NORTHEAST POWER MARKETS

ENERGY WATCH

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Summary

In this month's issue of *Energy Watch,* ESAI examines the issues surrounding the Regional Greenhouse Gas Initiative, (RGGI). RGGI prices have been clearing at the floor due to the high caps relative to CO2 output. With prices clearing at the floor, some states are challenging the relevance of RGGI and are looking to pull out of the program.

In PJM, the energizing of the TrAIL project in late May has had less impact on PJMWH heat rates and zonal price spreads than expected. ESAI examines the year on year impacts for its first full month of operations in June.

In New York, ESAI examines the impact of wind generation on market heat rates and capacity factors for plants in northern New York after observing lower operations at the Saranac combined cycle facility.

In this Issue

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POWER MARKETS

PJM

ESAI's PJMWH June on-peak heat rate forecast of 14,700 Btu/kWh was well above the actual cleared average heat rate of 13,450 Btu/kwh as weather was slightly more moderate than expected. The forward curve was 13,800 Btu/kWh. ESAI's on-peak PJMWH heat rate forecast for July remains at 13,600 Btu/kWh but the August is revised slightly downward to 14,200 Btu/kWh. The forward curve for this period is in line with the ESAI forecast, although higher in July and lower in August. TrAIL impacts are less bearish than anticipated due to the secondary effects of increased western power competing with eastern marginal coal plants. Lower coal plant operations are increasing volatility at PJMWH. ESAI's analysis indicates a wider spread of hourly heat rates in June 2011 vs. 2010.

New England

ESAI's expectation for June Mass Hub DAM on-peak heat rates was 10,900 Btu/kWh and was slightly above the cleared heat rate of 10,350 Btu/kWh. The forward heat rate for June was higher than the ESAI outlook at 11,400 Btu/kWh. ESAI's on-peak Mass Hub heat rate forecast for July is steady at 11,800 Btu/kWh but August increases slightly to 12,100 due to a warmer weather outlook. The forward heat rate is in line with the ESAI forecast. The WSI August outlook calls for much warmer-than-normal temperatures. The 620 MW Kleen Energy plant is expected on line in the second half of July as testing is still underway. Kleen will be bearish for CT premiums and Mass Hub heat rates.

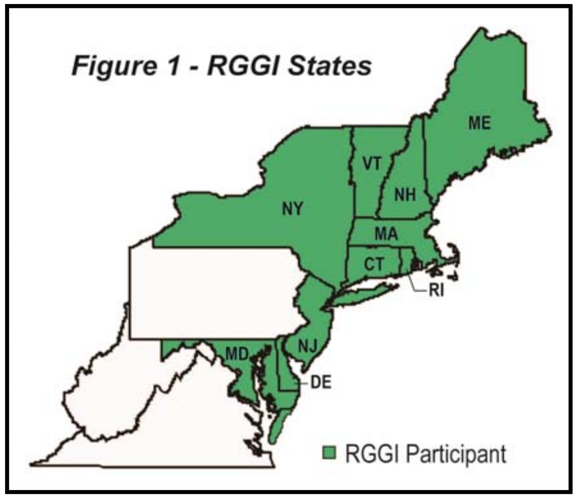
New York

ESAI's forecast for the June Zone G on-peak heat rate was 14,300 Btu/kWh and was above the cleared June heat rate of 13,650 Btu/kWh. The forward curve expectation for June was higher at 14,600 Btu/kWh. ESAI's July Zone G outlook has dropped dropped to 13,900 Btu/kwh; August is higher at 14,300 Btu/kWh. Summer Zone G forward values are higher for July at 14,316 Btu/kWh but in line for August at 14,260 Btu/kWh. The 550 MW Astoria II combined cycle unit has commenced commercial operations at the end of June. This Zone J unit is under contract to NYPA.

NATURAL GAS

Henry Hub

Marketed natural gas production continues to soar, setting a new record of 65.8 Bcf/day in April. Without an external event, such as a significant move in coal prices or a hurricane disruption in the Gulf of Mexico, gas prices are likely to remain stable through the end of 2011. While the natural gas rig count tapered off in late 2010, drilling has stabilized. Shale drilling and gas production in general remains very strong. Inventories remain slightly below the 5-year average, but should finish the injection season strong as power demand fades into September. Producers liquidated forward sales over the past month as prices slumped to the lower $4.00/MMBtu range. Commercial buying is now likely to support prices in this price range. We continue to see prices stuck in a technical trading range through most of the 2011. Price weakness is likely to be less pronounced into late autumn as coal supports the floor.



Developed in 2005-2006 as part of an unprecedented multi-state collaboration, the Regional Greenhouse Gas Initiative (RGGI) is the first U.S. regulatory mechanism designed to control carbon dioxide emissions from power plants. RGGI promised to be a blueprint for federal carbon and greenhouse gas regulation based on the cap-and-trade model of market-driven regulation, following in the heels of similar (and successful) cap-and-trade regulatory schemes for other pollutants (NOx and SOx).

But, more than five years after the initial multi-state agreement and development of its generic "model rule" program design, RGGI appears to be in trouble. At best, the mechanism has become increasingly irrelevant, both as a commodity market (for its carbon allowances) and as a consideration for power plant owners and investors. One of the largest participating states has announced its intent to withdraw from the mechanism, with other states considering similar action. How did RGGI go from a model for carbon regulation to an almost irrelevant mechanism? Can the mechanism survive more defections?

