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The Shale Juggernaut – Gains and Casualties

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Leading energy supply and demand developments are summarized in this overview, with an emphasis on natural gas. The time envelope is principally 2012 to mid-2013, with some historical information included along with comments and projections to 2020. The upside, or gains, from now-abundant natural gas include the flow of benefits from lower-cost gas to industry (e.g. petrochemical, steel, fertilizer) and consumers of natural gas and electricity. The downside, or casualties, include producers and processors affected by continued low prices and the sudden collapse of NGL prices, particularly ethane and propane, and coal producers who have lost market share to natural gas-fired generation, not to mention their exposure to softening global thermal and metallurgical markets and the beginnings of a wave of US coal plant retirements.

The selection of topics is far from exhaustive. Insights from analysts in industry and energy consultants, offered expressly to support the American Association of Petroleum Geologists' Energy Economics & Technology Committee, are included with appreciation. Contributors are identified at the appropriate places. Additional information is derived from EIA, the trade press, energy producers, and other public sources. This review is brief, contrasting with more lengthy material developed for the Committee a year earlier and available online to members of AAPG's Energy Minerals Division. The sequence addresses supply, resources and market impacts. It shifts to demand, and closes with limited remarks about the coal industry.

Appreciating the Scale of the Shale Gas Phenomenon

Shale gas now accounts for about 40 percent of U.S. gas supply -- more particularly the Lower 48 States' (L48) wellhead supply. The speed and scale of shale gas growth is remarkable and all the more astonishing in light of depressed natural gas prices and sharp curtailments of drilling. An easy way to keep track of shale gas' production growth is to consult the Energy Information Administration Administration's (EIA) Natural Gas Weekly (NGW) report issued each Thursday along with the latest data on natural gas storage. While this information is widely accessible, I have rarely encountered individuals inside or outside the industry conversant with the share achieved by shale gas production. Figure 1 is taken from the latest NGW at the time of writing. The data are provided to the EIA by Lippman Consulting, Inc. George Lippman, its president, also provided the data in Table 1 which calculate the shales' share of L48 supply. The figures will not agree precisely with alternative methods of calculation, such as relying solely on EIA production statistics, but they have the advantage of assuring that production figures are derived on the same basis.

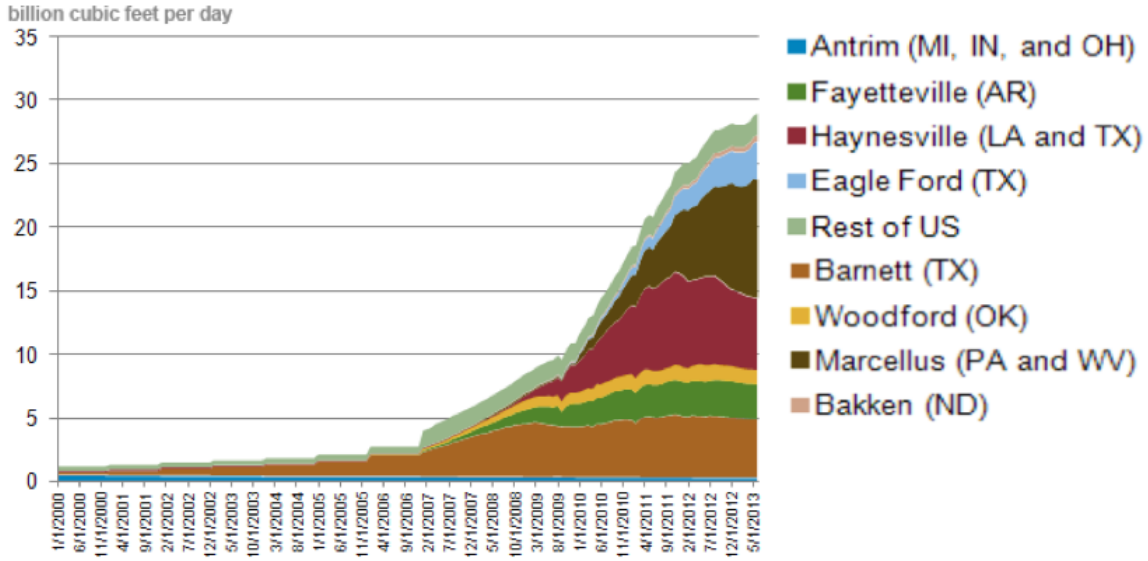

Figure 1. Growth of US Monthly Dry Shale Gas Production
Source: Lippman Consulting Inc. *in* EIA Natural Gas Weekly Update – data through June 1, 2013.

Billion cubic ft/day	US Wellhead Prod.	All Shales	% of US
Dec 2011	71.3	26.8	37.6%
Jun 2012	70.8	28.7	40.5%
Dec 2012	72.6	30.2	41.6%

Table 1. Shale Gas Share of L48 Wellhead Natural Gas Production
Source: LCI Energy Insight, G. Lippman, personal communication 11 May 2013.

Just how much gas is this?

30.2 Bcf/d on a gross basis is about 11 Tcf/yr (312 Bcm/yr) or 10 Tcf/yr on a dry basis (281 Bcm/yr). Looking at EIA 2012 statistics, this amount is 1.42 times the natural gas consumed in Texas, California and Louisiana; 2.4 times the amount of natural gas consumed in the entire residential sector; or 9.4% greater than all the natural gas consumed in electric power generation in 2012. Measured internationally, the dry gas total from US shales is equivalent to 67% of all gas consumed in Russia, 2.4 times Japan's consumption (even after accounting for the 10.3% increase in Japan's natural gas consumption after the Fukushima Daiichi tsunami and nuclear disaster of March 2011); or 93% of all natural gas consumed in the five largest gas consuming countries in Europe (UK, Germany, Italy, France and Netherlands). By any measure, the numbers are stunning. At this level of production, every dollar per thousand cubic feet saved by consumers from abundant natural gas adds up to direct savings of $10 billion/year.

Second Great Jump in Resource

The Potential Gas Committee (PGC) conducts bienniel assessments of potential gas resources – probable, possible and speculative resources, not reserves. Shale gas

was not broken out in its 2006 assessment, but it was estimated to be about 200 Tcf at the time. 2008 is when shale gas came onto the scene in the U.S. in a dramatic way, and the PGC reported shale gas resources of 615.9 Tcf (all shale gas has been in the probable and possible categories), an increase of 416 Tcf. The estimate increased by only 71 Tcf in 2010, reaching 686.6 Tcf. The latest (2012) assessment released April 9, 2013 recorded another spectacular jump of 386 Tcf, bringing the total resource attributed to shale gas to 1,073 Tcf. This is 53% of the Lower 48 resource, excluding coalbed gas. The growth in the shale resource accounted for 85% of the growth in the overall national estimate. The biggest growth occurred in the PGC's Atlantic region, which comprises the Marcellus shale, the Utica shale, other shales, and conventional resources. The Atlantic region resource more than doubled from 353.6 to 741.3 Tcf. As this progression clearly indicates, 2012 was a very important year in both confirming and extending the resource attributed to shales. Figure 2 charts these changes. The resource doubled in eight years. The markets are responding – both immediately and in prospect for the coming decade.

