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Issues in Energy Economics Led by Emerging Linkages between the Natural Gas and Power Sectors

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Fuel prices in 2006 continued at record levels, with uranium continuing upward unabated and coal, SO_2 emission allowances, and natural gas all softening. This softening did not continue for natural gas, however, whose prices rose, fell and rose again, first following weather influences and, by the second quarter of 2007, continuing at high levels without any support from fundamentals. This article reviews these trends and describes the remarkable increases in fuel expenses for power generation. By the end of 2005, natural gas claimed 55% of annual power sector fuel expenses, even though it was used for only 19% of electric generation. Although natural gas is enormously important to the power sector, the sector also is an important driver of the natural gas market—growing to over 28% of the market even as total use has declined. The article proceeds to discuss globalization, natural gas price risk, and technology developments. Forces of globalization are poised to affect the energy markets in new ways—new in not being only about oil. Of particular interest in the growth of intermodal traffic and its a little-understood impacts on rail traffic patterns and transportation costs, and expected rapidly expanding LNG imports toward the end of the decade. Two aspects of natural gas price risk are discussed: how understanding the use of gas in the power sector helps define price ceilings and floors for natural gas, and how the recent increase in the natural gas production after years of record drilling could alter the supply–demand balance for the better. The article cautions, however, that escalation in natural gas finding and development costs is countering the more positive developments that emerged during 2006. Regarding technology, the exploitation of unconventional natural gas was one highlight. So too was the queuing up of coal-fired power plants for the post-2010 period, a phenomenon that has come under great pressure with many consequences including increased pressures in the natural gas market. The most significant illustration of these forces was the early 2007 suspension of development plans by a large power company, well before the Supreme Court's ruling on CO_2 as a tailpipe pollutant and President Bush's call for global goals on CO_2 emissions.

KEY WORDS: Fuel prices, coal, natural gas, uranium, SO_2 emission allowances, fuel expenses for power generation, coal transportation, LNG, natural gas market outlook, natural gas production, coal-fired electric generation.

OVERVIEW

Fuel price trends continued at record levels in 2006, with uranium continuing on its upward trajectory, yet 2006 marked a significant turnaround in coal and, for most of the year, natural gas prices (which at least through mid-2007 have shown surprising strength). Natural gas storage levels and weather extremes typically control price levels and 2006 was no exception. Record storage levels of natural gas were set throughout 2006 (EIA, 2007b). The underlying weakness in the market was revealed

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by the sharp price drop in September, reflecting storage levels and diminished hurricane prospects—recognition of which came too late for some and caused the enormous and notorious financial collapse of an inadequately hedged gas trading company in September (Anderson, 2006; Morgenson and Anderson, 2006). The other major price movements were a summer spike when extreme heat forced a first-ever summertime withdrawal from storage, a firming with the approach of winter, a drop in response to mild-early winter weather, and another firming in response to frigid February 2007 weather. Since then, however, analysts have been confounded because prices through mid-June 2007 have traded above levels supported by fundamental factors (Haywood, 2007). SO_2 prices plummeted off their record highs early in the year, yet have remained well above historic norms. The continued volatility of prices underscores the longer term uncertainty in many markets. This uncertainty will only be compounded once the rules change, spurred by such things, as President Bush's call for setting global goals on CO_2 emissions (announced on 31 May 2007 in advance of the G-8 Summit in Germany on June 6–8; White House, 2007).

With trends largely dominated by domestic developments in 2006, global forces remain a powerful latent force (exerted with great effect in the 2004 steam and metallurgical coal price spikes) and continued developments in LNG globally and in China's energy sector will assure that global considerations will continue to influence U.S. energy markets. And although it may seem obscure, globalization in the form of burgeoning imports and the expansion of intermodal traffic (combinations of container movement by truck, rail, and ship) is becoming a strategic factor in evaluating trends in rail rates and thus delivered prices of coal. This is because of the high capacity utilization of track and equipment, where continued capital investment is required to catch up with expanding traffic.

While the U.S. is on the receiving end of global market changes, the U.S. also influences global markets. Despite its price volatility and uncertainty, a new understanding of natural gas price risk is growing out of an appreciation of how the U.S. power sector shapes demand when the supply-demand balance is tight as well as when it is in an excess condition. This new understanding is important to all stakeholders in the natural gas industry and extends to participants gauging price risk in the Atlantic Basin LNG trade. It also is important indirectly to a broad base of additional stakeholders through the outsized importance that natural gas-fired power generating units play in setting wholesale power prices in many parts of the country.

Technological developments in 2006 are likely numerous and pervasive. Without attempting to give the topic justice, two things stand out to this observer. One is the maturation of expectations for coal generating technology and its movement into a lead position in power generation capacity additions after 2010. Promoting its acceptability are removal of emissions to low levels, efficiency improvements, and in some situations use of the nascent integrated gasification combined cycle technology where CO_2 capture can be accommodated more readily than after traditional combustion. Yet, strong counterforces emerged in 2007, bringing sudden doubt to the pace of coal-fired power plant additions. One of the most significant events is TXU Corporation's suspension of 8 of 11 proposed coal plants as part of its buyout by an investor group (TXU Corp., 2007a, 2007b, 2007c, 2007d; Feb., March, April, and May). Second is the continued escalation of capital costs for new coal-fired power plants, reaching a pinnacle with American Electric Power's estimate of $3,545/kW for its New Haven, West Virginia integrated gasification combined cycle power plant (AEP, 2007; Holt, 2007). This movement also is controversial, as is every approach to provide electricity, evidenced by a gap between projections of requirements and the commercial status of proposed projects. The myriad yet-to-be resolved technical and regulatory issues surrounding demonstration and commercial development of large scale CO_2 storage are delineated in a report from MIT (2007). The second technological development of long-term consequence is the maturation of methods and practices leading to greater exploitation of unconventional gas plays, such as horizontal drilling (see Hayden and Pursell, 2005; also, the AAPG Energy Minerals Division Gas Shales Committee is a rich source of information on the geology of gas shales). Several of these topics are expanded upon in this article.

