Global Energy Executive Briefing august '05

>energy industry briefing reports & updates

About Global Energy Decisions
Global Energy Decisions (Global Energy) provides the energy industry with software solutions, energy markets data, advisory services, and strategic consulting that are based on a common framework that enables industry professionals to make better decisions.

The Global Energy Executive Briefing is made available to qualified energy industry professionals free of charge. No reproduction or distribution of any kind is allowed without the permission of Global Energy.

For More Information:
Visit www.GlobalEnergy.com
or call 720-240-5554

Free Map Offer:
See Back Page for Details

Upcoming Global Energy Events

Visit www.globalenergy.com
for more info/to register

COMPLIMENTARY WEBCASTS
When Fuel Giants Compete: Coal vs. Gas - Which one will fuel your region's next power plant? Aug 29, 1-2 pm ET

Post Analysis and Operations Evaluation
Aug 10, 1-2 pm ET

Effective Fuel Management
Sept 20, 1-2 pm ET

Modeling Ancillary Services and Its Impact on the Portfolio Strategy
Oct 28, 1-2 pm ET

ENERPRISE PRODUCT TRAINING
Advanced PaR & Market Analytics Training, Sacramento, Sept 21-23, 2005

Planning & Risk (v5.x), Sacramento, Oct 19-21, 2005

Market Analytics-Fast, Zonal & Nodal (v6.x), Sacramento, Nov 9-11, 2005

inside this issue

Global Energy Decisions

Clear Skies Reality by 2015

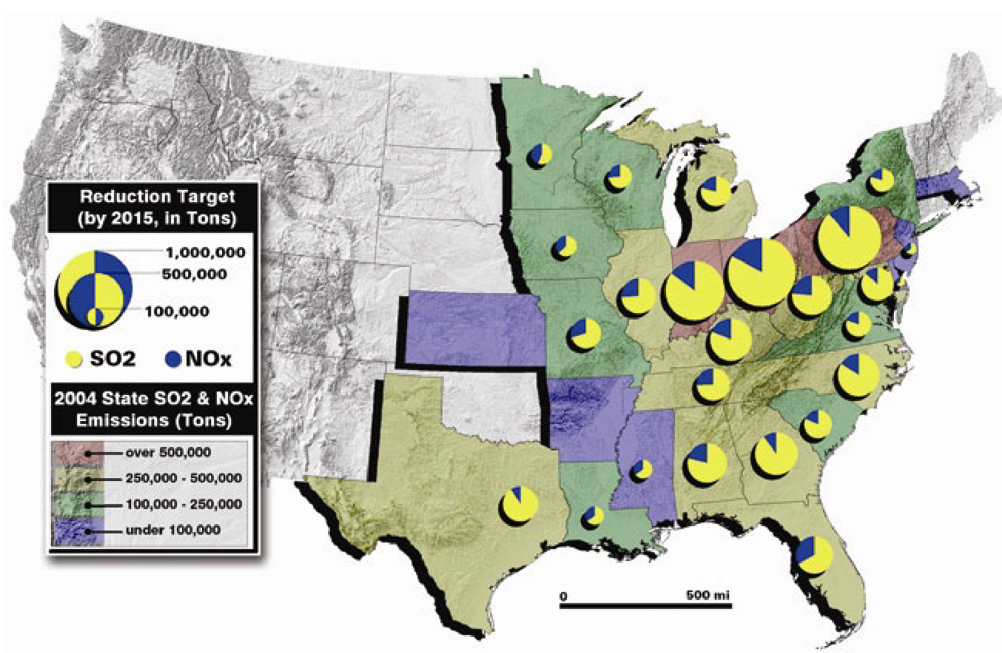
From the July “Power Measurements” of *Fortnightly* Magazine

A previous edition of *Fortnightly* included a lengthy discussion by EPA officials of the Clean Air Interstate Rule (CAIR) explaining the details behind the landmark regulations in terms of benefits and costs. In this article, Global Energy discusses which states, companies and generating units are most affected by the new rules.

The CAIR rulings affect 28 eastern states and the District of Columbia. The map below illustrates the amount of annual emissions reductions from 2004 levels necessary to comply with the two phases (2009/10 and 2015) of CAIR. Twenty-six of the affected states were granted allowance budgets for annual SO2 and NOx emissions. Two of the twenty-eight (Arkansas and Massachusetts) are required to comply only with seasonal ozone limiting regulations and are exempt from annual caps under CAIR The final rules excluded Kansas, based on new analysis of its contribution to downwind particulate emissions.

Figure 1

CAIR State 2015 Electric Generator Emissions Compliance Summary



When full compliance is reached in 2015, SO_2 emissions will have dropped by more than 83% and NOx by nearly 81% since the Acid Rain Program was created under Title IV of the 1990 Clean Air Act Amendments. Today the 28 CAIR regulated states account for more than 90% of the SO_2 and 77% of the NOx emissions from electric plants nationwide.

The following table summarizes the amount of reductions by electric generating units from 2004 levels necessary to comply with the CAIR rules:

Figure 2
Electric Utility Emissions: CAIR Compliance Summary (millions of tons)

	U.S. Total 2004 Actual	CAIR States	% From CAIR States	2009/10* CAIR Target	2015 CAIR Target	% Reduction from 2004 by 2015
SO_2:	10.1	9.1	90%	3.9	2.7	73.3%
NO_X:	3.7	2.8	77%	1.6	1.3	64.9%

* Phase I Nox compliance goes into affect in 2009 while the first Phase of SO2 compliance begins in 2010

The EPA regulations require the CAIR-affected states develop a compliance strategy by September of 2006. Utilities in the affected states will need to quickly decide where to put their money. The consensus is that most will, and have already begun to invest in emissions controls; however, given the backdrop of high natural gas prices and state renewable standards (19 states and counting) some will opt to increase their generation portfolios with renewable energy or invest in new clean coal projects.

Which states are affected?

Five states currently account for 39.3% and 27.9% of the nation's SO_2 and NOx emissions respectively. Generating companies in Ohio (10.7%), Pennsylvania (9.9%), Indiana (8.2%), Georgia (5.4%) and Texas (5.2%) are the most heavily impacted by the EPA regulations. Of these five states, only Ohio (11.2% in 2003) and Texas (5.5% in 2003) reported a smaller share of SO_2 emissions last year.

To put the impacts of CAIR into perspective consider Ohio, the largest state emitter of electric plant emissions. In order to comply with 2015 CAIR standards, 49 of Ohio's largest non-scrubbed units (16 GW) would need to be retrofitted with emission controls – the cost alone will range from $4 to $6 billion. Since 33 of these 49 generating units were built more than 35 years ago, decisions to retrofit will need to be carefully weighed with investment in new generation and other compliance strategies.

Which companies are affected?

To better understand the company impacts of the new EPA rules consider the 25 largest electric generators in the United States (Figure 3). The group as a whole accounted for 71% of all electric generating unit SO2 emissions and 59% of all NOx emissions in 2004. The top 3 companies, American Electric Power, Southern Company and the Tennessee Valley Authority alone accounted for more than 23% of the annual SO2 emissions and 20% of the NOx emissions nationally. Rounding out the top 5 in terms of emissions score (the combined SO2 and NOx ranking) are Cinergy and Progress Energy.

Figure 3

Top 25 U.S. Fossil Electric Generating Holding Companies

Holding Company--HQ State	2004 SO_2 (tons)	2004 NO_x (tons)	Number of Fossil Units	Total Fossil Nameplate Capacity	--Rank out of 355 Holding Companies-- SO_2	NO_x	Fossil Generation
American Electric Power--OH	976,730	320,610	94	34,374	1	1	1
Southern Company--GA	876,808	215,299	118	33,351	2	2	2
Tennessee Valley Authority--TN	488,315	199,155	83	19,476	4	3	3
Cinergy Corp--OH	570,497	114,508	66	13,290	3	5	8
Progress Energy, Inc--NC	349,996	104,912	77	19,499	6	7	14
Ameren Corp--MO	318,178	67,582	64	13,753	7	12	7
Duke Energy Corp--NC	285,440	68,644	86	19,120	8	11	10
Edison International--CA	271,078	90,588	25	11,831	10	9	11
Allegheny Energy Inc--MD	355,419	60,648	39	9,216	5	14	17
Dominion Resources Inc--VA	224,268	107,067	64	17,654	15	6	9
FirstEnergy Corp--OH	267,296	74,016	36	9,191	11	10	15
Xcel Energy Inc--MN	154,995	121,291	56	12,162	18	4	6
PPL Corp--PA	272,268	50,127	51	9,026	9	18	22
DTE Energy--MI	212,360	66,577	37	10,218	16	13	24
Scottish Power plc--OR	94,536	96,350	44	8,197	25	8	13
Reliant Energy Inc--TX	239,579	48,049	79	16,727	13	20	19
Mirant Corp--GA	235,668	48,695	50	14,449	14	19	21
TXU Corp--TX	239,823	43,578	35	15,464	12	22	12
FPL Group--FL	123,134	58,219	51	22,072	23	15	4
E On Ag--NY	167,792	42,056	32	8,218	17	23	23
Entergy Corp--LA	77,978	58,121	65	19,055	33	16	16
AES Corp--VA	132,216	34,033	45	12,590	20	29	18
Dynegy Inc--TX	93,026	32,800	59	12,489	26	33	25
Texas Genco--TX	76,818	16,975	22	9,759	35	53	20
Calpine Corp--CA	195	4,892	71	24,095	198	100	5
Top 10 Total	**4,716,731**	**1,349,013**	**716**	**191,563**			
% of U.S.	**46.8%**	**37.1%**	**22.7%**	**27.9%**			
Top 25 Total	**7,104,414**	**2,144,792**	**1,449**	**395,274**			
% of U.S.	**70.5%**	**59.1%**	**45.9%**	**57.6%**			
U.S. Totals for 355 Holding Companies	**10,082,676**	**3,700,628**	**3,157**	**686,289**			

* The emissions score is the sum of each companies SO2 and NOx emissions rank among 355 electric generating holding companies nationwide. Low scores reflect high emissions.

At the other end of the spectrum is Calpine with a predominately new gas-fueled fleet. Calpine ranked 5th in fossil generation in 2004, but 198th and 100th respectively in SO_2 and NO_x emissions. Along with Calpine, Texas Genco, LLC, and Dynegy Inc. represent the largest fossil fuel generators with the least amount of emissions.

The recently proposed merger between Cinergy and Duke Energy will move the new holding company to 3rd nationally while the proposed merger of Exelon and PSEG would create the 20th largest emitter nationally.

Which generating units are most affected?

To better understand the benefits of emission control investment consider the 25 largest SO_2 emitting generating units (Figure 4). The group consists of coal units all built during the 1960's and 1970's. In 2004, the group accounted for 14% of the nation's electric plant SO_2 and represented nearly 19% of the CAIR rule clean-up necessary to meet 2015 standards. The average size of each unit is more than 760 megawatts and during 2004, the group ran at nearly 71% of capacity. Based on those parameters, their allocated 2015 emission budgets and assuming the addition of new emissions controls, the group could generate nearly 50,000 surplus allowances annually by the first year of phase II compliance in 2015.

Nationally, based on 2004 annual emissions, older units (> 35 years) emitted 423 times more SO_2 and 33 times more NO_x than newer units built since 1999, yet at the same time, these older plants generated only 1.8 times more electricity (Chart 5). The newer units are predominately cleaner gas fired units with state of the art emissions control equipment. Most of the units operating prior to 1980 are not scrubbed – 86.4% of the nation's SO_2 emissions are generated by fossil units currently without emissions control devices. This is about to change as many of the largest emitters in the country are in the process or have recently announced plans to invest in control technologies.