Where RGGI Went Wrong

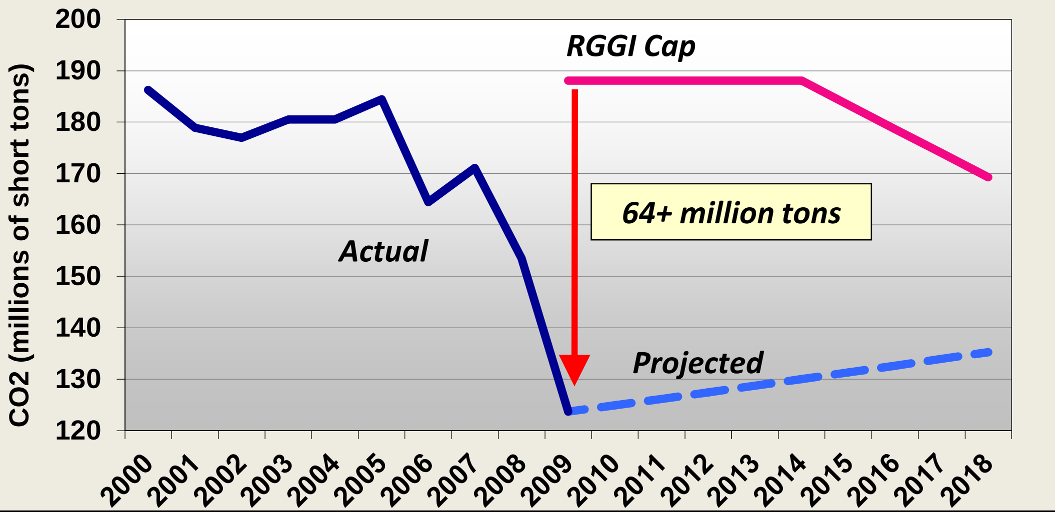
In some ways, RGGI has become a victim of its own success. By design, the mechanism set relatively lenient carbon caps, meant to provide a relatively pain-free transition to a carbon cap. The cap on emissions was always intended to be above actual emissions at the start of the mechanism, with the intent being to make the 10% ratcheting down of the cap (starting gradually in 2015) the real driver for compliance. By basing the cap on 1990 emissions levels, the cap excludes most of the low-carbon natural gas-fired generation built since that date.

However, the RGGI designers did not foresee the dramatic drop in emissions experienced since development of the program. RGGI has released preliminary emissions data for the first RGGI compliance year (2009), which indicate a huge gap between the cap and actual emissions – a gap of over 34%.

Foremost among the factors that led to this substantial drop in emissions are the 2008-2010 economic recession and the extraordinarily low natural gas prices since 2008 (and in particular the gap between gas and fuel oil prices), with more gas-fired capacity displacing higher carbon-emitting (i.e. coal and oil-fired) resources. The trend of low gas prices continued into 2010, which (all other factors equal) would contribute to a further widening of the gap between the RGGI cap and actual emissions. However, summer 2010 was very warm across the RGGI states, suggesting that 2010 carbon emissions will most likely surpass the levels seen in 2009.

The sizable surplus of allowances resulting from actual emissions coming in far below the RGGI cap is more than enough to depress RGGI allowance prices; however, RGGI's provisions regarding the banking of allowances effectively perpetuate this surplus. The banking of allowances without limitation will keep RGGI allowance prices at or near the floor price for the foreseeable future, barring a resetting of the cap or a major redesign of the RGGI mechanism.

Figure 2 - Actual/Forecast CO2 Emissions vs. RGGI Cap (Ten RGGI States; Actuals through 2009)



The balance in this "bank account" is enormous. Using the 2009 estimate of actual emissions of 123.7 million short tons, the beginning balance of this "carry-forward" account stands at 64.4 million tons, which represents over one-half (52%) of actual emissions. Even assuming a sizable increase in 2010 as a result of the relatively warm summer, at this pace the balance in this account is likely to surpass total annual actual emissions within three years, i.e. by the end of 2011. In other words, the carried forward balance in the allowance bank will be enough to meet the entire compliance obligation for a single year.

Even if we assume a tightening of the cap, the balance in the banked allowances account remains large. In Figure 3, we have assumed an additional 10% tightening of the cap, to a total reduction of 20% instead of the present 10%. We further assume that the 20% cut would be implemented earlier than the present mechanism – the tightened cap would be implemented over four years in 5% steps beginning in 2013, as opposed 10% over four years (2.5% steps) starting in 2015 under the present mechanism. This tighter cap would result in a cut of 20% by 2016, so that the cap would roughly equal total actual annual emissions in 2016 (roughly 150 million short tons). This admittedly extreme example still shows that the cumulative balance of banked allowances would take many years to be used up, well past 2020.

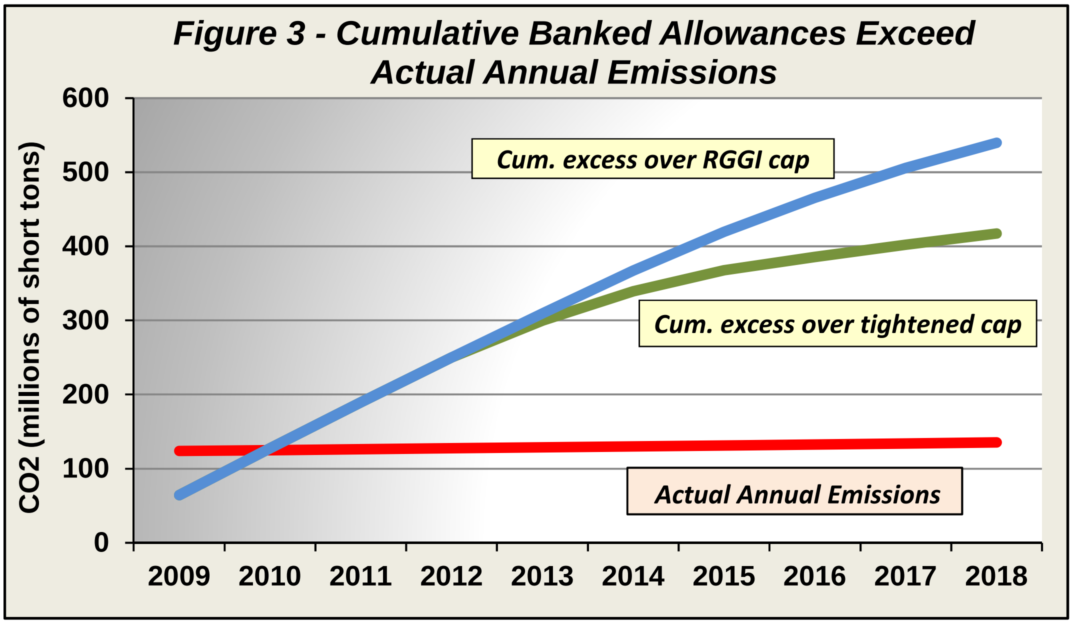
Perpetual Oversupply Kills Markets

The immediate result of this seemingly perpetual oversupply has been the collapse of RGGI allowance auction clearing prices down to the stipulated reserve or floor price. The most recent auction, held on June 8, cleared at the $1.89 per short ton floor prices for both current compliance period (2009-11) and future compliance period (2012-14) allowances.