The year 2006 is notable in the sophisticated level of discourse provided to energy and economic topics. Outside of industry trade periodicals and proprietary reports, widely accessible and informed writing on energy and electric power topics appeared in The New York Times series "The Energy Challenge" which began August 2nd and "Power Play—Against the Current" which began October 15th. Topics have spanned deep drilling in the Gulf

of Mexico, the Barnett Shale boom under Fort Worth, Gulf region LNG terminal siting and expansion, TXU's bid to build coal generation units, and in 2007 have extended coverage to a host of other topics, such as wind power, ethanol, coal-to-liquids, and China and India's energy dilemmas. Notable books on energy topics include Peter Tertzakian's *A Thousand Barrels a Second—The Coming Oil Break Point and the Challenges Facing an Energy Dependent World* (2006), and the collaborative book *Natural Gas and Geopolitics from 1970 to 2040*, edited by Victor, Jaffee, and Hayes (2006).

SYNOPSIS OF FUEL PRICE TRENDS

The first series of five charts summarizes recent price movement in representative coals (Fig. 1), the SO_2 emission allowance market (Fig. 2), uranium (Fig. 3), and oil and natural gas (Fig. 4). Fossil fuel prices declined gradually (or in fits and starts) during much of the year, yet levels remained well-above historic norms at year end. Natural gas prices became thoroughly delinked from oil prices as they moved in opposite trajectories throughout the entire year, holding a lesson for those who believe prices move in approximate parity for these fuels.

Powder River Basin (PRB) coal was the last of the major coal regions to spike, and its trajectory along with that of SO_2 emission allowances dropped sharply from Mid-winter 2005–2006 highs. The Western coal market, where coal flows were exacerbated by rail bottlenecks and maintenance, was in short supply during 2005, leading to record low PRB coal inventories at power plants and record spot prices (e.g., $20.00 per ton). Tight PRB coal supply also contributed to heightened use of higher sulfur coals, thus contributing to simultaneous record prices in the SO_2 emission allowance market. Conditions eased during 2006, with PRB prices closing the year at $10.00 per ton ($11.02 per metric ton; $0.57 per million Btu). The decline in SO_2 emission allowance prices was even more dramatic, falling from over $1,500/ton in January to below $500 at

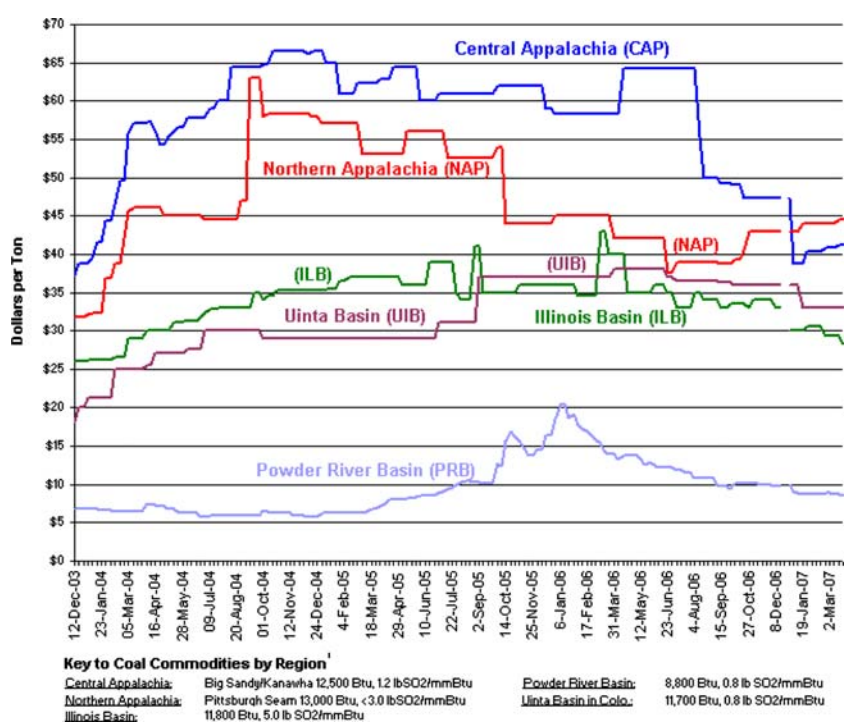

Figure 1. Coal prices December 2003 to March 2007. Source: EIA Coal News and Markets, March 29, 2007 for week ended March 23rd. http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html. Note: It is not clear when or if EIA will update this price series of average weekly coal commodity spot prices. 1 metric ton is 1.1023 short tons. $10/ton (short) is $11.02/ton (metric).

Figure 2. SO_2 prices January 2004 to June 2007. Source: Cantor Environmental Brokerage Real-Time Market Summary. http://www.airtradeservices.com/. Note: SO_2 emission allowance market activity is reported and traded in U.S. short tons. The end-December, 2006 market price index was $483/ton.

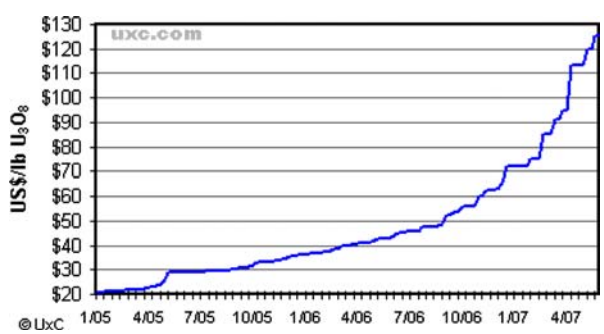

Figure 3. Uranium prices January 2005 to May 2007. Source: Ux Consulting Company, LLC U_3O_8 Prices. Note: Selected UxC weekly spot prices: Dec. 25, 2006, $72.00/lb; May 28, 2007, $125/lb; June 18, 2007, $136/lb. $100/lb U_30_8 is $260/kg uranium. http://www.uxc.com.

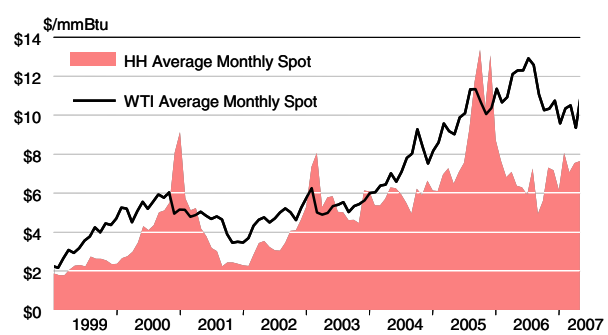

Figure 4. Natural gas and oil prices January 1999–May 2007. Source: West Texas Intermediate crude oil prices: Petroleum Intelligence Weekly; Henry Hub natural gas prices: Natural Gas Weekly. Note: Prices shown are average monthly spot market prices.

year end.[1] In other regions, the most notable decline was for Central Appalachian coal, where spot "compliance" coal prices dropped from over $60/ton to below $50/ton near the end of the summer, as mild weather lessened power generation loads ($66.14 and $55.12 per metric ton; $2.40 and $2.00 per million Btu). The softening of coal prices has contributed to some supply-side corrections, with several new mine developments reportedly being deferred.