Figure 4

Top 25 Largest Electric Generating Unit SO_2 Emitters in 2004

State	Plant Operator--Name--Unit	Online Year	2004 SO_2 Emissions (tons)	Nameplate Capacity (MW)	Capacity Factor	Reductions Needed to Comply with CAIR in 2015*	Estimated SO_2 Allowance Banking with Scrubber
PA	Reliant Energy Mid Atlantic--Keystone (PA)--1	1967	90,039	936	78.5%	80,162	873
PA	Reliant Energy Mid Atlantic--Keystone (PA)--2	1968	79,730	936	71.6%	69,214	2,543
PA	Midwest Generations EME--Homer City Station--2	1969	75,736	660	81.7%	70,026	-1,864
PA	Midwest Generations EME--Homer City Station--1	1969	70,023	660	75.7%	63,808	-787
PA	PPL Montour LLC--Montour--MT1	1972	64,333	806	71.4%	55,866	2,034
OH	Cincinnati Gas & Electric Co--Miami Fort--7	1975	62,946	557	70.9%	57,133	-482
PA	PPL Montour LLC--Montour--MT2	1973	62,343	819	66.1%	53,705	2,404
PA	Allegheny Energy Supply Co--Hatfields Ferry--1	1969	61,414	576	69.4%	55,705	-432
KY	Tennessee Valley Authority--Paradise--3	1970	55,177	1,150	49.5%	46,248	3,412
PA	Allegheny Energy Supply Co--Hatfields Ferry--3	1971	54,531	576	60.5%	48,454	625
AL	Alabama Power Co--E C Gaston--5	1974	53,561	952	67.2%	44,529	3,676
IN	PSI Energy Inc--Gibson Station--3	1978	52,310	668	73.5%	46,110	969
WV	Allegheny Energy Supply Co --Fort Martin--2	1968	50,734	576	78.2%	44,515	1,145
PA-	PPL Brunner Island --PPL Brunner Island--BI3	1969	50,453	790	78.1%	42,330	3,078
GA	Georgia Power Co--Wansley (GPC)--1	1976	50,402	952	77.2%	39,721	5,641
GA	Georgia Power Co--Bowen--3	1974	50,393	952	77.8%	39,563	5,790
IN	Indiana Michigan Power Co--Tanners Creek--4	1964	50,330	580	65.1%	46,583	-1,286
OH	Ohio Power Co--Muskingum River--5	1968	50,070	615	70.3%	43,963	1,100
WV	Allegheny Energy Supply Co--Fort Martin--1	1967	49,082	576	72.0%	42,804	1,369
GA	Georgia Power Co--Wansley (GPC)--2	1978	47,466	952	70.0%	37,592	5,127
OH	Columbus Southern Power Co.--Conesville--4	1973	47,143	842	38.5%	39,782	2,647
NC	Duke Energy Corp--Belews Creek--2	1975	45,840	1,080	82.0%	34,444	6,812
IN	PSI Energy Inc--Gibson Station--2	1975	45,521	668	75.9%	39,332	1,637
OH	Cardinal Operating (AEP)--Cardinal--1	1967	44,283	615	71.7%	39,111	744
TX	TXU Generation Co LP--Big Brown--2	1972	43,483	593	86.6%	36,525	2,609
		Total	**1,407,344**	**19,087**	**70.8%**	**1,217,227**	**49,382**

* 2004 SO_2 Emissions minus 2015 CAIR SO_2 emissions budget.

** Potential annual SO2 allowance banking assuming the addition of scrubbers with 90% removal efficiency

Figure 5

2004 U.S. Fossil Electric Generation & SO_2 Emissions by Plant Age

	Net Generation (TWh)	%	Summer Capacity (MWs)	%	SO_2 Emissions (Tons)	%	SO_2 (Tons/GWh)	NO_x Emissions (Tons)	%	NO_x (Tons/GWh)
New Plants (1999-2004)	390	11.6	190	24.9	11,149	0.1	0.03	40,199	1.1	0.10
1990 to 1998	188	5.6	50	6.6	95,120	0.9	0.51	108,684	2.9	0.58
1980 to 1989	915	27.3	132	17.3	1,484,812	14.7	1.62	807,411	21.8	0.88
1970 to 1979	1,157	34.5	221	29.0	3,772,011	37.4	3.26	1,404,011	37.9	1.21
Old Plants (pre-1970)	700	20.9	169	22.2	4,719,584	46.8	6.74	1,340,323	36.2	1.91
Total U.S.	3,350	100	762	100	10,082,676	100	3.01	3,700,628	100	1.10

Compliance

To comply with the CAIR rules, generating companies will need to carefully weigh the costs and benefits of adding emissions controls, expanding their renewable generating portfolio, building new clean coal generating plants or securing and banking enough emission credits to comply with the stringent EPA caps.

The cost of complying with CAIR has been estimated by industry experts at between $50 and $60 billion during the next 15 years. Several heavily impacted companies are currently adding scrubbers and NOx controls or have announced their intentions to invest heavily in emissions technologies. American Electric Power is expected to spend $5 billion retrofitting their fossil plant fleet over the next 15 years. The Tennessee Valley Authority recently announced plans to invest an additional $4 to $5 billion to the nearly $4 billion invested in emissions controls since the 1970's. Add to these announcements recent decisions by Southern Company, Cinergy, Duke Energy and Progress Energy to invest in emissions controls as well.

Additionally, according to the EPA, to date there have been nine settlements addressing New Source Review (NSR) violations with a combined effect of reducing nearly a million tons of emissions through the installation of $5.5 billion worth of pollution controls.

At the same time investments are being made for emissions controls, companies are investing heavily in renewable energy – wind development is at an all time high. Driven by the predicted extension of the federal production tax credit (PTC), wind capacity is expected to more than quadruple during the next 5 years alone. In addition, according to Global Energy's NewEntrant project tracking system, there are more than 37 GW of new coal projects planned – more than 15 GW are clean burning coal gasification and fluidized bed technologies. And finally, adding to the myriad of complex compliance decisions, the prices of SO2 and NOx allowances have increased dramatically since the EPA CAIR rules were put into motion this past March. In May, average trades for SO2 and NOx were $840 and $3,300 respectively – SO2 allowance prices were running four times higher than during the same period a year ago.

Given the convergence of the new CAIR regulations and state renewable energy standards, one thing is for certain, "Clear Skies" will become a reality. Global Energy projects more than $100 billion will be invested in a combination of emission controls and renewable energy projects nationwide during the next 15 years. This does not include additional investments in new clean coal and long-term nuclear power projects.

Kent Knutson, Manager of the Renewable Energy Project | kknutson@globalenergy.com, 720-221-2121

Opening Electric Markets in Japan:

Overnight move from feast to famine for some Japanese utilities

The Japanese electric markets are opened for wholesale market competition in April. While many are optimistic about the opportunities for generators in this market, opening the market to inter-area competition will have profound effects on prices, power trading and transfers as well as on the need for new capacity that will affect the market for years to come. This Briefing Report looks at the changing Japanese market.

An Overnight Shift? Really?

The Japan Electric Power Exchange (JEPX) is scheduled to opened in April, marking the start of wholesale electric market competition in Japan. At the same time low voltage customers become eligible for retail electric choice. With the opening of low voltage competition, all retail customers will have a choice of electric provider.

So far each region (or utility territories) has been shielded from out-of-area competition by T&D charges that by most standards are astronomical. T&D charges (or wheeling rates) are the electric equivalent of tariffs and duties on international trade and their removal could potentially have a huge impact on the way electric power is generated and distributed in Japan. Up until now, Japanese wheeling rates have averaged well over ¥2/kWh (about US$16/MWh and 7-8 times higher than U.S. averages).

Moreover, the rates are pancaked when sending power across more than one transmission area, resulting in cross-country transfers of electric power quickly becoming more expensive than native generation. For instance, let's say you want to sell the output from your coal-fired plant in the Chugoku (Hiroshima) area to a buyer in Chubu (Nagano). The over-the-fence cost of the power is about ¥2/kWh and total wheeling costs after sending the power across the Kansai area and into Chubu is approximately ¥3.5/kWh, bringing the total cost delivered in Chubu to about ¥5.5/kWh. The cost of this power is more expensive than a comparable combined cycle station located within Chubu and almost on par with a Chubu gas-steam unit thus providing little incentive to wheel low cost baseload power and share reserves among market areas.[1]

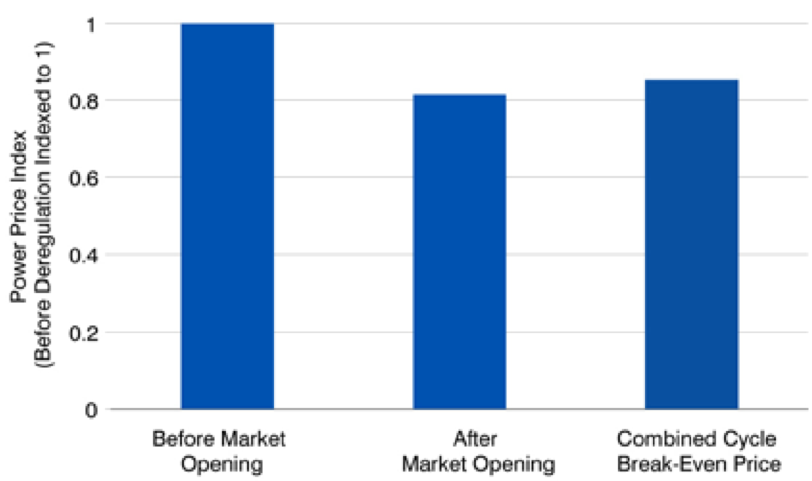
In the 2005 market all per unit wheeling rates are set to be removed as operation of the grid moves to the Electric Power System Council of Japan (ESCJ), which will function as an independent transmission operator where costs for operation of the grid are no longer tied to the MWhs moved.

[1] Based on a $6/MMBtu price of natural gas. If oil prices would come down to about $30/Bbl it would actually be less expensive to run a 10,000Btu/kWh oil-steam unit than to import power from two wheels away.

Why is this so important? Well, in a nutshell before deregulation wheeling power is expensive, resulting in high reserve margins, extensive use of existing inefficient capacity to meet peak demand and ultimately, high power prices. In this world it is profitable to build new capacity, and there are about 16,000 MW of new capacity in some form of development that supports this notion. However, when wheeling rates are eliminated, it becomes economical to move cheap baseload power across regions and the high heat rate units that today are used frequently would be sitting idle. As a result, power prices drop significantly and reserve margins can be allowed to decline towards 15-17 percent without any loss of reliability. This renders new capacity largely unneeded for nearly a decade and makes the outlook for new merchant generation capacity to look pretty gloomy.

Figure 1 shows the approximate impact on power prices (energy-only without compensation for capacity) before and after eliminating wheeling rates. Figure 2 shows the average inter-area transfer between market areas before and after eliminating wheeling rates, and Figure 3 shows the estimated net revenues for a new combined cycle plant before and after eliminating wheeling rates.

Figure 1
Relative Power Prices Before and After Eliminating Wheeling Rates



SOURCE: Global Energy Decisions

Figure 2
Inter-Area Transfers of Power Before and After Eliminating Wheeling Rates

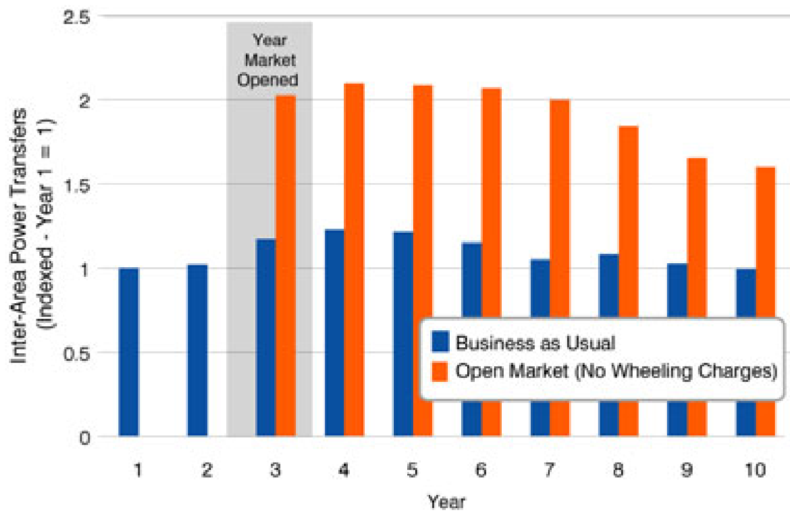
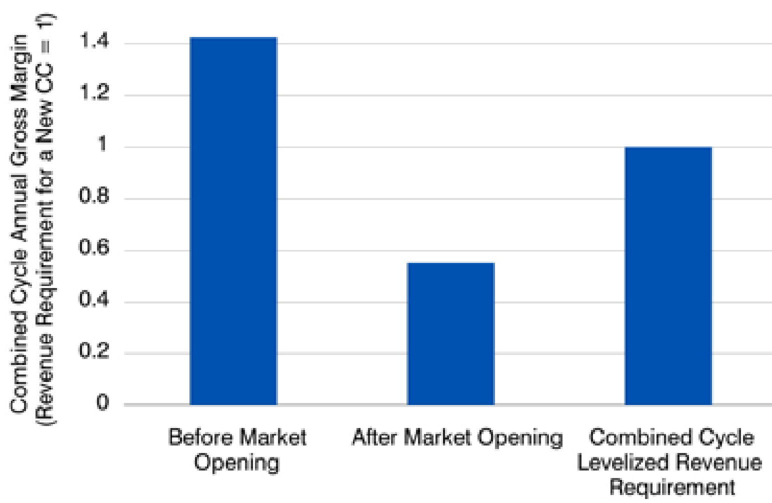


Figure 3
Generic CC profitability before and after deregulation



The results are dramatic. Prices fall by about 20 percent, average inter-area transfer of power doubles and profitability of a new combined cycle station falls from about 40 percent in excess of the investment threshold for a new plant to a non-starter, receiving only about half of what the plant needs in order to realize reasonable returns on equity and cover fixed and financing costs. This analysis is based on an energy-only analysis of the market where generators are assumed to bid only their incremental cost into the market. While in reality some bidding markups of prices could be expected, our model gives some sense of the magnitude of change that market can expect upon opening.