TABLE 1
Actual CO2 Emissions 2000-2009

Year	10-State Total (short tons)	% below RGGI Cap
2000	186,269,063	1.0%
2001	178,913,809	4.9%
2002	176,935,941	5.9%
2003	180,532,482	4.0%
2004	180,508,070	4.0%
2005	184,444,457	1.9%
2006	164,440,172	12.6%
2007	171,112,099	9.0%
2008	153,457,865	18.4%
2009*	123,700,000	34.2%

** estimate from 11/2/10 RGGI draft white paper*



In addition, and perhaps more importantly, the June 8 auction was the first quarterly auction of the 12 held to date to be substantially undersubscribed, selling only 30% of the more than 42 million current period allowances offered. (The auction did sell 51% of the relatively few 2012-14 allowances offered; more details on the June auction are provided below.)

The RGGI futures markets at the CME Green Exchange and Chicago Climate Futures Exchange (CCFE) have essentially collapsed, with very little if any trading taking place. Auction premium has disappeared to just one to three cents, with prices hovering around the $1.89 floor price. Trading and volumes remain extremely limited, with the only activity occurring in the CCFE (no RGGI futures contracts have traded on the CME Green Exchange for several months).

2012 Scheduled Program Review Underway, But Little Action Seen

The RGGI Memorandum of Understanding among the ten RGGI states calls for a comprehensive review of the RGGI program design in 2012. The scope of the 2012 review is not limited, meaning that any and all aspects of the program could be revised. At the forefront of discussions is a tightening of the cap, as well as potential restrictions on the banking of allowances and other changes to the mechanism intended to address the massive oversupply of allowances.

Stakeholder meetings to begin the process were held in September and November 2010, with work beginning on developing a reference or base case model to support the evaluation of potential revisions to the mechanism. However, discussions seem to have stalled, perhaps reflecting substantial changes in the debate over carbon regulation since implementation of the RGGI mechanism. Given the massive surplus, we had been expecting the RGGI states to implement measures to reduce the oversupply of allowances, including a potential tightening of the cap. But, significant changes to RGGI that result in allowance price increases are a very tough sell in the present political and economic environment. Simply put, carbon regulation and cap-

JUNE 2011 BRINGS MAJOR CHANGES TO PJM SYSTEM

In late May, PJM energized the final section of the TrAIL line (502 Junction to Mt Storm) and began the process of ramping up the AP-South interface limits. PJM increased the AP-South limits from the higher level of 3,200 MW in May to a steady-state level in the second half of June of 4,400 MW, a solid increase of 1,200 MW. The 1,200 MW net increase in the AP-South flow limit is very close to our previous expectations of a conservative 1,100 MW increase. The formal introduction of the ATSI zone also commenced June 1, 2011.

The AP-South interface operated at a slightly higher average limit of 4,600 MW from May 31 to June 13 with a high of 4,800 MW on June 9, presumably for testing purposes. As shown below in Figure 1, the day-ahead flows have followed the limits upward, although they are not always fully constrained at the limit on a daily average basis (some hours during the day may reach the flow limit). Day ahead scheduled flows in June averaged 4,200 MW, a full 1,000 MW increase above the 3,200 MW upper limit seen in May.

Table 1 compares June 2010 and June 2011 indicators that help define congestion impacts for the AP south interface constraint. While we are careful to place too much emphasis on one month's results, we note that the number of constrained hours dropped from 279 to 196, a drop of 29.7 percent. The marginal value of the constraint (MVC or shadow price) dropped from $33.76 to $22.98/MWh. Average on-peak load in June 2011 was slightly lower than in June 2010 (40,327 vs. 41,339) and some of the lower congestion can be attributed to the slightly lower load.