Oil prices also dropped sharply beginning in August. Although oil prices are vital concerns in the transportation sector and, of course, the petroleum industry, natural gas prices have achieved greater prominence in the economy because natural gas' role in power generation. The net use of natural gas in the power sector has increased because the rapid growth in the number of combined cycle units using natural has more than canceled out their increased efficiency and displacement of natural gas steam units. Although power prices must rise sufficiently high to recover the costs of this generation, power markets are designed in much of the country, so that all generation receives the same price as the most costly or "marginal" units required at any moment.

[1]Allowance prices are quoted and traded in dollars per short ton.

Natural gas-fired units, typically combustion turbines during peak periods of demand, therefore, have an impact on power prices that far exceeds their share of generation and the associated costs. It is through power pricing dynamics that the factors shaping natural gas prices and the outlook for natural gas prices have catapulted to become major strategic concerns across the energy industry. The power sector's use of fuel and its implications are the main themes to be highlighted in these notes.

Natural gas prices defied evidence of favorable changes in fundamentals (record storage filling—January 2006 was the warmest ever recorded in more than 100 years, and record drilling levels with the first appearance of long-awaited production growth). Record heat at the end of July and early August led to the first-ever summer withdrawal of natural gas and a short-lived price spike. Mild weather and reduced prospects of hurricanes cause a rapid drop in Henry Hub spot prices during September (falling to a remarkable $3.66 per million Btu, or $3.47 per gigajoule, on September 29; Fig. 5). Futures prices for the period March–April 2007 time frame also dropped, a phenomenon that is reported to have led to the bankruptcy of Amaranth Investors whose large positions in the market were inadequately hedged (Morgenson and Anderson, 2006). Later, the underlying softness of fundamentals was ignored until December when mild weather and storage levels at 5-year highs contributed to daily spot prices falling from $8.33/mmBtu ($7.90/GJ) on the last trading day in November to below $6.00 ($5.69/GJ)—in fact, to $5.48/mmBtu ($5.19/GJ) on Dec. 29. Although such prices are high by historic standards, some producers have reported that costs have escalated so much that prices in the $5.75–6.25 range ($5.49–5.92/GJ) are required to offer threshold margins.

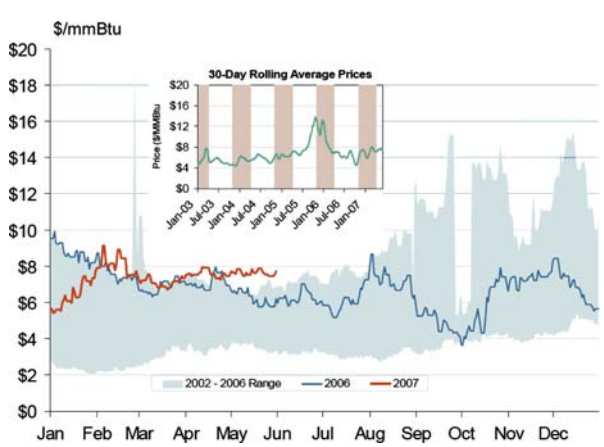

Figure 5. Natural gas prices: 2006, 2007 and 2002–2006 Year Range. Source: Federal Energy Regulatory Commission (FERC), http://www.ferc.gov/oversight, updated June 7, 2007. Derived from *Platts* data. Note: The FERC on January 17th, 2007, launched a web-based service offering energy market data. Prices shown are daily Henry Hub spot market prices.

Uranium is the one fuel, whose trajectory continued upward throughout 2006 at a rate greater than a straightline (from $36.25 per pound U_3O_8 in December 2005 to $72.00 in December 2006; that is, from $94.00 to $187/kg U). As of mid-June 2007, the price had nearly doubled again (reaching $136 per pound or $354/kg U on June 18th). Recognition of the need for greater supplies of primary uranium rather than withdrawals from inventories and secondary supplies (conversion of weapons-grade material) has driving this market upward since September 2003. The prospect of a setback in the pace of future supply—growth, because of flooding during development of Cameco's (the lead joint venture partner) Cigar Lake deposit in Canada gave added impetus to prices later in the year. Initially slated to begin operations in 2007 and facing delays of uncertain extent, this single mine has a projected capacity equal to 10% of 2006 world demand and 16% of 2006 world production.

FUEL EXPENSES IN THE POWER SECTOR

The power sector is a large direct consumer of energy, as well as a provider of energy throughout the economy. It is informative to track fuel expenses of this sector, not only because it consumes nearly all the coal produced in the U.S. (barring some thermal and metallurgical coal exports) and represents 27% or more of natural gas demand, but also because of the extraordinary extent to which natural gas costs have come to dominate all other fuel costs. This surprising development reflects the relatively high cost of natural gas compared to all other fuels and the confinement of oil to a small and declining fraction of generating units. Statistics and recent trends are provided in the Tables 1–3 and Fig. 6.

The telling changes in the power sector's fuel expenses are:

(1) The total expense grew from $61.7 to $90.9 billion in just the two years from 2003 to 2005 (Table 1). Coal expenses have been reported by the EIA to have increased by another 10% in 2006, whereas data through

Table 1. Power Sector Annual Fuel Expenses by Fuel Type, 2003–2005

	Billions/Yr						
	Coal	Oil	NG	Uranium	Petcoke	Total	NG % of Total
2003	25.6	4.8	30.5	0.61	0.12	61.7	49.5
2004	27.5	4.8	35.1	0.81	0.16	68.3	51.4
2005	31.9	7.4	50.4	0.94	0.24	90.9	55.4
% change							
	Coal	Oil	NG	Uranium	Petcoke		
2003–05	24.7	53.3	65.2	54.2	99.8		

Source. DOE EIA. See references, Figure 6. Totals and percentages may not match data shown because of rounding effects.