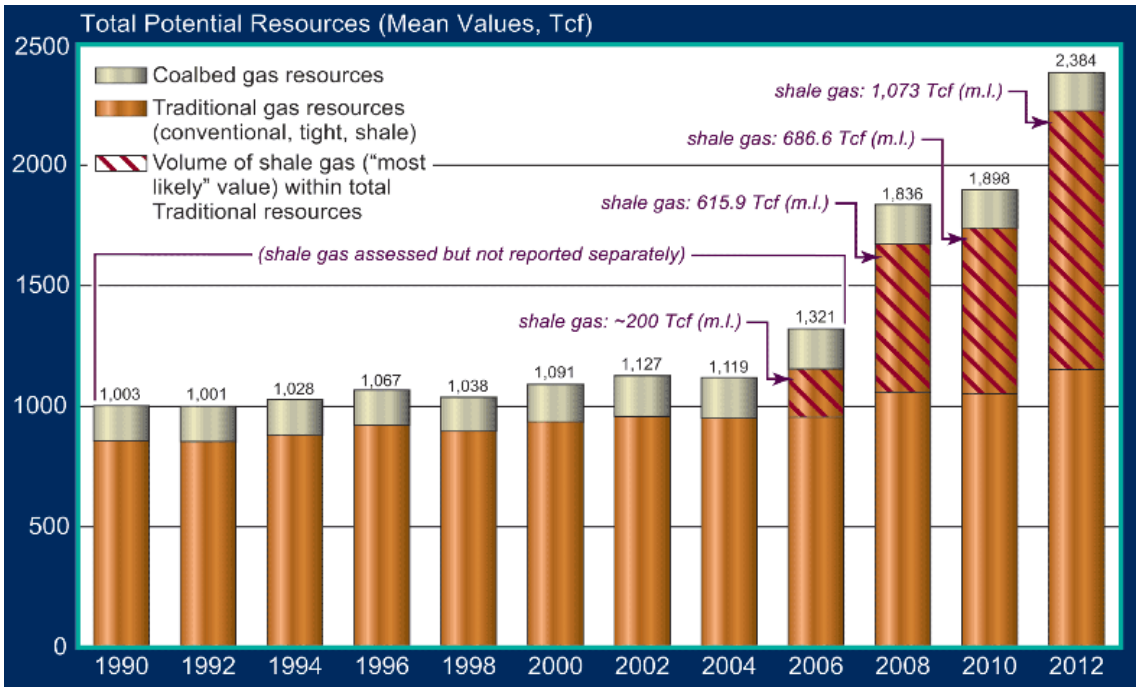

Figure 2. PGC Resource Assessments, 1990-2012

Source: Potential Gas Committee, April 2013 slideset. Used by permission of PGC, July 24, 2013

Commodity Price Collapse – Company Downgradings Risks

One effect of burgeoning production is the oversupply of 2012, which drove prices (e.g. Henry Hub) below $3.00/mmBtu (lowest prices of below $2.00 the first two weeks of April) and promoted record displacement of coal-fired generation by natural gas. This is potentially great for end-use consumers of natural gas and electricity and disastrous for natural gas producers. Its impact on power companies is mixed. Perhaps the most notable casualty of generally-depressed natural gas prices, and thus power prices, is Energy Futures Holding Company, the firm created

after the 2007 $45 billion buyout of TXU Corp., the largest generator in Texas. Its Achilles Heel was expectation of continuing high or rising natural gas prices – the same driver behind LNG import terminal developments at the time. Restructuring arrangements remain in limbo in mid-2013.[1]

Dr. Michelle Foss of the University of Texas pointed out the problem of company downgrading, as follows:
"It [natural gas] is not cheap - with a gas well you get 1/6 the Btu content for the same cost of a good black oil well and still less than one that is (hopefully) NGLs rich. The best shale wells produce less than 1k boepd, and that is mostly dry Haynesville converted to make the books look good. We went through a list of companies that we expect to downgrade - there just aren't enough good liquids positions to be had and the ones that are out there are very expensive." *(Personal communication, January 24, 2013)*

Supply Momentum

To make things worse on the upstream side, an added price-weakening consideration are the many billions of dollars in yet-expended "drill carries" in the US and Canada that will prop up E&P beyond the normal economics of drilling for some years to come. Drill carries are financial arrangements by which investors taking a stake in a shale producer's properties agree to shoulder some or all exploration expenses for a period of time, in effect decoupling drilling from normal market signals. The period from mid-2008 through 2010 saw many such arrangements, along with outright acquisitions. These were recorded in the Energy Economics and Technology Committee report of March 2011, where the total of drill carries alone had climbed to $13.2 billion. This influence has shrunken but not yet faded away. To this effect, the inventory of drilled but uncompleted wells adds to the ability to add supply at low incremental cost. *(Personal communication, Steve Thumb, Energy Ventures Analysis, Inc.)*

Ethane and Propane Price Aberration

The collapse of NGL and propane prices is adding to upstream cash flow pressure even for wet gas plays. This was pointed out to me by Kyle Sawyer of Boardwalk Pipeline Partners, LP.:

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[1] This deal was characterized as "the largest leveraged buyout in history". A natural gas price of $6.15/mmBtu was cited as the break even threshold. (*New York Times*, Feb. 28, 2012. Peter Latman: "A Record Buyout Turns Sour for Investors"). Comprised of Luminant, Oncor and TXU Energy, in February, 2012 the company reported a 2011 loss of $1.9 billion. Losses since 2007 have climbed to $18 billion (Wall Street Journal, April 13, 2013. Mike Spector: "Former TXU Seeks to Erase Debt"). Its bankruptcy "would rank among the 10 largest in the U.S.". (*Wall Street Journal*, July 13, 2013. Tom Fowler and Cassandra Sweet: "At Texas Electric Firm, Users May Hold Key"). The outstanding debt of $32 billion is comparable to the value of all US gas shale production over a year (10 Tcf, $3.50/mcf, $35 billion).

> "…ethane prices dropped below rejection levels last year, starting in Appalachia and the Rockies, moving to the Mid-Continent and finally to Mt. Belvieu over the last two months. Propane has moved downward significantly as well due to high inventories from last year's 'non-winter' and burgeoning production.
>
> "The lower NGL prices are pressuring returns from the shift to the wet gas shale plays and could impact the amount of capital available for new wells, particularly since a large number of E&P companies are running negative cash flows." *(Personal communication, January 30, 2013)*

The 2011 to 2012 split in price trajectories is captured in FERC Market Oversight's summary of NGL prices, Figure 3. Rejection occurs when it is more costly to fractionate and transport ethane than to leave it in the gas stream. Both the ethane and propane oversupplies are transitory, with the timing depending on construction schedules of ethane crackers, NGL pipeline capacity, and on the market response to bargain propane and ethane prices. An implication of Sawyer's comments is that upstream market participants attempting to understand current and future revenue streams will have to be knowledgeable about much more than "gas" and "oil", to include ethane, propane, and butanes and the fundamentals leading to their anomalous price-depression. An informative web-based resource on natural gas processing economics is RBN Energy LLC. They have tallied an increase of over 40% in fractionation capacity over the next few years – 2/3s of which will be in the Mont Belvieu, Texas, NGL hub region (RBN Energy and MidstreamBusiness.com).[2]

Access to low-cost feedstock coming from expanding shale gas/liquids production is known in the chemical industry as the US "ethane advantage" compared to facilities that use naphtha as a feedstock (e.g., Western Europe). Industry participants foresee this advantage persisting for as little as five years, for ten years, for as long as shale gas remains prominent, or for as long as oil prices remain above $70/barrel. Despite the uncertainty, major investments to exploit US' globally competitive natural gas and NGL prices are proceeding apace in the industrial sector.