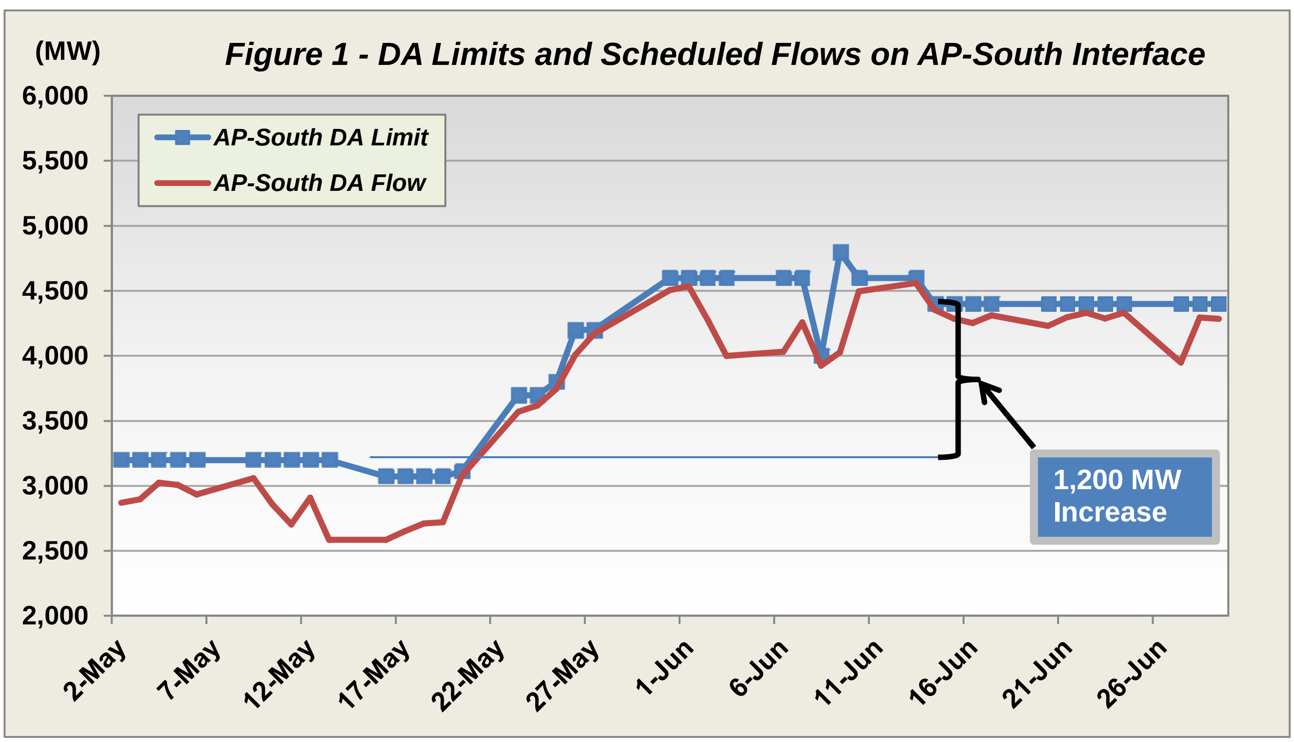


Table 1 - Comparison of June Congestion 2010-2011			
Metric	**June '10**	**June '11**	**Change**
Number of Peak Days	22	22	0.0%
Number of Congested Hours	279	196	-29.7%
Avg Congested Hours Per Day	12.68	8.91	-29.7%
Avg Hourly Constraint Value	$33.76	$22.98	-31.9%
PJM-E Avg Hourly Load (MW)	41,339	40,327	-2.4%
Central App Coal* Price $/MMBtu	$2.52	$2.89	14.7%
TETCO M3 Gas Price	$5.15	$4.85	-5.8%
PEPCO-PJMWH Spread, $/MWh	$11.90	$11.80	-0.8%
PEPCO Heat Rate, Btu/kWh	14,000	15,440	10.3%
PJMWh Heat Rate, Btu/kWh	11,715	13,145	12.2%
**12,500 Btu/lb, 1.2% SO2*			

Zonal and Regional Impacts

The average DA Pepco-PJMWH spread in June 2010 was $11.90/MWh. As a result of TrAIL, a drop in the Pepco-WH spread would have been expected, however, the June 2011 average was almost identical at $11.80/MWh (see Table 1). Prevailing conditions for June 2011 are shown below along with their expected impacts on PEPCO on-peak prices in June:

- 1,000+ MW increase in AP South flows due to TrAIL , bearish
- 1,000 MW lower PJM East load, slightly bearish
- $0.30/MMBtu lower gas price, slightly bearish
- $0.37/MMBtu higher spot CAPP coal price, neutral to slightly bullish

Overall, conventional wisdom suggests that PEPCO spreads should have come down in June 2011 relative to 2010, however, the spread was unchanged year on year. Adding the increased 1,000 MW of energy across the AP-South interface due to the TrAIL upgrade should allow increased supply to PEPCO, shifting the zonal supply curve to the right to lower average prices. Slightly lower loads and gas prices should also have contributed to lower PEPCO-WH spreads.

Likewise, conventional wisdom suggests that PEPCO and PJMWH heat rates should have dropped under the conditions noted above. However, both PEPCO and PJMWH heat rates increased significantly in June 2011 as compared to the previous June due to the bearish influence of TrAIL (major) and lower loads (minor). Other factors such as generator outages and transmission outages should be neutral when comparing the month of June as planned outages are generally complete by end-May/early June.

For June 2011 to finish with higher heat rates than in June 2010 suggests that the in-

NORTHFIELD MOUNTAIN RETURNS; KLEEN TO START-UP SHORTLY

In New England, a few factors have the potential to set this summer apart from last. Kleen Energy, a CCGT in Connecticut should be fully available soon and Northfield Mountain pumped storage was offline last summer. Connecticut has also implemented a new tax on fossil-uel power producers in the state. Each of these issues are large enough to slightly alter the supply curves in the region and impact prices.

We've analyzed the implied supply curve over the past couple of years, similar to analysis outlined in this month's PJM section, to get a sense of any underlying trends. Looking back at the past summers in context with this past June gives us a sense of trends that may be occurring in the wholesale energy market. Gas prices have been relatively low since 2009, dropping from much higher prices in 2008, so any analysis going back further than 2009 would present problems. We lined up hourly load and power prices, with the daily settlement of gas for the day, and placed them on a scatter chart (see Figure 1). The best fit trendline gives a sense of how heat rates change with changing load levels and normalizes incidental differences in the prevailing gas prices. June 2009 was an extraordinary year marked by cool rainy weather for most of the month. As a result, the peak load never exceeded 18,200 MW. We've excluded the 2009 curve from our comparative analysis (but show the curve at the end of this section to show how persistently lower than normal temperatures effect bidding strategies and the supply curve). For the 2009 curve shown in Figure 4, we set the scale of the x- and y-axes in line with Figure 1 to highlight the difference in load and heat rate effects.

The implied supply curves shown in Figure 1 for 2011 to 2010, indicate some minor differences in the implied supply stacks. While the mid-merit portion of the supply curve appears to have grown slightly (i.e. implied market heat rates for system loads between 16,000 MW and 19,000 MW is lower), the peaker section of the curve appears to have steepened.