Table 2. Growth in Power Sector Fuel Expenses by Fuel Type, 2003–2005

	Increase '03 to '05 $ Billions	% of '03 to '05 Total Increase
Coal	6.314	21.6
Oil	2.585	8.8
NG	19.898	68.0
Uranium	0.332	1.1
Petcoke	0.119	0.4
Total	29.248	100.0

Source. DOE EIA. See references, Figure 6.

September showed little change in total natural gas expenses.

(2) $19.9 billion or 68% of this increase was the result of higher natural gas costs (Table 2).

(3) $50.4 billion or 55.4% of the 2005 total fuel expense was for natural gas (Table 1 and Fig. 6)

(4) Natural gas accounted for only 18.7% of electricity generation in 2005 (Table 3).

Gas-fired electric generation has been gradually growing; in fact, the power sector is the only major market sector to have increased its use of natural gas more or less steadily during the past 10 years. A projection provided here (see first section on natural gas price risk) indicates continued growth in natural gas use even though more efficient generating technology units, known as combined cycles (where generation from a combustion turbine precedes a steam generator), have displaced much of the generation from less efficient gas-fired steam units.

GLOBALIZATION (COAL, RAIL TRAFFIC PATTERNS, LNG)

Global considerations are widening their reach beyond oil. A signal event was the surge in Central Appalachian coal prices in early 2004, which was preceded by a similar surge in Amsterdam–Rotterdam–Antwerp prices (Fig. 7). A worldwide shortage of metallurgical coal pulled steam coals into the metallurgical market, aggravating already tight supplies. Factors contributing to this price escalation included reduced exports and greater imports by China and surges in ocean freight rates.

Table 3. Shares of Electricity Generation by Fuel Type, 2000–2005

	% of Generation					
	2000	2001	2002	2003	2004	2005
Coal	51.7	51.0	50.1	50.8	49.8	49.7
Oil	2.9	3.3	2.5	3.1	3.0	3.0
NG	15.8	17.1	17.9	16.7	17.9	18.7
Uranium	19.8	20.6	20.2	19.7	19.9	19.3
Hydro	7.2	5.8	6.9	7.1	6.8	6.6
Other	2.5	2.2	2.5	2.6	2.7	2.7

Source. DOE EIA. See references, Figure 6. "Other" is principally comprised of non-hydro renewables such as geothermal, wind and biomass. The sum of percentages may not be 100% because of rounding effects.

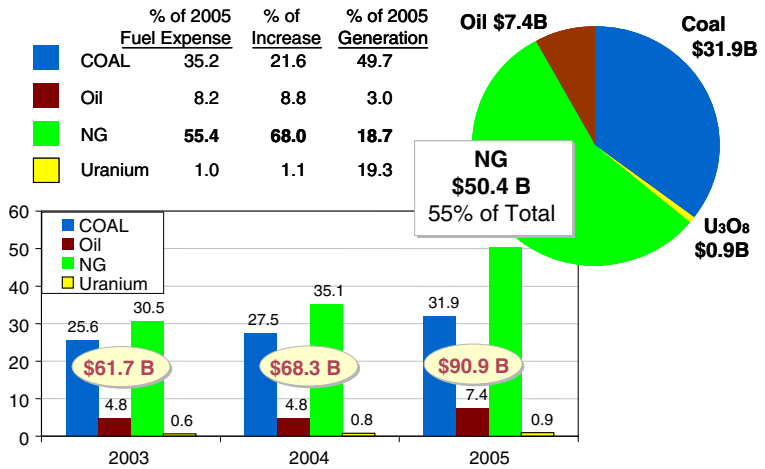

Figure 6. Power sector fuel expense trends: chart and summary data. Source (Fig. 6 and Tables 1–3): DOE EIA (Energy Information Administration). http://www.eia.doe.gov/cneaf/electricity/epm/epmxlfile4_1_cont.xls#_ftn3. http://www.eia.doe.gov/cneaf/nuclear/umar/summarytable1.html. http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile1_1.xls. Note: Petcoke expense included in totals, not shown graphically ($119 million in 2005).

A more subtle global consideration, but one of growing importance to the costs of coal generation, is the developing link between rail rates and the changes required of the rail system to accommodate ''intermodal'' shipments of imported goods. This is the movement of trailers and containers whose volumes have tracked, primarily, the growth in imports from China and other Asian countries. A recent phenomenon, as indicated by the remarkable growth in intermodal shipments involving a rail leg (Fig. 8 and Table 4), this traffic is affecting rail capacity and capital spending. Little understood is the degree to which these shifts could affect service and shipping costs in the future (rail bottlenecks, particularly cutbacks in handling of PRB coal, were implicated in the record drawdown of coal inventories in 2005).[2]

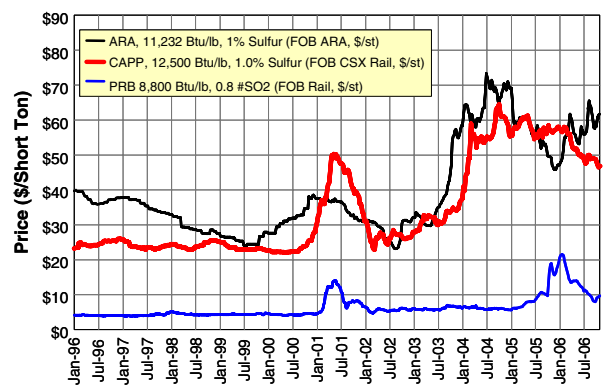

Figure 7. Rapid climb in international coal prices. Source: EVA. In Natural Gas Price Uncertainty: Establishing Price Floors, EPRI, Palo Alto, Calif. 2007. 1012249. Note: 1 metric ton is 1.1023 short tons. $10/ton (short) is $11.02/ton (metric).

The most significant factor in the recent widening globalization of the energy trade are the developments across the world in liquefied natural gas (LNG) liquefaction and regasification. Strictly from a U.S. point of view, imports are considered highly likely to reach 10 billion cubic feet per day in 2010 (280 million cubic meters per day) and possibly more (Fig. 9). Girding optimism is the four-fold growth in world liquefaction capacity during this decade (Fig. 10) and expansion of pipeline supplies in a number of countries, providing an alternative to LNG.