What is the rationale for this change? As discussed above, when wheeling charges are removed, it becomes economic to transfer more power between market areas so as to use low cost baseload power more efficiently. At the same time, the need for running high-cost oil- and gas-fired plants decrease and thus power prices fall, along with the profitability for new capacity in the market.

In the context of the significant changes projected above, it is perhaps interesting to take a closer look at J-Power's (or Electric Power Development Company) recent IPO, especially since it is one of the largest IPOs in history. Also, since it started trading publicly, the stock has increased by about 20 percent—from an introductory price of ¥2,700 to about ¥3,200 as of February 2005.

J-Power stands in a rather unique position with respect to further market deregulation. Global Energy's analysis suggests that opening the electric markets would benefit J-power. The main reason for this result is J-Power's heavy reliance on assets with low dispatch costs—all of its capacity is either coal-fired, hydro, or nuclear (future), the very types of assets that we would expect to see being utilized more heavily when pancaked wheeling rates are removed.
However, depending on the final shape and tariffs applicable in future transmission markets, there is a risk of some negatives as well. About 11 percent of J-Power's electric market revenues currently come from transmission.[2] There is a risk that these revenues will decline substantially or vanish completely after the elimination of pancaked wheeling charges.

In order to get a sense of how J-Power's value might be affected by the market opening, Global Energy compared two simulated market outcomes for the next 15 years, one in which the current wheeling rate structure is maintained (status quo case) and one in which all wheeling rates are eliminated, allowing for a freer flow of power among market regions (open market case). Using the 2004 J-Power IPO price as a benchmark, we found that the projected cash flow of our status quo case would put the real discount rate implicit in J-power's IPO at about 12.1 percent. That is, with a 12.1 percent real discount rate, our projected cash flows, adjusted for debt, would correspond to a stock price of ¥2,700. Now, switching over to the cash flow in the open market case where J-power no longer receives any wheeling revenues and using the same 12.1 percent discount rate, the implied stock price would jump to about ¥2,900, a slight increase compared to the IPO price, but well below the ¥3,200-3,500 market prices observed in early 2005. This before-after comparison suggests that J-power would end up a net winner of further market liberalization even if it would lose most or all of its current wheeling revenues. The higher prices at which the stock traded in early 2005 also indicates that the market expects to see J-power as a winner in a competitive electric market.

[2] Based on J-Power's 2004 Annual Report.

Utilities that rely more on gas- and oil-fired capacity cannot be expected to be as lucky. As illustrated in the above figures, units that are more often on the margin such as gas- and oil-fired units should expect to see significant declines in profitability, since with a more efficient use of baseload generation there will be less need to run high heat rate peakers in each respective market area (region). As a result, it should not come as a surprise if in the nearest few years, we observe patterns similar to those taking place right now in the United States: extensive mothballing of older high heat rate capacity and increasing demands among generators for separate non-market compensation for installed capacity (ICAP or LICAP).[3]

Olof Bystrom, Project Manager, Global Energy Decisions | obystrom@globalenergy.com

Thomas O'Meara, Senior Vice President, Global Energy Decisions | tomeara@globalenergy.com

[3] i.e., economic compensation for remaining capacity that is deemed needed for reliability but that is not utilized sufficiently to be sustainable on energy sales alone.

Global Energy Acquires KWI

Combination creates platform that can deliver full range of operational and financial solutions to energy companies worldwide

In July, Global Energy acquired KW International, Ltd. (KWI), a leading energy trading and risk management (ETRM) software firm. Financial terms of the transaction were not disclosed.

"Our acquisition of KWI advances our ongoing effort to offer a full range of operational and financial solutions to companies active in the highly competitive and dynamic global energy marketplace," said Ron McMahan, Chairman and Chief Executive Officer of Global Energy. "KWI provides us with a proven, multi-commodity ETRM product that rounds out our product suite, an expanded international customer base, and a team of highly experienced trading experts."

As part of the transaction, KWI and Global Energy will consolidate London offices, creating a single European headquarters for Global Energy. KWI's management team, including Chief Executive Officer David Bucknall, will remain with the newly combined company, which retains the Global Energy brand name. Quadrangle Group LLC remains a shareholder in Global Energy and Insight Venture Partners, a previous backer of KWI, will take an equity stake in Global Energy.

"KWI's combination with Global Energy is a great fit for KWI and our customers," said Mr. Bucknall, Global Energy's new Chief Technology Officer and a member of the combined company's executive management team. "We and our new colleagues at Global Energy share a similar vision for the global energy industry. Our highly complementary pairing provides us with the resources and expertise we need to grow and enhance the value we deliver to our clients worldwide."

The combination of Global Energy and KWI represents an important step in Global Energy's commitment to deliver an integrated product line to meet the needs of the modern energy industry. An increasing number of companies want physical and financial analytics integrated with ETRM, particularly those with physical assets.

"Utilities and energy companies attempting to cover their enterprise risk profile and to enable revenue enhancement are looking for comprehensive solutions," explained Terry Ray, Vice President-Energy and Utilities Strategies at Gartner Group. "The ability to deploy pre-wired applications that link supply, demand, and markets can provide significant advantages."

While KWI's flagship ETRM product K2 will be available on a stand alone basis, Global Energy is working to integrate K2 into its EnerPrise EPM platform. With K2, Global Energy now offers a comprehensive and integrated suite of software and services on a single platform, including forecasting, generation modelling, simulation, financial planning, market data/analytics, and ETRM solutions.

"Integrating the sophisticated trading and risk management capabilities of K2 with Global Energy's EnerPrise platform enables us to greatly enhance our clients' risk management, asset optimization, price forecasting, planning, and trading capabilities," said Vikram Janardhan, President of Global Energy's software division.

Andy Bane, Vice President of Operations and Marekting, Global Energy Decisions | abane@globalenergy.com

Trends in Power Generation Asset Sales

Buyers & sellers, regions, prices

Over the past two years the trend in generation power plant sales has picked up and continued at a healthy pace with almost 70 announced transactions of over 50 GW of capacity. This represented just under $16 billion in total value (cash and debt assumed).

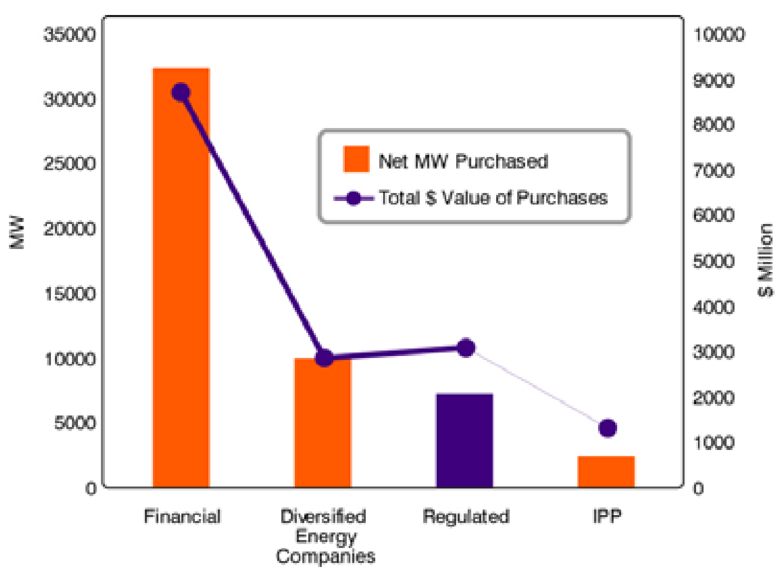
Buy Side Dominated by Financial Players

Financial players including private equity groups and investment banks dominated the buy side picking over 60 percent of the total MWs sold and were responsible for over 50 percent of the total value of the capacity purchased (see figure 1). This group of buyers also paid the least on an average $/kW basis. As figure 2 indicates, three of the top five buyers by net MW were financial players.

The vast majority of the financial players are private equity groups including ArcLight Capital Partners, Kohlberg Kravis Roberts, MatilinPatterson, AIG, and Complete Energy. In the largest transaction, four private equity firms—KKR, Texas Pacific Group, Blackstone and Hellman & Friedman—joined to purchase Texas Genco's 16,400 MW of assets. In one deal, the private equity firm Carlyle/Riverstone teamed with Sempra Energy to buy a collection of AEP's plants in Texas.

Figure 1

2004 Buyers by Total Value



Diversified energy companies, those entities with both regulated and unregulated subsidiaries, and regulated utilities (including munis and co-ops) were distant second and third buyers by MW capacity and total dollar value.

Figure 2
Top Five Buyers by Net MW (2003-2004)

Buyer	Seller	Net MW	Total $M	$/kW
GC Power Acquisition LLC (KKR, Texas Pacific Group, Blackstone Group, Hellman & Friedman)	Texas Genco (CenterPoint unregulated assets)	16,388	$3,650	$223
KGen Partners LLC (MatlinPatterson)	Duke Energy	5,321	$475	$89
Sempra Energy and Carlyle/Riverstone	AEP	3,813	$430	$113
Dominion Resources	USGen	2,839	$656	$231
Goldman Sachs	Cogentrix	2,544	$558	$219

SOURCE: Global Energy Decisions

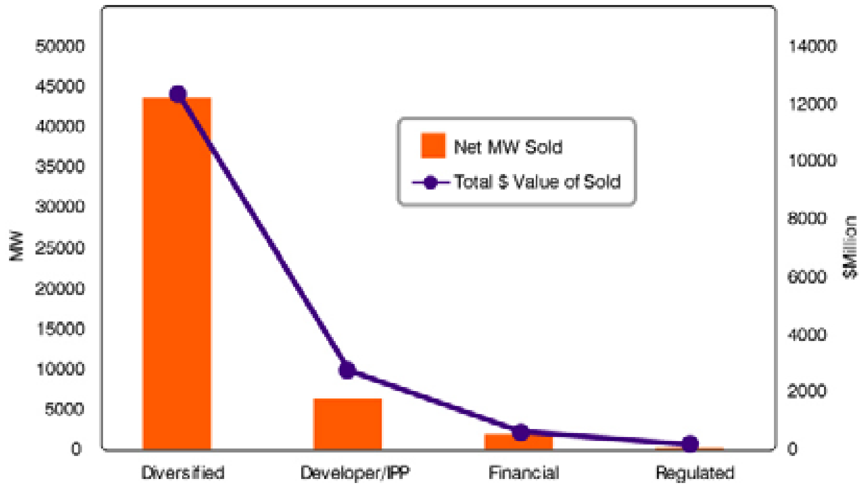
Although not shown in the buyer's column yet, hedge funds will likely make an appearance soon. These firms, which are proliferating, not only have the capital (estimated at $1 trillion under management), but also are even more nimble and can move fast. They have already tested the waters in a big way—one of the three runners up for the Texas Genco assets was a consortium of hedge firms. The other runner up was another private equity consortium.

