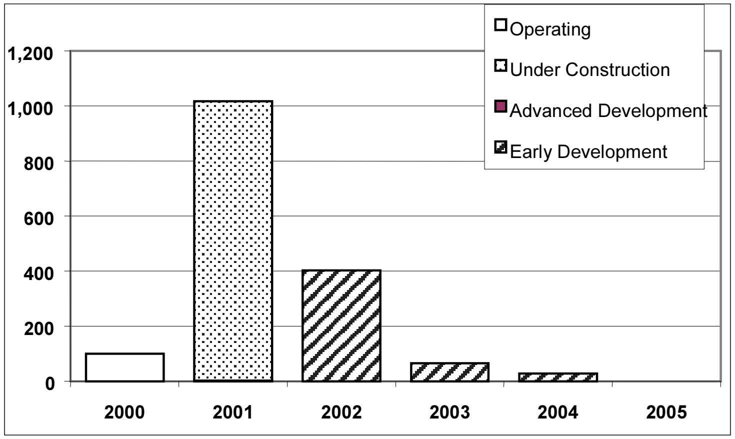
This NERC region is comprised of Nebraska, Minnesota, Iowa, North Dakota, most of South Dakota, and parts of Wisconsin. The region has experienced a steady decline in reserve margins since 1992, with dangerously low margins projected for the next five years. This region imports additional power, which reduces the risk associated with the low reserve margin. However, as a result of the very slow pace of deregulation in the MAPP region, very few unregulated generation projects have been proposed. For the period of 2001 to 2005, only about 1,500 MW of generation additions are currently planned. This represents an annual growth rate in capacity additions of only about 0.8%, which we believe will not be sufficient to keep pace with electricity demand growth. About 85% of the projected capacity additions are peaking projects. We expect additional supply announcements over the next few years. Demand growth should be about 3% annually.

Figure 16 shows the variable cost curve for the generation plants in the region. Although not extremely steep, the variable cost of power at peak appears to exceed $60 per megawatt hour. This should drive additional development in this region. At $5.00 per mmbtu natural gas, a new combined cycle combustion turbine would have variable costs of about $40 per megawatt hour and total costs of about $55 per megawatt hour. However, the large difference between average demand and peak demand suggests a below average capacity factor for units in this region. The MAPP region is a winter peaking region, so capacity is purchased in the winter and sold in the summer from the region.

Figure 15: **Capacity Outlook**

MAPP - Mid-Continent Area Power Pool

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	100
2001	1,017
2002	402
2003	65
2004	28
2005	0
Total	***1,612***

TOP FIVE BUILDERS IN MAPP

Company	MW*
1) Northern Alternative Energy	950
3) Great River Energy	438
4) Xcel Energy	290
5) Tenaska, Inc.	275
2) NRG Energy	231

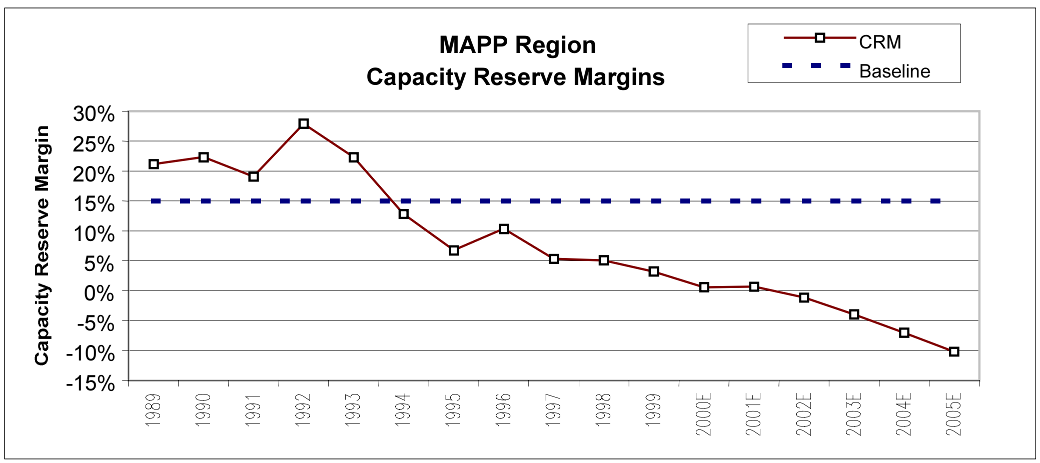
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

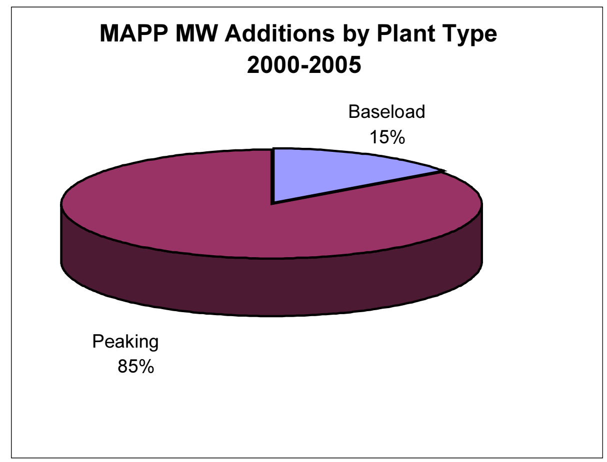
States w/in MAPP

ND, SD, NE, MN, WI, IA

DEREG STATUS

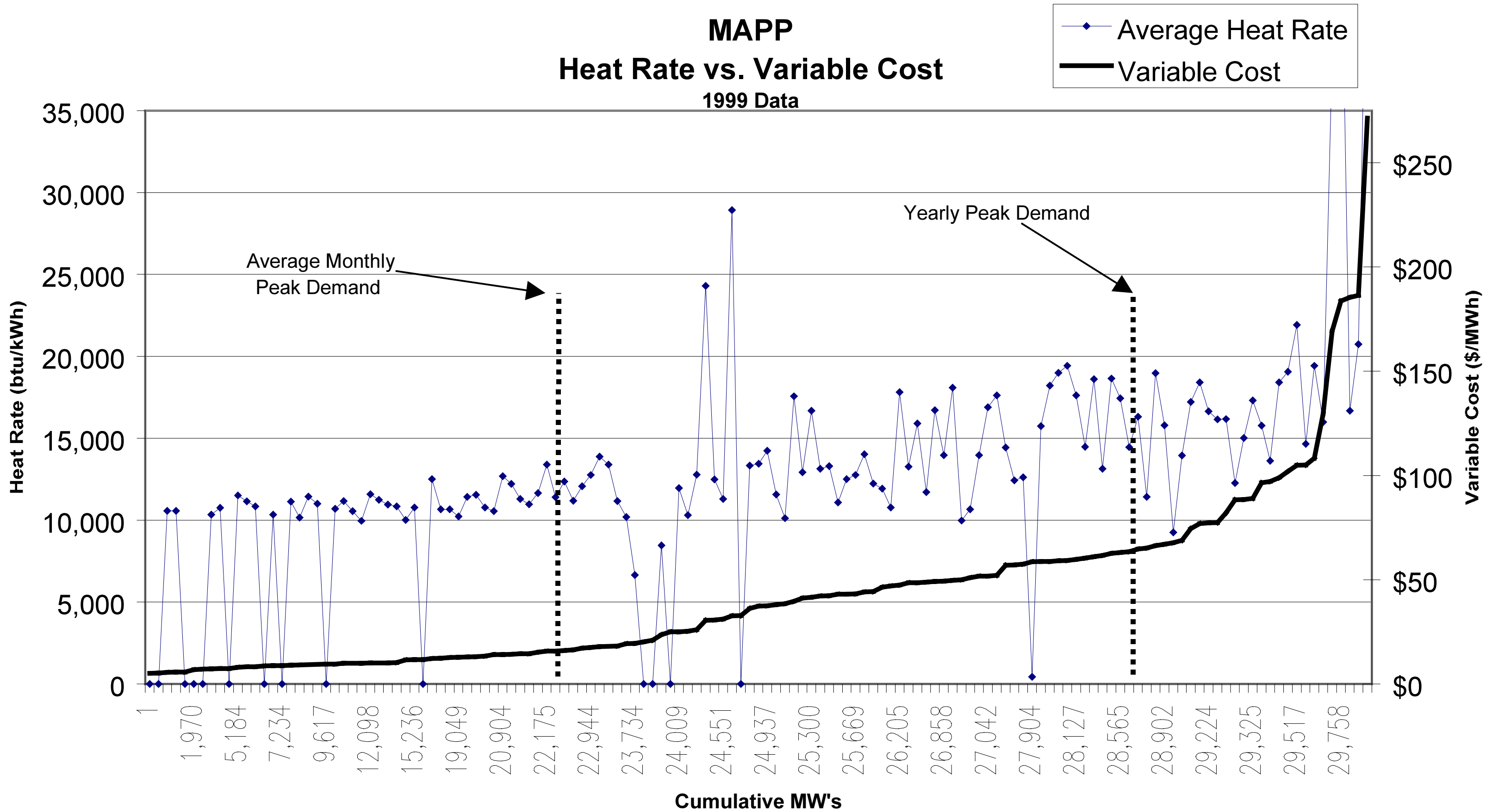
MN, IA, ND, WI - Investigating
NE, SD - No activity





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure16:



Note: Chart excludes 3,393MW of hydro capacity in region.

Note: Chart excludes 2 plants totaling 68MW with an average heat rate of 61,614 btu/kWh and average variable cost of $974/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

New England Power Pool (NEPOOL)

Total 2000 Capacity: 25,522 MW
Total Under Construction: 6,753 MW
Total Announced Additions (2000 – 2005): 13,020 MW

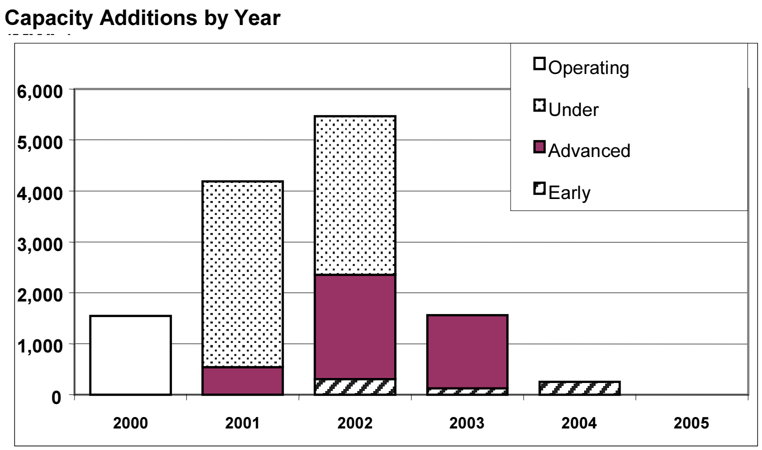
The NEPOOL region is a sub-region of the Northeast Power Coordinating Council (NPCC). The NPCC includes New York, New England and parts of Eastern Canada. The NEPOOL sub-region consists of Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut. Retail choice has begun in five of the seven states in the region, which has been the catalyst behind the large amount of generation additions announced for the region. The region also has high variable costs of existing capacity and rising amounts of natural gas available. Approximately 10,000 MW are slated to come online in the region in 2001 and 2002, with most of these projects either under construction or in advanced development. These capacity additions appear likely to result in a significant jump in the region's reserve margin over the next few years. However, we are not highly concerned with the possibility of overbuild in this market.

The NEPOOL region has a large amount of inefficient and costly plants currently operating in the region. The region has a very steep variable cost curve (see Figure 18) relative to most other U.S. markets, which indicates that as new, more efficient gas-fired plants are added, older, higher heat-rate oil-fired plants will likely be forced off the grid. Thus, we do not believe the significant amount of generation additions in the region will have a radically negative effect on baseload power prices. The capacity additions will reduce the volatility in the wholesale market, however, by 2002.

Despite the capacity additions in NEPOOL in 2001, we expect summer prices to be volatile. Only about 70% of the 2001 capacity additions will be operational by June 1. Our forecast assumes 3% annual demand growth in New England. Therefore, although our calculated capacity reserve margin is 19% for 2001, the summer reserve margin will be closer to 15%. In 2002, with the 5,000 MW of capacity we expect volatility should be reduced, but we do not expect spot prices to collapse below short run marginal costs any time soon.

Figure 17:

NEPOOL - New England Power Pool (subregion of NPCC)



Capacity Year	MW
2000	1,552
2001	4,188
2002	5,469
2003	1,561
2004	250
2005	0
Total	*13,020*

TOP FIVE BUILDERS IN Company	MW*
1) Sithe Energies	2,402
2) International Power	1,960
3) FPL Group	1,950
4) Calpine Corp.	1,597
5) PG&E	1,152

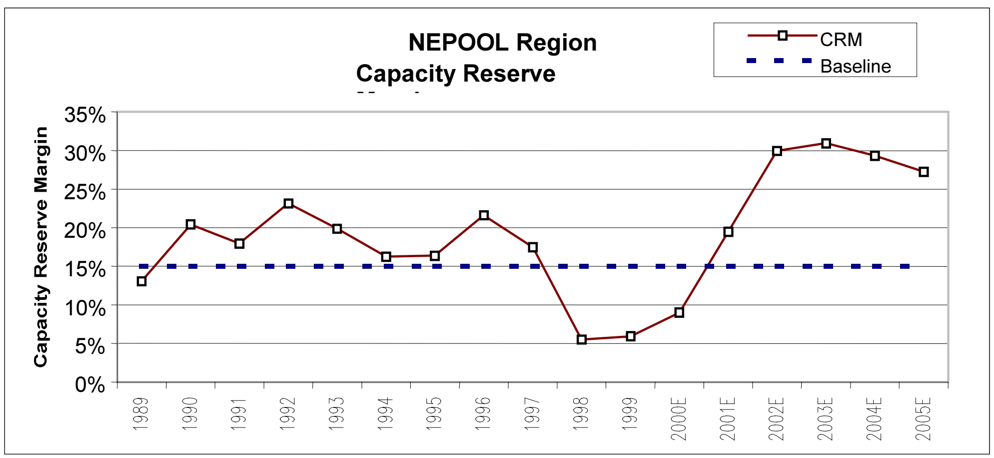
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

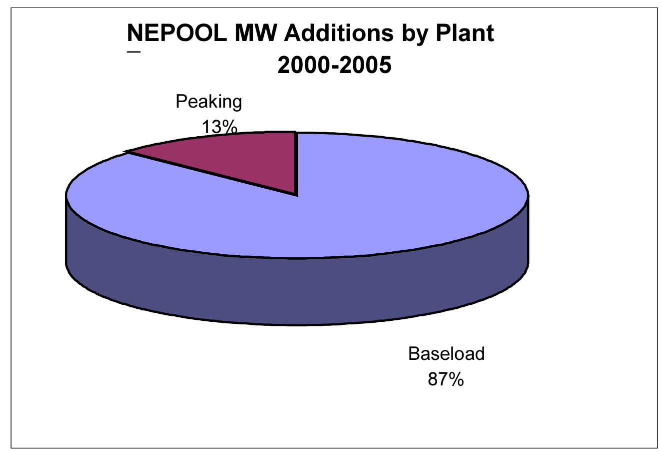
States w/in

CT, MA, NH, ME
VT, RI

DEREG STATUS

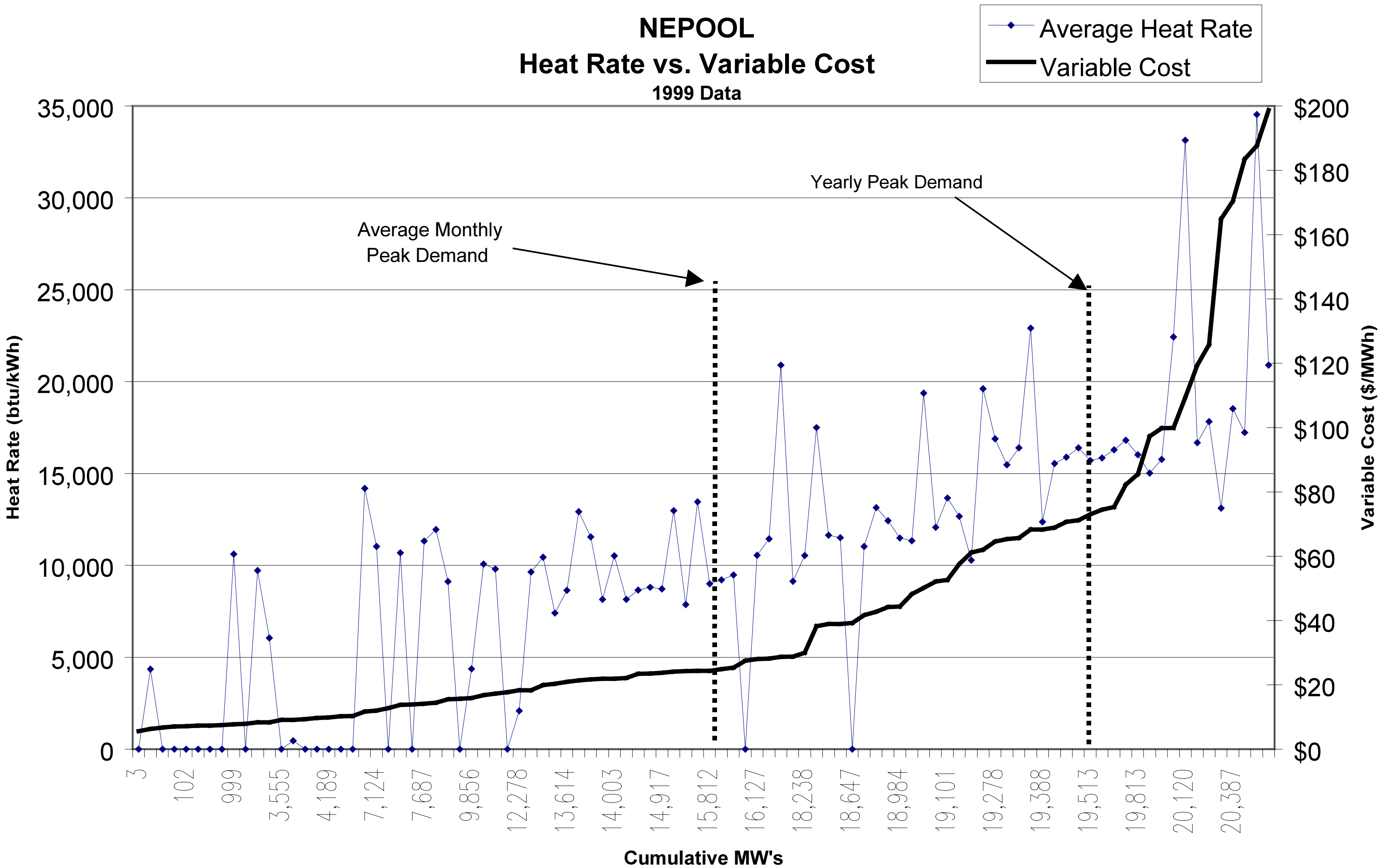
CT, MA, NH, ME, RI - Retail choice
NH - Legis. enacted; retail choice
VT - Investigating





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 18:



Note: Chart excludes 3,499MW of hydro capacity in region.
Note: Chart excludes 3 plants totaling 103MW with an average heat rate of 71,280 btu/kWh and average variable cost of $449/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

New York Power Pool (NYPP)

Total 2000 Capacity: 34,669 MW
Total Under Construction: 284 MW
Total Announced Additions (2000 – 2005): 8,283 MW

The NYPP region, or New York Power Pool, is also a sub-region of NPCC. This region is made up of the state of New York. The region has experienced a steady decline in reserve margins since 1996 and the reserve is expected to be around 10% by the end of 2001. As indicated in Figure 18, very few capacity additions are scheduled for the state over the next two years, and essentially no capacity was added in 2000. This dearth of capacity additions in the state is largely due to residential opposition to new power plants. The New York Independent System Operator (ISO) estimates that New York City is about 300 MW short of the capacity it needs to meet peak summer demand in 2001. It is clear that supplies are very tight. Our reserve estimates for the region assume peak demand growth of 2.5% annually through 2005. However, even with zero demand growth, we would expect this market to remain constrained through 2001 and 2002, with some relief likely coming in 2003. About 400 MW of capacity will be added in 2001, most of which is temporary barge-mounted generation. The supply situation will be tight during the summer of 2001.