[2]Research for the Electric Power Research Institute has shown how base rail rates (i.e., excluding surcharges for escalating diesel costs) for coal shipments to plants captive to a single railroad increased by 30–70% between 2003 and late 2005, whereas those for shipments to competitively served destinations increased by approximately 20–40%. For captive shippers, these increases equate to $0.25 to $0.60 per million Btu to move PRB coal to Texas, or $0.25 to $0.45 per million Btu to move Central Appalachian coal the Southeast. *New Price Structures for Coal Transportation: Evidence and Implications*, Palo Alto, Calif. 2005. 1012250.

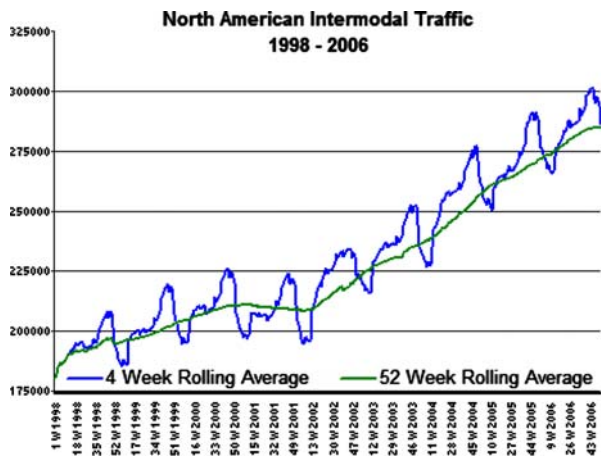

Figure 8. Rapid growth in intermodal traffic since 2003. Source: Summary of Rail Traffic from Atlantic Systems Inc., in Weekly Railfax Rail Carloading Report (http://railfax.transmatch.com/). See "2006 Annual Report: Long Term Charts! 1998–2006." Data on weekly carloadings through June 16, 2007.

NATURAL GAS PRICE RISK 1: THE FRAMING EFFECT OF GAS USE IN THE POWER SECTOR

Price movements in 2006 and reasoning behind increasing softness in the natural gas market has increased the importance of understanding what may provide a floor under natural gas prices, in contrast to a price ceiling. This discussion touches on both concepts, since the resulting envelope—drawing on the latest research into their quantification—helps frame gas price risk. The power sector has been a driving force behind growth in gas consumption—since 2000 consumption of natural gas for power generation has grown by one trillion cubic feet per year (28 billion cubic meters), while total consumption has declined (Fig. 11).[3]

For many years, the power sector has been known to switch readily between natural gas and oil (residual fuel oil of varying sulfur contents) in steam generating plants when it has been economically advantageous to do so or when natural gas supplies have been in short supply. This phenomenon of fuel switching has been determined to be larger and more rapid than that occurring in the industrial sector, and has greatly helped mitigate natural gas price spikes during harsh winters. During the especially cold winter of 2000–2001, for example, the power sector reduced its demand for natural gas by, as much as 3.2 billion cubic feet per day (90 million cubic meters), while averaging a cutback of 2.3 billion cubic feet per day (65 million cubic meters). About two-thirds of this form of fuel switching takes place in just three regions—New York, Florida, and New England—where dual fuel generating units are most abundant. This phenomenon, because of its buffering effect on price spikes, helps to set a "ceiling" on natural gas prices.

Ceiling

Calculations of the point at which switching becomes economic have become complicated. The price of oil is a key factor, of course. At $60/bbl crude oil, it would be more economical to use 1% sulfur resid, if permitted to do so, in a typical natural gas steam unit when natural gas prices exceed $7.34/mmBtu ($6.96/GJ). With a requirement to use lower 0.3% sulfur oil, the gas price would have to rise to $8.19/mmBtu ($7.76/GJ). In contrast, few combined cycle units are fitted to burn any substantial amount of distillate or No. 2 fuel oil. Those that are would not find it economic to switch to this fuel for other than emergency or disruption reasons until the natural gas price reached $12.69/mmBtu ($12.03/GJ). Taking into account different heat rates for different generating units, transportation costs, and environmental penalties, this "ceiling" mechanism is triggered across a range of prices. In 2006, oil prices exceeded natural gas prices so consistently that minimal economic switching occurred.

Floor

At the opposite end of the scale, there is at rare times an interplay between coal-fired generation and natural gas generation. Particularly with the construction of about 140 GW natural gas-fired combined cycle units since 2000, there now is a substantial yet largely latent capability to increase efficient gas-fired generation when economic conditions are warranted, namely when gas prices are low, costs of coal generation are high, and the generation is needed in the first place (power demand is high,

[3]EIA statistics indicate total gas consumption peaked at 23.3 trillion cubic feet in 2000, when power sector gas use was 5.2 Tcf or 22.3% of the total. In 2006, total consumption was 21.9 Tcf and power sector use was 6.2 Tcf or 28.6% of the total. These figures correspond to total demand of 661 billion cubic meters in 2000, of which 174 Bcm was for power generation and 619 Bcm in 2006, of which 177 Bcm was for power generation.

Table 4. Traffic Growth by Type for Major Coal Hauling Railroads, 2000–2006

(All traffic in thousands of units for intermodal, and in thousands of carloads for other commodities)

	2000	2001	2002	2003	2004	2005	Annualized % change 2000–05	% change for 1H2006
Western Railroads (BNSF & UP)								
Intermodal	6,356	6,223	6,515	6,995	7,644	8,195	5.2	8.2
Coal	3,953	4,294	4,261	4,235	4,388	4,416	2.2	5.9
Other	6,759	6,554	6,543	6,655	6,962	6,956	0.6	2.2
Total	17,068	17,071	17,319	17,885	18,994	19,567	2.8	5.6
Eastern Railroads (CSX & NS)								
Intermodal	4,294	4,218	4,473	4,697	5,198	5,320	4.4	4.2
Coal	3,442	3,494	3,253	3,250	3,421	3,544	0.6	3.0
Other	6,429	6,031	6,086	6,198	6,376	6,273	−0.5	−0.3
Total	14,165	13,743	13,812	14,144	14,994	15,137	1.3	2.0

Source. Calculations by Pace Global Energy Services in "Changing Expectations for Coal Transportation," October 2006a. EPRI newsletter: Energy Markets and Generation Response.