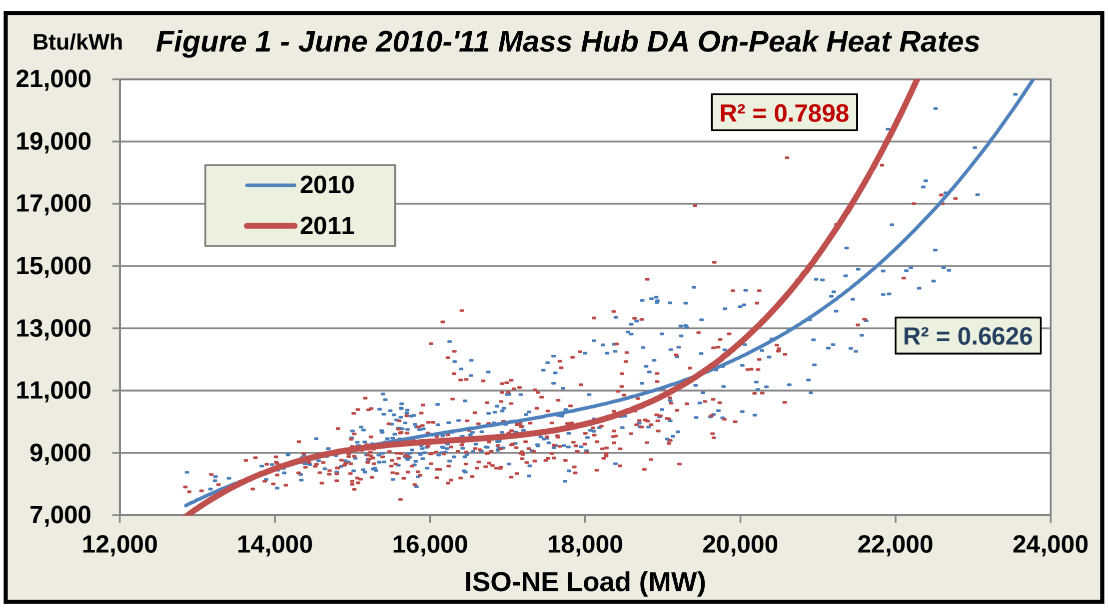
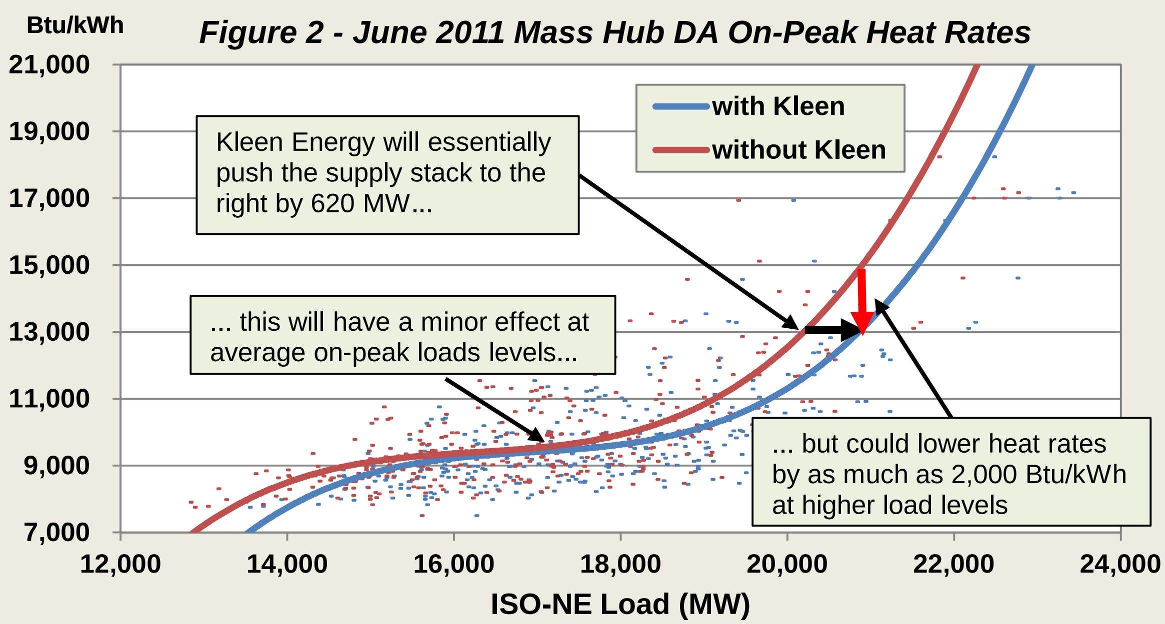


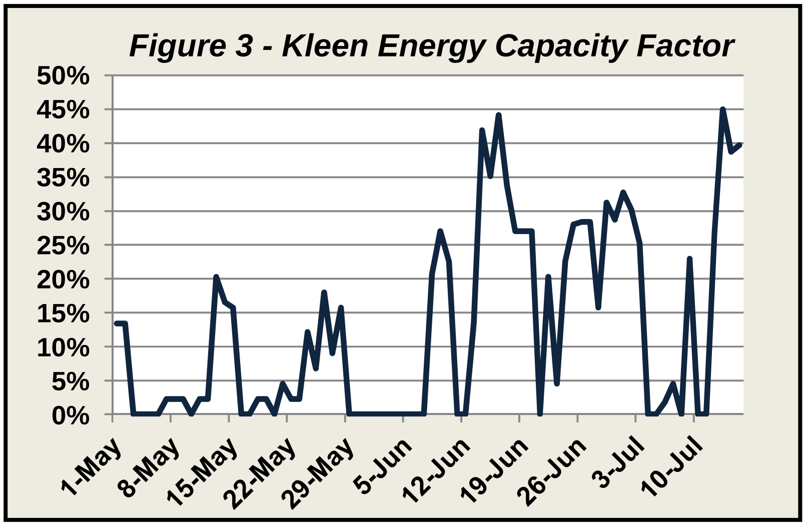
Table 1 - Comparison of Mass Hub June 2010-2011				
Metric	June '09	June '10	June '11	2010-11
ISO-NE Average Hourly Load (MW)	15,506	17,534	17,077	2.6%
Mass Hub Average Hourly LMP	$ 38.69	$ 55.86	$ 51.44	7.9%
Algonquin City Gates Gas	$ 4.15	$ 5.20	$ 4.97	4.4%
Mass Hub Average Hourly HR	9,344	10,738	10,253	4.5%
Central APP Coal* Price $/MMBtu	$ 1.80	$ 2.52	$ 2.89	-14.7%
*12,500 Btu/lb 1.2 SO2				

Kleen Energy to Begin Full Operations Shortly

After much delay, Kleen Energy is should be nearly ready to begin full operations in late July. The plant was originally expecting to begin operations last summer, but experienced an explosion while blowing out their pipeline prior to initial testing. In May of this year, repairs had been completed and Kleen began final testing. It has been gradually running at higher and higher daily capacity factors but is yet to nominate even half of its available gas, and run for at full capacity for a full day at a time. As of July 15th the plant appears to be continuing its test runs and was nominating just 40% of its daily gas capacity. In Figure 3 on the next page we show the run rates as determined by gas nominations. Off-peak heat rates at Mass Hub have been averaging above 7,000 Btu/kWh so we would expect it to run near full capacity this summer once it begins full operation. While the effect of Kleen Energy at average on-peak loads appears to be minimal, at higher load levels the addition of 520 MW of efficient combined cycle capacity could help to push heat rates lower (approximately 100 MW of Kleen capacity is duct burner supplemental firing). Kleen Energy will impact Mass Hub prices at lower loads, when the Connecticut import interface is not binding. At higher load levels, the Kleen Energy plant will directly serve to meet Connecticut load only, when the import interface is binding. Kleen Energy does raise the level at which the CT interface binds and is therefore bearish for Connecticut zonal premiums.