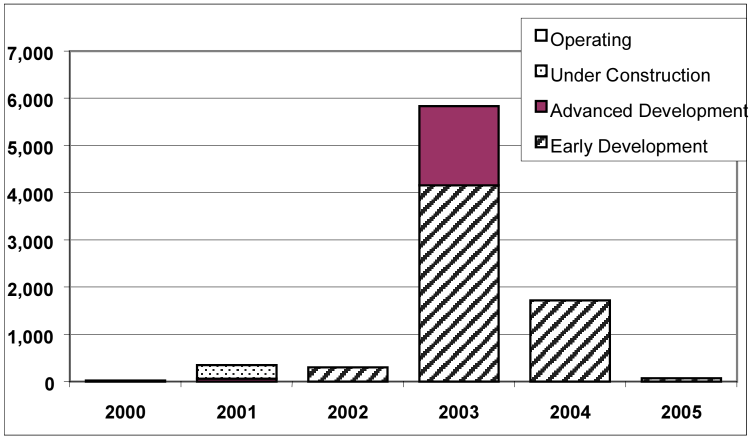
The New York Power Authority (NYPA) is adding about 400 MW of capacity with generation barges around New York City — approximately eleven 44-MW barges will be added. Several new plants are pending permitting and should be on line in 2003 or 2004. Most of the new capacity is baseload and natural gas fired. We expect additions in 2003 to approach 6,000 MW, which would result in a capacity reserve margin of about 18%.

Figure 20 shows the variable cost curve for generation in the New York market. The region has some efficient generation, which keeps the variable cost of power generation relatively flat through recent peak demand. This is likely to encourage more intermediate and peaking capacity to be added to the generation mix. The 8,000 MW expected to be added from 2001 to 2005 is over 85% baseload. This is driven by the absolute shortage of generating capacity in New York.

Figure 19: **Capacity Outlook**

NYPP - New York Power Pool (subregion of NPCC)

Capacity Additions by Year (MW's)



Capacity Additions	
Year	MW
2000	18
2001	346
2002	300
2003	5,833
2004	1,716
2005	72
Total	*8,283*

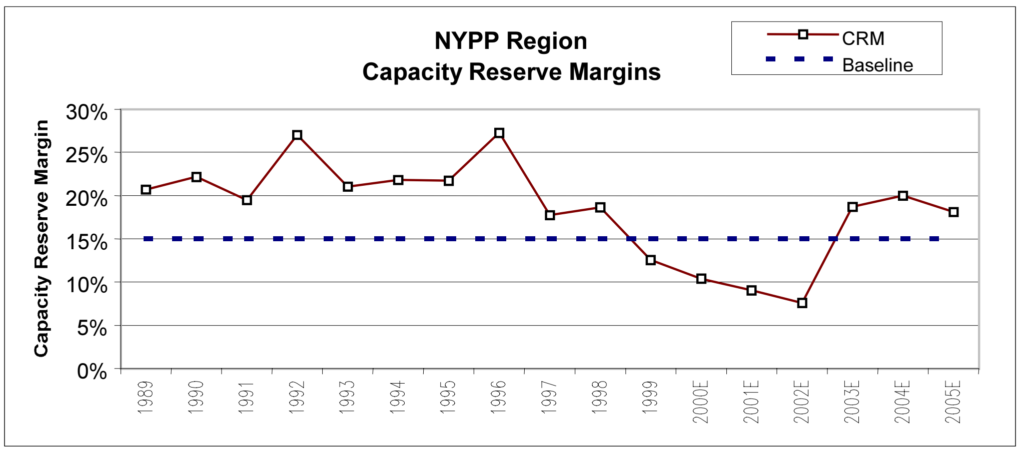
TOP FIVE BUILDERS IN NYPP	
Company	MW*
1) International Power plc	1,640
2) Sithe Energies	1,577
3) PG&E Corp.	1,092
4) ABB Ventures	1,075
5) NYPA	952

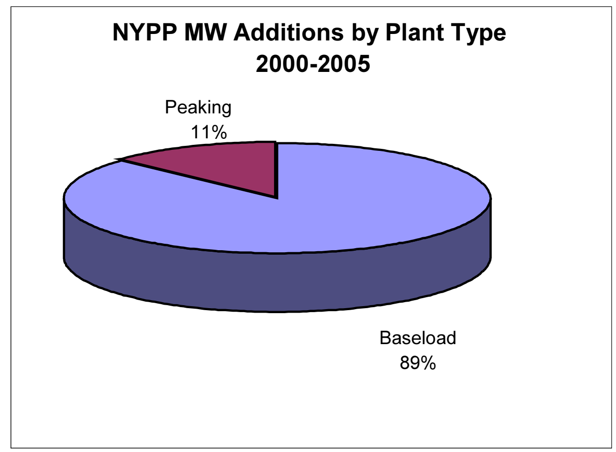
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NYPP
New York

DEREG STATUS

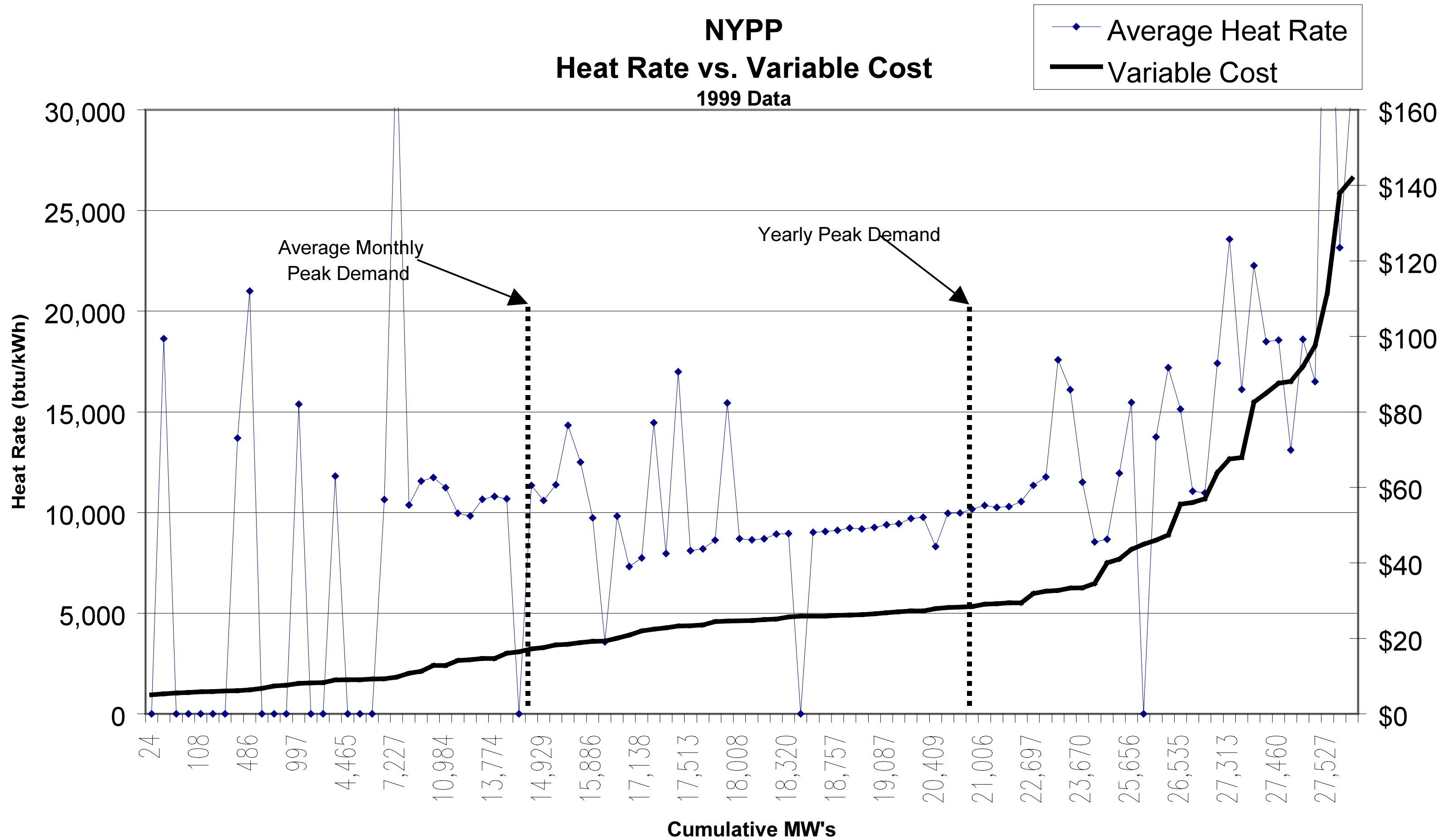
NY - Restructuring order issued, but not enacted.





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 20:



Note: Chart excludes 9,364MW of hydro capacity in region.
Note: Chart excludes 3 plants totaling 87MW with an average heat rate of 79,701 btu/kWh and average variable cost of $648/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Southeastern Electric Reliability Council (SERC)

Total 2000 Capacity: 159,078 MW
Total Under Construction: 21,768 MW
Total Announced Additions (2000 – 2005): 51,937 MW

The Southeastern Electric Reliability Council (SERC) includes the states of Georgia, North Carolina, South Carolina, Alabama, Mississippi, and parts of Louisiana, Virginia, and Arkansas. The Southeastern region is the largest region, from a capacity standpoint, in the country. The SERC region represents about 21% of total U.S. generating capacity. Due to its size, it is divided between four different sub-regions: Entergy, Southern, TVA, and VACAR (Virginia and Carolinas). The entire region appears short capacity through 2005. The capacity reserve margin barely gets to 13% in 2003 before demand growth begins to outpace supply growth and the reserve margin heads lower. We expect about 45 GW of capacity to be added in the period of 2001 to 2005. The biggest chunk of this capacity should be added in 2002, when about 20 GW of capacity will be added. About one-third of the capacity is expected to be peaking capacity, while the other two-thirds will be baseload capacity. Through a review of the different sub-regions in SERC, many different stories can be told. However, the combined capacity reserve margin in this region probably has the most meaning. This suggests that the region is somewhat short capacity over the forecast horizon.

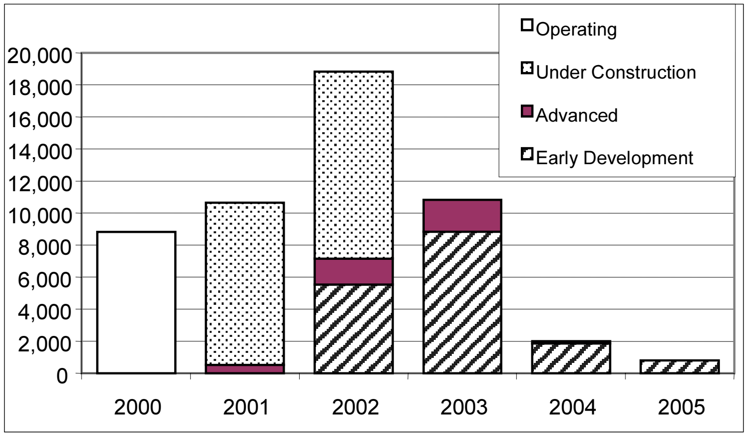
Figure 22 shows the variable cost curve for all generation in the region. As the peak demand grows (in our forecast at 4%) in SERC, we expect natural gas fired capacity to easily be developed as a matter of the steepness of the variable cost curve. Although the proposed capacity additions in SERC suggest a high level of interest in the region, we expect additional development to add more capacity than we are forecasting in 2004 and 2005.

A sub-regional analysis follows for each of the four sub-regions. Although the Entergy sub-region looks to have excess capacity in 2003 with a 26% reserve margin, every other sub-region has a less than adequate reserve margin over the forecast horizon.

Figure 21: **Capacity Outlook**

SERC - Southeastern Electric Reliability Council

Capacity Additions by Year



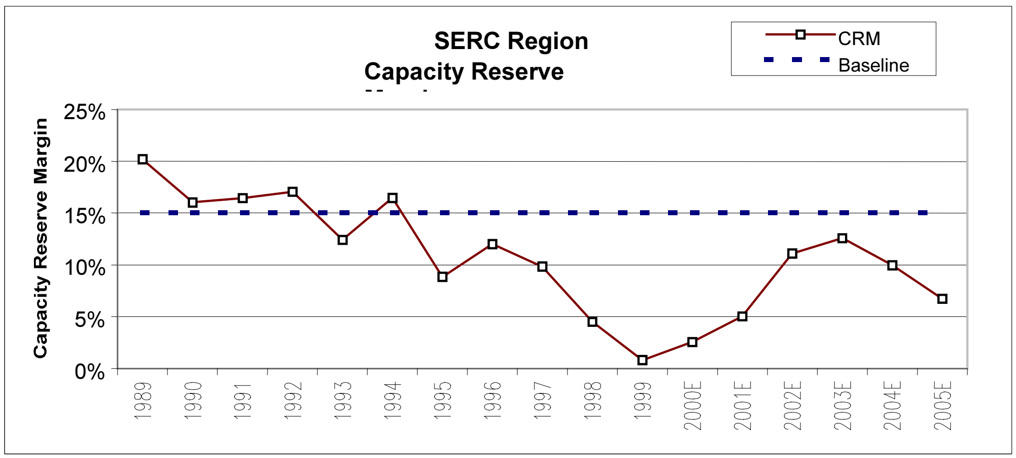
Capacity Additions	
Year	**MW**
2000	8,824
2001	10,653
2002	18,819
2003	10,842
2004	2,000
2005	800
Total	***51,937***

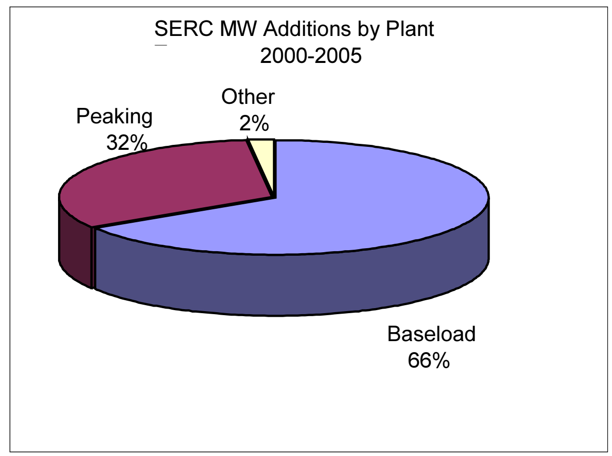
TOP FIVE BUILDERS IN	
Company	MW*
1) Calpine Corp.	8,306
2) Southern	6,260
3) Duke Energy	5,590
4) Tenaska Inc.	5,274
5) Progress Energy	3,729

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SERC
LA, AR, MO, TX, AL, GA, KY, TN, VA NC, SC

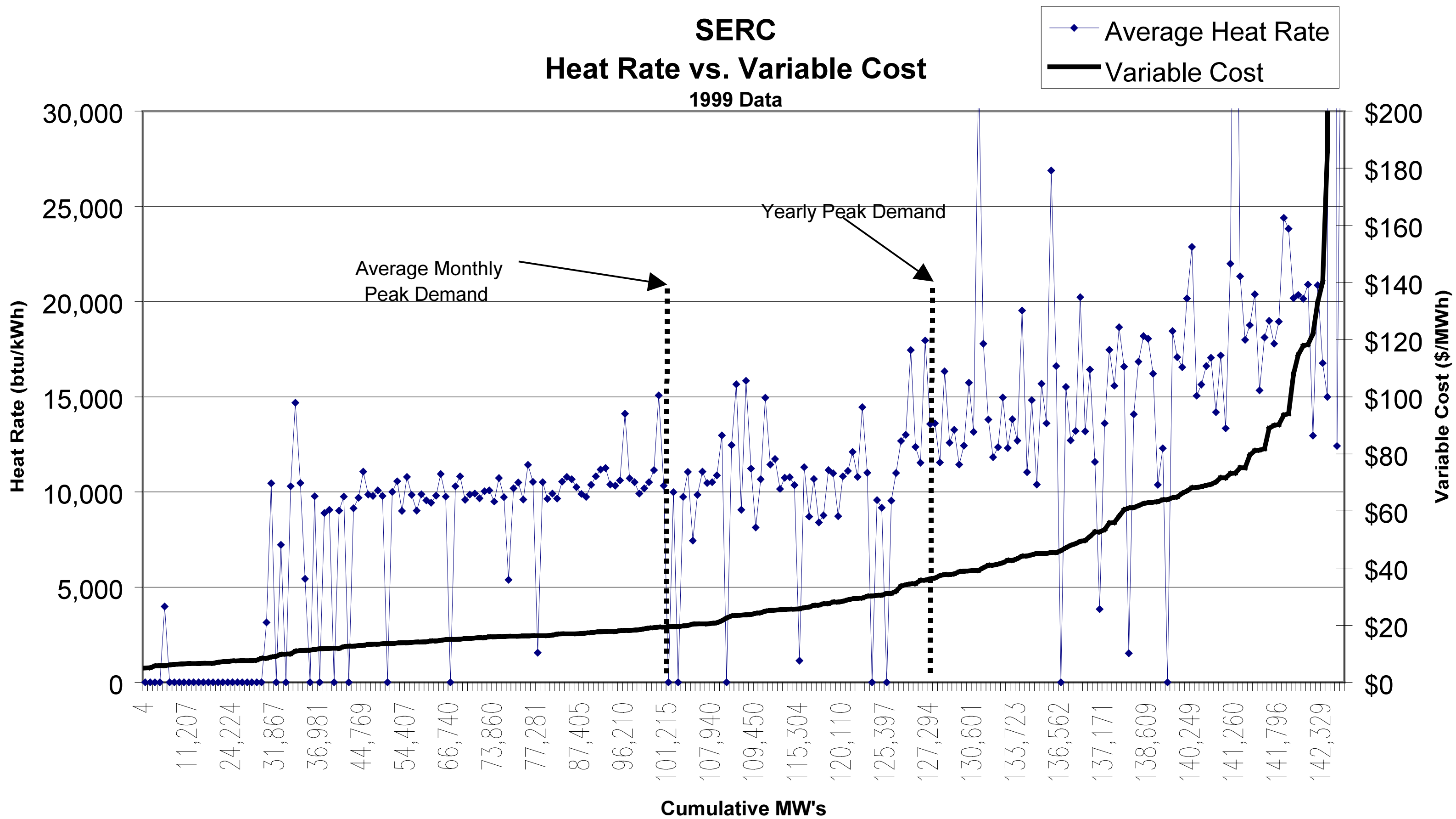
DEREG STATUS
TX, AR, VA - Legis. enacted; retail choice
SC - Legislation
LA, MS, MO, KY, NC -
AL, GA, TN - No