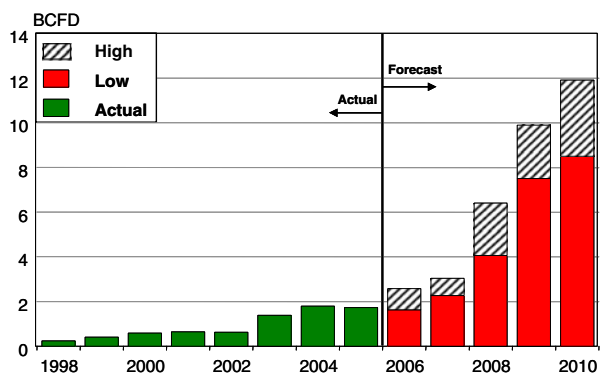

Figure 9. Projection of growth in U.S. LNG imports. Source: *Putting LNG into Perspective on a Global Basis*, EPRI, Palo Alto, Calif.: 2006d. 1013693. Note: 10 billion cubic feet per day are 283 million cubic meters per day.

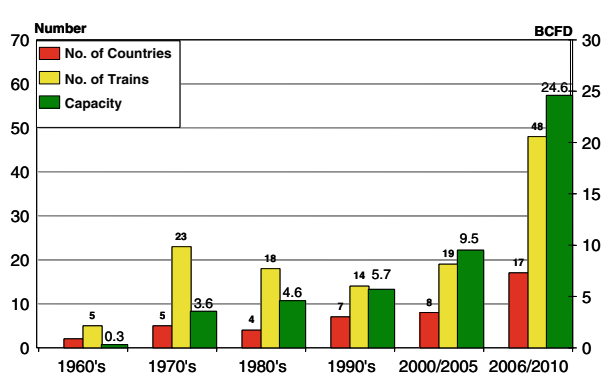

Figure 10. Projection of growth in world liquefaction capacity. Source: Putting LNG into Perspective on a Global Basis, EPRI, Palo Alto, Calif.: 2006d. 1013693. Note: 9.5 and 24.6 billion cubic feet per day are 269 and 697 million cubic meters per day.

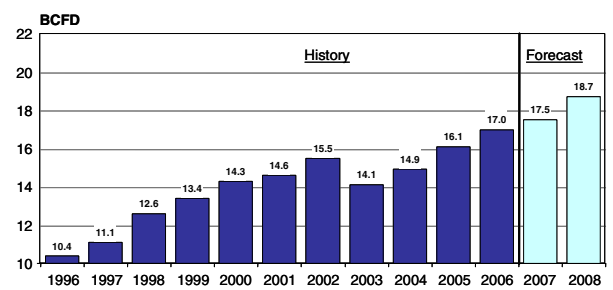

Figure 11. Growing natural gas demand in the power sector. Source: Energy Ventures Analysis, Inc. S. Thumb, personal Communication, January 2007. Note: These projected levels from 2006–2008 are 6.2, 6.4 and 6.8 trillion cubic feet/yr (177, 182 and 193 billion cubic meters/yr).

calling on generation from higher cost units to meet loads). Average capacity utilization of this new fleet is only about 30%. Should natural gas prices fall considerably, a point is reached where these units will actually displace generation from the most expensive fraction of coal units. And should this occur to any substantial extent, increasing demand will eliminate the excess supply that led to falling prices in the first place—thus causing coal generation to serve as a price "floor." In order to understand the relevance of this concept, it is important to point out that during September when weather conditions were remarkably mild (and thus little high cost coal generation was required in the first place), some coal generation was displaced by that from gas-fired combined cycle units.

Costs for coal generation have been increasing with escalating coal and transportation prices and SO_2 emission allowance prices. Calculations of how the floor has changed indicate that, during the

''ozone season'' when coal generation incurs an added layer of costs for NO_x emissions, the gas price floor rose from $2.35/mmBtu in 2002 (when natural gas prices were $3.33 on an annual average basis) to $6.01 in 2005 (with gas prices at $8.55; Table 5).[4] Although gas prices exceeded floor prices, the healthy floor price would be good news to investors in natural gas E&P or infrastructure. Then in 2006 gas prices dropped along with coal prices and SO_2 prices, and NO_x prices (which have not been summarized in a chart) also fell precipitously (from $1,400 to $400 per ton). All this led to a calculation of floor prices of only $4.75/mmBtu ($4.50/GJ).

Looking beyond 2006, floor prices based linkage to coal-fired electric generation costs tend to hover in the $6.00/mmBtu range in nominal dollars ($5.70/GJ), lower in the earlier years and higher in later years. Such calculations are every bit as complex as those required to estimate the range of ceiling prices, requiring local analysis and projections of delivered coal costs, installation of emission controls, emission levels and prices (spanning SO_2, NO_x, and CO_2), efficiencies and other factors. Figure 12 presents a scenario of price ceiling and floor calculations that takes into account generating costs at nearly all coal-fired plants in the eastern U.S. By September 2006, softening prices raised the possibility that down-side price risk could threaten some supply projects.

Rethinking the Price Floor Mechanism in Response to Cost Escalation

Cold late-winter weather drove demand and propped up prices for natural gas through the first quarter of 2007, diverting attention from price floors. The economics of some gas supply projects are under pressure yet, however, not as much from falling prices as from rising costs. Escalation of finding and development costs is overwriting the price floor mechanism just described, leading to the more familiar situation in which marginal costs of gas set market prices. The way in which these costs are setting a floor above that set by coal generation costs also is indicated on the figure. The critical question now is how long high finding and development costs can be sustained.

[4]These estimates correspond to a 2002 floor of $2.23/GJ when gas prices averaged $3.16/GJ to a 2005 floor of $5.70/GJ when gas prices averaged $8.10/GJ.

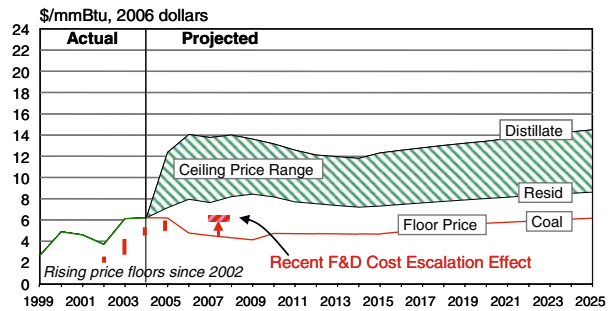

Figure 12. Ceiling band and floor prices for natural gas, Henry Hub. Source: *Natural Gas Price Uncertainty: Establishing Price Floors*, EPRI, Palo Alto, CA: 2007. 1012249. Note: Ceiling prices are based on current NYMEX oil price through 2012; after that they are based on investigator forecasts. Floor prices are based on forecasts of factors affecting costs of coal generation across most of U.S. east of the Mississippi River. Escalation of finding and development costs (F&D Cost Escalation Effect) has raised the floor over the intermediate term to levels higher than those shown here based on displacing coal-fired generation. $6.00 per million Btu (mmBtu) is $5.69 per gigajoule.