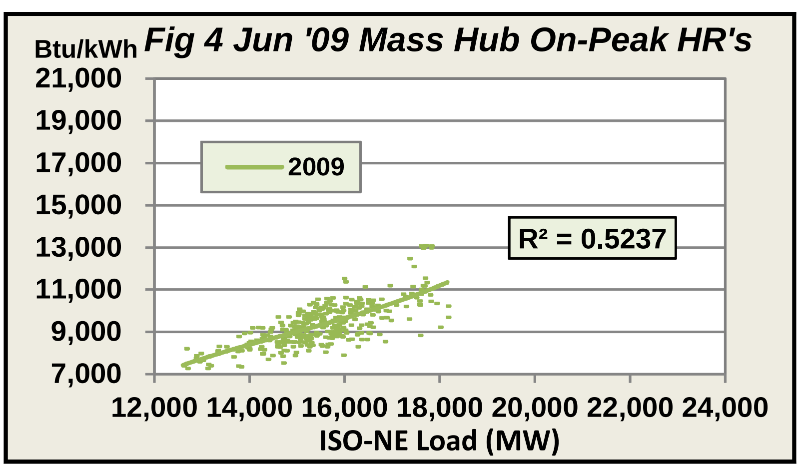
Figure 2 - June 2011 Mass Hub DA On-Peak Heat Rates





Northfield Mountain Back to Summer Service After Missing Out on 2010

Northfield Mountain is a pumped storage facility on the Connecticut River in western Massachusetts capable of generating up to 1,080 MW of energy during a limited number of on-peak hours per day. Water is pumped to a reservoir at the top of the mountain overnight, using less expensive off-peak power. This essentially adds 1,080 MW of overnight load to the system while providing low cost price taker energy to the on-peak hours. Generally speaking pumped storage units buy 7-8 hours of off-peak energy while providing 5 hours of on-peak energy. In May 2010, Northfield shut down for what was supposed to be a three-week maintenance period. Regular maintenance requires that every five years accumulated sediment in the reservoir and in mechanical parts be cleaned. It had been a longer than five years since the prior maintenance, and the extended period without this maintenance led to unforeseen problems. On May 1, 2010, FirstLight started draining their upper reservoir, and during the early drainage process a great deal of silt and sediment became entrained into the project's works. Maintenance work quickly turned into damage control, and the firm was forced to dig out the tailrace and tunnel area. Early repair resulted in a fatality, and in a rush to complete the job the firm began dumping the silt back into the river. The EPA intervened, and the dumping stopped on August 5. This further de-

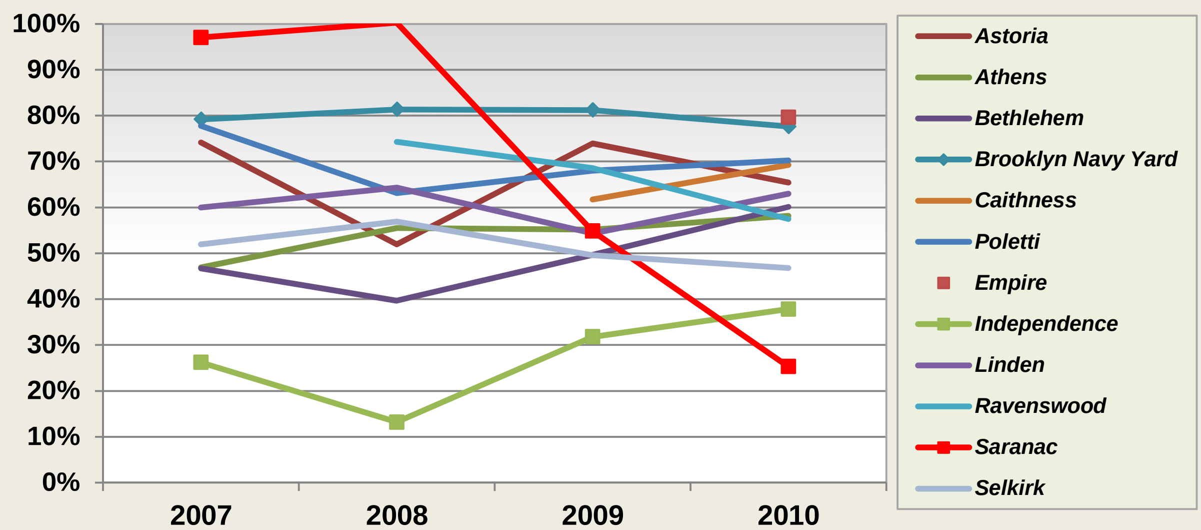


NY ROS CC RUN RATES STEADY; SARANAC STANDS OUT

In the June quarterly issue of ESAI's *Energy Watch*, the capacity factors of gas-fired combined-cycle (CCGT) generators in NYISO were examined. The data shows that, for the most part, New York CCGT capacity factors have been steady since 2007. However, one plant stands out as having seen a dramatic decrease in its capacity factor.

The Saranac Power Facility is a 255 MW gas-fired CCGT on the shores of Lake Champlain in NYISO's Zone D. Saranac entered service in 1994 as a PURPA qualifying facility and with a 15 year Power Purchase Agreement (PPA) with the New York State Energy Research and Development Authority (NYSERDA). During the first fourteen years of operation, SPF had a consistently strong capacity factor that was one of the highest in NYISO. Beginning in 2009, operations dropped significantly as shown in Figure 1. Although wind production in northern New York has increased significantly, the drop in Saranac operations was mostly due to the ending of its 15 year QF contract in June 2009.

Fig 1 - Saranac Capacity Factor vs. Other NYISO CCGT Plants



New Wind Capacity Impacting Gas-Fired Gen Capacity Factors?

ESAI has also explored whether or not the increases in wind capacity in the northern zones (D and E) have had any bearish impact on Saranac or other northern New York generators. Since the year 2000, 1,280 MW of wind capacity has been placed into operation within New York (see Table 1).