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 22:



Note: Chart excludes 21,460MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Entergy Sub-Region of SERC

Total 2000 Capacity: 27,352 MW
Total Under Construction: 10,366 MW
Total Announced Additions (2000 – 2005): 17,211 MW

The Entergy region is a sub-region of SERC, or the Southeastern Electric Reliability Council. The region is comprised of Louisiana, most of Arkansas, and parts of Mississippi, Missouri and Texas. As in much of the southeastern U.S., capacity reserves are currently tight in the Entergy region. Over 10,000 MW of new generation are presently under construction in the region, yet only about 2,500 MW are scheduled to come on line by the end of 2001. Thus, we expect CRM's to remain low in Entergy throughout 2001, with about a 5% reserve margin projected by the end of this year. Approximately 9,000 MW of capacity are projected to be added to the grid in 2002, which should boost reserve margins sharply. Our reserve estimates for the Entergy region assume peak demand growth of 4.0% annually through 2005. We expect prices to remain firm in the region throughout 2001. However, the large amount of additions scheduled for 2002 could put downward pressure on power prices in that year. However, every other sub-region in SERC is short capacity over the forecast horizon, which limits our concern about the capacity impacts on wholesale prices.

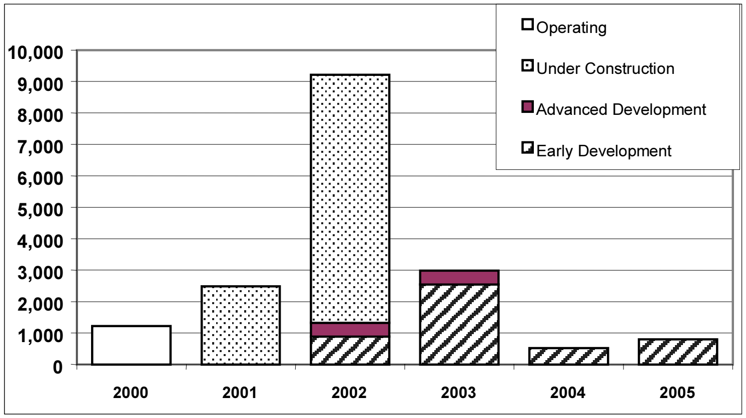
The variable cost curve for the Entergy sub-region is shown in Figure 24. Most of the generating capacity additions in the region are expected to be baseload. This will keep the variable cost curve relatively flat over the forecast horizon.

A detailed regional breakdown of supply, demand and capacity reserve margins from 1989 to 2005 is shown in Appendix A on pages 74 and 75.

Figure 23: **Capacity Outlook**

ENTR - Entergy (subregion of SERC)

Capacity Additions by Year (MW's)



Capacity Additions

Year	MW
2000	1,221
2001	2,479
2002	9,212
2003	2,979
2004	520
2005	800
Total	***17,211***

TOP FIVE BUILDERS IN ENTERGY

Company	MW*
1) TECO Energy, Inc.	3,113
2) Calpine Corp.	2,126
4) Ls Power	2,100
5) Cogentrix Energy	2,035
3) Panda Energy	1,873

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

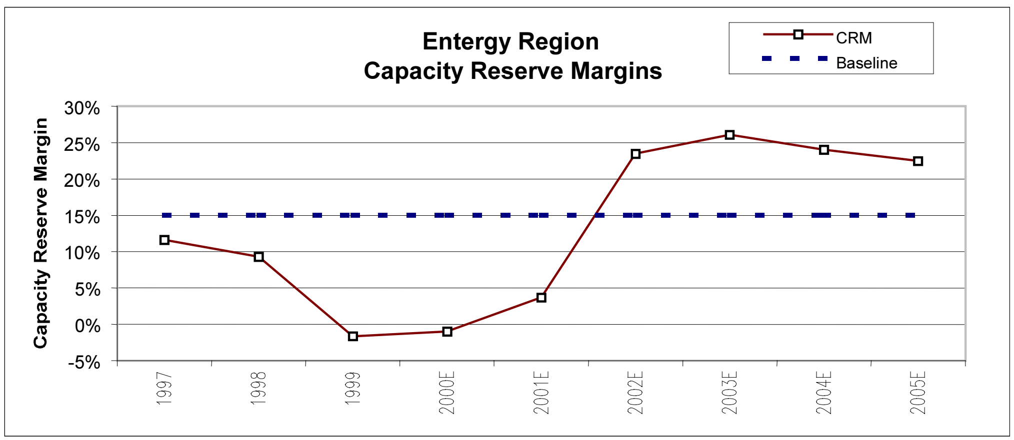
States w/in ENTR

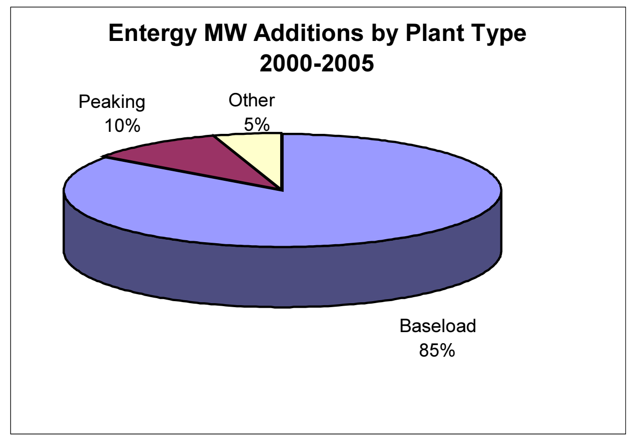
LA, AR, MO, TX, MS

DEREG STATUS

TX, AR - Legis. enacted; retail choice pending

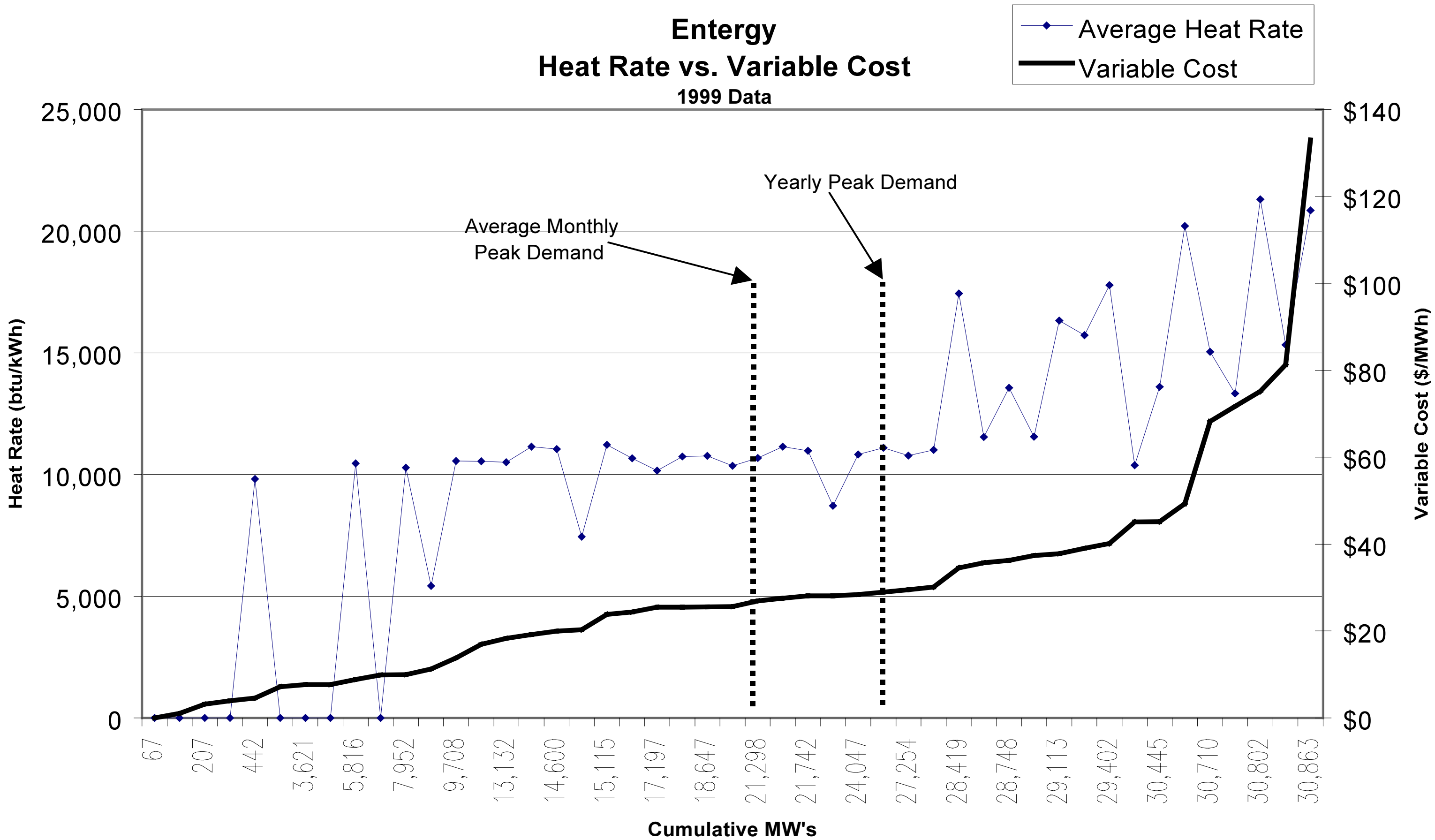
LA, MS, MO - Investigating





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 24:



Note: Chart includes all capacity in the region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Southern Sub-Region of SERC

Total 2000 Capacity: 44,918 MW
Total Under Construction: 5,956 MW
Total Announced Additions (2000 – 2005): 18,387 MW

The Southern region is a sub-region of SERC and is comprised of Alabama and Georgia. Approximately 3,600 MW of generating capacity were added in the region in 2000. However, due to strong economic growth, reserve margins are still very low in the Southern region. We expect to see some recovery of the reserve margin by the end of 2001, to about 10%, as nearly 5,000 MW of additions are projected to come on line. By the end of 2003, the reserve margin is projected to move towards the 15% baseline. Our capacity reserve margin estimates for the region are based on 4.0% annual growth in electricity demand. Neither Alabama nor Georgia is currently pursuing a deregulation strategy.

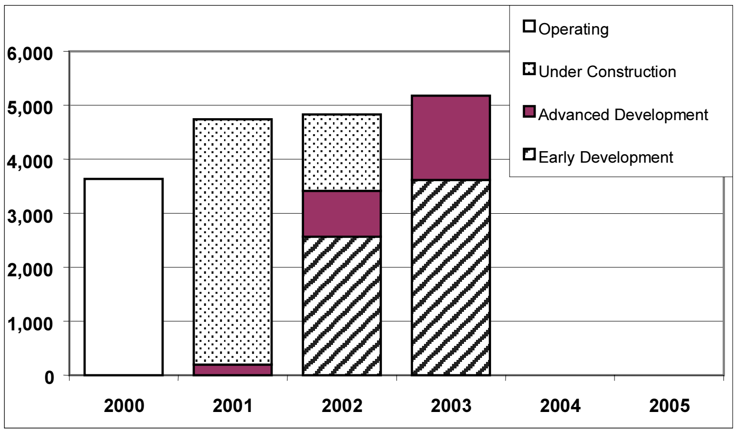
As a result of the regulated nature of this region, Southern Company is the largest developer of new capacity. With Southern's spin-off of its unregulated generation business in 2001, we expect the company's level of activity in regulated generation development in the Southeast region to remain high.

As the variable cost curve of the region is steeper than we expected, we are forecasting mostly baseload additions to the region. About 61% of the proposed capacity is baseload.

Figure 25:

SOU - Southern (subregion of SERC)

Capacity Additions by Year (MW's)



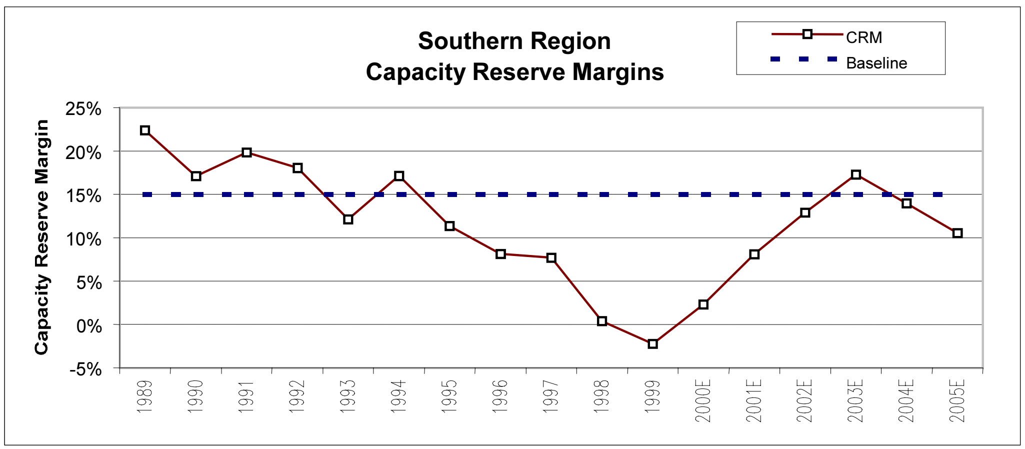
Capacity Additions	
Year	**MW**
2000	3,635
2001	4,740
2002	4,832
2003	5,181
2004	0
2005	0
Total	***18,387***

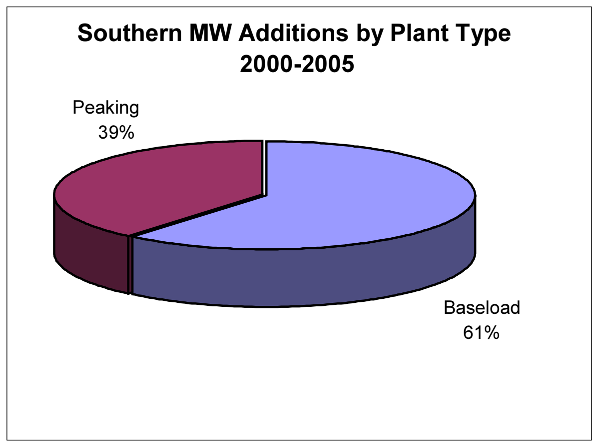
TOP FIVE BUILDERS IN SOUTHERN	
Company	MW*
1) Southern Company	6,033
2) Duke Energy	3,720
3) Tenaska, Inc.	2,674
4) Calpine Corp.	1,850
5) Oglethorpe Power Corp.	1,640

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SOU
AL, GA

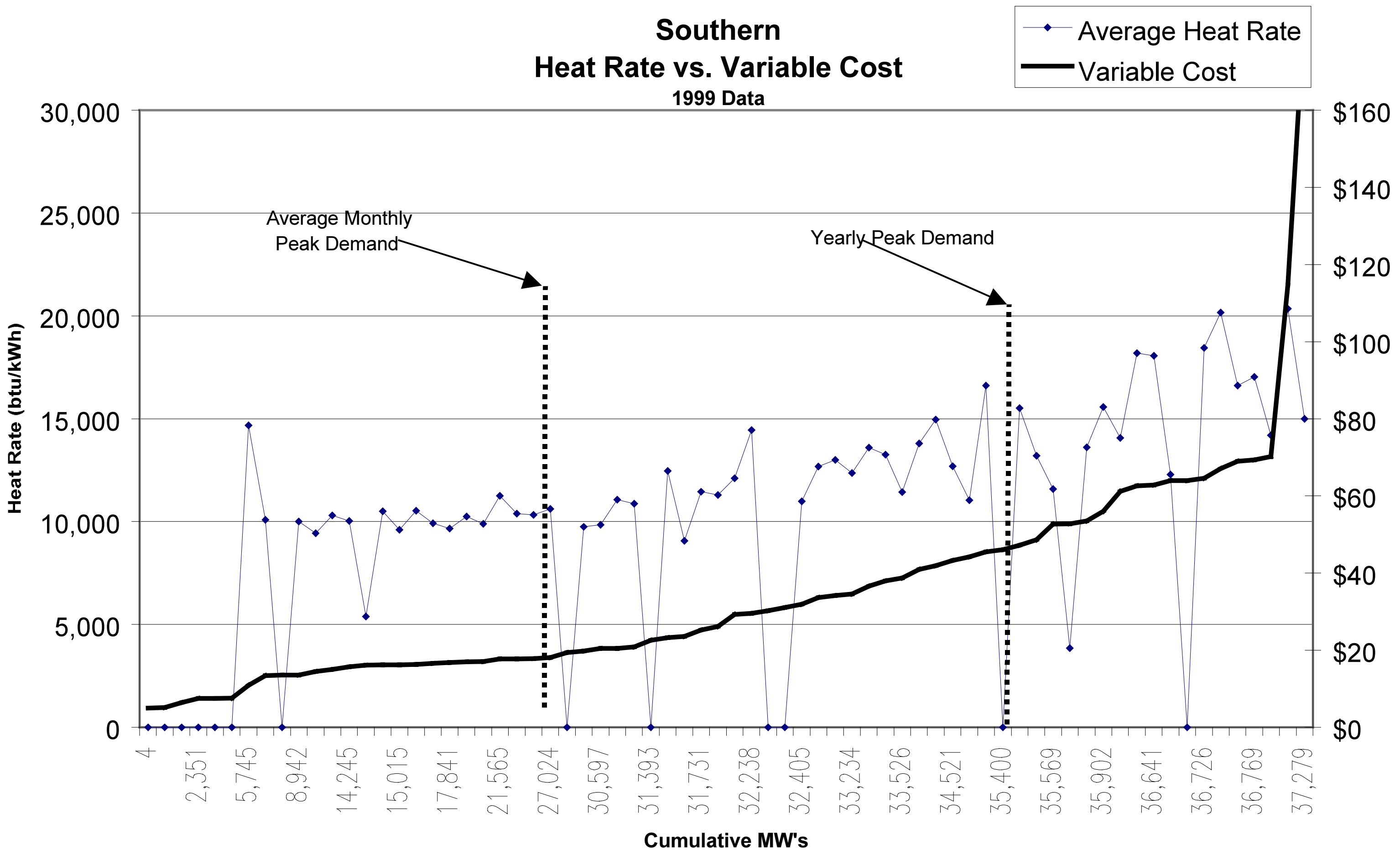
DEREG STATUS
AL, GA - No activity





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 26:



Note: Chart excludes 6,761MW of hydro capacity in region.