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[2] Example reference: "Fractionation Projects Abound": http://www.rbnenergy.com/fractionation-projects-abound

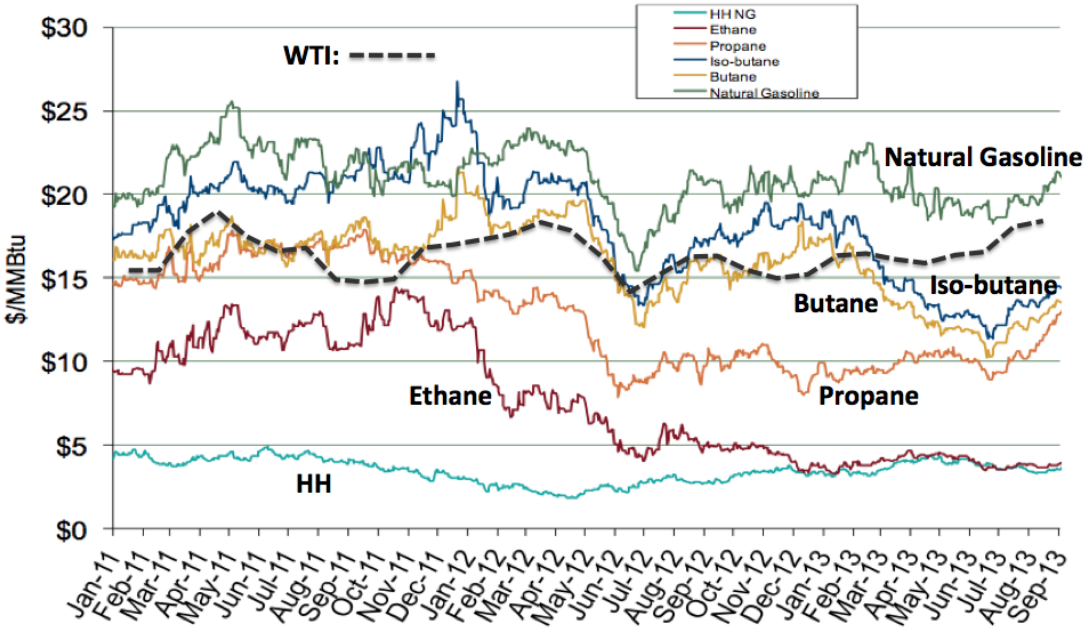

Figure 3. Ethane and Propane Price Aberration

Source: FERC Market Oversight, September 10, 2013, derived from Bloomberg data. West Texas Intermediate spot crude price added by author (EIA price data, converted at 5.8 mmBtu/barrel).

Shift in Fundamentals of Industrial Gas Use

The American Chemical Council issued a report in May which identified 97 projects announced by the chemical industry, amounting to a capital investment of $71.7 billion through 2020 (*Shale Gas, Competitiveness, and New US Chemical Industry Investment: An Analysis Based on Announced Projects*). Prior ACC studies examined impacts of more abundant natural gas on, not just chemicals, but also paper, plastics, and metals (e.g. iron and steel). A theoretical boost in ethane supply, which has subsequently begun, was also examined.

ACC's report is a strong indicator of directional trends, but it takes a sharp pencil and intimate familiarity with each project to vet the most likely candidates and their progress to key milestones. Energy Ventures Analysis, Inc. (EVA) has examined announced projects in the power and industrial sectors. Rather than focus on jobs, capital spending, and industrial policies – the principal thrust of chemical industry's voice – EVA's objective is to gauge energy use. The company's calculations are based on its vetting of announced projects and translating these into total gas requirements per year. Their results are shown in Figure 4. Among industrial demands, the chief components are petrochemicals (various substances plus methanol), fertilizer, and at the end of the decade, at least two (and possibly four) gigantic gas-to-liquids "trains" rated at 0.42 Bcf/d each. A smaller segment is represented by expansion in the steel industry. *(Steve Thumb and Jeffrey Quigley, personal communication, May 15, 2013).*

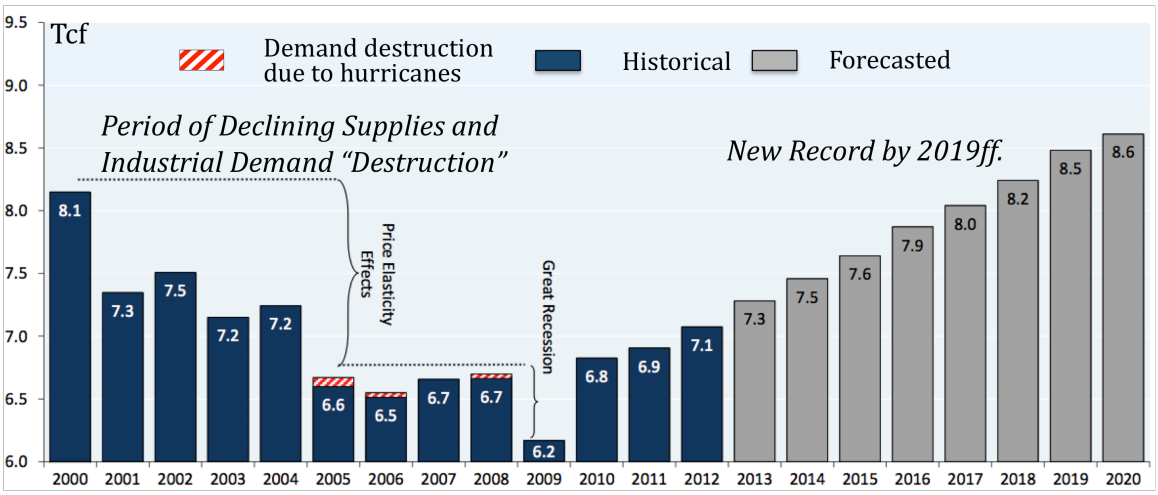

Figure 4. Industrial Sector Gas Demand
Source: Energy Ventures Analysis, Inc.

Underlying this chart, the tidal wave of growth in the industrial sector has been calculated to be about 3.6 Bcf/d or 1.3 Tcf/year, and possibly more. This is a topic that is dynamic and warrants continued monitoring. The broad sector is one component of increasing demand. The other major components are the power sector – experiencing swings of gas use in existing units as well as retirements and replacement of generating units over time – and LNG exports. The transportation sector remains a question mark.