Table 1 - Wind Capacity Additions In New York, (MW)	
WEST (ZONE A)	**247**
CENTRL (ZONE C)	**278**
NORTH (ZONE D)	**281**
MHK VL (ZONE E)	**475**

Table 2 - NY Annual Wind Generation, (MWh)	
Year	Wind Output
2002	81,630
2003	41,201
2004	97,652
2005	102,989
2006	655,372
2007	833,478
2008	1,206,049
2009	2,266,342
2010	2,439,147

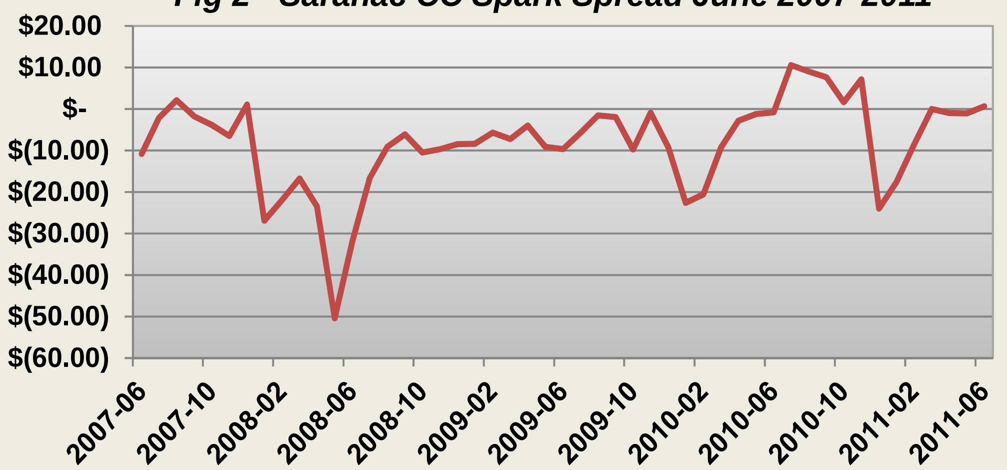
Annual wind production has increased from 81 GWh in 2002 to 2.4 TWh in 2010, (see Table 2). In contrast, the New York power pool total energy usage was 161.5 TWh as provided in the 2011 NYISO Gold Book. Despite the admirable strides in wind development in New York, spurred on by the NYSERDA RFPs, wind production in 2010 was only 1.5 percent of total production.

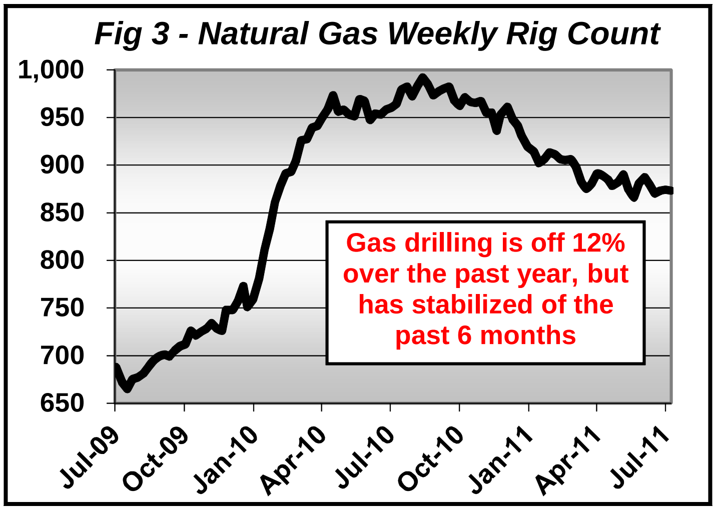
For 2011, only one additional project has come on-line so far, the 74 MW Iberdrola Hardscrabble wind farm in Herkimer County (Zone E). The only other project slated for completion this year is the 51 MW Howard Wind project (Zone C) which is expected to come on-line in October.

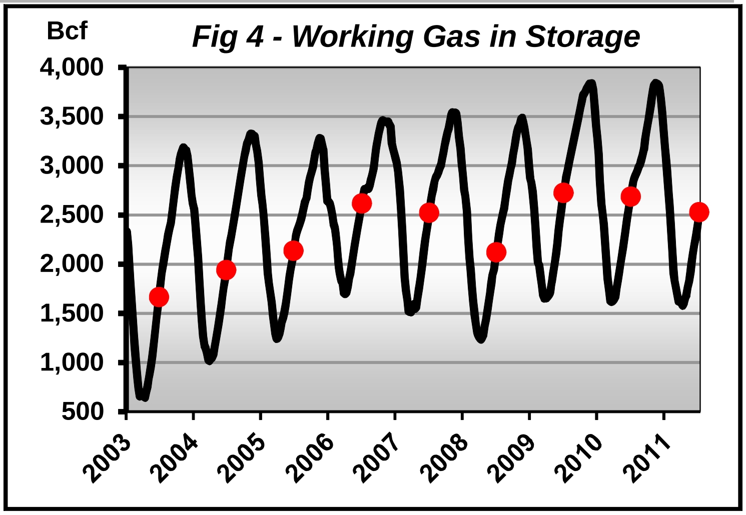
2011 wind production will therefore be relatively unchanged from 2010 levels and will be more influenced by weather patterns than by the addition of one or two new facilities for partial-year operations. However, because wind production has almost quadrupled from 2006 to 2010 with almost 60 percent of the total wind installations occurring in Zones D and E, it could be expected that heat rates and gas-unit spark spreads would be adversely impacted. Figure 2 shows that spark spreads at the Saranac node do not appear to have any downward bias between 2007 and 2010 with the additions of wind production in the region. If anything, spark spreads at Saranac appear to be improving slightly in 2010 and 2011 as compared to mostly negative results prior to 2010.

Under the right system conditions and high wind availability, wind output in northern New York is being curtailed. This would certainly have an adverse impact on local LMPs and spark spreads at facilities such as Saranac. However, these occurrences are sporadic and do not appear to be influencing month average LMPs and spark spreads. The fact is that Saranac's