Note: Chart excludes 2 plants totaling 13MW with an average heat rate of 139,552 btu/kWh and average variable cost of $1,165/MWh.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Tennessee Valley Authority Sub-Region of SERC

Total 2000 Capacity: 30,910 MW
Total Under Construction: 3,020 MW
Total Announced Additions (2000 – 2005): 6,946 MW

The TVA region, or Tennessee Valley Authority, is comprised of the state of Tennessee, as well as parts of Kentucky, Mississippi, Alabama and Georgia. This region is a sub-region of SERC. Reserve margins in the region have steadily declined since 1989 as few capacity additions have been made in the period. However, unlike most other regions, current projections do not show a significant recovery of reserve margins in the TVA region over the next few years. About 3,500 MW are scheduled to come on line in 2001 and 2002, which would bring reserve margins up to the 10% range by the end of 2002. Our capacity reserve margin estimates for the region are based on 4.0% annual growth in electricity demand. The state of Tennessee, which makes up the majority of the region, has made no steps toward deregulation. This is a result of the federal government ownership of the Tennessee Valley Authority. This may be a factor contributing to the lack of generation projects announced in the region. TVA is the largest developer in this region.

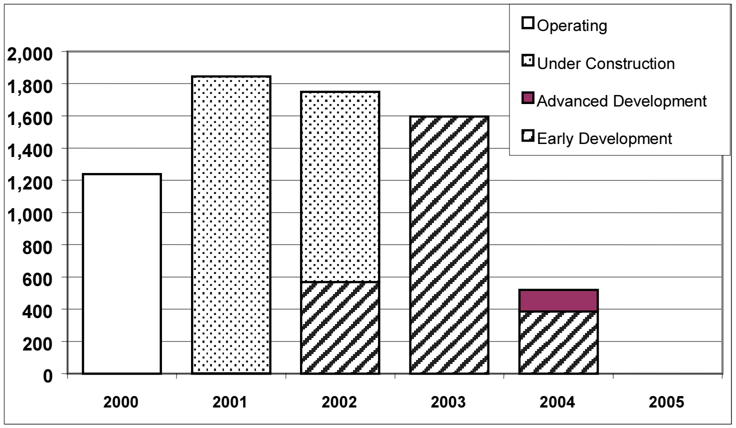
Considering the variable cost curve of the region, we can quantitatively explain why little capacity is being proposed in the region. The variable cost of power is below $20 per megawatt hour for all but the peak annual period in the region. This is the result of hydro and nuclear capacity in the region, as well as the federal ownership of the plants.

Although the region appears short generating capacity, the SERC region as a whole has growing capacity over the next four years. Therefore, we are not particularly concerned about the shortage.

Figure 27: **Capacity Outlook**

TVA - Tennessee Valley Authority (subregion of SERC)

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	1,238
2001	1,843
2002	1,750
2003	1,596
2004	520
2005	0
Total	***6,946***

TOP FIVE BUILDERS IN TVA	
Company	MW*
1) Tennessee Valley Authority	2,942
2) Calpine Corp.	2,930
3) Panda Energy	1,300
4) Cogentrix	800
5) PG&E	360

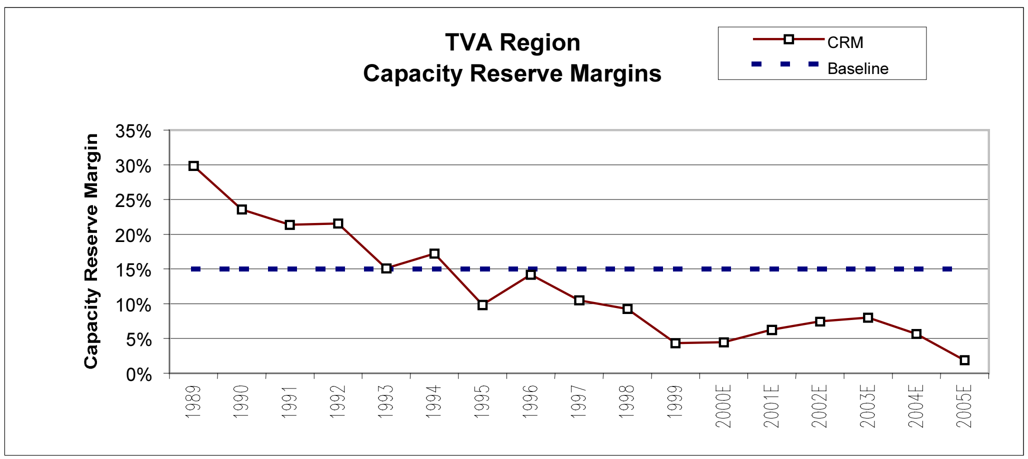
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

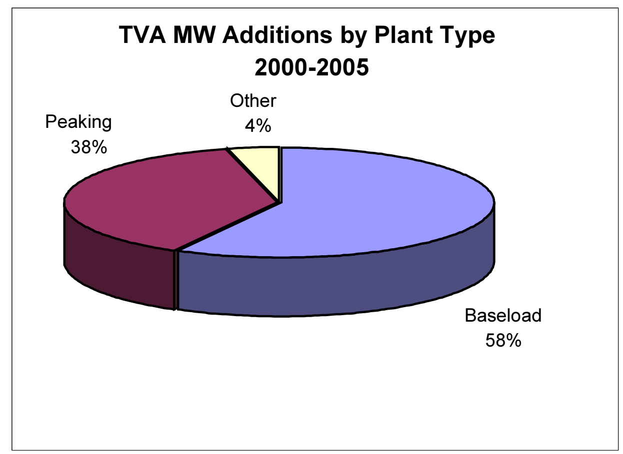
States w/in TVA

KY, TN, MS, AL

DEREG STATUS

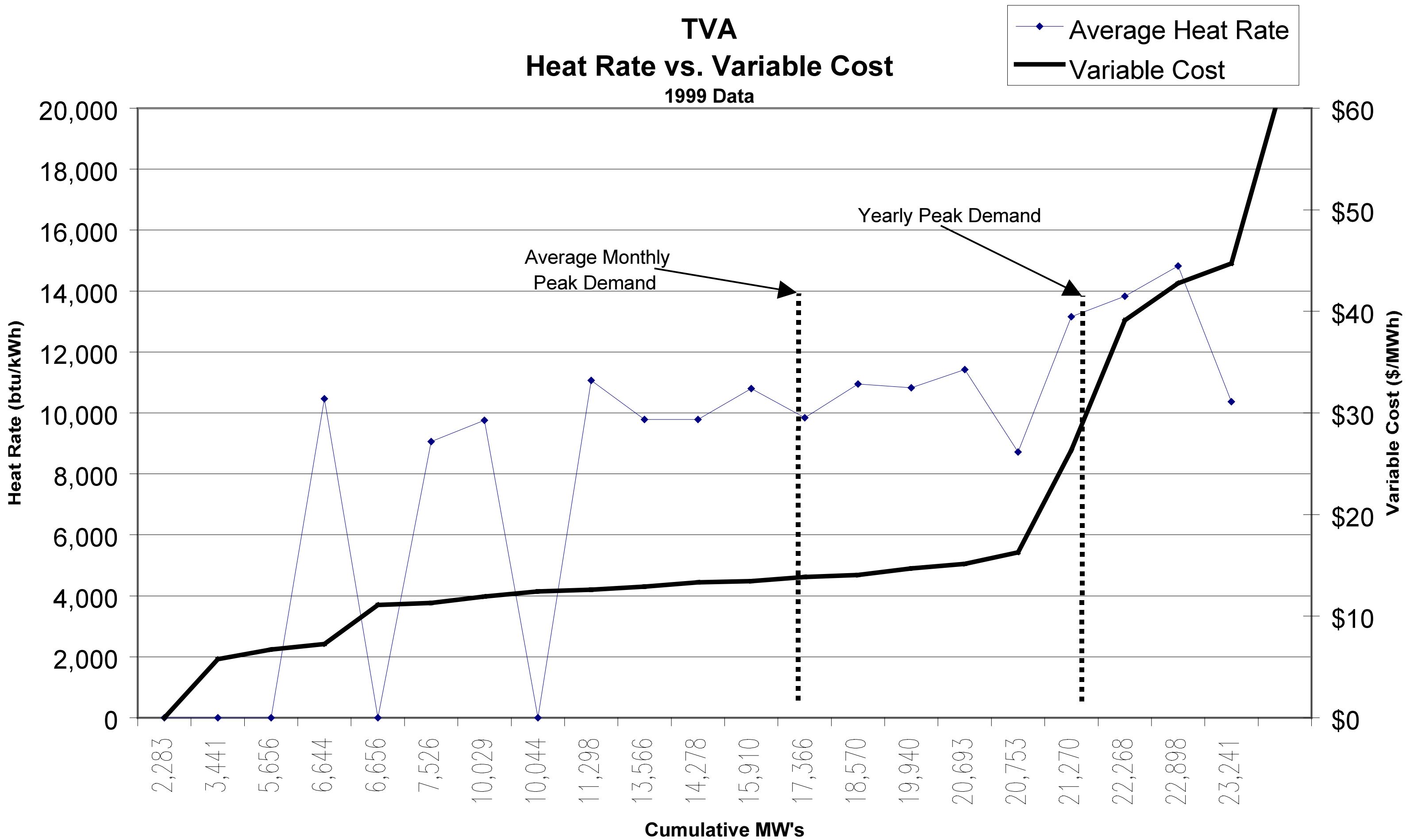
MS, KY - Investigating
TN, AL - No activity





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 28:



Note: Chart excludes 6,550MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Virginia-Carolinas (VACAR) Sub-Region of SERC

Total 2000 Capacity: 55,898 MW
Total Under Construction: 2,426 MW
Total Announced Additions (2000 – 2005): 9,394 MW

The VACAR region, a sub-region of SERC, consists of North Carolina, South Carolina and most of Virginia. Reserve margins in the region have declined sharply over the past few years and current projections show continued erosion of reserves through 2005. This has been a relatively high-growth area in recent years, and continued strong growth is expected over the next few years. However, only about 1,500 MW of capacity additions are scheduled for 2001, which would leave the reserve margin below 5%. Another 3,000 MW are slated for 2002,but half of this capacity is in the early development phase. A total of about 2,000 MW are projected in the 2003 to 2005 period. Based on our estimates of demand growth in the region, these capacity additions will likely not keep pace with electricity demand. Our reserve estimates for the region assume peak demand growth of 4.0% annually through 2005. One possible reason for the expected shortfall in the region may be the fact that North Carolina has not made significant progress toward a deregulation strategy, which has likely discouraged generation additions in the state. We expect eventual deregulation in the region.

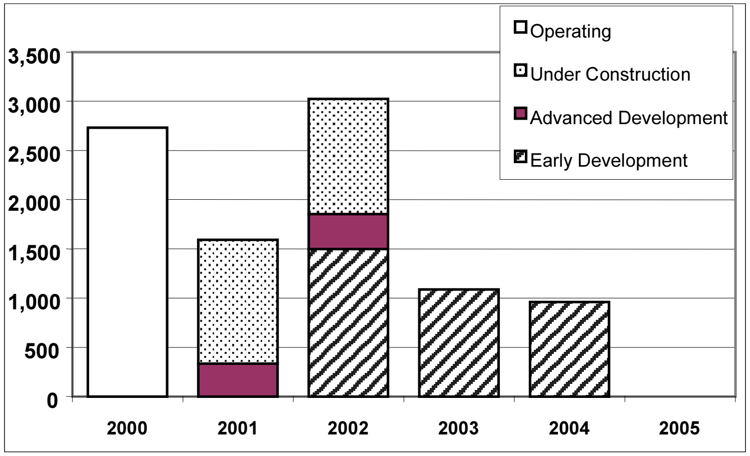
In consideration of the capacity position of the region, it is important to recognize that the sub-region is bordered by the Southern sub-region of SERC to the south and the MAAC region to the north. Both of these regions have adequate reserve margins and transmission capacity allows the movement of power between these regions.

The region's variable cost curve is low through most peak periods. However, we expect additional capacity to be developed in the region as a result of the high heat rate plants that are evident above peak demand.

Figure 29: **Capacity Outlook**

VACAR - Virginia-Carolinas (subregion of SERC)

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	2,730
2001	1,591
2002	3,025
2003	1,088
2004	960
2005	0
Total	***9,394***

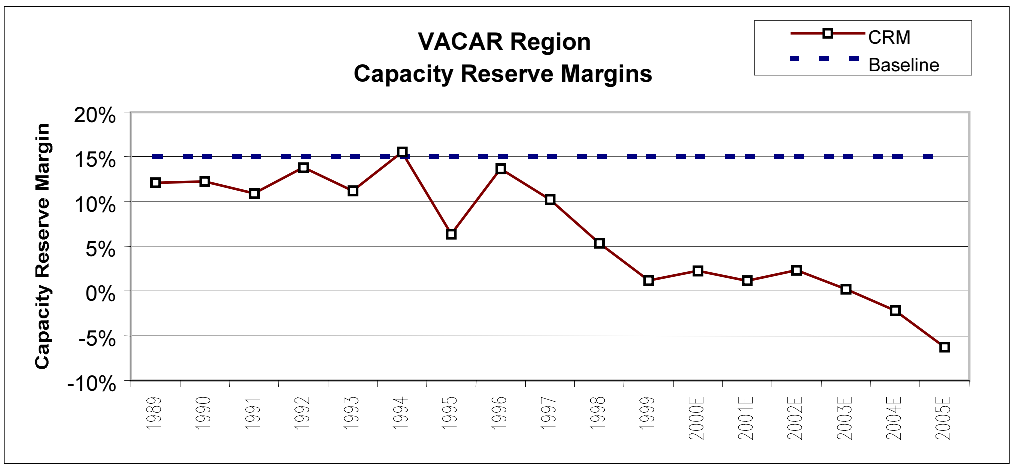
TOP FIVE BUILDERS IN VACAR	
Company	MW*
1) Progress Energy, Inc.	3,044
2) Calpine Corp.	1,400
3) Group Suez Lyonnaise	1,375
4) South Carolina PSC	1,370
5) Dominion Resources	1,241

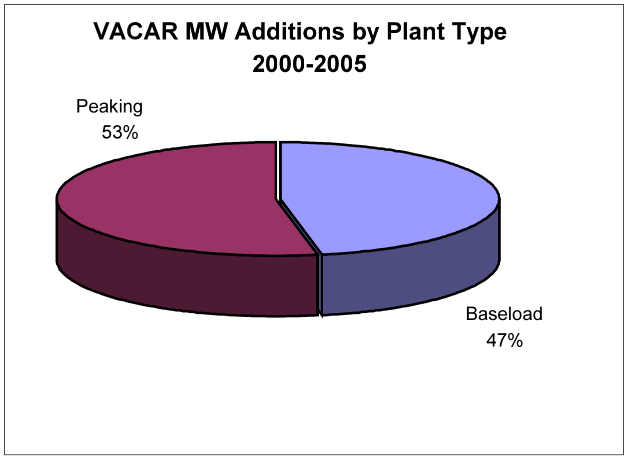
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in VACAR
VA, NC, SC

DEREG STATUS

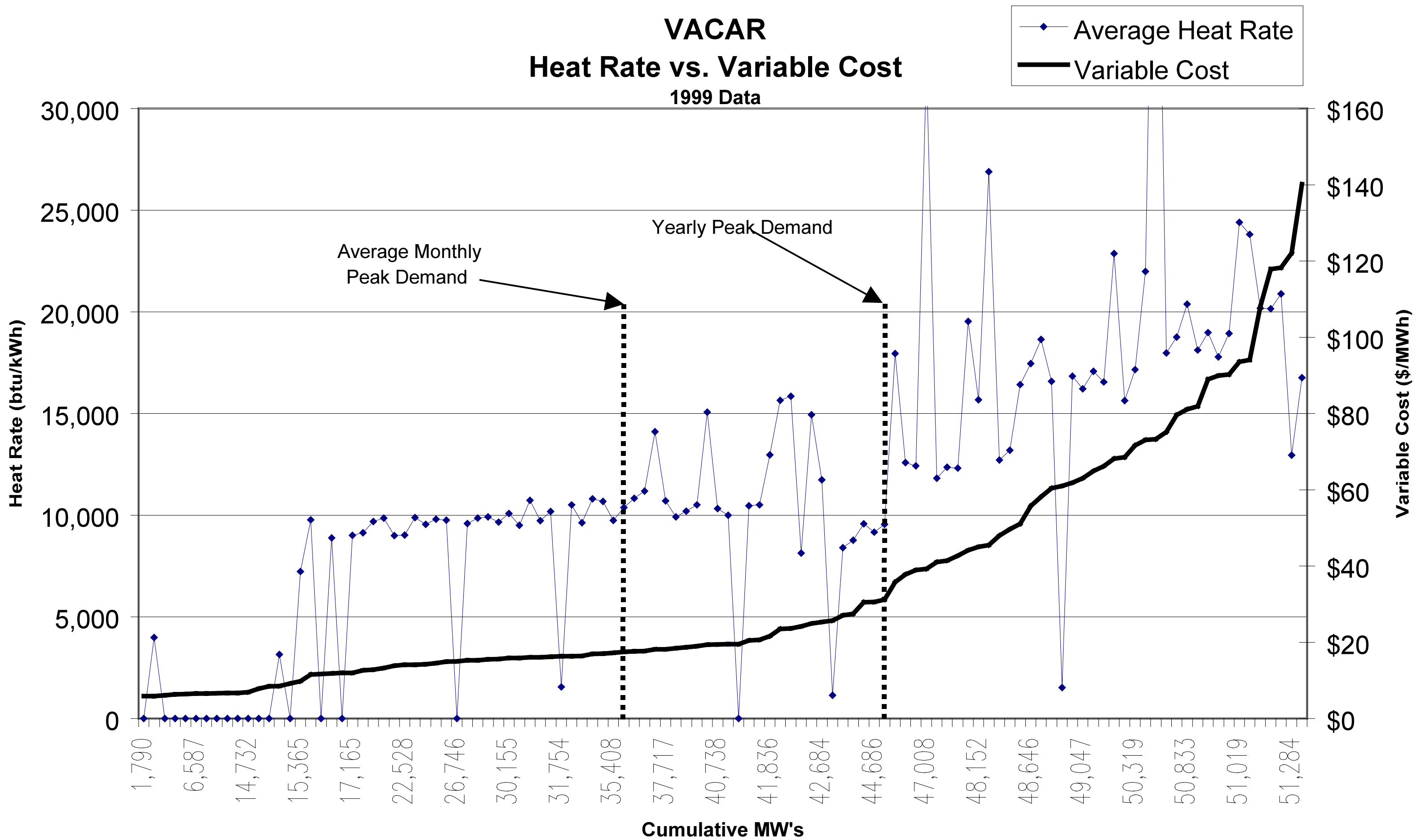
VA - Legis. enacted; retail choice pending
SC - Legislation pending
NC - Investigating





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 30:



Note: Chart excludes 7,706MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Southwest Power Pool (SPP)

Total 2000 Capacity: 44,800 MW
Total Under Construction: 6,096 MW
Total Announced Additions (2000 – 2005): 12,813 MW

This NERC region is comprised of Oklahoma, Kansas, and parts of Missouri, Arkansas, Texas and New Mexico. Peak reserve margins in this region have declined from about 35% in 1989 to 10% in 2000. Relative to most other U.S. regions, reserve margins have held up well in SPP. This was aided by the addition of over 2,000 MW of new generation in 2000. Another 3,000 MW are under construction for 2001 operation. Margins are projected to increase to nearly 20% in 2003, following the addition of about 3,500 MW in that year. Our reserve estimates for the SPP region assume peak demand growth of 3.5% annually through 2005.