Diversified Energy Companies Are the Top Sellers

Figure 3 on the next page shows the breakout on the sell side was equally lopsided with diversified energy companies responsible for over 80 percent of the capacity sold. The top three sellers in this category were CenterPoint, Duke Energy, and AEP, and they made up over 65 percent of group total. The average value for the assets sold by this group was about $280/kW, the lowest.

Developer/IPP and financial players represented respectively 12 percent and 3 percent of sales by capacity (and 17 percent and 4 percent by total dollar value) with regulated utilities having negligible sales.

Figure 3
2004 Sellers by MW and Total Value



SOURCE: Global Energy Decisions

For a number of the diversified energy companies such as Aquila, El Paso, TECO Energy, and Allegheny Energy, their assets represent a strategy shift away from unregulated power business. In many cases this was a by necessity “back-to-basics” tactical move.

With the significant amount of capacity picked up by private equity groups it may be expected that these players will be at the top of the seller list in a few years as they look to unload assets to pay back limited partners over the four to seven year life of the their funds. Yet, as they have done in other industries, and to some extent in power, financial players will likely sell and buy assets among themselves. There are some private equity groups whose investment strategy is focused on purchasing and holding high quality assets generating steady long run returns. Energy Investors Funds Group, which has been in business and focused on energy assets since the birth of the IPP industry in the late 1970s, exemplifies this approach.

Gary L Hunt, President, Global Energy Advisors I ghunt@globalenergy.com

Mark Griffith, Vice President, Global Energy Advisors I mgriffith@globalenergy.com

Devrim Albuz, Manager, Power Generation BlueBook I dalbuz@globalenergy.com

New World of Higher Oil and Gas Prices

After a year of dramatic events, which saw oil prices climb toward $60 a barrel, analysts polled by Thomson First Call in February, for example, said they expected oil to average $40 a barrel. But so far this year spot prices have not cooperated with expectations.

Lately crude-oil futures remain stubbornly high, despite Energy Department and industry rig count and inventory reports that would suggest a softening of prices should occur. Yet, there is an indication that there has been a fundamental shift in the oil markets. Early in 2005, OPEC abandoned its old price target of $25 a barrel. This was followed by Saudi Arabia, the world's largest oil producer, announcing that its forecast price range is $40-$50 for the year. Hence, the belief on the part of analysts that the past year's higher plateau reflected a temporary bubble and oil prices will return to "normal levels" is likely to be misplaced.

Thanks to surging demand for cleaner-burning fuel, worldwide natural gas consumption has risen faster than oil as utilities around the world build gas-fired power plants. This creates higher gas prices and more volatility. The world consumed 91.5 trillion cubic feet of natural gas in 2003, up 13 percent from five years before. Over the same span, the globe's thirst for more oil grew 7 percent.

Global Competition for Energy Resources

What perhaps has not sunk in with many observers is that the global energy marketplace is dramatically changing. Consider the growing competition for energy resources:

- India and China will significantly increase their imports of oil and gas if their economies are to continue growing at annual rates of 6-10 percent.

- China, once an oil exporter, is now the world's biggest oil consumer after the United States, and is increasingly dependent on imports—already a third of its oil is imported.

- India has just reached a $40 billion agreement to import LNG from Iran and develop Iranian oil fields, and is securing pipeline projects to import oil and gas across neighboring countries.

- China National Offshore Oil Corporation has put on the table a $18.5 billion takeover of Unocal of the United States; Sinopec, another Chinese state-controlled oil group, has struck a $70 billion deal to buy Iranian crude oil and liquefied natural gas over three decades. China has sent $6 billion to Rosneft, the Russian company that bought the main production unit of the embattled Yukos oil group, as advance payment for oil supplies.

- India's state-owned energy giant, Oil and Natural Gas Corporation, has announced a partnership in Russia; Indian Oil Corp., a gas development project in Iran; and Gas Authority of India, a stake acquisition with a Chinese energy company.

- Enbridge is reportedly close to agreement to build its $2.5 billion Gateway pipeline from Alberta to the west coast of Canada to export to Asia crude extracted from the country's bitumen oil sands.

- Japan, the world's second largest economy, and highly dependent on energy imports, spent much of last year in a diplomatic confrontation with China over a gas field in a disputed part of the East China sea.

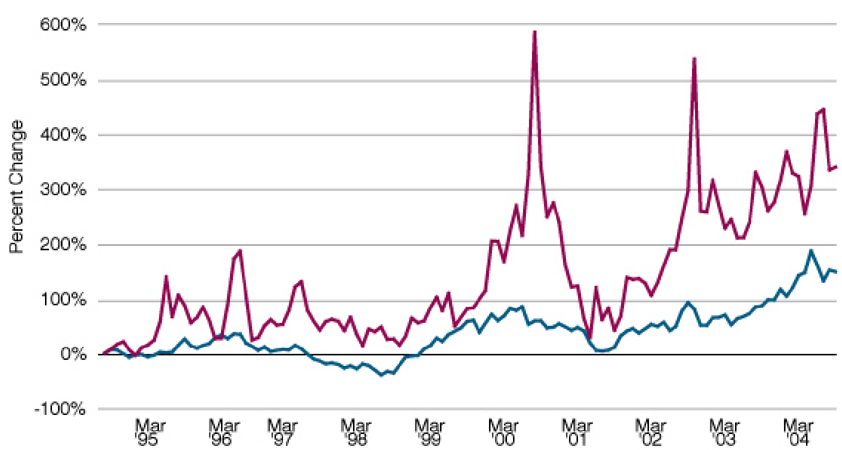
- South Korea, another energy-dependent Asian country, recently signed an agreement to buy $20 billion of LNG from the Russian Far East and Yemen.

- Last year the UK for the first time became a net gas importer.

- The small number of OPEC producers and Russia suggests a formidable force for keeping prices high.

The Federal Reserve Chairman, Alan Greenspan, did offer some solace last October when he noted that in spite of the recent surge in oil prices, average crude prices adjusted for inflation were only three-fifths of the 1981 peak. Moreover, he noted that higher oil prices would eventually lead to the discovery of new reserves, greater investment in new production, and alternative energy sources that would allow supplies to keep up with demand over the long term. Figure 1 shows oil and gas prices have risen significantly since 1995.

Figure 1
Oil and Gas Market Prices Growth



SOURCE: Global Energy Decisions

Energy Legislation

It is far from certain that after two failed attempts to pass an energy bill in the Bush administration's first term that it will succeed in the second term. Recent rising gasoline prices are putting enormous pressure on both the administration and Congress to do something. The president acknowledged in a recent prime-time press conference that there was little the administration could do in the short term to bring down gasoline and energy prices. That perceived need "to do something" in the face of escalating oil and natural gas prices and a strengthened Republican majority in Congress, suggests that an energy bill is more likely to provide tax relief for energy companies than price relief for consumers.

Pressure remains to keep together parts of the earlier bill to open up more federal lands to drilling, and streamlining permits for building new oil refineries and terminals to import liquefied natural gas. The last bill was blocked by the Senate in November 2003, sunk in great part from the weight of more than $30 billion in appropriations that would be disbursed to the energy, utility, and auto sectors.

A stripped-down bill costing around $12 billion is likely to have the best chances of passing. This would probably focus more supply-side measures and steer away from the research elements, notably for renewables and energy conservation that inflated the costs of the previous proposal. The contentious proposal to open up parts of the Alaska National Wildlife Refuge to exploration is also expected to be stripped out. The increasing support for nuclear energy indicates that a new bill may also include strong financial incentives for utilities to build new plants.

There has been no shortage of policy ideas to include in a new energy bill. Perhaps the most ambitious in terms of its efforts to bridge the gap between different interest groups has been that of the National Commission on Energy Policy, made up of a diverse group of environmentalists, academics and former government officials. The commission's December 2004 report, *Ending the Energy Stalemate*, recommended that the government require increases in efficiency in cars and electrical equipment, stimulate global oil production, regulate greenhouse gas emissions with a trading system, rapidly expand a new method of burning coal, and explore a revival of nuclear power. In contrast, the commission found that hydrogen, ethanol, wind, and solar did not justify government support given their unattractive economics.

Energy and the U.S. Budget

The Bush administration's budget for fiscal 2006 would provide more dollars to advance the production of domestic energy from coal, hydrogen and nuclear sources. The Department of Energy's overall budget request for fiscal 2006 of $23.4 billion represents a 2 percent decrease from fiscal 2005 funding appropriated by Congress. Fossil energy programs, on the other hand, would see an 18.7 percent increase in funding under the department's budget request.[4]

---

[4] "Budget Backs Coal, Hydrogen, Nuclear, MarketWatch, February 7, 2005.

Highlights include:

- Over $480 million proposed for coal related initiatives including: coal research, FutureGen, carbon sequestration, and coal gasification;

- Hydrogen Fuel Initiative would receive an additional $35 million in funding in fiscal 2006, bringing total funding to $260 million;

- $3.6 billion in tax incentives through 2010 to spur renewable energy, as well as hybrid and fuel-cell vehicle purchases; and

- $511 million to advanced nuclear-energy technologies and over $600 million proposed for other nuclear related initiatives.

Gary L Hunt, President, Global Energy Advisors I ghunt@globalenergy.com

George Given, Vice President, Global Energy Advisors I ggiven@globalenergy.com

Green Convergence

Renewable Energy and Clean Air Compliance

The electric utility industry has recently witnessed an extraordinary amount of regulatory activity focused on renewed clean air initiatives and new generating technology. "Green convergence", a term recently applied to a combination of state and federal regulatory events, has utility industry executives more closely scrutinizing their generation investment decisions and power supply alternatives.

Electric generation and distribution companies alike currently face the long term impact of compliance with the recently enacted EPA Clean Air Interstate Rules (CAIR) and existing mandates to meet state renewable portfolio standards (RPS). The convergence of these two similar but independent sets of regulations and mandates has utilities in affected states scrambling to develop new strategies to meet both air quality and renewable energy standards simultaneously. The complexity of each set of standards and the difficulty in monitoring results may well lead policy makers toward a national policy addressing not only emissions but renewable energy as well. This article takes a broad look at some of the federal clean air compliance requirements, the nature of state renewable portfolio standards, and some of the investment initiatives planned or underway by electric utilities.

The investment in emission controls necessary to meet federal CAIR standards have been estimated by a number of industry observers at more than $50 billion between now and 2020. In addition to those investments in clean air technology required of generators, a recent study by Global Energy, "Renewable Energy: The Bottom Line", projects that the investment necessary to meet state renewable portfolio standards (RPS) by 2020 will reach $53.4 billion -- $17.6 billion alone in those states also affected by the new EPA CAIR rules by 2015. When fully implemented, Global Energy forecasts both RPS and CAIR will require more than $100 billion in investment over a 15-year window.

At the same time that funds are dedicated to emissions controls, companies are investing heavily in renewable energy. Wind capacity alone is forecast to more than quadruple during the next five years. In addition, according to Global Energy's NewEntrant project tracking system, there are more than 37 GW of new coal projects planned to be operational before 2010 – more than 15 GW are clean burning coal gasification and fluidized bed technologies.

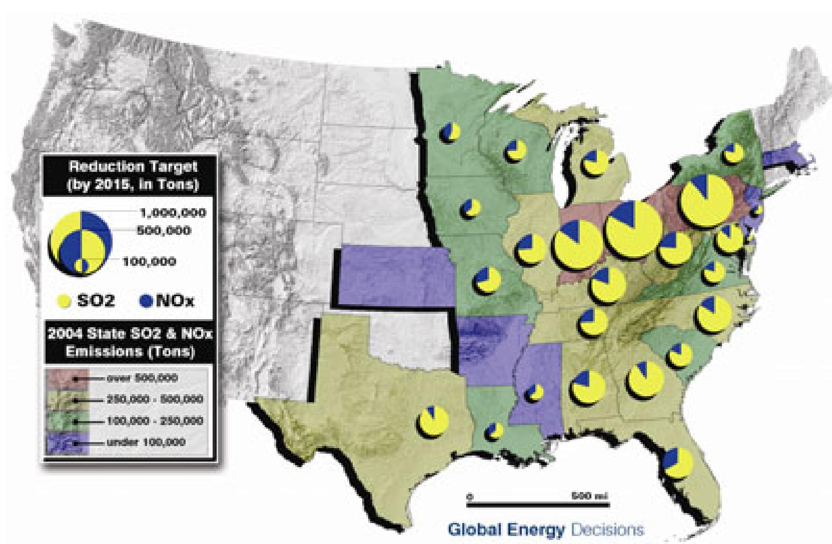
Adding to the myriad of complex compliance decisions facing utility executives, the prices for SO2 and NOX allowances have increased dramatically since the CAIR rules were adopted in March 2005. In May, average trades for SO2 and NOX were $840 and $3,300 respectively, with SO2 allowance prices running four times higher than during the same period a year ago.