Power Sector Natural Gas Demand in the Short and Intermediate Term

Short Term. Displacement of coal-fired generation by natural gas has been unprecedented and newsworthy ever since it commenced during the last five months of 2008, continuing essentially unabated and reaching peaks in 2012. Principally spurred by low gas prices, especially in 2012, it has also been spurred by the global boom in coal prices (climbing coal prices 2010 through mid-2011) and other factors. It occurs via substitution "on the grid" of power from gas-fired combined cycle units, not by substituting fuel into coal steam generators.

Peak monthly levels of this kind of fuel switching increased natural gas demand by as much as 8 billion cubic feet per day in May 2012, as calculated by Energy Ventures Analysis, Inc. who prepared the analysis of monthly coal displacement/enhanced gas-fired generation shown in Figure 5. While natural gas prices recovered in 2013 and coal generation indeed increased, it is notable that very significant levels of switching continued throughout the first quarter of 2013. *(Steve Thumb and Jeffrey Quigley, personal communication, May 15, 2013).*

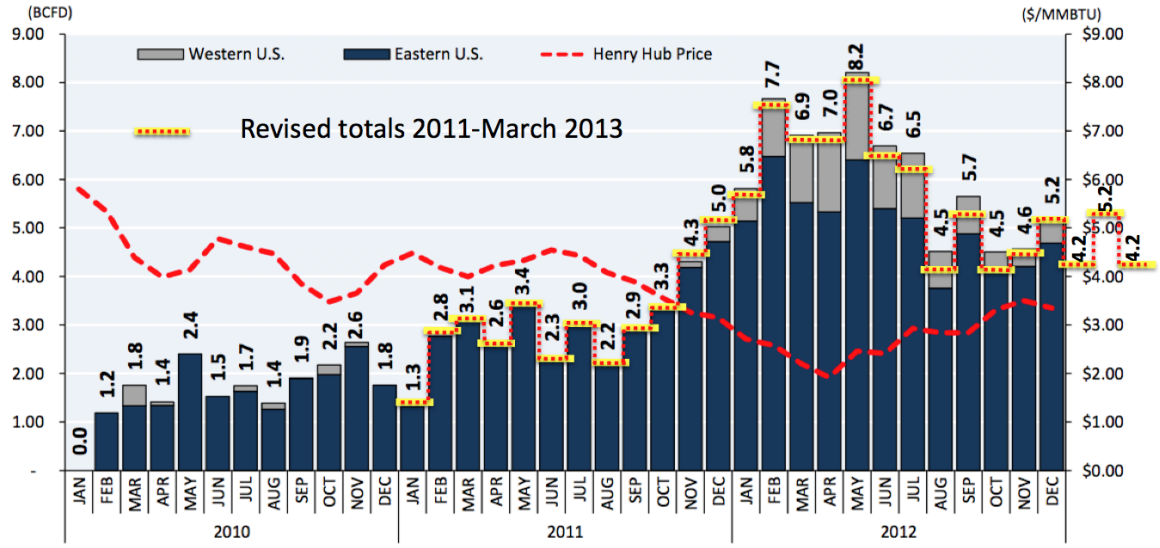

Figure 5. Monthly Coal Generation Displaced by Natural Gas
Source: Energy Ventures Analysis, Inc.

On an annualized basis, high efficiency gas-fired generation from 4 Bcf/d is roughly equivalent to that derived from over 70 million tons of high quality coal – one of the primary reasons for the record decline in coal generation and US CO2 emissions experienced in 2012 even as global emissions reached a new high (International Energy Agency World Energy Outlook Special Report, June 10, 2013: *Redrawing the Energy-Climate Map*).[3]

Intermediate Term. Changes in the generation capacity mix (retirements, replacements, new capacity additions) govern how much gas will be required for power generation in the long run. The principal impetus through mid-decade is the retirement of coal-fired capacity in response to continued competition from natural gas and investment hurdles to meet Mercury and Air Toxics Standards.

Metin Celebi of The Brattle Group emphasizes the vulnerability of coal plants to the remarkable levels of coal switching, pointing out "Low natural gas prices (spot and forward), result not only in coal-to-gas dispatch switching and but also worse projections for coal units' future energy margins. *(Personal communication, January 29, 2013).*

Brattle's assessment of possible coal plant retirements are summarized in Figure 6. The study, released in October 2012, indicates retirements of 59-77 GW of coal capacity by 2016, the range depending on the stringency of air toxics standards. To replace the generation from 59 GW, based in these units' 2011 output, would require about 6 Bcf/d. This allows one to get a sense of the possible boost in gas use

[3] This translation assumes gas-fired generation is 30% more efficient that coal-fired generation (Btu/kWh) and that the representative coal heat content is 12,500 Btu/lb.

in the power sector from pending coal retirements. Some of this replacement generation has already occurred, contributing to the 2012 peaks of coal switching.

The authors found that additional coal retirements from assuming $1.00/mmBtu cheaper natural gas are comparable to those which would be caused by imposing a $30/ton carbon tax. It is possible to conclude, then, that abundant gas is already impacting coal power plants like a controversial carbon tax and without incurring the political expenditure of enacting such measures.[4] Coal plant retirements are addressed again in a later section.

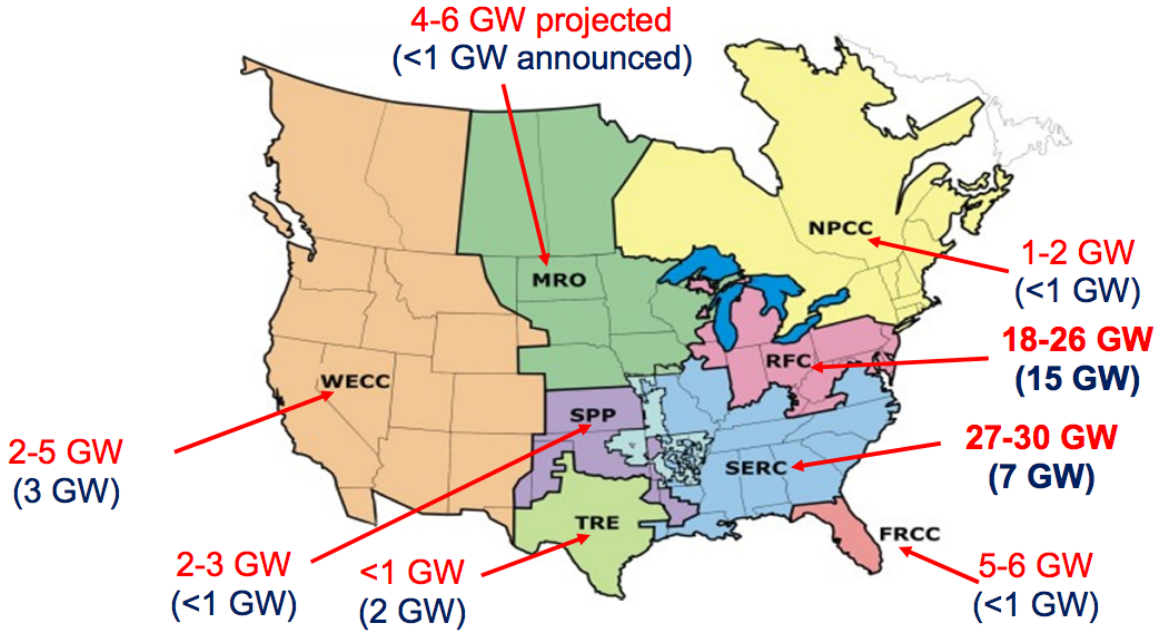

Figure 6. Brattle Group's Announced and Projected Coal Retirements by NERC Region

Source: The Brattle Group Discussion Paper, October 2012. M. Celebi, F. Graves, and C. Russell: "Potential Coal Plant Retirements 2012 Update". Base Map: North American Electric Reliability Corp.