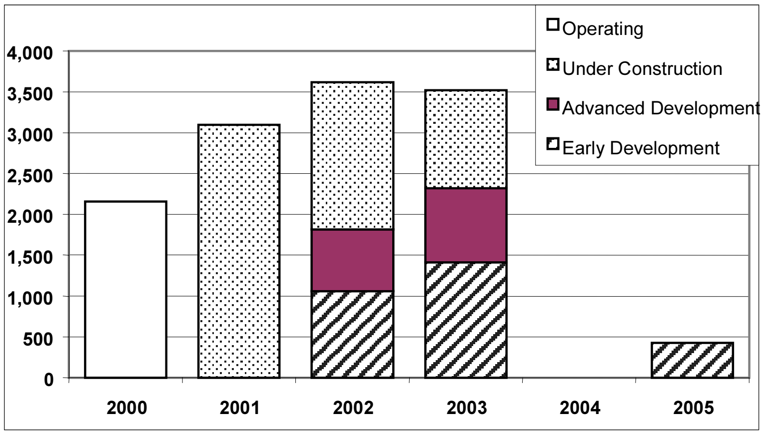
We expect about 11,000 megawatts of new capacity to be added between 2001 and 2005. This coupled with the 3.5% demand growth leads to a 14% capacity reserve margin in 2005, down from 20% in 2003. Most of the supply additions in this region are natural gas fired and baseload capacity. The largest publicly traded developer in the region in Calpine.

The variable cost curve for the region does not provide a very favorable backdrop for new generation additions. At annual peak load, variable costs for power are below $40 per megawatt hour. Further, the slope of the curve does not steepen materially thereafter until peak rises another 5,000 MW. The variable cost curve for SPP is shown in Figure 32.

Figure 31: **Capacity Outlook**

SPP - Southwest Power Pool

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	2,157
2001	3,096
2002	3,616
2003	3,519
2004	0
2005	425
Total	***12,813***

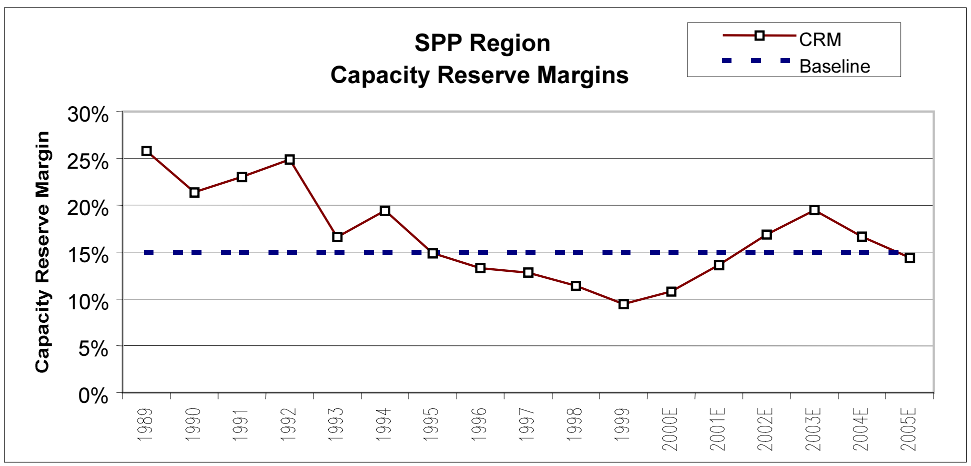
TOP FIVE BUILDERS IN SPP	
Company	MW*
1) Energetix	1,925
2) Calpine Corp.	1,673
3) InterGen N.A.	1,200
3) American Electric Power	1,200
3) Smith Cogeneration	1,200

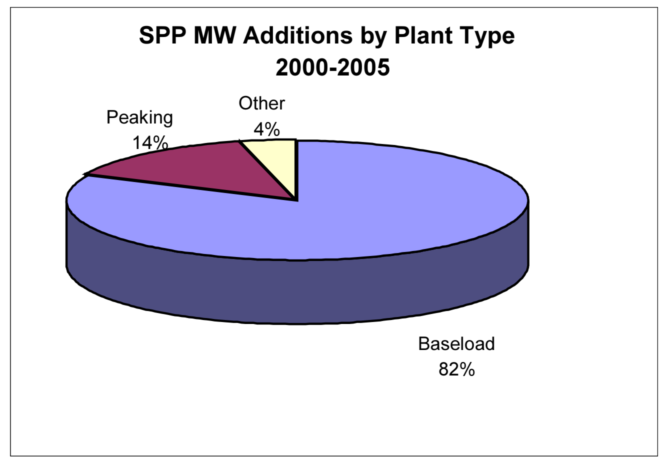
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in SPP
KS, OK, MO, AR, TX NM

DEREG STATUS

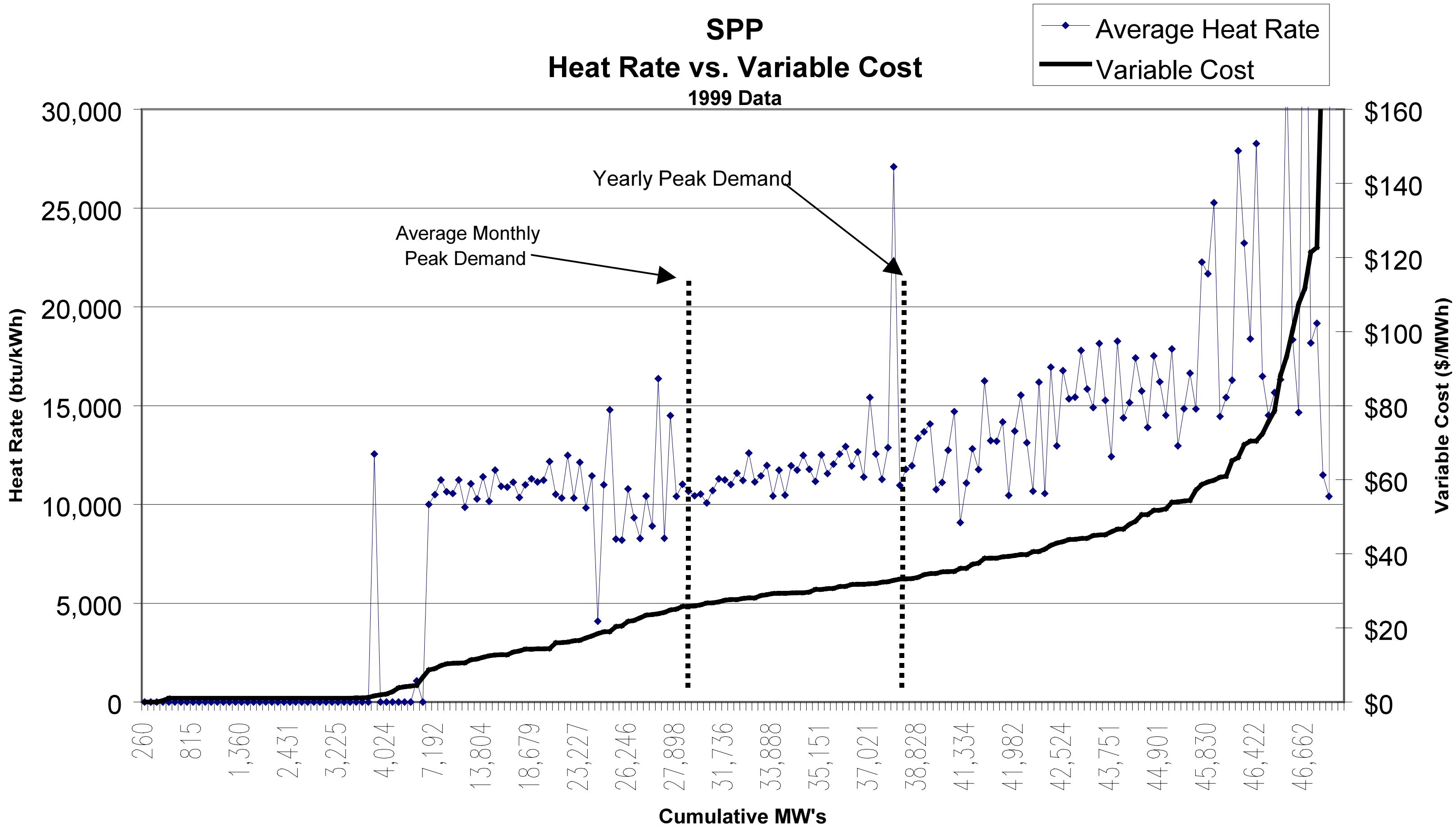
TX, NM, AR - Legis. enacted; Retail choice pending
OK - Legislation pending
MO - Investigating
KS - No activity





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 32:



Note: Chart includes all capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Western Systems Coordinating Council (WSCC)

Total 2000 Capacity: 136,976 MW
Total Under Construction: 9,729 MW
Total Announced Additions (2000 – 2005): 33,406 MW

The Western Systems Coordinating Council (WSCC) includes the states of Washington, Oregon, California, Arizona, Nevada, Utah, Idaho, Colorado, Wyoming, and parts of Montana and New Mexico. Behind the Southeast, the WSCC is the second largest region in the United States. About 1,000 megawatts of capacity were added in 2000 and we expect about 6,000 to be added in 2001. From 2001 to 2005, we expect about 30,000 megawatts of capacity to be added. However, a lot of this capacity is in early development, so it is far from assured to become operational. Further, the reserve margin is deceiving at 21% in 2003, since over 40% of the region's capacity is hydroelectric.

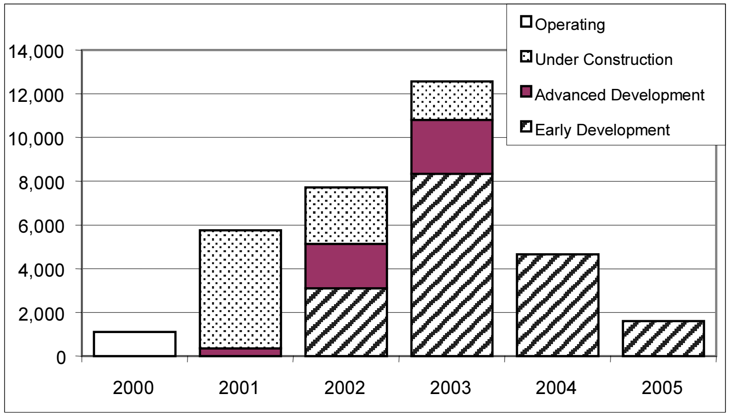
The WSCC is divided into four sub-regions, as a result of its size. These regions are AZ-NM-NV (Arizona, New Mexico, Nevada), California, Northwest Power Authority, and the Rocky Mountain Power Authority. There is a lot of hydroelectric capacity in the northwest, which skews some of the capacity numbers in these regions. Since hydroelectric capacity depends on adequate water flows, redundant capacity is often assumed and part of the regional plan. Therefore, most regions with a lot of hydroelectric capacity have a higher capacity reserve margin, holding all other things constant. The year 2001 has been a particularly poor water year to date, which bears out this fact through a significant rise in wholesale electricity prices.

As a result of the hydroelectric capacity, the variable cost curve for the WSCC is not particularly steep. This varies by sub-region, but would not tend to encourage additional capacity in the region. At $5.00 per mmbtu natural gas, a new combined cycle combustion turbine would have variable costs of about $40 per megawatt hour and total costs of about $55 per megawatt hour. Variable costs at regional annual peak appear to be about $35 per megawatt hour. In the Southwest (AZ-NM-NV) and California, these costs are more economic and will encourage development.

Figure 33: **Capacity Outlook**

WSCC - Western Systems Coordinating Council

Capacity Additions by Year (MW's)



Capacity Additions	
Year	**MW**
2000	1,104
2001	5,751
2002	7,719
2003	12,577
2004	4,660
2005	1,595
Total	***33,406***

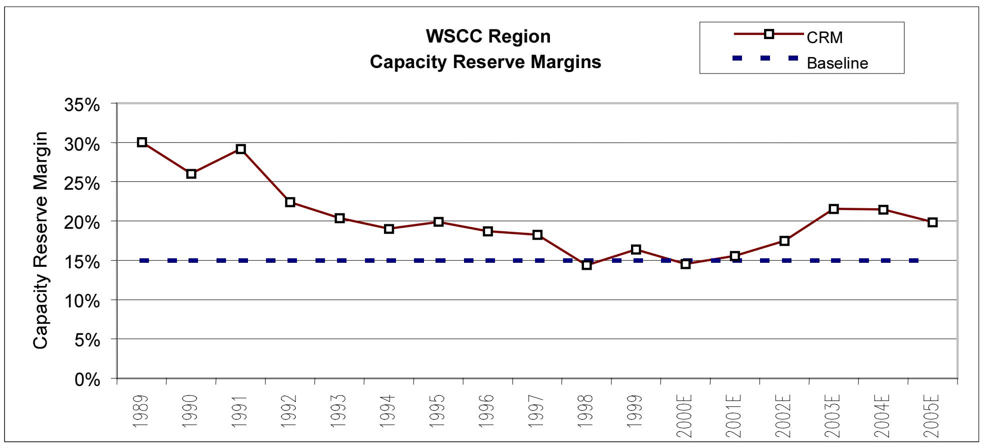
TOP FIVE BUILDERS IN WSCC	
Company	MW*
1) Duke Energy	5,114
2) Calpine Corp.	4,748
3) PG&E Corp.	4,123
4) Enron Corp.	2,265
5) Southwestern Power Group	2,000

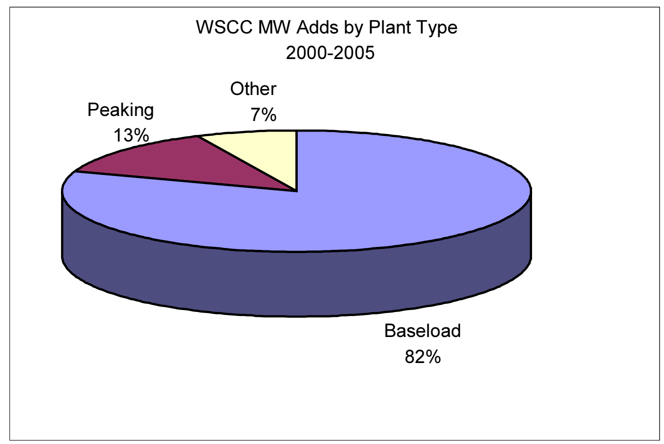
* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in WSCC
AZ, NM, NV, CA, MT, WY
WA, OR, ID, UT, CO

DEREG STATUS

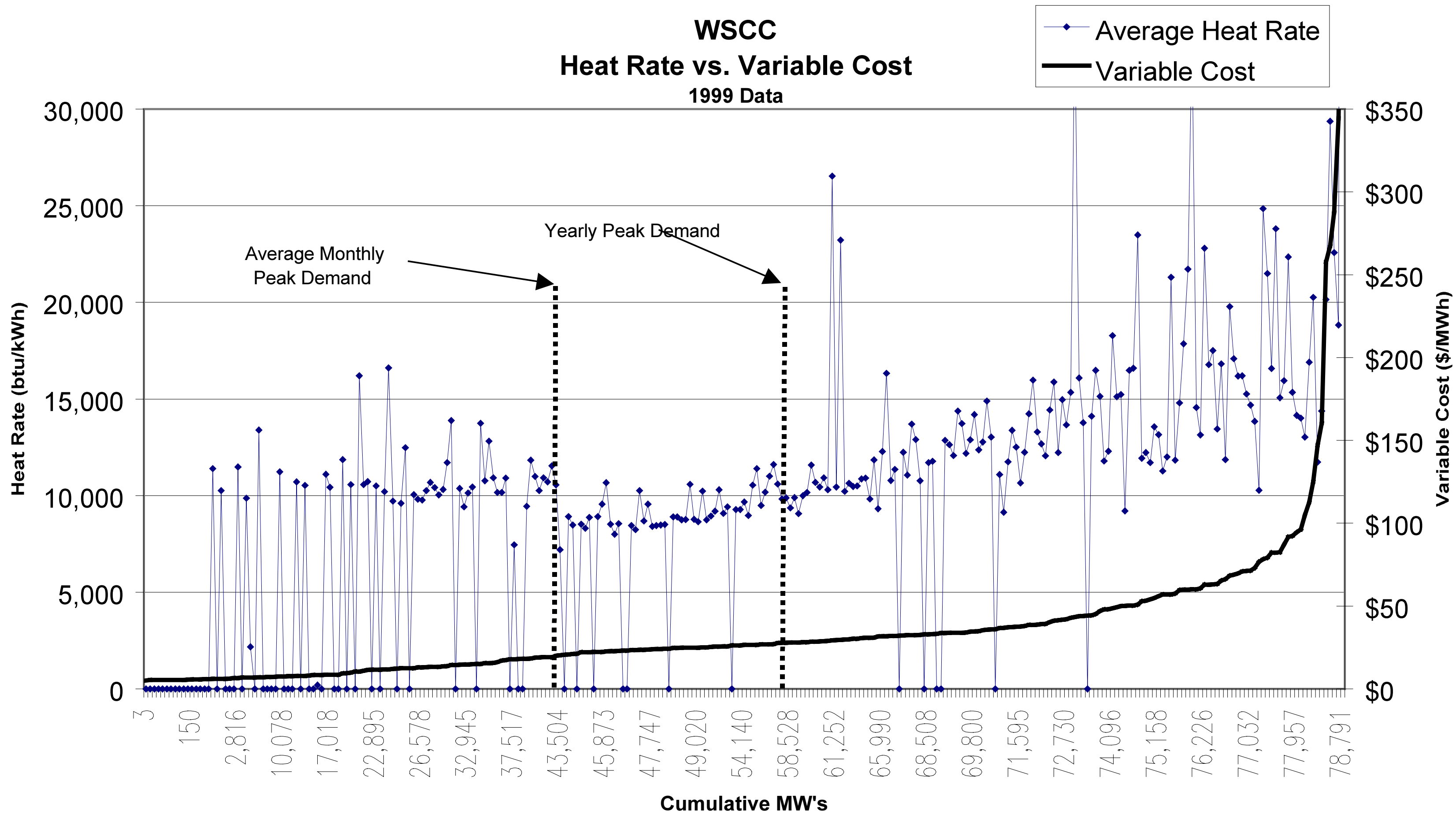
CA - Retail choice begun.
AZ, NV, NM, OR, MT - Legis. enacted; choice pending
UT, WA, WY, CO - Investigating
ID - No activity.