Clean Air Interstate Rules – CAIR

The CAIR rulings affect utilities in 28 eastern states and the District of Columbia. Twenty-six of the affected states were granted allowance budgets, or caps for annual SO_2 and NO_X emissions. Two of the twenty-eight states (Arkansas and Massachusetts) are required to comply only with seasonal ozone limiting regulations and are exempt from annual emissions caps under CAIR The EPA's final rules excluded Kansas, based on new analysis of that state's contribution to downwind particulate emissions. The map below illustrates the amount of annual emissions reductions from 2004 levels necessary to comply with the two phases (2009/10 and 2015) of CAIR.

Affected states are required to provide the EPA with a CAIR compliance implementation plan (SIP) by September of 2006. Generating companies reliant upon fossil-fueled generation, primarily coal-based, are responsible for complying with CAIR. Like the Title IV requirements of the 1990 Clean Air Act, CAIR is a 'cap and trade' program. While statewide emissions caps must be met, individual utilities may trade emissions credits among themselves to meet those emissions caps in the most cost-effective manner. The utilities in the states not regulated under CAIR, predominately those located in the western U.S., will continue to meet standards set in the Title IV amendment.

Figure 1
CAIR State 2015 Electric Generator Emissions Compliance Summary



When full compliance is reached in 2015, SO_2 emissions will have dropped by more than 83% and NO_X by nearly 81% since the Acid Rain Program was created in 1990. Today the 28 states regulated by CAIR account for more than 90% of the SO_2 and 77% of the NO_X emissions from electric power plants nationwide.

Figure 2 summarizes the amount of reductions of SO2 and NOx emissions that will be required by electric generating units from 2004 levels in order to comply with the CAIR rules:

Figure 2
Electric Utility Emissions: CAIR Compliance Summary, millions of tons

Electric Utility Emissions: CAIR Compliance Summary
Millions of Tons

	U.S. Total 2004 Actual	CAIR States	% From CAIR States	2009/10* CAIR Target	2015 CAIR Target	% Reduction from 2004 by 2015
SO_2:	10.1	9.1	90%	3.9	2.7	73.3%
NO_X:	3.7	2.8	77%	1.6	1.3	64.9%

* Phase I Nox compliance goes into affect in 2009 while the first Phase of SO2 compliance begins in 2010

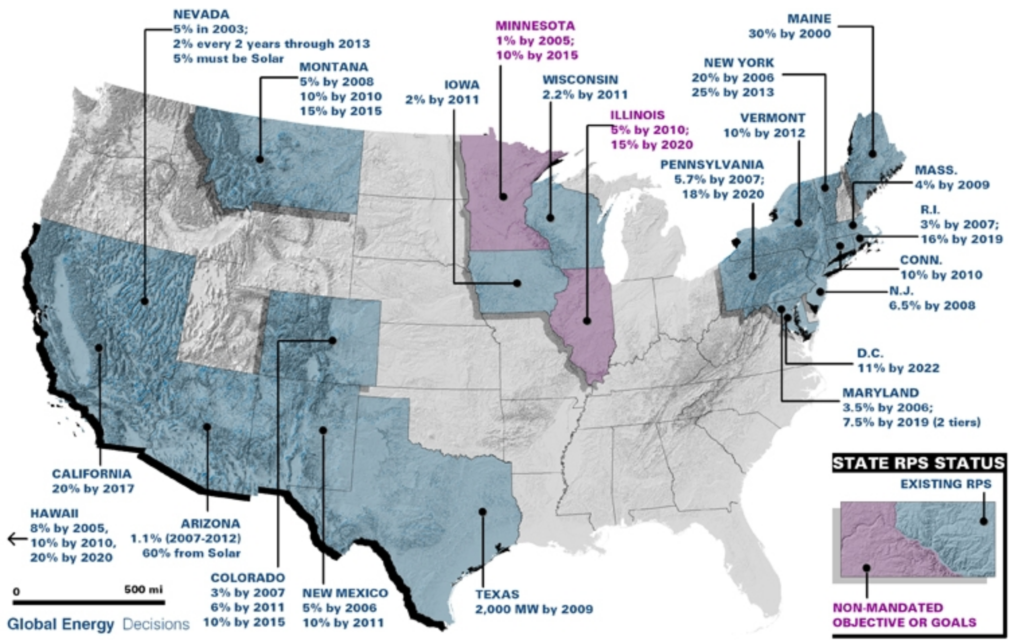
Source: Global Energy Decisions

Renewable Portfolio Standards – RPS

Renewable portfolio standards have been implemented in 21 states and the District of Columbia. The standards vary significantly from state to state: in the timeframe for reaching compliance; the rules regarding what utilities are affected; what technologies count; and what types of incentives are offered. For the most part, however, the RPS rules affect electric distribution companies as they are mandated to meet a specified percentage of their load with renewable energy. Delaware is currently very close to adopting a new renewable portfolio standard. Six additional states have formally considered renewable standards, but have not yet initiated programs.

Today the distribution utilities in states with renewable portfolio standards account for 52.6% of the nation's retail electricity revenue. These states account for virtually all of the current production of solar, wind and geothermal power generated in the United States annually. Figure 3 on the next page illustrates those states with current portfolio standards and key milestones regarding compliance.

Figure 3
Renewable Portfolio Standards



Many industry observers argue that few states with renewable portfolio standards have the necessary clout to enforce compliance. The counter argument is that customers will demand compliance regardless of the costs. A notable example is the referendum held in Colorado in November 2004. Voters in that state passed an RPS requiring the seven largest utilities serving the state to meet 10% of their load by 2015 with renewable energy. The RPS passed even though consumers were well aware of the cost implications – estimated at $2 billion.

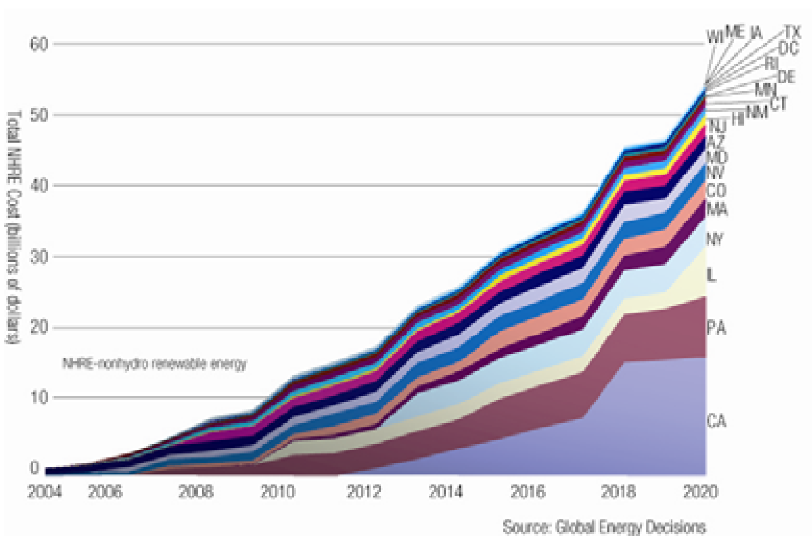
As part of its renewable energy study, Global Energy conducted an economic assessment of current wind power projects. Conclusions from the study indicate that in only a few regional power markets are wind projects profitable without the 1.8 cent/kWh federal production tax credit (PTC). Those areas include parts of California and the Northeastern U.S. In some areas with significant wind resources -- like the Dakotas and Wyoming -- it is currently extremely difficult for wind projects to compete head-to-head with low-cost coal generation, even with the PTC. The good news for wind power technology, however, is that over time, learning rates and experience will improve the economics of this energy resource. As with many new technologies, the costs of generation decline with increasing cumulative capacity in the market. The Global Energy study projects that with each new megawatt of installed wind powered capacity, efficiencies improve and costs decline. The study projects cost reductions for wind projects of more than 30% over the next decade alone.

Regardless of today's challenging regional economics for wind and other difficult obstacles -- including the availability of transmission and the intermittency of output -- it will become increasingly more difficult for utilities to posture against renewable energy. Customers have demonstrated that they will demand it and volatile oil and gas prices will add support for these new generation sources. For affected utilities, the strongest strategic position is to adopt the best renewable technologies and to secure long-term supply agreements with qualified renewable generators.

The Financial Impact of Portfolio Standards

Utilities in California, Pennsylvania, Illinois and New York will experience the largest financial impact of meeting renewable portfolio standards. Given their overall size and the extent of regulations in their state standards, their investment in these new technologies will be substantial. The chart below illustrates the cumulative investment expected by each portfolio state over the next 15 years. Three states -- Maine, Iowa and Wisconsin -- have enacted standards, yet they already comply with the 2020 goals.

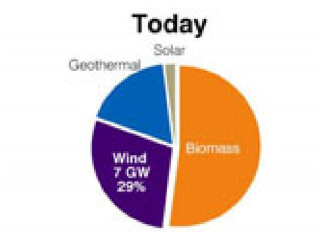
Figure 4
Total Non-Hydro Renewable Cumulative Capital Investment by State

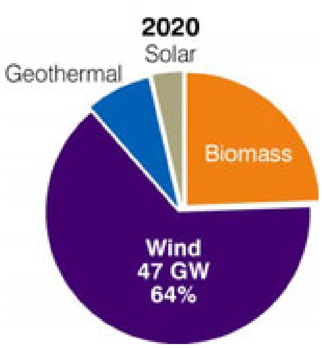


Despite the varying rules and incentives unique to each state, RPS programs share one common thread – the largest electric distribution companies in each state are responsible for meeting a specified percentage of their load with qualifying renewable energy. The top 75 utilities affected by the state standards account for 76% of the cumulative expected 2020 investment in renewable technology, but account for only 28% of U.S. retail electric sales.

In the U.S. today, wind powered technology accounts for about 7 GW of installed electric generating capacity.

Driven by state RPS mandates, wind powered capacity is expected to increase by nearly seven times during the next 15 years – topping 46 GW. By 2020, this resource is projected to provide more than 64% of all non-hydro renewable energy.





A Blustery Future for Renewable Energy: "Wind to Fill RPS Gap"

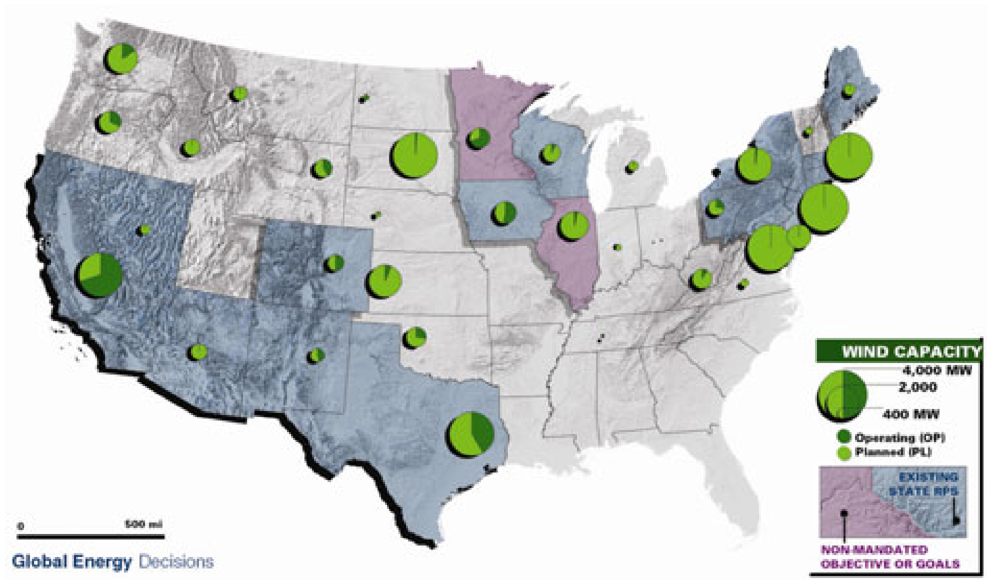
The increasingly attractive economics of wind technology, combined with the emerging initiatives of state governments to curb emissions and lessen dependence on fossil fuel, have created a fertile environment for the development of wind powered generation. The expansion in the number of states implementing renewable standards has given rise to a new era of opportunity for renewable energy in electric markets. Unlike the outcome from the Public Utilities Regulatory Policy Act (PURPA), passed during the late 1970s, the new renewable energy era is being led by individual states and will be met largely with new cost-competitive wind technology.