The government's climate policy plays into the longer term outlook. This too was highlighted by Celebi: " EPA's GHG limits on new generation units to be less than 1000 lbs CO2 per MWh essentially block new coal units without CCS. There are rumors that EPA will try to introduce limits for existing units as well ...." *(Personal communication, January 2013).* This emission rate would make new coal plants' emission profile similar to gas units, provided one overlooks the considerable parasitic energy loss associated with CCS and the implications of lessening diversity of dispatchable generation – for neither issue is there a clear methodological path on how to take it into account.

[4] The Brattle natural gas price trajectory reaches ~$4.00/mmbtu in 2015, increasing to ~$5.25 in 2020.

The principal policy change announced June 25, 2013 in the President's Remarks on Climate Change (White House Press Release – Georgetown University) and Presidential Memorandum – Power Sector Carbon Pollution Standards concern development of standards during 2014-15 to be applied to existing power plants in accord with states' implementation in 2016. This confirms the direction of the rumors noted by Celebi, although it is too early to see the details.

The policy direction is toward natural gas and renewables. The Federal Energy Regulatory Commission (FERC) has begun to address increasing gas dependency and deliverability risks at a regional level. This is being accomplished through a series of technical conferences under FERC auspices, according to Celebi. Early responses of industry organizations to the announced climate policies include concerns that natural gas, so important in its downstream applications, not be unnecessarily hindered in its upstream capabilities.

LNG Exports as a Source of Natural Gas Demand

LNG exports are experiencing a period of exuberance with ultimate outcomes still uncertain. While a large number of export applications are before the FERC and MARAD, only a fraction are considered likely to move forward as a result of high capital investment costs and financing challenges, competition between sources, international competition, and US policies and policy responses to market developments over time. As of June 3, 2013, FERC counts 26 export terminals. 16 are proposed projects (13 US proposed to FERC – 18.29 Bcf/d, 3 Canada – 1.95 Bcf/d), 9 are potential projects (6 US – 6.42 Bcf/d, 3 Canada – 3.445 Bcf/d), and 1 project is before MARAD/Coast Guard (3.33 Bcf/d). The total of proposed and potential capacity is 33.32 Bcf/d (US - 27.93 Bcf/d; Canada – 5.39 Bcf/d). New projects are still being announced. A single project to date is approved and under construction, Cheniere/Sabine Pass LNG's 2.6 Bcf/d facility in Sabine, Louisiana. This brings FERC's grand total to 35.92 Bcf/d. *[Export terminal update on last page.]*

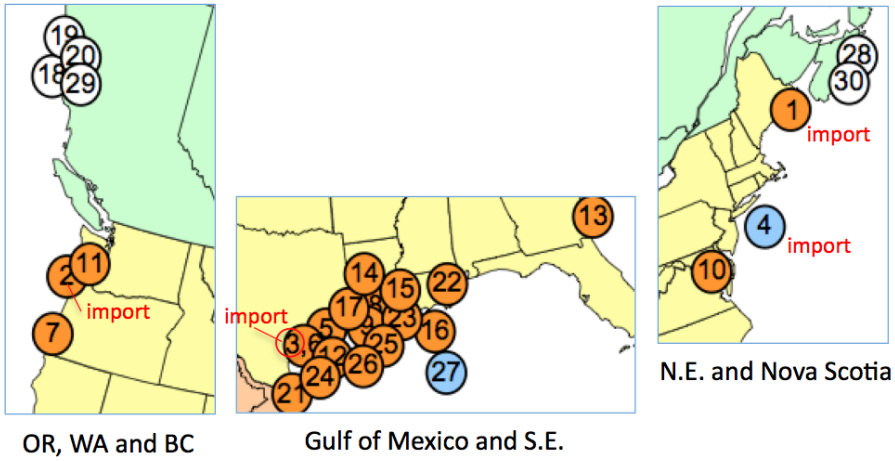

Figure 7. Proposed and Potential Import and Export LNG Facilities
Source: FERC; sections of original map extracted by author.

Financial knowledge, experience and trained skepticism are required to winnow the herd and set realistic expectations. Kyle Sawyer, Boardwalk Pipeline Partners, LP, made a cautious observation: "The LNG export projects are one of the major potential drivers for demand growth in the next 5 to 8 years. Although compliance with MATS [Mercury and Air Toxics Standards, discussed above] will certainly drive electric generation demand for natural gas higher, it may not be enough to balance the supply surplus without a contribution from another consumption segment such as LNG. Current expectations are for LNG exports to reach ~6 Bcf/d by 2020 and it could go quite a bit higher if the DOE does not crimp investment plans." *(Personal communication, January 30, 2013)*

The lure of selling LNG overseas and particularly to the Asian markets is the historical practice of linking LNG prices to oil. Whether this linkage can hold at its current levels is a matter of debate. LNG delivered into the UK and Western Europe commands much lower prices, reflecting historical pricing linked to a basket of fuels rather than to oil alone, to more competitively priced pipeline gas, and even to coal. Even incoming oil-linked gas from Russia has been under price pressure. Transactions compiled by FERC Market Oversight in Fig. 7 illustrate price changes geographically over a year. Price fluctuation is a considerable investment risk for developers. South American Atlantic coast prices appear to be tracking oil linkage.