Fig 2 - Saranac CC Spark Spread June 2007-2011



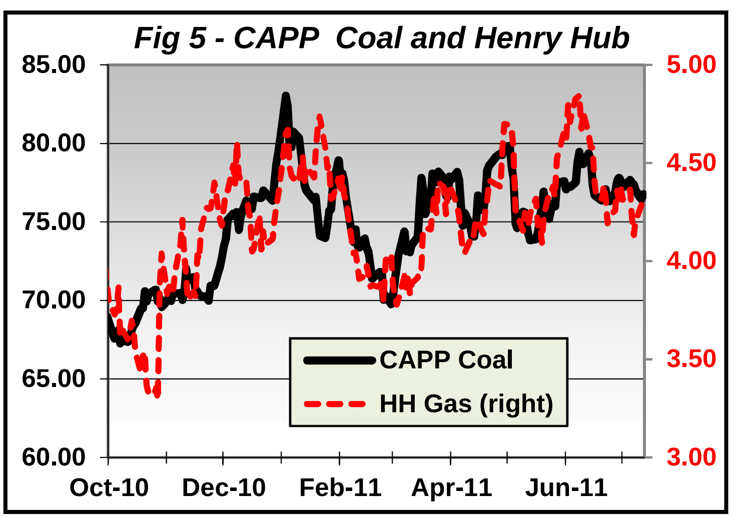


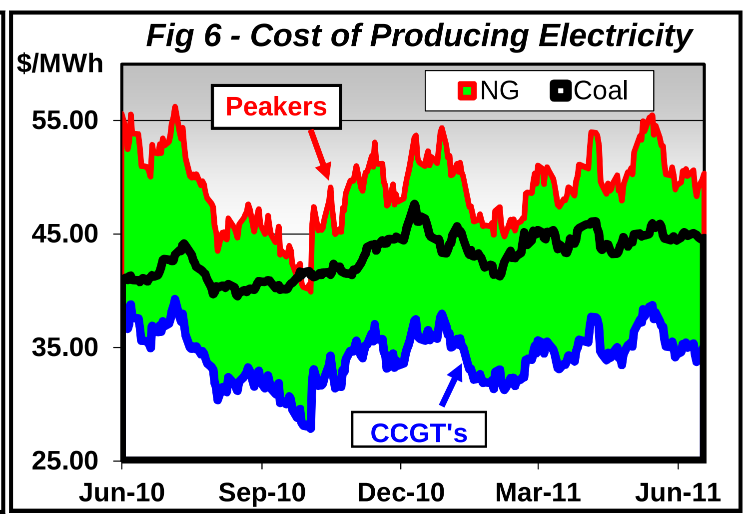


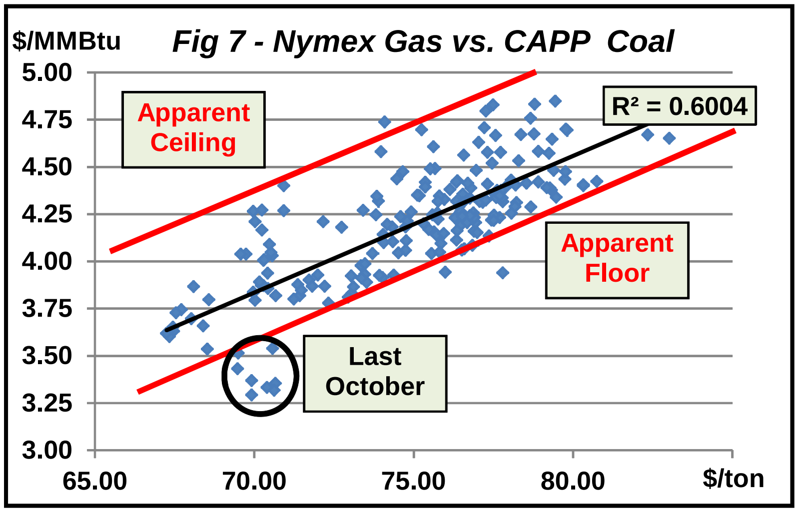
this demand destruction is elastic; if dark spreads were to increase rapidly (in the event of a hurricane disruption in the Gulf of Mexico, for example) coal fired generation capacity could quickly become available and reduce demand for natural gas (for power production). The fact that we are in the early stages of demand destruction (i.e. before the permanent retirement of significant number of coal fired generators) creates a significant fundamental ceiling for natural gas prices. As more and more coal fired generators retire over the next few years, however, the power sector will become more and more dependent on the recent increased levels of natural gas production. At that point the firm ceiling above natural gas prices will begin to weaken. It is important to note, however, that this does not preclude the possibility that the floor for natural gas prices could rise and lift gas prices.

In Figures 5 & 6, we show the relationship between coal and gas prices over the last nine months and year (respectively). It is clear to see that the prices are related, we've commonly called the relationship intertwined or braided, with each price series having an effect on the other. When gas prices rose in December 2010 and May 2011, for example, coal prices followed gas price higher. The increase in dark spread (i.e. the spread between gas and coal prices) in December opened up coal profits and allowed more coal-fired generators to run (thereby marginally increasing demand for coal and coal prices in the process).

In March 2011, there is an example of the coal floor rising and pushing gas prices higher. CAPP coal prices quickly rose from \$70/ton to \$78/ton, in this case gas prices followed coal







higher; Henry Hub prices rose from $3.80/MMBtu to $4.30/MMBtu.

In Figure 6, we show the mid-merit section of the power production supply curve. The lower edge of the green band shows the cost of production of the most efficient CCGTs operating with Henry Hub prices (plus basis to the Northeast), while the upper edge of the band shows gas-fired steam production costs. The black line running through the middle of the green band shows the production cost of a coal-fired steam generator (operating at CAPP coal price plus transportation costs). It is important to note that the values in figure 6 are highly dependent on the location of the analysis because coal transportation costs vary greatly by region, as do gas basis prices. We use this chart for illustrative purposes.

Figure 7 illustrates more clearly the floor and ceiling of gas prices related to the price of spot month CAPP coal prices. Each point represents the day's price for each fuel; with CAPP coal prices shown on the x-axis and Henry Hub gas prices shown on the y-axis. While the r-squared value is just 0.60, a clear band of prices can be seen. We've drawn lines for the gas floor and gas ceiling for prices relative to the price of coal prices that contain 99% of the days. This chart does not tell the complete story as because as we've noted, a hurricane disruption would increase gas prices thereby pressuring coal prices higher, but the chart is very illustrative in defining the price band for gas during most periods. With the exception of last October when prices slumped on OFO's and high pipeline pressures related to full storage facilities, the floor and the ceiling contain 99% of the price series.

Over the next six months we believe spot prices should remain relatively well supported as inventory players try to play catch-up to the 5-year average. A price collapse in autumn like those seen in in the past (to levels in the lower $3.00/MMBtu range) is becoming less likely due to the inventory deficit to the 5-year average. Above normal temperatures in July and August are expected to remain stuck along the Northeast and Southwest and should also support prices into late summer. This should shorten the early autumn period of depressed prices, and in fact WSI is forecasting above normal temperatures in September as well. Even with above normal power demand related to the weather, however, we don't believe a major price advance is possible unless coal prices increased on export pressures or a major hurricane disruption occurs in the Gulf of Mexico. Even if the latter were to occur we don't believe prices could mount a meaningful advance above $5.00/MMBtu. Colorado State University said that it expects 9 hurricanes this summer (50% more than normal) with five reaching category 3 or higher; twice the historic average. Moreover, CSU said that the implied risk that a major hurricane would make landfall on the Gulf Coast was 47% this year (compared to a 30% average between 1950 to 2000).