Source: Deutsche Banc Alex. Brown estimates: RDI Consulting; NERC

Figure 34:



Note: Chart excludes 55,359MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Arizona, New Mexico and Nevada Sub-Region of WSCC

Total 2000 Capacity: 21,441 MW
Total Under Construction: 2,915 MW
Total Announced Additions (2000 – 2005): 11,833 MW

This region is a sub-region of WSCC, or the Western Systems Coordinating Council. The region is made up of Arizona, most of New Mexico and a part of southern Nevada. Reserve margins in the region have shown a similar pattern as seen throughout most of the U.S., with steady declines in reserve margins over the last 10 years and some recovery expected over the next five. Margins are projected to remain tight in the region through most of 2002. By the end of 2002, margins are expected to have moved to the 15% baseline. Our reserve estimates for the region assume peak demand growth of 3.0% annually through 2005. All three states within the region have enacted legislation that calls for restructuring of the power industry. However, due to the problems plaguing California, the commencement of deregulation may be delayed beyond original time frames.

Additions of new generating capacity appear to peak in 2003 with about 5,000 megawatts of generating capacity. This could drive the capacity reserve margin above 25%. However, most of the 2003 capacity additions are early development plants. Therefore, the prospect of operation is less than certain. Most of the capacity entering operation in 2001 through 2005 (about 11,000 MW) is base load capacity and is natural gas fired. It is noteworthy that a lot of capacity is sold into California from this region, which reduces our concern about the 27% reserve margin in 2003.

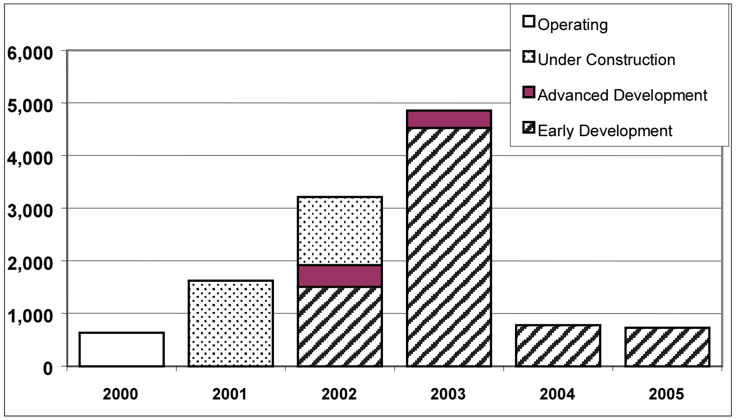
The region has a relatively flat variable cost curve. However, a lot of capacity is exported into California and other regions. Therefore, the variable cost around peak is less relevant. As a lot of the capacity is transmitted to California, it is interesting to compare the variable cost curves of AZ-NM-NV and California. This comparison completes the logic behind the exports. The low variable cost power in the AZ-NM-NV region is shipped to a higher variable cost market in California.

Although we expect spot price volatility to decline over the next few years in the AZ-NM-NV region, we believe shortages in California will maintain above average profitability for the region. The capacity reserve margin in California is not expected to exceed 10% over the forecast horizon, 2001 to 2005.

Figure 35: **Capacity Outlook**

AZ-NM-NV Region (subregion of WSCC)

Capacity Additions by Year (MW's)



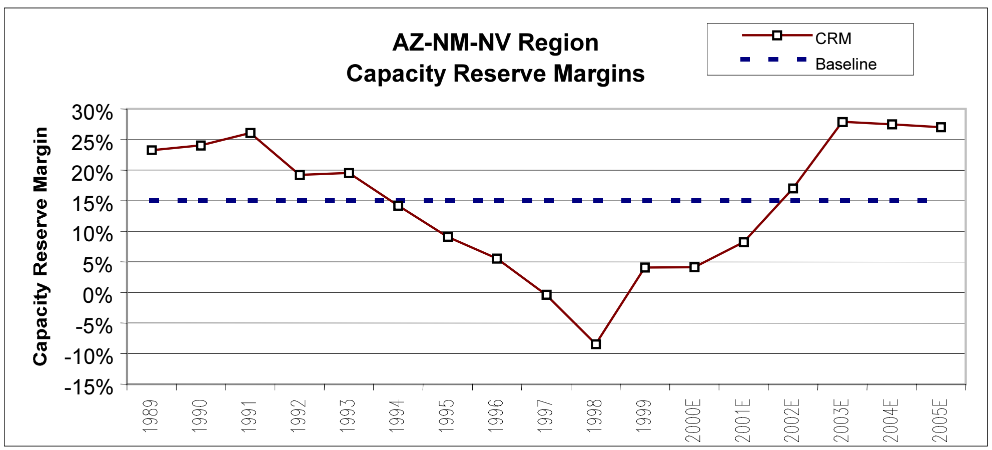
Capacity Additions	
Year	**MW**
2000	632
2001	1,625
2002	3,212
2003	4,857
2004	778
2005	730
Total	***11,833***

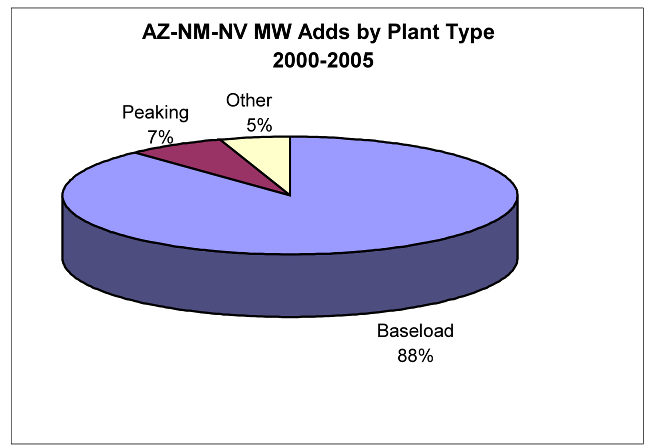
TOP FIVE BUILDERS IN AZ-NM-NV	
Company	MW*
1) Duke Energy	2,530
2) PG&E Corp.	2,083
3) Southwestern Power Group	2,000
4) Reliant Energy	1,675
5) Sempra Energy	1,540

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in AZNMNV
AZ, NM, NV

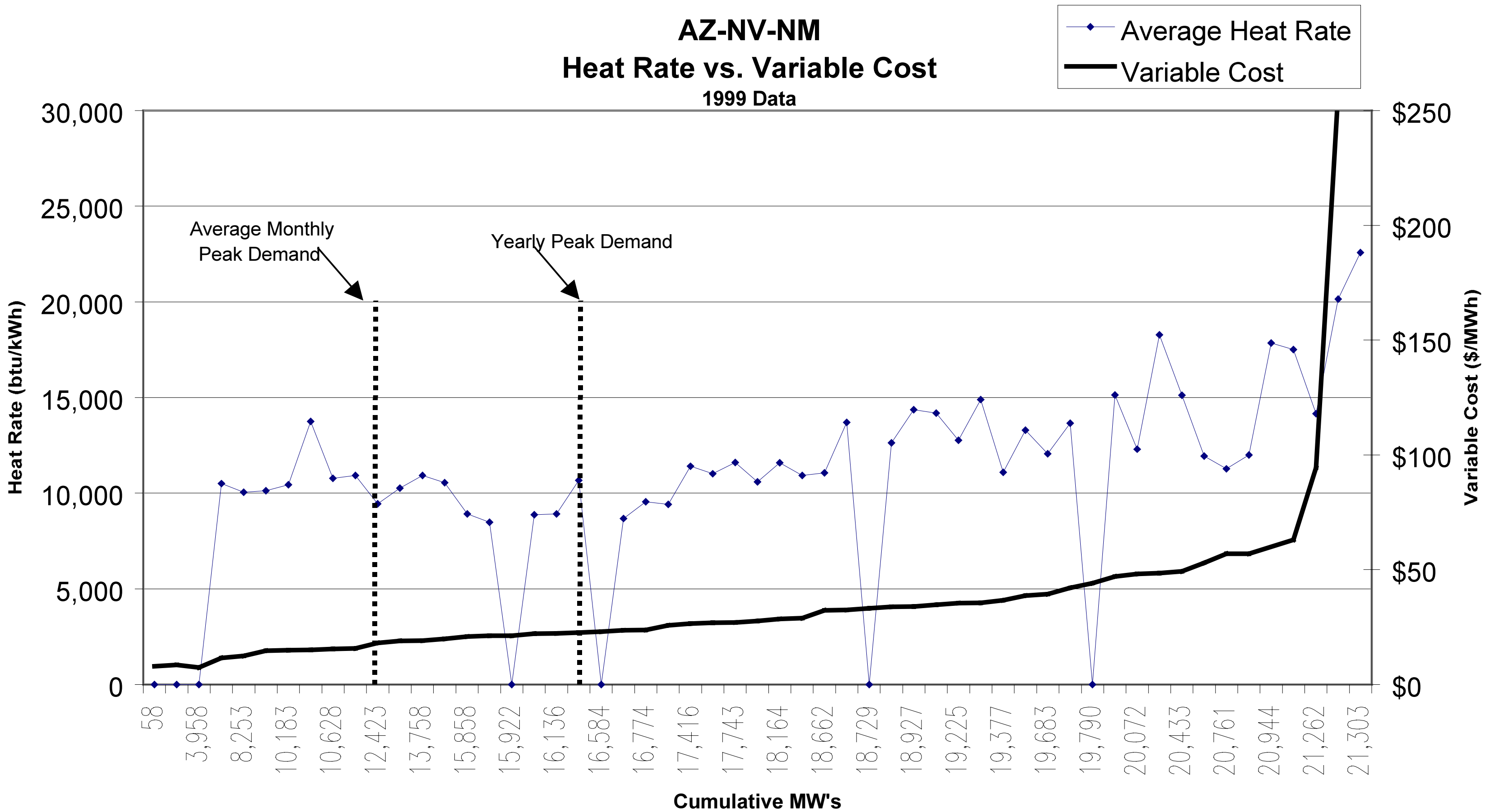
DEREG STATUS
AZ, NV, NM - Legis. enacted; choice pending





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 36:



Note: Chart excludes 3,700MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

California Sub-Region of WSCC

Total 2000 Capacity: 54,027 MW
Total Under Construction: 4,623 MW
Total Announced Additions (2000 – 2005): 11,826 MW

California is a sub-region of WSCC and consists of the state of California. Reserve margins have reached dangerously low levels in the state over the past few years, which has resulted in an enormous increase in wholesale power prices and helped to drive profits of many power generators in 2000. The reserve shortfall in the state stems from the fact that California has added essentially no additional generating capacity over the last ten years, while the state has simultaneously experienced an explosion in economic growth. Through this period, California has become increasingly dependent on power imports, especially from the Pacific Northwest, to meet its daily load. The state currently imports about 30% of its daily power. However, reserves have grown tight in the Northwest as well, especially in recent months as hydroelectric facilities have been crippled by record low precipitation levels. The convergence of these factors has led to rolling blackouts in the state in recent months.

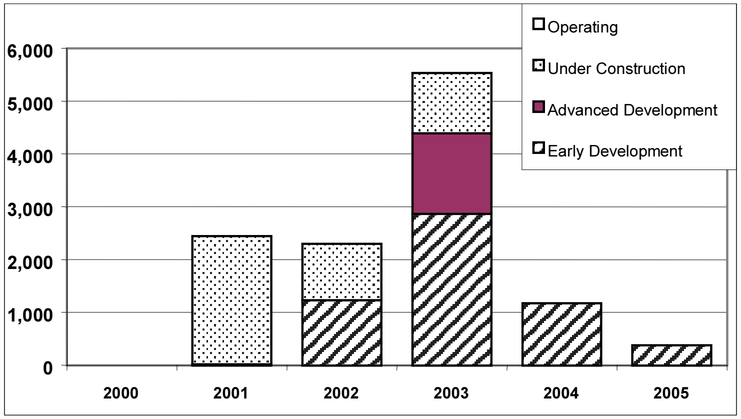
The state is now scrambling to get power projects on line and has made efforts to expedite the plant approval process. Currently, about 2,445 MW are scheduled for operation by the end of 2001. However, the California Independent System Operator estimates that the state will need about 5,000 MW of additional power to meet peak demand this summer. We believe that 2001 will be a very difficult year for the state, in terms of meeting its power load, and power prices are expected to remain high. Demand reductions will be critical to matching supply and demand in 2001 and 2002. However, as the regulatory and political environment begins to show some clarity and direction, hopefully by the second half of this year, more generators will likely be encouraged to commit capital within the state, which should help to boost margins and stabilize prices. However, due to the lag time required to get new projects into operation, it could be 2003 before the state sees real relief from its power woes. Our reserve estimates for the region assume peak demand growth of 3.0% annually through 2005.

The variable cost curve for California is steep. More interestingly, the curve is steep but does not meet annual peak demand. This emphasizes the import necessity that California operates in. As the economies around California have grown and less capacity has been available for export, the shortage of capacity situation has been exacerbated.

Figure 37: **Capacity Outlook**

CALIFORNIA (subregion of WSCC)

Capacity Additions by Year (MW's)



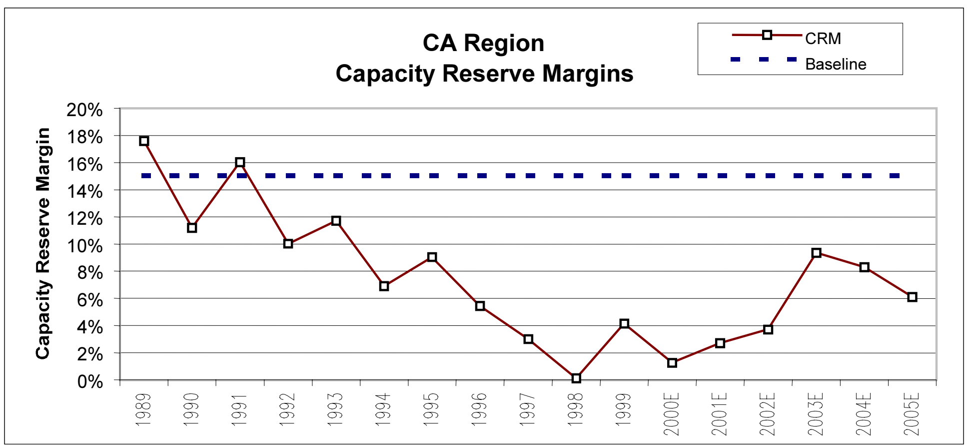
Capacity Additions	
Year	**MW**
2000	0
2001	2,445
2002	2,295
2003	5,535
2004	1,175
2005	375
Total	***11,826***

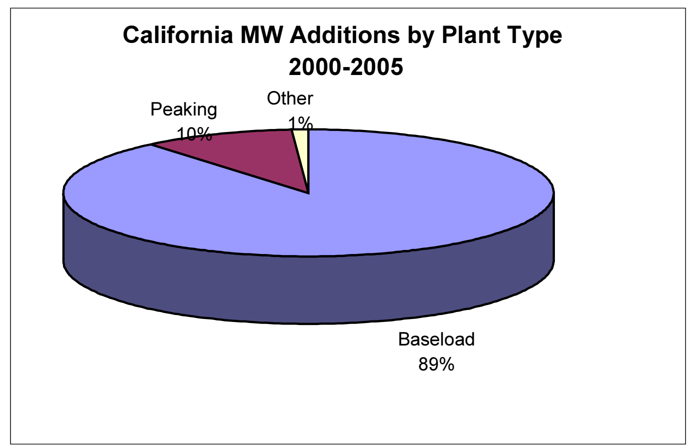
TOP FIVE BUILDERS IN CALIFORNIA	
Company	MW*
1) Calpine Corp.	3,543
2) Enron Corp.	2,050
3) AES Corp.	1,715
4) Duke Energy Corp.	1,590
5) PG&E Corp.	1,558