PURPA created attractive economic incentives for cogeneration (fueled by natural gas) and "Qualifying Facilities" that used renewable resources by guaranteeing a rate of return equal to the avoided cost of developing new generating capacity. While PURPA did stimulate growth in renewable projects during the 1980s, the development was primarily confined to those areas with high avoided costs such as California and the northeastern U.S.

This time around, with federal assistance like the production tax credit, state incentives, and state policies and mandates requiring that utilities meet part of their load with renewable power, the opportunity for renewable project development -- particularly wind turbines -- is extremely high. Additionally, what makes this era different from the 1980s is that it is being driven largely by consumer demand rather than government policy.

According to the Global Energy study, wind powered generation is expected to meet more than 75% of the gap created by the state RPS standards. Though most of the wind capacity operating today is located in states with renewable portfolio standards (80.9%), more than 30% of the wind turbines under construction or in the planning stages are targeted to be built in states without current portfolio standards. These include most of the northwestern states, the Dakotas, Nebraska, Kansas and Oklahoma. This is best illustrated by Figure 5 on the next page highlighting operating and planned wind capacity projects.

Figure 5
Operating and Planned Wind Capacity



The projected renewable generation market share for wind in 2020 is expected to be 64 percent (up from just 29 percent today) implying the need to construct more than 40,000 MW of wind generation over the next fifteen years. The challenges are not limited to building and installing enough turbines. Substantial challenges remain in locating, permitting and assuring sufficient electric transmission capacity to deliver new renewable generation to customers. And, to the extent that intermittent renewable resources become a more substantial portion of generation in regional markets, changes in operating protocols and market rules will need to be made.

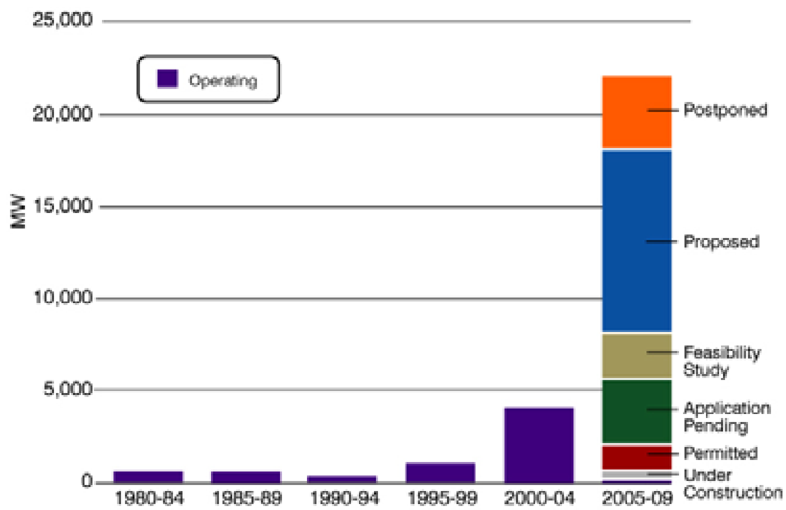
For some, these issues comprise a series of difficult challenges, especially when the business-as-usual approach of thermal generation oriented grid management is concerned. For others, these same challenges represent a number of opportunities to deliver cleaner, ever more economic generating resources to a customer base that seems to increasingly value renewable energy. Interestingly, in both wind and solar generation, many of the new entrants aren't new at all, but well financed, capable generators and equipment suppliers. Perhaps their experience and political savvy may smooth some of the bumps in the legislative and political roads.

Renewable energy is poised to reshape the North American electric power market place through the demand created by renewable portfolio standards being adopted by the states as well as the market, regulatory and economic consequences of expected environmental regulations. Driven by the convergence of clean air regulations and state renewable portfolio standards, significant sums will be spent on the combination of emissions controls and renewable energy technologies.

Global Energy estimates the cost of meeting these converging mandates at over $100 billion over 15 years. Utilities in the states most affected by the CAIR rules will need to quickly decide where to put their money. The consensus is that generators will -- and have already begun to -- invest in emissions controls. However, given the backdrop of higher oil and natural gas prices and the proliferation of state renewable standards many will opt to increase their generation portfolios with renewable energy.

Driven by the recent extension of the production tax credit (PTC) through December of 2005, there are more than 22,000 MW of wind powered generation projects earmarked to come online during the next five years.

Given the uncertainty of another federal extension for the PTC, however, there are very few projects in the planning pipeline beyond 2010.



Understanding the gaps between today's renewable energy portfolio and current emissions, and the levels of each necessary to comply with state and federal standards is essential for every player in the power business today. The convergence of these two similar yet quite different sets of regulations will require a sound analytical approach that carefully weighs the financial and operational tradeoffs of a number of complex compliance options. The winners will be those companies with the most diversified and cost efficient generation portfolios.

Kent Knutson, Manager of the Renewable Energy Project | kknutson@globalenergy.com, 720-221-2121

To RTO or Not-RTO? That is the Question

Transmission Market Planning in the West

Transmission planning has taken on a whole new meaning with the restructuring efforts of the electricity markets. Transmission planners are challenged to anticipate where new generation projects will be built. The location of new generation projects, in turn, depends not only on local project economics, but also on statewide economic development mandates and renewable portfolio standards. This Briefing Report updates how regions with RTOs and those without formal RTOs deal with transmission planning as a work in progress.

Any regional transmission planning initiatives will ultimately need to be squared with the resource plans of load serving entities, primarily existing utilities. Global Energy has yet to see how these separate, but necessarily related, initiatives will be brought together. For example, while transmission planning is being done to move large amounts of new Alberta generation to California, the IRPs filed by California IOUs do not reflect these potential supplies.

As shown in figure 1 on the next page, much of the new generation has been built in the populated coastal areas of California and the populated areas of Western Washington and Oregon. Also, significant generation has been added in the Palo Verde area of Arizona (a high growth state) in the vicinity of Las Vegas, Nevada (a high growth area); and in the Denver, Colorado; and Salt Lake City, Utah; areas. The rest of the new generation is spread throughout the WECC.

There are a number of critical questions that arise:

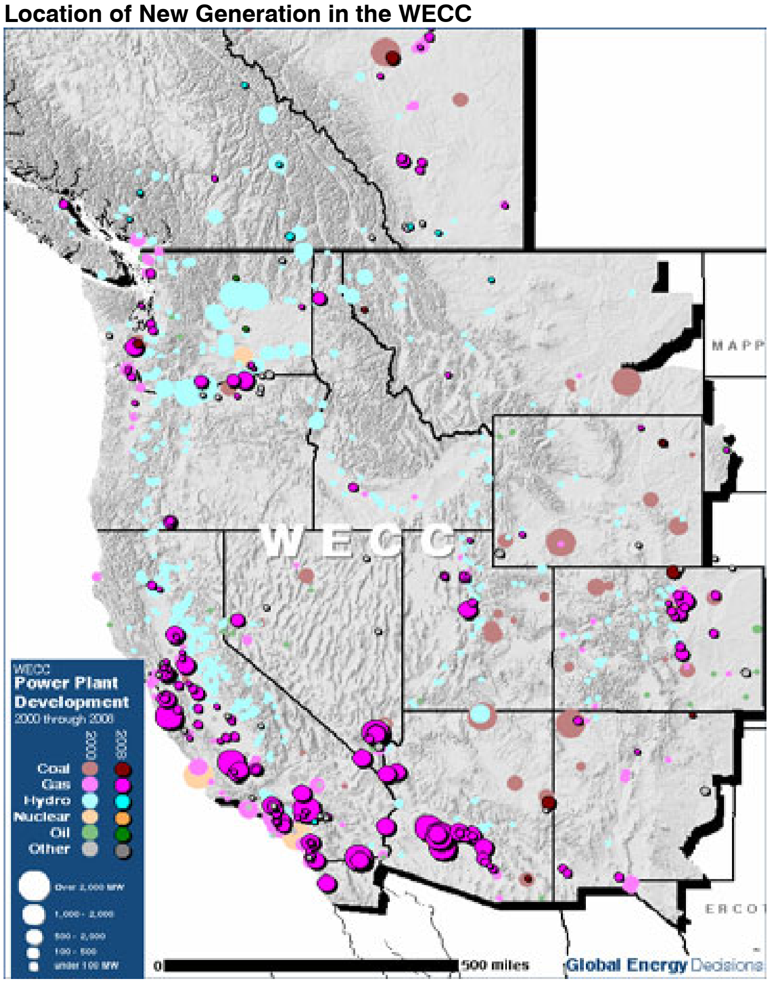
- Is the region building generation near the load in a manner that minimizes the need for major new transmission lines in WECC?
- Has the region built so much generation that it is not harmed if some of the generation is not able to access load because of a lack of new generation?
- Surely generation owners would like better transmission access to many markets, but are they willing to pay for the new transmission?
- Customers may be interested in getting access to new supplies with low operating costs, but does it make sense for them to pay the cost of the new transmission in order to save a little on power costs?
- What about "societal goals" such as increased use of renewable energy resources such as wind, or decreasing the nation's reliance on imported fuel supplies?

Efforts to answer these questions are under way. The first set of issues related to the costs and benefits of new transmission start with the question of reliability. Is a new line needed to demonstrate reliability of supply to loads?

If there is not a need for reliability purposes, is the lack of new transmission causing congestion in meeting loads? Often the answer to this question is "yes." With so much new efficient generation, often it is not necessary to locate it in the local area. The new generation may be cheaper to operate than generation located in some load pocket, far from the new generator. For example, during light load conditions in

Arizona, it might be more economic to operate the new efficient plants in Arizona in order to avoid operating more expensive plants in Southern California. But the lack of new line capacity inhibits this option. In other words, there is presently congestion on this path. Can the efficiencies accomplished by building the new line offset the cost of the new line?

Figure 1
Location of New Generation in the WECC



SOURCE: Global Energy Decisions

Tension exists between generation and transmission projects. On February 24, 2005, CAISO's board of governors approved a 230-mile 500 kV transmission expansion project that will start moving additional power out of the Southwest into heavily populated areas of Southern California. Estimated to cost $680 million, this project, the Palo Verde-Devers 2 (PVD2), will add 1,200 MW of transmission import capacity into Southern California in 2009. To be constructed, however, PVD2 still needs approval from the California Public Utilities Commission (CPUC).

At the same time, Calpine Corporation announced on February 22, 2005, plans to re-start the building of a 775 MW combined cycle power plant in Southern California using General Electric Company's most advanced gas turbine technology. Calpine's Inland Empire Energy Center is targeted for commencement of commercial operation by mid-2008. Will this, and perhaps other new power plants constructed in Southern California, offset the economic benefits attributable by CAISO to PVD2?

Integral to the RTOs function is the planning and evaluation of transmission projects. In early 2003, CAISO, for example, filed a general blueprint of a methodology to evaluate transmission upgrades. Called TEAM, for Transmission Economic Assessment Methodology, it incorporates elements of market prices, treatment of uncertainty, network modeling (with data provided by the WECC) and substitution of generators or demand-side management in place of the proposed transmission project. TEAM has been undergoing continued development with input from many stakeholders including out-of-state interests such as BPA. The TEAM approach was used to evaluate the upgrade of Path 26 (CAISO staff reported it "may be economic," but was not economic in certain scenarios) as well as the upgrade of PVD2, which was found to be economic.

Several in-area CAISO projects are discussed to illustrate some of the issues that occur with transmission evaluations within an RTO.