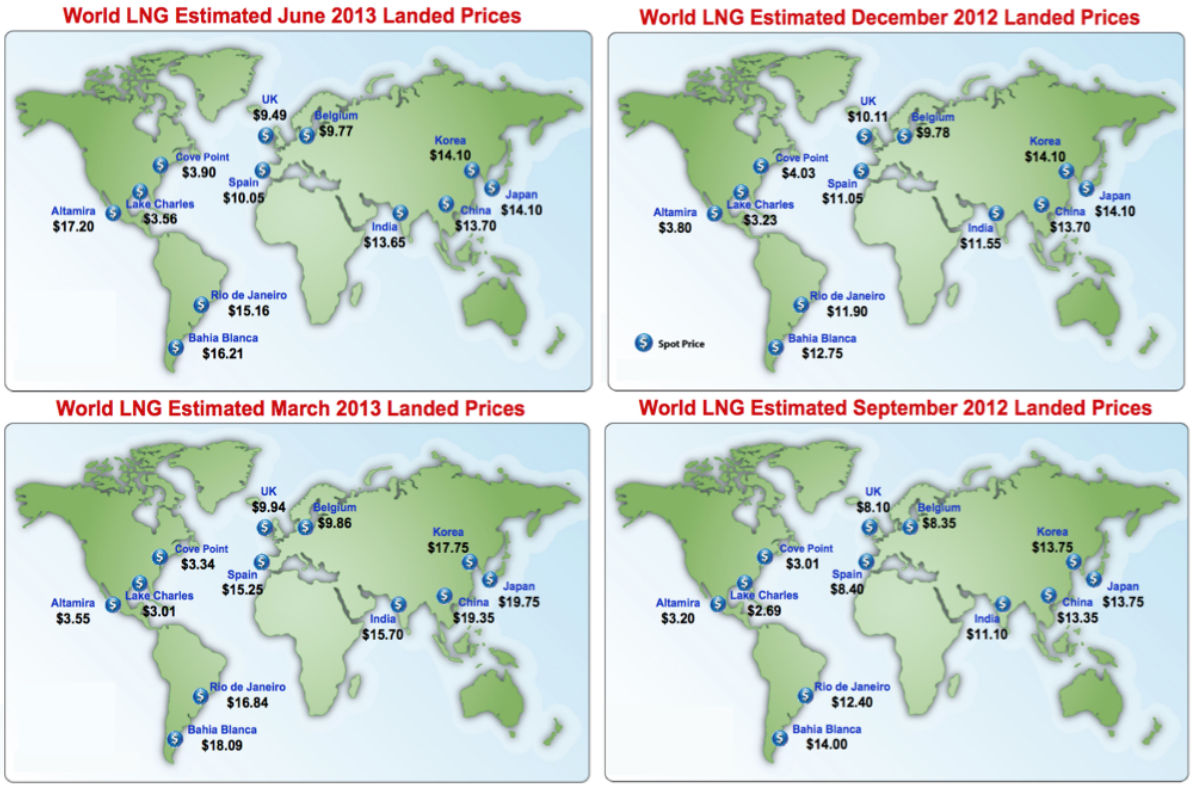

Figure 7. Spot LNG Prices

Source: FERC Market Oversight. LNG prices provided to FERC by Waterborne Energy. The author cannot confirm whether the anomalous Altamira price for June 2013 is a reporting error.

Natural Gas and Regulations Hammer Coal in the U.S.

The turndown of US coal consumption is the most immediate impact of natural gas competition. On its heels are effects of MATS-driven coal plant retirements occurring 2015-16 and into 2017. The turndown is of historic proportions, as shown clearly in Figure 7. Production in 2012 (1,016 million short tons) dropped to levels not seen since before 1994 (1,034 million short tons); consumption (890 million short tons) to levels not seen since 1989 (895 million short tons).

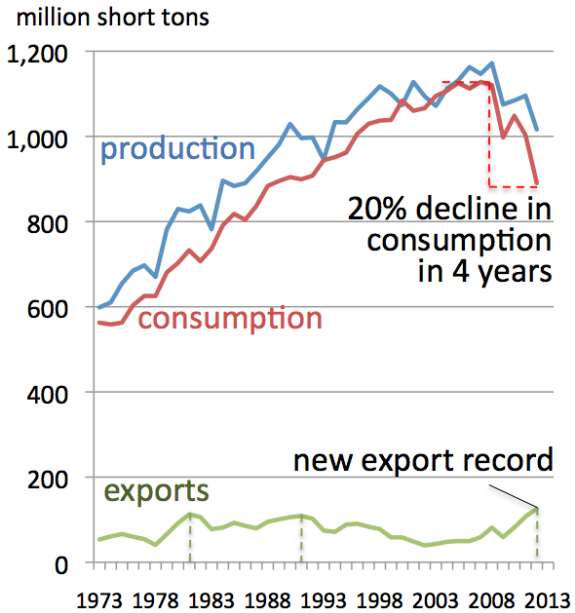

Figure 7. US Coal Production, Consumption and Exports 1973-2012
Data source: EIA Monthly Energy Review, April 25, 2013

Much has been said of booming US coal exports, also shown in Figure 7 (126 million short tons in 2012). Prior peaks in coal exports (marked with dashed lines on the figure) have rivaled those of today, namely 1981 and 1991 (113 and 109 million tons).[5] Metallurgical tonnages have slightly exceeded thermal, averaging 56% of exports in 2012, 57% during 1Q2013. These have offered a bright spot to various coal producers; but financially, exports have not fully offset the domestic tonnage turndown nor the global thermal and metallurgical coal price-depressive effects from weak European economies and weakening Chinese growth.

The sector's performance and that of several US, US-based, and international companies are shown in Figure 8. US coal has been highly competitive in Europe due to far higher-priced natural gas from Russia, other sources of pipeline gas (e.g., Norway, Netherlands, N. Africa) and LNG. But the coal sector's financial performance continued to suffer. Both Peabody, with Australian production, and BHP Billiton, with Australian and other global production, are exposed to China's

[5] In June 2013 EIA reported that March 2013 exports set an all-time monthly record of 13.6 million short tons. Prior peaks were recorded April-June 2013 of 12.5, 12.3 and 12.7 million short tons.

slowdown. As a multi-commodity energy, iron ore, metals and potash producer, BHP Billiton's slippage has been mitigated by the portfolio effect of this mix.

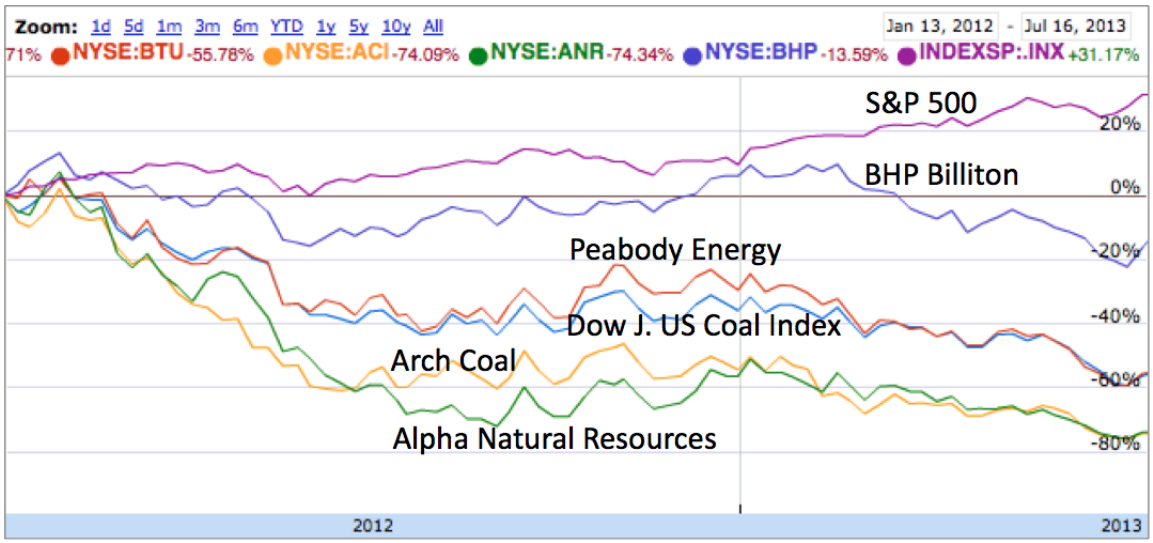

Figure 8. Selected US and International Coal Producer Performance
Source: Google Finance, July17, 2013. Weekly changes Jan. 13, 2012 to July 16, 2013.