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

CALIFORNIA DEREG STATUS

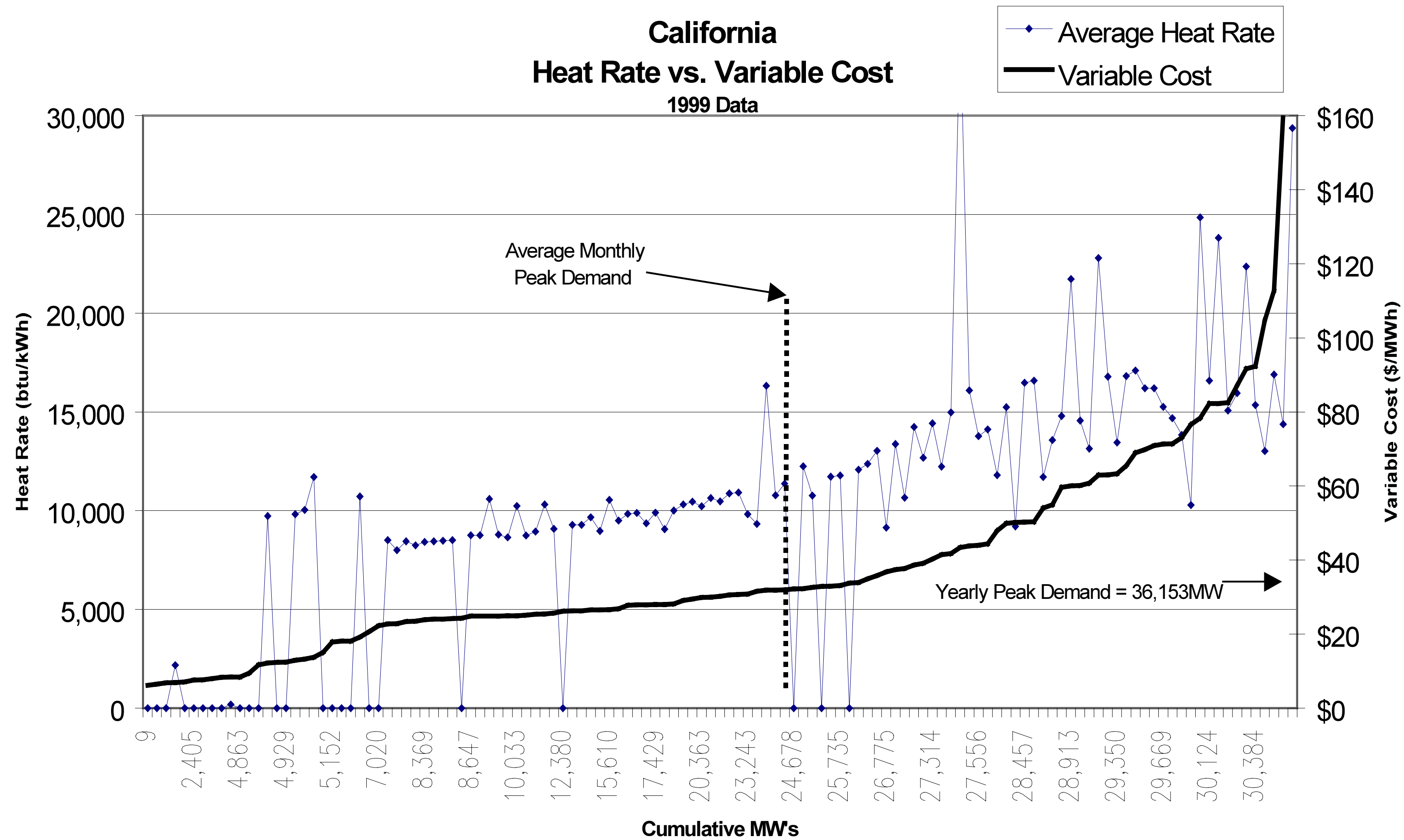
-Retail choice began March '98
-First state to allow choice
-Current CA electricity crisis should not reverse deregulation in the state





Source: *Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC*

Figure 38:



Note: Chart excludes 15,629MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown; RDI Consulting

Northwest Power Authority Sub-Region of WSCC

Total 2000 Capacity: 52,449 MW
Total Under Construction: 2,061 MW
Total Announced Additions (2000 – 2005): 7,812 MW

The Northwest Power Authority is a sub-region of WSCC and consists of Washington, Oregon, Idaho, Utah and most of Montana, Wyoming, and Nevada. As a result of the high amount of hydroelectric capacity in the region, the capacity reserve margin looks extra healthy at 50% in 2000, and remains at that level across the forecast horizon. We have assumed electricity demand growth of 3% annually through 2005. We expect about 1,000 megawatts of capacity to be added in 2001, with an additional 2,000 megawatts in each of the next three years. Most of the capacity is baseload and natural gas fired capacity.

This region exports a large amount of capacity to California, therefore reserve margins are somewhat lower including these exports. Only about 7,000 MW of capacity additions are expected over the 2001 to 2005 forecast horizon.

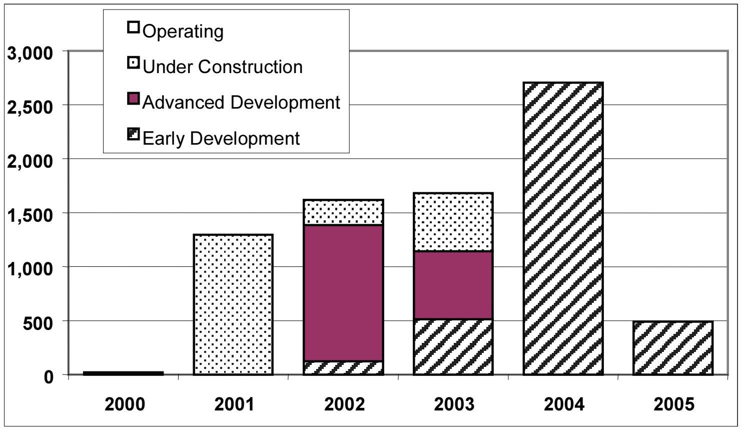
Almost half of the region's generating capacity is hydroelectric. Therefore, it is not surprising to see the variable cost curve as flat as it is. However, in a low water year (similar to early 2001), the cost of power rises dramatically.

A detailed regional breakdown of supply, demand and capacity reserve margins from 1989 to 2005 is shown in Appendix A on pages 74 and 75.

Figure 39:**Capacity Outlook**

NWPA - Northwest Power Authority (subregion of WSCC)

Capacity Additions by Year (MW's)



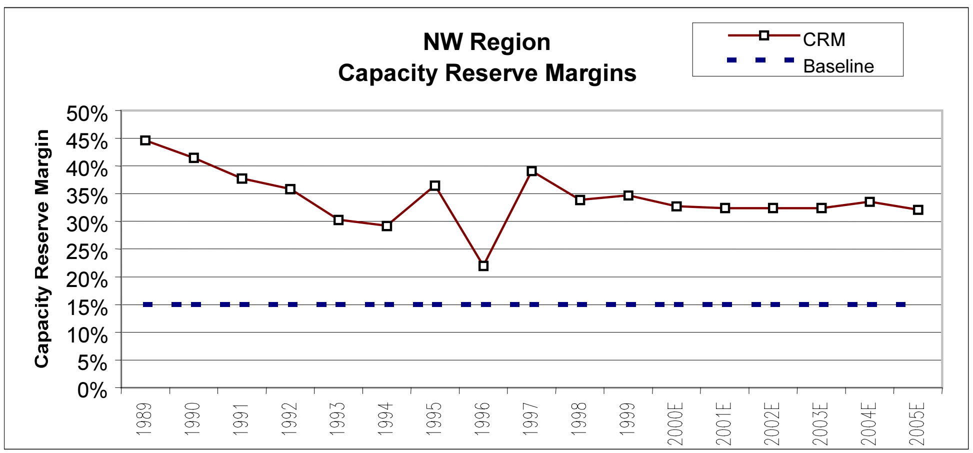
Capacity Additions	
Year	MW
2000	22
2001	1,294
2002	1,619
2003	1,679
2004	2,708
2005	490
Total	*7,812*

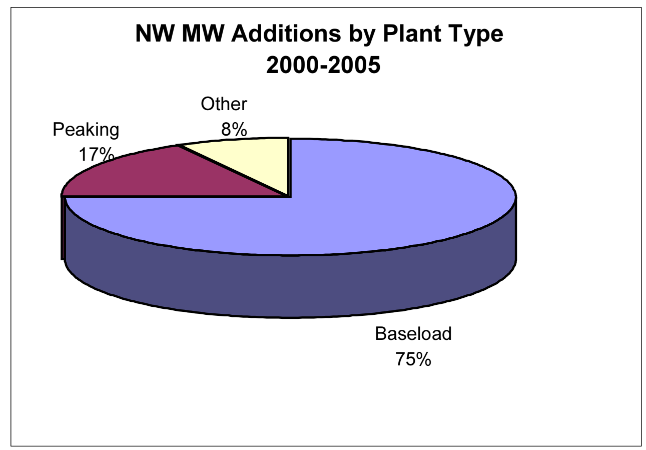
TOP FIVE BUILDERS IN NWPA	
Company	MW*
1) Cogentrix Energy	1,965
2) Newport Northwest	1,300
3) PPL	1,100
4) Duke Energy	994
5) Northwest Power Enterprise	838

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in NWPA
MT, WA, NV, OR, WY ID, UT

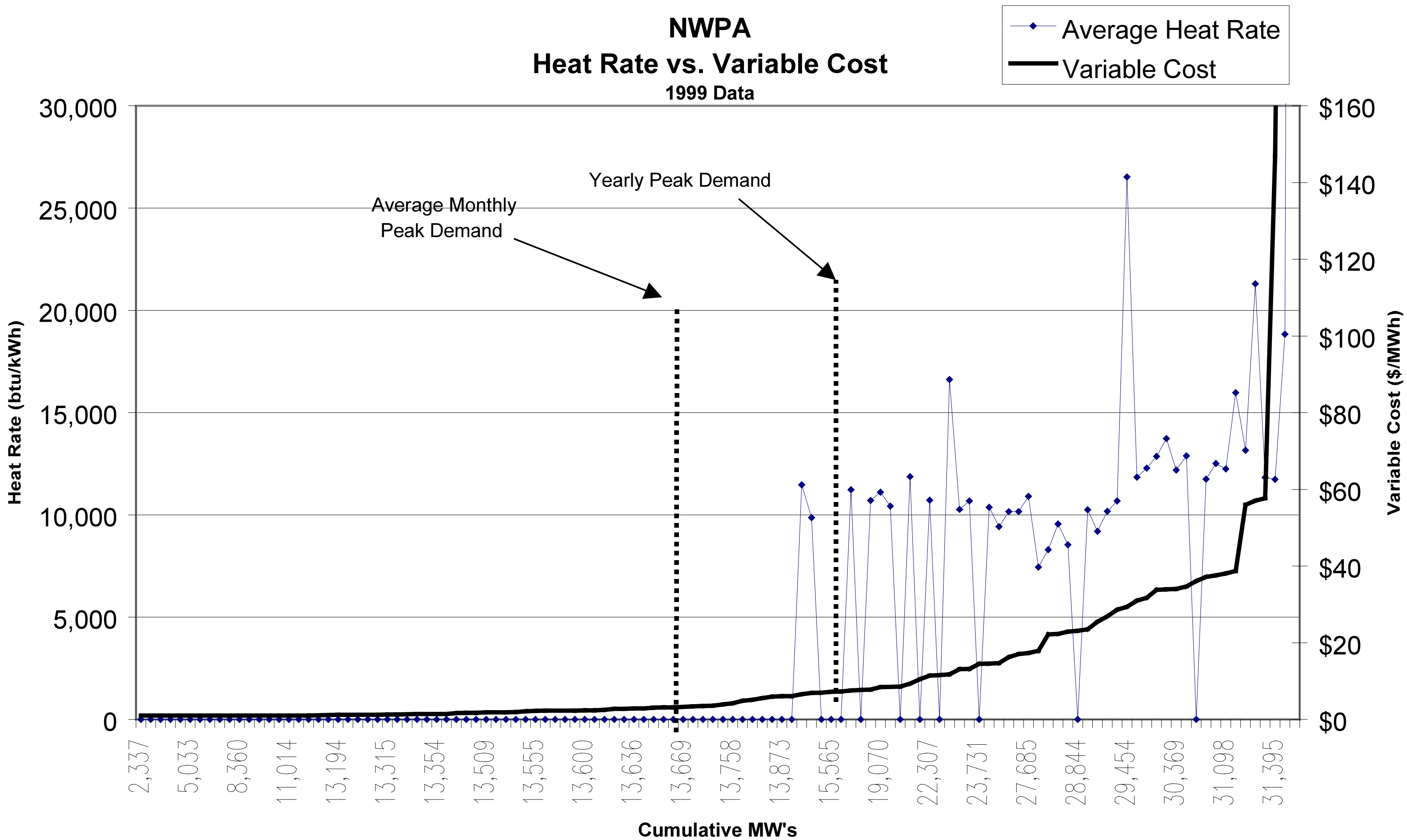
DEREG STATUS
OR, MT, AZ - Legis. enacted; choice pending UT, WA, WY - Investigating ID - No activity





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 40:



Note: Chart excludes 20,671MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

Rocky Mountain Power Authority Sub-Region of WSCC

Total 2000 Capacity: 9,059 MW
Total Under Construction: 130 MW
Total Announced Additions (2000 – 2005): 1,936 MW

The Rocky Mountain Power Authority is a sub-region of WSCC and is made up of Colorado and parts of Wyoming. In contrast to the rest of the U.S., capacity reserve margins have held above the 15% baseline in this region in most of the past five years. However, the region has experienced a steady decline in margins over the last ten years. Approximately 1,500 MW of new capacity are projected to be added in the region from 2001 to 2005. This is likely to maintain the capacity reserve margin around the current level of 15%. These margin estimates are based on annual demand growth through 2005 of 3.0%. About 57% of the expected capacity additions are classified as peaking plants. Additional capacity from hydroelectric facilities in the Northwest would also provide additional resources for this region.

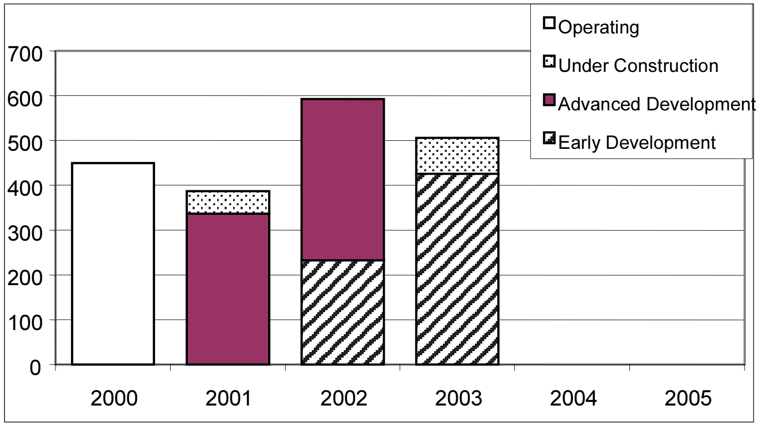
The low and flat variable cost curve does not provide much of a catalyst for additional generation development in the region. This region has been slow to deregulate, which has also slowed capacity additions. Only about 2,000 MW of capacity is expected to be added over the forecast horizon, 2001 to 2005.

A detailed regional breakdown of supply, demand and capacity reserve margins from 1989 to 2005 is shown in Appendix A on pages 74 and 75.

Figure 41: **Capacity Outlook**

RMPA - Rocky Mountain Power Authority (subregion of WSCC)

Capacity Additions by Year (MW's)



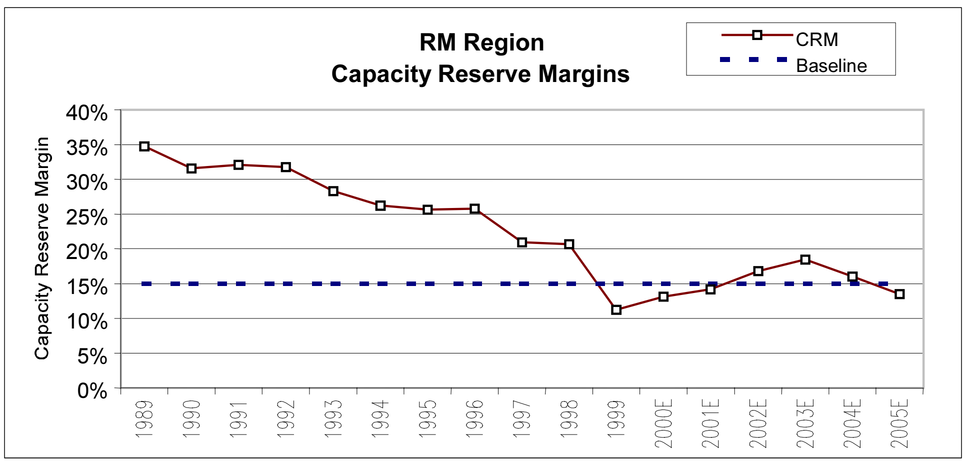
Capacity Additions	
Year	**MW**
2000	450
2001	387
2002	593
2003	507
2004	0
2005	0
Total	***1,936***

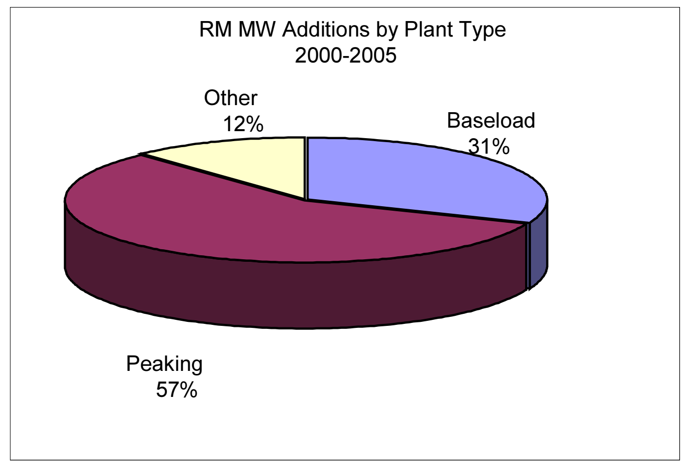
TOP FIVE BUILDERS IN RMPA	
Company	MW*
1) El Paso Energy Corp.	565
2) North American Power Grp	450
3) Xcel Energy	448
4) Black Hills Corp.	361
5) Tri-State G&T	280

* Actual additions announced & completed 2000 to 2005; Not probability weighted.