California upgraded its Path 15 transmission line and put it into operation on December 14, 2004. The upgrade of this 84-mile key electrical connection between Northern and Southern California (NP15 and SP15) increased the path rating to 5,400 MW from 3,900 MW. What was unique about this upgrade was the financing of the line that involved a public-private partnership between Pacific Gas and Electric Company, Western Area Power Authority and Trans-Elect, a merchant transmission owner that arranged most of the financing for the project. The three entities will share ownership of the line's capacity in what is now being challenged as an inequitable arrangement.[5]

CAISO also approved a 25-mile Antelope-Pardee line to help deliver wind energy from the Tehachapi and Antelope Valley to the California grid. The Tehachapi range already has over 600 MW of installed wind capacity on line and the potential for about 4,000 MW. Construction of this line may be instrumental in helping

[5] This ownership arrangement is being challenged by SDG&E, the California Electricity Oversight Board, and others because WAPA put up only 1 percent of the funding and ends up with the rights to 10 percent of congestion and firm transmission right auction revenues.

California's IOUs meet the state's Renewable Portfolio Standard (RPS). However, although CAISO has a key role in approval of a transmission line, SCE, as a CPUC jurisdictional entity, had to obtain final permission to build the project from the CPUC.

Assignment of responsibility for financing transmission is becoming a major issue as the CPUC approved the project, but directed SCE to finance the transmission line project and recover the associated costs in rates. SCE, joined by PG&E, argued that under FERC policy the generators must fund the projects. The Second District of California Court of Appeal agreed, ruling on August 31, 2004, that the CPUC was wrong to assign responsibility to the utilities for the cost of upgrading the grid to accommodate the wind resources. This is not a novel concept, as other, conventional types of generators have been required to finance the network upgrade costs in the past. Recently, FERC ruled that Calpine and Reliant Energy must pay Nevada Power for transmission service from a 500 kV transmission line under construction even if they never build the power plants that would use the new line.[6] Do the wind developers have the financial wherewithal to take on the potentially high cost of funding such a line? If the line is delayed or not built, how will it impact the ability of the IOUs to meet the state's RPS? These are key questions that need to be addressed. For example, an issue with the Tehachapi transmission is that to meet the RPS standards by 2010, FERC must approve a new regulatory category for renewable transmission facilities. This new category would have to provide assurance to the IOUs of cost recovery of the transmission facilities in advance of interconnection requests. Given that the Tehachapi transmission upgrades needed to get the 4,000 MW of wind generation to load would cost about $2 billion, this is a very big issue.

On February 24, 2005, CAISO approved SCE's proposed 230-mile Palo Verde-Devers 2 (PVD2) 500 kV transmission line that will connect the Palo Verde substation in Arizona to the Devers substation in California. CAISO used the TEAM approach to demonstrate the economic and reliability benefits of increased access to Palo Verde. But more significant, it was the first application of the TEAM approach to an interstate transmission project conceived by a WECC subregional planning group, the Southwest Transmission Expansion Plan (STEP). STEP was created as an ad-hoc subregional planning group to address transmission concerns in the Arizona, southern Nevada, Southern California, and the northern Mexico areas.

To summarize, even within an RTO, the evaluation methodology of transmission lines is evolving. As CAISO demonstrated in its analysis of Path 26 in California, a transmission upgrade that has a cost-to-benefit ratio greater than 1.0 when viewed on a WECC-wide or societal perspective, but has a cost-to-benefit ratio less than 1.0 within an RTO may not be approved by that RTO.As transmission planning expands beyond the boundaries of the RTO, then interstate issues arise—especially in regard to financing and approvals to construct—and a more regional focus is needed.

---

[6] November 29, 2004 issue of Power Week, page 4.

The regional focus has many supporters. There is the WGA and its energy arm, the Western Interstate Energy Board (WIEB). WGA is an independent nonprofit organization representing the governors of 18 states and three U.S. flag islands in the Pacific. The WGA leads for energy issues are governors Bill Richardson of New Mexico, Arnold Schwarzenegger of California, Dave Freudenthal of Wyoming, and John Hoeven of North Dakota. WIEB is comprised of representatives of 12 western states and the Canadian provinces of British Columbia, Alberta and Saskatchewan. In turn, WIEB and the Western Conference of Public Service Commissioners formed a joint committee, the Committee on Regional Electric Power Cooperation (CREPC).

Public utility commissioners, energy agencies and facility siting agencies in the Western Interconnect are eligible to participate in CREPC. One of CREPC's participants is the Northwest Power and Conservation Council (NWPCC) that is funded by BPA. WIEB provides staff support to CREPC. The WGA also created an advisory committee to oversee their Clean and Diversified Energy Initiative (CDEAC). CDEAC has, in turn, established eight task forces to recommend how the West can bring on line 30,000 MW of clean energy by 2015 and increase energy efficiency 20 percent by 2020. The task forces cover energy efficiency, wind, clean coal, advanced natural gas, biomass, solar, geothermal, and transmission. While environmental stewardship is the pronounced impetus for this activity, several governors are keenly interested because of the perceived economic benefits to their states. The goals of CDEAC are to provide the roadmap to meet the WGA's aggressive clean energy goals that will increase jobs, improve the nation's energy security, and prevent pollution. Bill Real, Vice President of Public Service of New Mexico and co-chair of CDEAC, stated that both intrastate and interstate transmission siting and construction would be key to accessing clean energy resources.[7]

How will the needed facilities get constructed? Governor Bill Richardson of New Mexico and Montana State Representative Alan Olson have some ideas.

In New Mexico, Governor Bill Richardson said he would ask the state legislature to create a transmission financing authority to help wind energy developers. With the financing to help construct new interstate transmission lines, New Mexico can send needed renewable energy to Arizona, California, and Nevada and, in turn, reap the economic benefits of producing power from wind, solar, and other renewables. For comparison, the wind potential in New Mexico is estimated to be 435,000 GWh or over 7.3 times the wind potential in California. From Governor Richardson's perspective, the southwest market for wind energy is growing rapidly since the establishment of Renewable Portfolio Standards and he sees this as a great economic investment opportunity for his state.

[7] Press release from WGA dated February 23, 2005.

In fact, six western states have adopted or are proposing to adopt RPS. They require the following percentages of renewables in utility portfolios:

- New Mexico – 5 percent by 2006, 10 percent by 2015;
- Colorado – 3 percent by 2007, 6 percent by 2011, 10 percent by 2015;
- California – 20 percent by 2017;
- Nevada – 7 percent by 2005 and 2 percent added every 2 years until 15 percent by 2013 (may be credits[8] or physical purchases, 5 percent must be solar);
- Arizona – 1.1 percent by 2007 (60 percent must be solar); and
- Washington – *pending legislation* – 15 percent by 2023 (may be credits or physical purchases).

It is important to understand that, at least in the case of California, investor-owned utilities are not required to meet the targets if renewable resources are above a so-called market price referent (MPR) issued by the CPUC after each auction is conducted. However, as has been observed in the past (e.g., QF standard offer contracts), the CPUC may be pressured to mix politics into its analysis to ensure the MPR is sufficiently high to allow acceptance of many renewable resources that would otherwise be deemed not cost effective. Higher RPS goals in California, beyond that established by law with Senate Bill 1078, are already being advocated with a target of 20 percent by 2010. Governor Schwarzenegger has proposed a goal of 33 percent renewables by 2020. Regardless of how the RPS process evolves in California, transmission expansion and cost allocation will be major issues that must be addressed.

Montana legislator Alan Olson has drafted legislation to create the Montana Transmission Authority, a state agency that would be authorized to issue up to $750 million to finance needed transmission lines. The purpose of this agency is to provide funding for transmission lines that would allow Montana to export power generated from its enormous coal reserves (the largest in the U.S.) and good wind potential (ranked 5th overall in the U.S.). The wind potential in Montana is over 2.3 times the wind potential in New Mexico and over 17 times the wind potential in California. In 2004, Wyoming established a state infrastructure authority with $1 billion in bonding authority. The wind potential in Wyoming is about 1.7 times that of New Mexico and almost 12.7 times that of California. Efforts are under way in North Dakota to establish a similar authority.[9] North Dakota has even more wind potential than Montana.

Probably the main implication of all the focus on energy and transmission planning by the WGA is that it does not see much of a need for the SSG-WI. In its February 2005 Report to Western Governors, “The Western Interconnection: Unfinished

[8] Renewable Energy Credits.
[9] Power Week, Monday January 17, 2005 issue, pages 2 and 3.

Business," WGA staff and CREPC concluded that "...the states and power market participants in the Western Interconnection would benefit from an effective industry institutional infrastructure that is not yet in place."[10] The report took to task both the WECC and the SSG-WI. In particular, the report noted that much of the data the WECC collects is confidential and therefore cannot be used in a public forum. In addition, while it praised the WECC for its role in reliability standards, it cautioned that the WECC was at risk of losing budget funds for its functions because it is a voluntary organization.

The report was more critical of the SSG-WI because its "...fragile institutional structure and inadequate funding imposes critical limits on its ability to address..." the commercial issues of transmission planning and expansion, market monitoring, and protocols for power sales.[11] According to the report CAISO and WestConnect have been particularly reticent in providing financial support to some of SSG-WI's activities. Some have suggested this is due in large measure to a desire on the part of CAISO and WestConnect to have the WECC assume greater responsibility in transmission planning and expansion. Several Grid West entities on the other hand do not want to see that happen.So, the drama continues along with the transmission planning.

Gary L Hunt, President, Global Energy Advisors | ghunt@globalenergy.com

Richard Lauckhart, Vice President, Global Energy Advisors | rlauckhart@globalenergy.com

George Given, Vice President, Global Energy Advisors | ggiven@globalenergy.com

[10] February 2005 Report to Western Governors, "The Western Interconnection: Unfinished Business," page 12.
[11] Ibid, page 8.

Global Energy News & Updates

Global Energy's Renewable Energy Wall Map Wins MapWorld 2005 MapInfo Contest

Third Time Global Energy Cartographers have won the award

The Global Energy "2005 Renewable Energy" wall map recently won 1st Prize in the MapWorld 2005 MapInfo user competition. This is the third 1st prize awarded to cartographers from Global Energy's Maps unit (formerly ENERmap).

The award is for excellence in cartographic production, data representation, geographic portrayal of findings, clear presentation of subject-oriented issues, and precise & detailed depiction of the geographic aspects of the subject at hand. The contest is open to all 300,000+MapInfo users worldwide.

"We're very proud of the award and the Herculean effort behind the map. This is the first renewable map that ties together the range of disparate and fragmented portrayals of renewable resources," said Jason McMahan, President of Global Energy Maps.

"As such, we wanted the full picture. That meant displaying data on everything from existing and future development, to transmission infrastructure and market dynamics…. even wind speed data. We are lucky to have access to some of the best information and thinkers in the industry. The map is the result of a team effort on the parts of all of Global Energy's units."

The map was authored by McMahan and Farid Tabaian. It is 48"x92" and displays:

- Over 750 existing renewable energy projects, labeled with project name and operator, indicated by generating capacity
- Over 200 proposed renewable energy projects, also indicated by name, capacity and developer
- Transmission infrastructure of lines (indicated by voltage) and electrical substation locations
- Conventional plants of 100MW or greater, showing primary fuel
- The industry's first comprehensive, nation-wide composite of the latest detailed wind resource measurements
- Tabular displays of facility information such as name, company, capacity, fuel, map location and estimated on-line date (where appropriate)
- Insets showing geothermal and solar resources, as well as State-level Renewable Portfolio Standards (RPS) and aggregated planned and existing renewable capacity
- Reference features of cities, counties, topography and more for a complete view of the geographic issues surrounding renewable energy development

----

Wholesale Electric Competition Produced $15 Billion in Savings for Customers in Eastern Power Markets

Study available free of charge via download

Global Energy released a major study on the impact of wholesale competition in electric power markets titled Putting Competitive Power Markets to the Test, which concludes that competitive wholesale power markets in the eastern United States and Canada produced at least $15.1 billion in customer savings during 1999-2003 and has resulted in dramatically improved power plant efficiencies nationwide.

"Competition is working to lower costs in wholesale power markets in the Northeast and Midwest," explained Gary L. Hunt, president, Global Energy Advisors, a Global Energy business unit. "Without competition to lower the costs of building and operating power plants, our nation's fuel efficiency would be worse and consumer's fuel and electricity bills would be higher than they currently are. The study results confirm that one of the best ways the nation can save energy and reduce prices is to make competitive wholesale electric markets work.”