How does the coal industry itself view these events? Recent investor presentations, while aimed at Wall Street to respond to events without undermining confidence, gauge effects from the wave of retirements, shifts among producing regions and longer-term international prospects. Alpha Natural Resources confirmed that 212 coal units, mostly in the eastern US, will be retiring or discontinuing to run on coal due a number of different environmental regulations. These amount to 32.8 GW.[6] Arch Coal described the extent of retirements as 29% of units by 2018, 13% of capacity and only 7% of coal consumption.[7] Peabody Energy underscored the winning production regions, the Powder River Basin (PRB) and the Illinois Basin, projected to serve a 20% growth by 2017 from plants using these coals in a combination of new generation, expanded use from existing plants, and plants switching sources to these coals. They see retirements as primarily centered in the southeast US. And they drew attention to the prospects of greater overseas sales of these coals from both the Gulf region and from such proposed terminals as the

[6] Alpha Natural Resources: BMO Capital Markets 22nd Global Metals & Mining Conference, Feb. 26, 2013. Source: ACCCE (American Coalition for Clean Coal Electricity) as of September 2012. Regulatory drivers listed are: Mercury and Air Toxics Standards, Maximum Available Control Technology standards, the Cross-State Air Pollution Rule (a reference to pollution "transport" regulations – due to court ruling EPA's Clean Air Interstate rule, CSAPR's predecessor, remains in effect), Coal Ash regulations and New Source Performance Standards.

[7] Arch Coal: J.P. Morgan CEO Dinner Series, May 8, 2013. J. Eaves, Pres. & CEO. Source: Ventyx and ACI (Arch Coal internal analysis).

Gateway Pacific Terminal (GPT) slated to handle as much as 48 million short tons per year of Powder River Basin coal.[8]

Replace a Coal Plant with New Natural Gas Units? The Knife's Many Edges of this Decision

Many decisions will be made over just the next few years about keeping older coal generating units after adding high capital cost environmental controls or replacing these with new, relatively flexible high-efficiency natural gas combined cycle units. Many studies, including those cited here, have indicated how many retirements are likely and what the implications are for a surge in natural gas use (e.g., on the order of 6 Bcf/d – greater than industrial use and on par with some judgments about LNG exports). John Dean of JD Energy offers observations about the factors at play. His work pits one unknowable, the price of natural gas, against another unknowable, the timing and stringency of carbon regulations/legislation – shedding light on how solid are the computer analyses we rely on to gauge even near term changes in the natural gas market (Personal communication July 19, 2013).

> "The extraordinary fickleness of such decisions is exemplified by First Energy's Hatfield's Ferry coal units in southwest Pennsylvania, which received an injection in excess of $500 million dollars to retrofit flue gas desulfurization (FGD) scrubbers on the plant's three 576 MW units in 2009-10. On July 9, 2013, the company announced it will deactivate the plant at the end of 2013 because it is too expensive to operate." *(John Dean, JD Energy)*

What happened? There are lessons in this extraordinarily compressed turn of events and scores of similar decisions which JD Energy explored by examining local economic factors at some 70 GW of coal capacity. A large fraction of this capacity is slated for retirement according to company announcements. Dean points out that the consensus view of $4-6/mmBtu gas prices over the next decade "is not very helpful. Scores of coal plants will be competitive after retrofitting controls at $6, but will have no hope of recapturing this hefty investment if the price is $4." He finds that the magnitude of the capital investment in a coal retrofit (FGD, selective catalytic reduction, activated carbon injection for mercury control, and a baghouse/fabric filters) is often equal to the cost of an entirely new natural gas unit.

When coupled with risk of even a "moderate" carbon price of $7-15 per ton in the 2020-2025 period, he found that a plant's dispatch (i.e., capacity utilization) would fall from 65-75% to 45-60%. This destroys the economics, raising the specter that a unit won't "outlive its investment" and forcing companies to adopt ever more stringent criteria, such as 10-year paybacks rather than the 15-25 year norm. These considerations would tend to tilt toward plant retirement/natural gas options, but many executives remember the late 1990's gas-fired capacity building frenzy

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[8] Peabody Energy: Howard Weil Annual Energy Conference, March 18, 2013. "Energizing The World One BTU At A Time", G.H. Boyce, Chairman and CEO. Source: Peabody Global Analytics.

predicated on low gas price expectations, which "led to construction of 270 MW of combined cycle and peaking units. The CC's were intended to operate at 65-70% but rarely exceeded 30% when higher prices emerged in the 2000-2007 period. This has created a 'once burned, twice shy mentality'." Dean concludes that power company's perceptions of what lies ahead plays a much larger role in this kind of decision making than can be supported by any "hard data".

Asian Markets Define Coal's Growth Prospects

Just as Asia provides the "lure" for LNG export projects, it is where the action is in the global coal trade. Typical of many international energy assessments, Peabody Energy captures this phenomenon in Figure 9. The 2013-2017 period is anticipated to see a 1.1 billion metric ton expansion in coal use driven principally by China's 760 million metric ton increase, by which times China's use will have increased from about 5.2 to 6.2 times US levels.

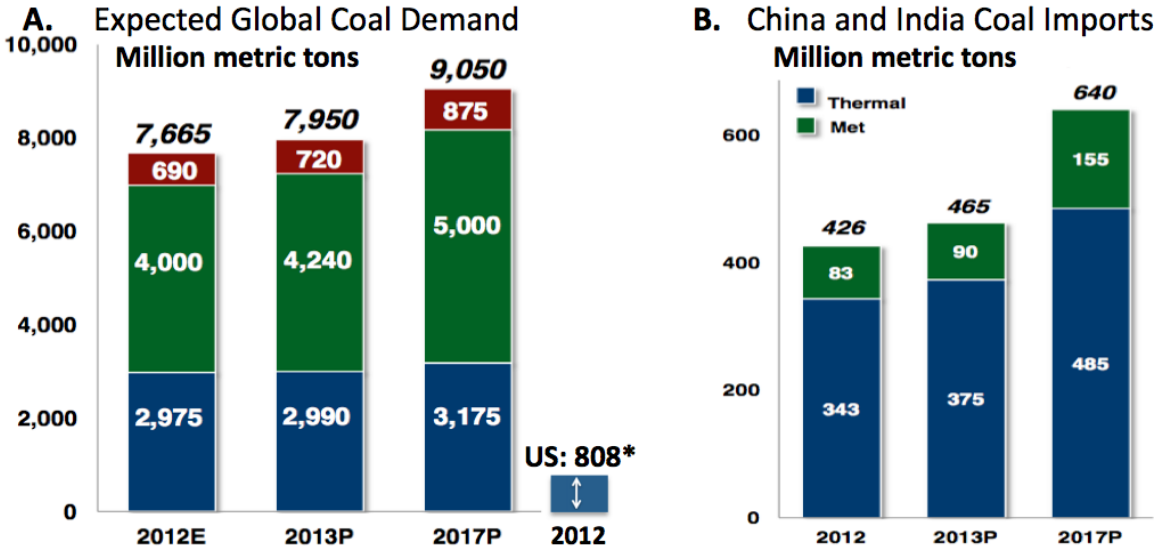

Figure 9. Projected A. Global Demand and B. China and India Coal Imports

Source: Peabody Energy Corp., Howard Weil Annual Energy Conference, March 18, 2013. Peabody Global Analytics (A, B) and India Market Watch (B). US 2012 consumption added for reference to A by author, EIA data. Legend A: blue, Rest of World; green, China; red, India.