NATURAL GAS PRICE RISK 2: THE CHANGING SUPPLY-DEMAND EQUATION

The year 2006 seems to be a pivotal year in one additional important respect, the turnaround in declining Lower 48 gas production after years of increasing levels of drilling. The gas-directed rig count exceeds 1,400 (Fig. 13). Play by play analysis of production trends show 2006 is the year that the first really meaningful increase in production occurred since the rig count started to climb above 800 during 2003—even apart from taking into account

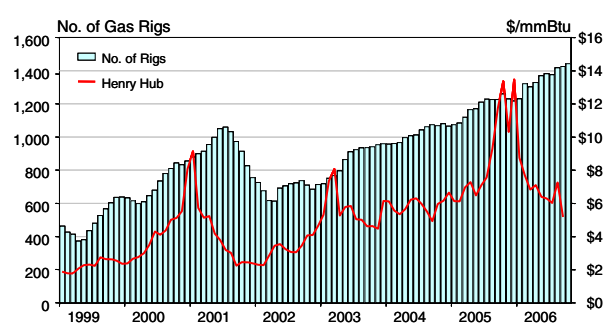

Figure 13. Rig count for gas-directed wells. Source: NGW; Energy Ventures Analysis, Inc. in ''Changing Perspective: Intermediate-Term Increases in both U.S. Production and LNG Imports Lead Toward Excess Supply,'' December 2006c. EPRI newsletter: Energy Markets and Generation Response.

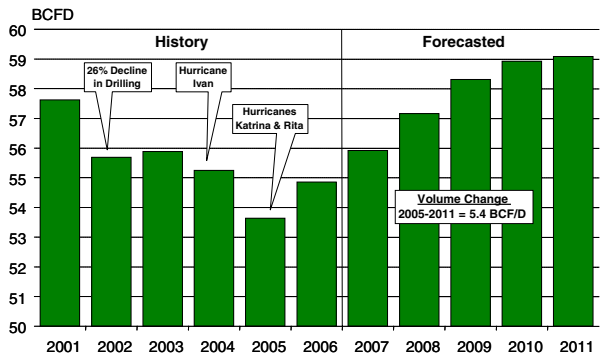

Figure 14. Lower-48 states gas production and scenario. Source: Lippman Consulting, Inc.; Energy Ventures Analysis, Inc. in ''Changing Perspective: Intermediate-Term Increases in both U.S. Production and LNG Imports Lead Toward Excess Supply,'' December 2006c. EPRI newsletter: Energy Markets and Generation Response. Note: 2006 is estimated. 55 billion cubic feet per day are 1.56 billion cubic meters per day.

the severe impacts on production from Hurricanes Katrina and Rita in 2005 (Fig. 14).

A simple projection that considers sustained drilling and typical recoveries and production decline rates for typical plays in each region leads to the surprising prospect that Lower 48 production could actually increase during the next several years or even longer. Of course, this prospect requires a host of assumptions, among them sustained drilling rates. The result is a new supply–demand ''equation'' (Fig. 15). In spite of likely declines in imports from Canada and growth in U.S. demand, the combination of expanding LNG imports, which carries the lion's share of incremental supply growth, and the ramping up of U.S. production leads to a net ''excess'' condition. One can readily cite the many caveats, yet the scenario deserves serious consideration. The year 2009 marks the year in which the calculated ''excess'' seems to be greatest, owing especially to the increase in LNG imports in that year. And if such a scenario transpires, the ''price floor'' logic will be increasingly important to gas price risk assessment.

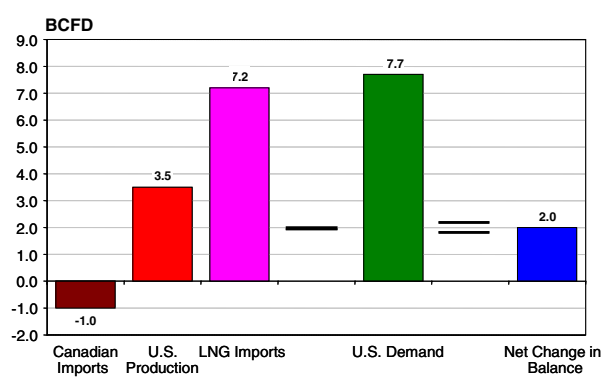

Figure 15. New supply-demand equation shows possible ''excess'' supply: 2006–2011. Source: Energy Ventures Analysis, Inc. in ''Changing Perspective: Intermediate-Term Increases in both U.S. Production and LNG Imports Lead Toward Excess Supply,'' December 2006c. EPRI newsletter: Energy Markets and Generation Response. Note: 2.0 billion cubic feet per day are 57 million cubic meters per day.

Technology Highlight: Coal-Fired Capacity Additions

On the technology front, surely the exploitation of tight shales and gas sands is critical to the growth seen and anticipated in production. Yet, an important development is again emerging on the consumer side: expansion of coal fired generating capacity (Fig. 16). This is a far slower developing phenomenon than the recent boom in gas-fired generating capacity. Although one might think construction of gas-fired units is over, that is not at all true, as natural gas units dominate additions to the end of the decade. Beginning in 2010, coal becomes the dominant choice.