States w/in RMPA
CO, WY

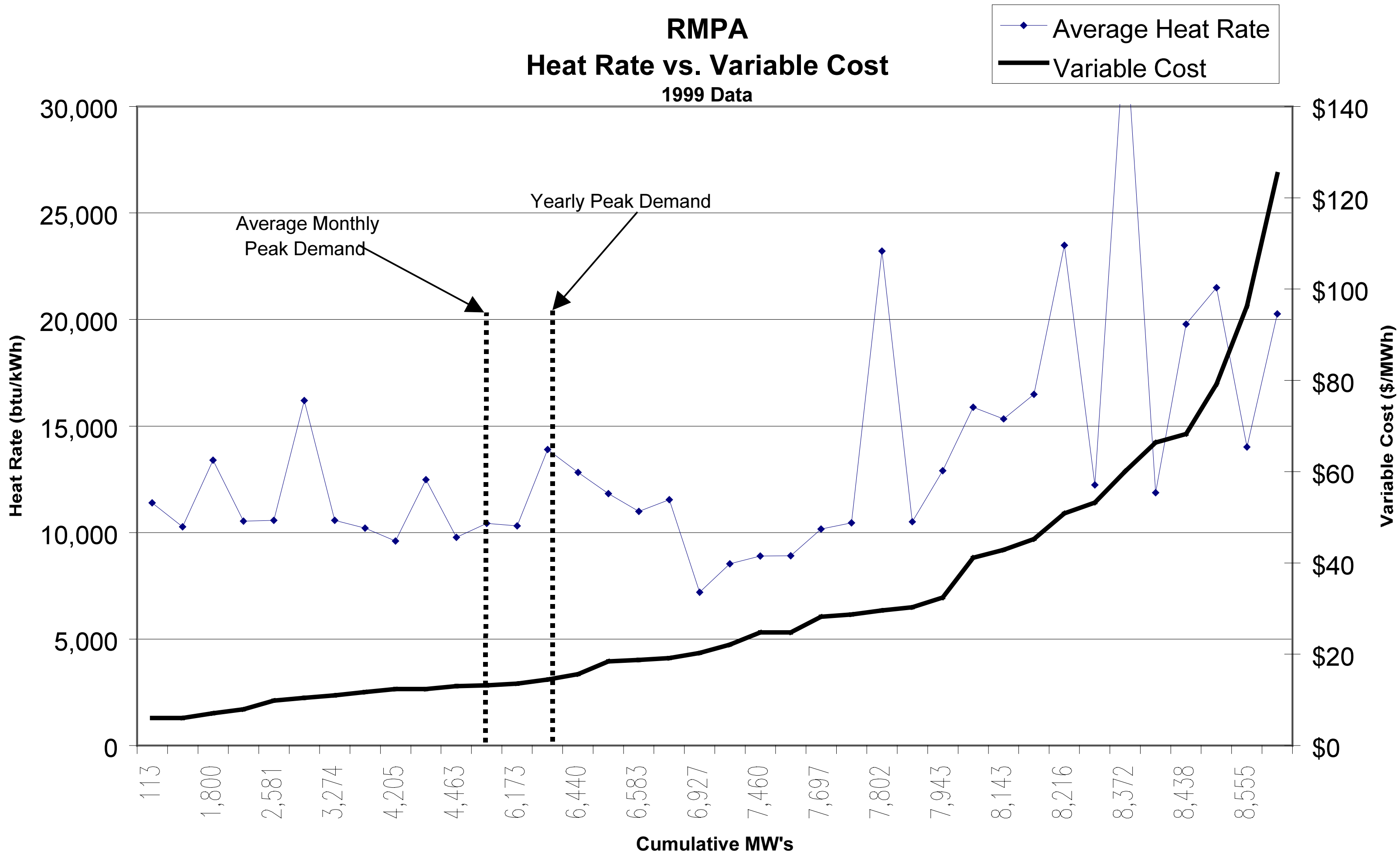
DEREG STATUS
CO, WY - Investigating





Source: Deutsche Banc Alex. Brown estimates; RDI Consulting; NERC

Figure 42:



Note: Chart excludes 1,440MW of hydro capacity in region.

Source: Deutsche Banc Alex. Brown estimates; RDI Consulting

What Commodity Futures Are Telling Us About 2002

Electricity prices in the futures market for summer 2002 indicate that prices will be down on average about 25% over the prices realized in 2001, excluding California-Oregon Border and Palo Verde. Although this is possible, looking back over history, the future price has not been a particularly good predictor of spot prices this far in the future. We would argue that the futures prices for electricity in 2002 could be accurate if the capacity additions in 2001 and 2002 met or exceeded our forecast. However, we are not optimistic that this will materialize. Importantly, this would not reduce gross profit margins as much, as a result of the expectation of lower fossil fuel prices (primarily natural gas), according to futures prices for summer 2002. Natural gas futures in 2001 are showing a summer price averaging $4.74 per mmbtu, versus $5.47 per mmbtu for the summer of 2001. The decline in natural gas prices appears to account for more than half of the decline in wholesale electricity futures. Therefore, we are not convinced that the futures price is foreshadowing a collapse in electricity profit margins in the summer of 2002. However, we believe average generation profit margins will peak no later than the summer of 2002, and probably before. This suggests a decline in the spark spread in 2002 over 2001.

Overall, the supply additions in aggregate for the US and by region will be the single best determinant of pricing in the wholesale electricity market. We continue to believe that the regional variable cost curves will play a role in tempering the immediate reaction to excess capacity. However, as we are convinced the long-term outlook for the electricity generation sector includes excess capacity, this is not a long-term consideration.

The wholesale electricity prices in 2001 and 2002 are expected to remain above the cost of new natural gas fired generating capacity. We believe in the intermediate to longer term, this argues in favor of the addition of more generating capacity than we are currently forecasting. Specifically from an economic standpoint, new participants in the industry will continue to add new capacity until the wholesale price of power approximates the long run marginal cost of generation. At $5.00 per mmbtu natural gas, wholesale prices would have to approximate $55 per megawatt hour (the long-run marginal cost of production) to economically deter new capacity (price includes a 20% return on equity). Although we do not see $55 per megawatt hour power occurring much before 2003, we do expect that as new capacity is installed, wholesale power prices will stagnate or decline in many regions of the US in 2002. Figure 2 on page 7 shows our gas-fired generation plant cost model.

For a world-wide comparison of wholesale electricity, please see Deutsche Banc Alex.Brown's February 20, 2001 report "*Wholesale Electricity Prices: Predicting the Cycle*". The report includes the US supply and demand analysis completed for this report, in addition to other deregulated electricity markets world-wide.

Appendix: US Electricity Supply and Demand Detail, 1989-2005

Appendix A:

U.S. CAPACITY AND DEMAND GROWTH 1989 to 2005E - DBAB

Region		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000E	2001E	2002E	2003E	2004E	2005E
ECAR	Total Capacity	97,218	99,480	101,232	101,907	101,977	102,084	102,923	104,351	104,212	104,087	105,980	109,913	114,985	123,797	133,971	135,789	137,310
(Industrial Midwest)	Demand Summer	75,442	79,258	81,224	78,550	80,533	87,165	92,619	90,798	93,492	93,784	99,239	102,216	105,283	108,441	111,694	115,045	118,497
	CRM	22.4%	20.3%	19.8%	22.9%	21.0%	14.6%	10.0%	13.0%	10.3%	9.9%	6.4%	7.0%	8.4%	12.4%	16.6%	15.3%	13.7%
ERCOT	Total Capacity	51,927	54,114	53,882	54,164	54,642	54,446	54,672	55,129	55,236	59,096	59,504	63,247	72,658	78,208	83,246	84,089	84,089
(Texas)	Demand Summer	40,402	42,737	41,870	42,619	44,255	44,162	46,618	47,480	50,541	54,666	55,529	57,806	60,176	62,643	65,211	67,885	70,668
	CRM	22.2%	21.0%	22.3%	21.3%	19.0%	18.9%	14.7%	13.9%	8.5%	7.5%	6.7%	8.6%	17.2%	19.9%	21.7%	19.3%	16.0%
FRCC	Total Capacity	30,857	30,511	30,888	32,008	33,668	35,528	35,991	37,228	37,607	37,348	38,243	39,279	42,207	47,592	52,303	52,650	52,830
(Florida)	Demand Summer	27,972	27,266	28,818	30,601	32,823	32,904	34,524	35,444	35,375	38,730	37,493	38,805	40,163	41,569	43,024	44,530	46,088
	CRM	9.3%	10.6%	6.7%	4.4%	2.5%	7.4%	4.1%	4.8%	5.9%	-3.7%	2.0%	1.2%	4.8%	12.7%	17.7%	15.4%	12.8%
MAAC	Total Capacity	49,829	51,279	53,978	54,253	54,620	55,293	56,786	56,782	51,961	50,318	57,703	58,419	59,897	64,240	67,731	68,176	68,619
(Mid-Atlantic)	Demand Summer	41,614	42,613	45,937	43,658	46,494	46,019	48,577	44,302	45,887	47,509	51,645	53,065	54,525	56,024	57,565	59,148	60,774
	CRM	16.5%	16.9%	14.9%	19.5%	14.9%	16.8%	14.5%	22.0%	11.7%	5.6%	10.5%	9.2%	9.0%	12.8%	15.0%	13.2%	11.4%
MAIN	Total Capacity	49,373	49,184	49,212	49,265	49,876	50,479	51,008	51,336	51,961	50,318	51,710	52,773	57,527	62,223	67,887	68,280	68,732
(Midwest)	Demand Summer	39,460	40,740	41,598	38,819	41,956	42,562	45,782	46,402	45,887	47,509	51,535	53,081	54,673	56,314	58,003	59,743	61,535
	CRM	20.1%	17.2%	15.5%	21.2%	15.9%	15.7%	10.2%	9.6%	11.7%	5.6%	0.3%	-0.6%	5.0%	9.5%	14.6%	12.5%	10.5%
MAPP	Total Capacity	30,864	32,164	31,509	31,418	31,413	30,975	31,305	31,515	31,462	32,364	32,951	33,051	34,068	34,470	34,535	34,563	34,563
(Upper Midwest)	Demand Summer	24,336	24,994	25,498	22,638	24,396	27,000	29,192	28,253	29,787	30,722	31,903	32,860	33,846	34,861	35,907	36,984	38,094
	CRM	21.2%	22.3%	19.1%	27.9%	22.3%	12.8%	6.7%	10.4%	5.3%	5.1%	3.2%	0.6%	0.7%	-1.1%	-4.0%	-7.0%	-10.2%
NPCC																		
(New England)	Total Capacity	22,597	24,044	24,072	24,337	24,425	24,502	24,512	24,890	24,922	22,657	23,970	25,522	29,710	35,179	36,740	36,990	36,990
	Demand Summer	19,641	19,131	19,755	18,707	19,570	20,519	20,499	19,507	20,569	21,406	22,544	23,220	23,917	24,634	25,373	26,135	26,919
	CRM	13.1%	20.4%	17.9%	23.1%	19.9%	16.3%	16.4%	21.6%	17.5%	5.5%	5.9%	9.0%	19.5%	30.0%	30.9%	29.3%	27.2%
(New York)	Total Capacity	32,025	32,102	33,323	34,193	34,355	34,618	34,750	35,177	34,881	34,614	34,651	34,669	35,015	35,315	41,148	42,864	42,936
	Demand Summer	25,390	24,985	26,839	24,951	27,136	27,062	27,206	25,587	28,700	28,160	30,311	31,069	31,845	32,642	33,458	34,294	35,151
	CRM	20.7%	22.2%	19.5%	27.0%	21.0%	21.8%	21.7%	27.3%	17.7%	18.6%	12.5%	10.4%	9.1%	7.6%	18.7%	20.0%	18.1%
SERC																		
(Total)	Total Capacity	112,468	144,281	114,846	117,704	117,952	119,318	122,919	125,254	152,402	149,999	150,254	159,078	169,731	188,550	199,392	201,392	202,192
	Demand Summer	89,757	121,149	95,968	97,635	103,278	99,680	112,045	110,206	137,387	143,226	149,012	154,972	161,171	167,618	174,323	181,296	188,548
	CRM	20.2%	16.0%	16.4%	17.1%	12.4%	16.5%	8.8%	12.0%	9.9%	4.5%	0.8%	2.6%	5.0%	11.1%	12.6%	10.0%	6.7%
(Entergy)*	Total Capacity	NA	NA	NA	NA	NA	NA	NA	NA	27,147	30,144	26,131	27,352	29,831	39,043	42,022	42,542	43,342
	Demand Summer	NA	NA	NA	NA	NA	NA	NA	NA	23,993	27,343	26,558	27,620	28,725	29,874	31,069	32,312	33,604
	CRM									11.6%	9.3%	-1.6%	-1.0%	3.7%	23.5%	26.1%	24.0%	22.5%

(Continued on next page)

Source: Deutsche Banc Alex. Brown estimates and company information

Appendix A (cont.):

U.S. CAPACITY AND DEMAND GROWTH 1989 to 2005E - DBAB

Region		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000E	2001E	2002E	2003E	2004E	2005E
(Southern)*	Total Capacity	37,481	37,383	38,126	38,824	38,607	39,330	41,767	40,103	40,590	40,012	41,283	44,918	49,658	54,490	59,671	59,671	59,671
	Demand Summer	29,088	30,995	30,570	31,820	33,933	32,596	37,031	36,842	37,466	39,855	42,196	43,884	45,639	47,465	49,363	51,338	53,391
	CRM	22.4%	17.1%	19.8%	18.0%	12.1%	17.1%	11.3%	8.1%	7.7%	0.4%	-2.2%	2.3%	8.1%	12.9%	17.3%	14.0%	10.5%
(TVA)*	Total Capacity	29,596	29,574	28,364	28,288	28,353	28,269	28,274	29,566	29,782	30,144	29,672	30,910	32,753	34,503	36,099	36,619	36,619
	Demand Summer	20,768	22,595	22,300	22,201	24,072	23,398	25,496	25,376	26,661	27,343	28,397	29,533	30,714	31,943	33,220	34,549	35,931
	CRM	29.8%	23.6%	21.4%	21.5%	15.1%	17.2%	9.8%	14.2%	10.5%	9.3%	4.3%	4.5%	6.2%	7.4%	8.0%	5.7%	1.9%
(VACAR)*	Total Capacity	45,391	46,813	48,356	50,592	50,992	51,719	52,878	55,585	54,883	52,689	53,168	55,898	57,489	60,514	61,602	62,562	62,562
	Demand Summer	39,901	41,087	43,098	43,614	45,273	43,686	49,518	47,988	49,262	49,867	52,534	54,635	56,821	59,094	61,457	63,916	66,472
	CRM	12.1%	12.2%	10.9%	13.8%	11.2%	15.5%	6.4%	13.7%	10.2%	5.4%	1.2%	2.3%	1.2%	2.3%	0.2%	-2.2%	-6.3%
SPP	Total Capacity	66,625	66,833	67,423	68,325	68,492	69,540	70,029	69,290	41,845	42,587	42,643	44,800	47,896	51,512	55,031	55,031	55,456
(Southwest)	Demand Summer	49,439	52,541	51,885	51,324	57,106	56,035	59,595	60,072	36,479	37,724	38,609	39,960	41,359	42,806	44,305	45,855	47,460
	CRM	25.8%	21.4%	23.0%	24.9%	16.6%	19.4%	14.9%	13.3%	12.8%	11.4%	9.5%	10.8%	13.6%	16.9%	19.5%	16.7%	14.4%
WSCC																		
(Total)	Total Capacity	129,533	131,610	129,920	127,862	122,830	126,202	129,327	133,776	134,592	135,431	135,872	136,976	142,727	150,446	163,023	167,683	169,278
	Demand Summer	90,657	97,389	92,026	99,205	97,809	102,212	103,592	108,739	110,001	115,921	113,629	117,038	120,549	124,165	127,890	131,727	135,679
	CRM	30.0%	26.0%	29.2%	22.4%	20.4%	19.0%	19.9%	18.7%	18.3%	14.4%	16.4%	14.6%	15.5%	17.5%	21.6%	21.4%	19.8%
(AZ-NM-NV)**	Total Capacity	15,873	16,521	16,095	16,036	16,221	16,300	16,026	15,970	18,950	18,832	20,809	21,441	23,066	26,278	31,135	31,913	32,643
	Demand Summer	12,176	12,553	11,892	12,956	13,057	13,985	14,566	15,087	19,026	20,430	19,954	20,553	21,169	21,804	22,458	23,132	23,826
	CRM	23.3%	24.0%	26.1%	19.2%	19.5%	14.2%	9.1%	5.5%	-0.4%	-8.5%	4.1%	4.1%	8.2%	17.0%	27.9%	27.5%	27.0%
(California)**	Total Capacity	53,921	55,596	54,876	55,552	55,159	55,473	56,511	56,665	53,555	54,170	54,027	54,027	56,472	58,767	64,302	65,477	65,852
	Demand Summer	44,437	49,368	46,076	49,983	48,699	51,634	51,406	53,584	51,946	54,099	51,782	53,335	54,936	56,584	58,281	60,030	61,830
	CRM	17.6%	11.2%	16.0%	10.0%	11.7%	6.9%	9.0%	5.4%	3.0%	0.1%	4.2%	1.3%	2.7%	3.7%	9.4%	8.3%	6.1%
(Northwest)**	Total Capacity	50,042	50,054	47,542	46,922	42,063	44,182	49,461	51,197	52,460	52,806	52,427	52,449	53,743	55,362	57,041	59,749	60,239
	Demand Summer	27,718	29,306	29,608	30,101	29,326	31,277	31,426	39,941	31,943	34,908	34,253	35,281	36,339	37,429	38,552	39,709	40,900
	CRM	44.6%	41.5%	37.7%	35.8%	30.3%	29.2%	36.5%	22.0%	39.1%	33.9%	34.7%	32.7%	32.4%	32.4%	32.4%	33.5%	32.1%
(Rocky Mountain)**	Total Capacity	9,697	9,395	9,557	9,352	9,387	9,428	9,769	9,980	10,028	10,054	8,609	9,059	9,446	10,039	10,546	10,546	10,546
	Demand Summer	6,326	6,427	6,494	6,382	6,727	6,955	7,266	7,404	7,926	7,975	7,640	7,869	8,105	8,348	8,599	8,857	9,123
	CRM	34.8%	31.6%	32.0%	31.8%	28.3%	26.2%	25.6%	25.8%	21.0%	20.7%	11.3%	13.1%	14.2%	16.8%	18.5%	16.0%	13.5%
TOTAL	Total Capacity	673,316	685,091	690,915	695,436	694,250	702,985	714,222	724,728	725,829	724,193	733,481	757,727	806,421	871,532	935,010	947,511	952,999
(U.S.)	Demand Summer	524,110	545,537	551,320	548,707	575,356	585,320	620,249	616,790	637,677	660,293	681,449	704,618	728,575	753,347	778,961	805,445	832,830
	CRM	22.2%	20.4%	20.2%	21.1%	17.1%	16.7%	13.2%	14.9%	12.1%	8.8%	7.1%	7.0%	9.7%	13.6%	16.7%	15.0%	12.6%

* SERC subregion.
** WSCC subregion.

Source: Deutsche Banc Alex. Brown estimates and company information

Additional Information Available upon Request

Disclosure Checklist			
Company	**Ticker**	**Price**	**Disclosure**
Calpine Corp.	CPN	$49.05	#, ++, O
Exelon Corp.	EXC	$65.30	O
Reliant Energy	REI	$41.69	#, &, O
AES Corp.	AES	$58.02	&, O

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