In March 2005, Global Energy was engaged to perform an independent analysis of wholesale competition at work today to identify and quantify the existing and foreseeable benefits to consumers of competitive electricity markets.

Global Energy used its widely accepted power market simulation software and independent price forecast advisory service to compare two scenarios. The first scenario simulated existing competitive market conditions. The second scenario modeled prices and costs as if competition had not existed; the traditional vertically integrated utility environment was assumed to have continued without any wholesale competition. The results produced $15.1 billion in savings compared to the costs of electricity without competition. The savings resulted from competitive pressures associated with wholesale market operations that minimized fuel expenses, operating and maintenance costs, depreciation and taxes.

“Global Energy found improved performance at power plants operated by traditional utilities, as well as those by competitive generators,” said Hunt. “Competitive market forces have changed the way existing power plants are operated, producing substantial improvements in efficiency and cost savings.”

The study summarized the following efficiency gains:

- 13% reduction in nuclear plant refueling time since 1999;
- 8% lower nuclear operating & maintenance costs;
- 14% lower coal plant operating & maintenance costs;
- 17% improvement in nuclear plant capacity factors from 1995-2004, enough additional energy to supply over10 million residential households;
- 16% improvement in coal plant capacity factors from 1995-2004, enough additional energy to supply near 25 million residential households; and
- 4% improvement in coal plants heat rates since 1999.

Global Energy also examined the impact of the recent expansion of the PJM transmission market to include Midwest utilities and found $85.4 million in annualized savings for Eastern Interconnection wholesale customers through reduced transmission seams from combining utility transmission systems into regional transmission organizations (RTOs). "While the majority of the production cost savings derived from the PJM market expansion occurred among PJM members, we also saw production cost savings with non-PJM participants," Hunt said. "Eastern interconnection power market customers, who have traditionally had higher electricity rates, saw real savings by increasing their access to lower cost Midwest generation," Hunt said. “Our study confirmed the 4.2% decline in load-weighted spot market power prices in PJM, as reported by the PJM Market Monitoring Unit earlier this year.”

Global Energy’s study compared the integration of Commonwealth Edison (ComEd), American Electric Power (AEP) and Dayton Power & Light (DPL) into the PJM Interconnection with a simulated 2004 market case in which ComEd, AEP and DPL did not join PJM.

The sponsors of this Global Energy analysis are BP Energy Company, Constellation Energy, Exelon Corporation, Mirant, NRG Energy, Inc., PSEG Power, Reliant Energy, Shell Trading Gas and Power Company, SUEZ Energy North America and Williams.

To download the study, visit: www.globalenergy.com/competitivepower

----

North American Natural Gas Prices to Remain High

New Natural Gas Reference Case Report Shows Historically High Prices Won’t Moderate Until 2008-2009

Global Energy recently announced the release of its Natural Gas Reference Case, a comprehensive and fundamentals-based forecast of supply and demand fundamentals, annual and monthly market clearing prices, infrastructure and market uncertainty. Annual and monthly market clearing prices through 2029 are forecast for 36 gas market pricing centers and hubs.

"The convergence of high gas production replacement costs, persistently high crude prices, and the petroleum industry's preference for oil development over gas development has created persistently higher gas prices," explained Gary L. Hunt, president, Global Energy Advisors, a Global Energy business unit. "Our analysis indicates that gas prices will remain high until significant new North American supply materializes or LNG imports become material to meeting demand. Steps being taken right now will result in greater supply and price moderation beginning in the 2008-2009 period."

The Natural Gas Reference Case forecast utilizes a fundamentals-based supply and demand analysis that maximizes the economic rents available in the market and models "real world" business strategies. Two alternative scenarios—Global Cartel Pricing and LNG Displacement—and stochastic volatility analysis were utilized to help quantify market prices.

The key findings in the Global Energy Natural Gas Reference Case are:

- Natural Gas prices will remain stubbornly high for the next few years.
- Industrial demand destruction is a profound outcome of higher gas prices across the regions.
- Natural gas demand in the future will be driven by gas requirements for power generation.
- North American gas production is slowing and industry is in preservation mode not exploration mode.
- Major oil & gas players are moving overseas. This opens opportunities for smaller players near term to spur smaller scale E&P activities in the US.
- LNG will become increasingly important to meet supply needs and US dependence on LNG imports is expected to rise.
- These changes in fundamentals shift the North American gas market to a GLOBAL gas market with all the volatility and potential for cartel behavior now seen in the oil markets.
- How many LNG re-gas facilities will be built is more a factor of the liquefaction capacity at the other end. More than 40 proposals are pending but the US needs only a fraction of that. Expect 4-6 re-gas terminals with Gulf Coast the most likely home for many of them.

"If, when, and how much LNG will be brought into North America remains a critical question to the future of North American natural gas prices," said George Given, Vice President of Global Energy's Market Advisory Services. "In the next 15 years our increasing reliance on LNG will transform the continental gas market into a global gas market, a new reality that cannot be underestimated for its influence on market prices, industry financial performance and investment."

The Natural Gas Reference Case is available as an advisory service or on a stand-alone basis.

Visit www.globalenergy.com to download a complimentary executive summary of the report.

Global Energy Decisions and PowerWorld Expand Alliance

Provides Electric Industry's Leading Locational Marginal Pricing Solution for FTR Valuation and Nodal Price Forecasting

Global Energy and PowerWorld Corporation announced an expanded alliance whereby Global Energy will become a PowerWorld reseller partner. Since 2001, the companies have offered a joint software solution combining PowerWorld's Simulator OPF™ and Global Energy's Market Analytics LMP for use in nodal-level Locational Marginal Price (LMP) forecasting, FTR valuation, transmission congestion and generation dispatch analysis for the emerging ISO/RTO markets.

"Global Energy has done the hard work required to bring an LMP solution to market, including engineering a solution to our specification and developing the necessary LMP data sets" said Mark Laufenberg, PowerWorld CEO. "Together, we've succeeded at putting many clients into daily production use of our combined solution."

“We’re delighted to strengthen our four year old relationship with PowerWorld in order to continue bringing best in class nodal market analytics to companies operating in competitive electricity markets” said Ron McMahan, Global Energy CEO. “Our latest work represents a breakthrough in automatic congestion relief. In addition, our unique ability to switch between AC and DC operating modes allows analysts to study both the economic and the reliability impacts of new and existing transmission”.

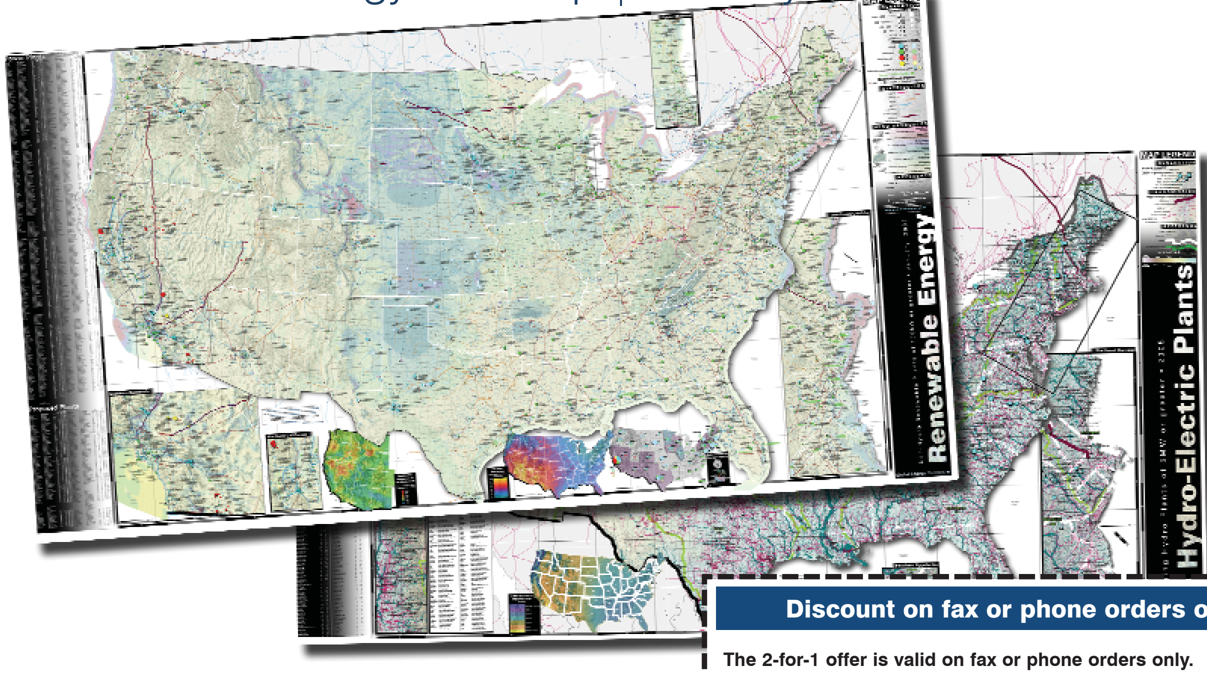
Global Energy's EnerPrise Market Analytics module is powered by the PROSYM™ simulation engine, the industry leading solution currently in use by over 150 companies worldwide. Advanced market analytics capabilities are provided by fully modeling, on an hourly or sub-hourly chronological basis, the operational constraints that impact proper unit commitment. The module provides zonal-level economic dispatch, including weekly and seasonal dispatch of resources such as peak-shave hydro and pumped storage hydro. The module also supports the management of input data and results data across the package of models provided by both companies.

PowerWorld's Simulator OPF™ (Optimal Power Flow) provides simulation of high voltage power system operations, giving analysts a comprehensive view of issues surrounding electric power flows in a transmission grid. The OPF capability provides analysis for the optimal dispatch of generation in an area or group of areas while enforcing the transmission line and interface limits. Simulator OPF can calculate locational marginal price (LMP) while taking into account system congestion, and is one of the only products which allows these analyses to be performed in either an AC or DC mode.

The combined Global Energy and PowerWorld products provide the industry’s most comprehensive solution for nodal market price analysis and economic-based transmission assessment and planning.

Get A Free Renewable Energy Wall Map!

2005 Renewable Energy Wall Map | 2005 Hydro-Electric Plants Wall Map



SPECIAL OFFER FROM GLOBAL ENERGY MAPS!

Buy either the Renewable Energy, or U.S. Hydro Electric Plants Wall Map and get a 2nd renewable map FREE!!!*

To meet current Renewable Portfolio Standards (RPS) in the next 15 years, U.S. utilities will need to plan, finance, and build more than 52,000 MW of renewable capacity at an estimated capital cost of more than $53 billion.

The 2005 Renewable Energy Map Includes: Over 1,000 existing and proposed renewable energy projects | transmission infrastructure | substations | regulatory status | facility information (name, company, capacity, fuel, and estimated on-line date where appropriate) and much more!

The 2005 U.S. Hydro-Electric Plants Map Includes: Over 850 operating hydro plants greater than 5MW | detailed transmission infrastructure | 200,000 miles of rivers | major lakes and reservoirs hydrological units | topography | average annual precipitation and much more!

*Offer expires Aug. 31, 2005;
Valid on fax or phone orders only.
Must mention this offer to qualify!

To order, call 303-444-2393

See the entire line of energy industry wall maps
www.globalenergy.com/maps

Discount on fax or phone orders only!

The 2-for-1 offer is valid on fax or phone orders only.
To order, complete this order form and fax to 303-415-0101
or call 303-444-2393 (M-F, 9:00-5:00 MT)

Cost: $475 first map; 2nd map free

Qty___ 2005 Renewable Energy Map

Qty___ 2005 U.S. Hydro-Electric Plants Map

Laminate? ($90 extra per map & highly recommended) Yes No

NAME ____________________

COMPANY ____________________

ADDRESS 1 ____________________

CITY/STATE/ZIP 1 ____________________

CITY/STATE/ZIP ____________________

PHONE ____________________

E-MAIL ____________________

○ BILL ME LATER ○ CHECK ENCLOSED
○ VISA ○ AMEX ○ M/C ○ DISCOVER

CARD # ____________________

EXP __________

X ____________________
SIGNATURE