More than 88 gigawatts (GW) of new capacity (as of mid-2006) had entered active development for the period 2006–2015, with 60 GW anticipated by 2010. 34 GW each of natural gas and coal capacity and 19 GW of non-hydro renewables (incl. 14 GW

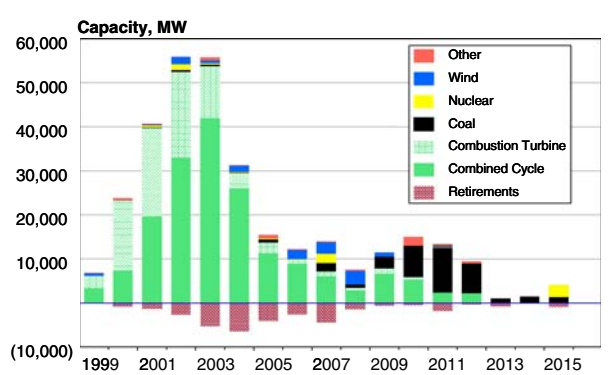

Figure 16. Capacity additions—view as of mid-2006. Source: Energy Ventures Analysis, Inc. in ''Tracking New Power Plants in the U.S.—Midyear Review: 60 GW Through 2010,'' October 2006b. EPRI newsletter: Energy Markets and Generation Response.

wind) comprise this total. Coal projects have ramped up rapidly in the past year, growing 80%.

These tallies are based, not on computer projections of energy growth and analysts' assessments of technology tradeoffs, but rather on tracking the development status and likelihood of plants that have been proposed by commercial entities. The subject remains controversial, and many headlines have spoken of a 100 coal-fired plants under development. The reality is smaller during the next ten years, and many changes in plants' prospects are likely. Only 53% of plants slated to come online 2006–2010 are already operational or under construction. Beyond 2010, only 27% of announced capacity is in an advanced development stage.

Announcements of coal capacity are beginning to show the same dynamics seen with the gas-fired power plant boom, where the wave of announcements in successive years after 2000 reshaped each quarter, with some of the plants proposed for early construction deferred to later years or dropped, and new projects added (Fig. 17). There is the expectation for integrated gasification combined cycle power plants (IGCCs), gaining popularity in part because the technology is more cost-effective at capturing CO_2 than conventional pulverized coal plants. At mid-year 2006, three such plants were in an advanced stage of development, whereas 22

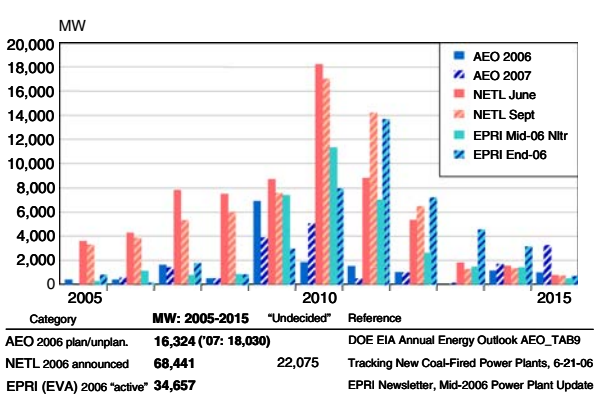

Figure 17. Progression and comparison of coal capacity addition projections. Source: US DOE EIA Annual Energy Outlook 2006 and 2007a; National Energy Technology Laboratory "Tracking New Power Plants" June and September, 2006; Energy Ventures Analysis, Inc. in "Tracking New Power Plants in the U.S.—Midyear Review: 60 GW Through 2010," October 2006b in EPRI newsletter: Energy Markets and Generation Response; with end-2006 update, S. Thumb, personal communication. Note: These tallies were provided prior to TXU's February 27, 2007a announced withdrawal of 8 of 11 proposed coal-fired power plants in Texas, and others in Virginia, Maryland, and Pennsylvania.

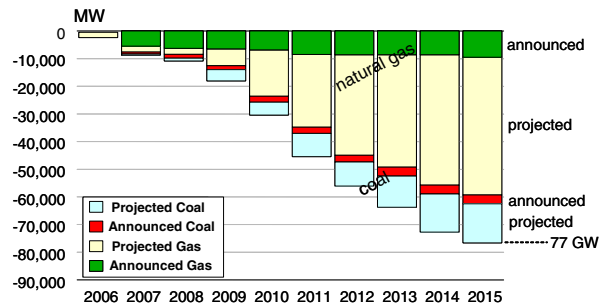

Figure 18. Announced and projected retirements of natural gas and coal generating capacity. Source: Energy Ventures Analysis, Inc. in "Tracking New Power Plants in the U.S.—Midyear Review: 60 GW Through 2010," October 2006b. EPRI newsletter: Energy Markets and Generation Response.

plants totaling nearly 13 GW were proposed or possible, but not yet firm, that is, not yet entering active permitting.

By the end of the first quarter of 2007, expectations for new coal-fired capacity are poised for more dramatic changes than were foreseeable at the end of 2006. A pivotal event was the decision in February 2007 by a major Texas power company (TXU Corp.) to cut back sharply on its plans for new coal-fired power plants in several states, arranged as part of a $32 billion buyout offer for the company by an investor group led by Kohlberg, Kravis Roberts & Co. and Texas Pacific Group (TXU Corp, February 2007). It seems inevitable that deferrals and cutbacks in coal-fired generation will translate into further increases in use of natural gas for power generation.

A further challenge to maintaining and expanding the country's generation capacity comes from retirements. During the same 2006–2015 period, 77 GW are expected to retire: 78% natural gas and 22% coal. Of these, less than 15 GW have been announced (Fig. 18).

CONCLUSION

The energy markets are as uncertain as ever, with developments on numerous fronts. For natural gas, which has ever increasing importance in the energy economy, understanding of fuel use in the power sector shows enormous promise in bounding expectations of future price risk. Many developments need to be watched closely and will shape expectations of going forward. Among the most important are the Canadian supply–demand balance

Table 5. Historical Progression of Floor Prices for Natural Gas

Year	Floor price ($/MMBTU)		Henry Hub
	Non-ozone season	Ozone season	Gas price ($/MMBTU)
2002	$1.90	$2.35	$3.33
2003	$2.88	$4.10	$5.63
2004	$4.52	$5.30	$5.85
2005	$4.90	$6.01	$8.55
2006	–	$4.75	$6.83[a]

Source. Natural Gas Price Uncertainty: Establishing Price Floors, EPRI, Palo Alto, Calif. 2007. 1012249.
[a]2006 estimate based on 10 months of actual prices.

and imports from Canada, progress in LNG terminal development and access to international liquefaction supplies required by these terminals, and the level and character of gas-directed drilling, particularly the profitability of maintaining activity at today's unprecedented highs. In the short run, a sharpening dilemma is likely to be the tensions brought about by cost escalation in exploration and development. The themes emphasized here are admittedly selective, drawing on a portion of the year's research developed for the Electric Power Research Institute whose cooperation is gratefully acknowledged.

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