The matter of Pacific Northwest coal exports. It is too early to speculate on any hard timelines or the scale or routing of coal exports out of existing (three terminals in British Columbia) or new terminals/expansions. Coal's losses in domestic markets to regulations and to cheap natural gas heighten interest in ways to expand business overseas. Gateway Pacific Terminal is located on Puget Sound between Bellingham and the Canadian border and could handle large, Capesize-class bulk vessels. It is owned by SSA Marine Terminals, with a commitment from Peabody Energy for a major share of its capacity. A second, similarly sized proposed terminal, also in the permitting stage, is Millenium Bulk Terminals- Longview (MBTL) on the

Columbia River in Longview, Washington.[9] It is being advanced by Ambre Energy (62%) and Arch Coal (38%). These terminals are important to monitor due to their size and therefore their market impacts. Each faces strong environmental opposition. Their effects potentially reach far beyond the direct stakeholders via mechanisms of "netback pricing". At some threshold of large tonnages, the value of Powder River Basin coal could become linked to the value of coal in Asian markets, even after accounting for costs of rail transportation, transloading and ocean shipment.

An October 2012 economic analysis calculated a $55/short ton cost advantage for PRB coal compared to major mines in Australian serving Chinese markets.[10] Should such differentials persist, the question is how much of this advantage, after taking into account different heating values, can be captured by the final consumer as savings and by other entities in the chain (e.g., railroads, PRB producers) as enhanced profits. There are no hard and fast analytical guidelines to such calculations. A doubling of the value of PRB coal can be envisioned, theoretically, which would have tremendous impacts in energy markets and in economies. Historical price swings in international coal and shipping markets have shown that netbacks are not stable. Further instability would come from supplier on supplier competition and the introduction or expansion of alternative transportation corridors – Capesize Gulf-based shipment through the enlarged Panama Canal is an example.

The Guar Gum Story: Nothing Cures High Prices Like High Prices

For economic historians, mineral economists and managers of some of the largest oil/gas well service companies and others, the recent, dramatic boom/bust of guar gum prices is a case study of the linkage of engineering to volatile agricultural markets. Too, it is a reminder that derivative instruments so widely used to manage risk in energy markets owe their origin to risk management in agriculture.[11] 2012 is the year in which this saga came to a head. The line between gain and casualty depends on a combination of outright luck, risk management practices, and point of view.

Guar gum is a thickener used in frac fluids. Its primary source is India, source of 70-80% of the world's supply and perhaps 96% of world trade. The hydraulic fracturing boom led to escalating demand, rising prices and then intense speculation

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[9] The state of Washington's Department of Ecology is a useful resource for tracking the permitting process. MBTL is entering a scoping process in 2013 to determine what to include in the coming Environmental Impact Statement. PGT has completed this phase and started to draft a preliminary EIS.

[10] Robert McCalister, "Briefing Paper – Coal Exporting Terminals". Interstate Energy Board, Coal Ports – October 9, 2012 webinar. http://www.westgov.org/wieb/coalports/

[11] Early trading occurred in rice (Japan). The Chicago Board of Trade was established in 1848 and introduced "forward" contracts in 1851. The first non-agricultural product, silver futures, did not trade on the CBOT until 1969 (CME Group timeline).

in guar seed and gum trading in India. Exports are only permitted for the gum, not the seeds. Prices did not reach $1.00 per pound until early 2011, as shown in Figure 10. Facing escalating oil industry demands and poor weather, prices peaked on March 27, 2012 at 95,920 rupees per 100 kg or $8.62/pound at then current exchange rates. This triggered India's Forward Markets Commission to suspend trading for over a year, to May 14, 2013. During the shortages and with up to 20,000 pounds required per well, guar gel alone was reported to comprise as much as 30% of a frac job. Plantings increased enormously. Guar seed crops have become India's most valuable export crop. With resumption of trading, spot prices had dropped to $2.45 per pound and continued to slide to $1.43 (as of June 19, 2013). The next season's crop (October) is trading even lower, $1.13.[12]

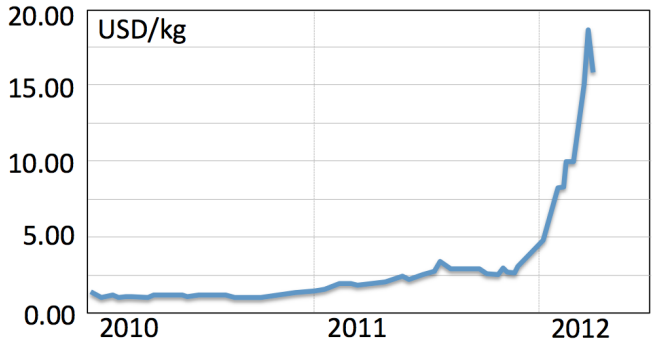

Figure 10. Guar Gum Price Boom 2010-2012

Source: NCDEX data in "Guar Gum Up 20x", N. Pensa, April 9, 2012.

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Addendum

Update on Department of Energy approvals of LNG export terminals to non-Free Trade Act countries as of October 9, 2013. Total capacity 6.37 Bcf/d.

1. Sabine Pass LNG Terminal (Cheniere Energy Partners, includes financing from commercial sources and Korean institutions), Cameron Parish, LA, 2.0 Bcf/d, May 2011;
2. Freeport LNG (Michael Smith and ConocoPhillips, with subsidiaries of Dow Chemical and Osaka Gas among the limited partners), Quintana Island, TX, 1.4 Bcf/d, May 2013;
3. Lake Charles Exports (BG Group and Southern Union), Lake Charles, LA, August 2013, 2.0 Bcf/d; and
4. Dominion Cove Point LNG (Dominion Energy), Chesapeake Bay, Maryland, 0.77 Bcf/d, September 2013.

[12] Current prices are available from India's National Commodity & Derivatives Exchange Ltd., or NCDEX, and the Multi Commodity Exchange of India Ltd. Guar gum's colorful history can be followed through news reports. These include: "Guar Gum Up Nearly 20x: Another Sticky Commodity Situation", Nick Pensa, April 9, 2012, spendmatters.com; "Shale Energy Triggers Bean Rush in India", Meenakshi Sharma and Selam Gebrekidan, May 28, 2012, Reuters; Prabhudatta Mishra, "Guar Gum Futures Trading in India Resumes on Record Harvest (1)", May 14, 2013, Bloomberg Businessweek; "Humble guar gum is India's top farm export", Surojit Gupta & Sidhartha, March 10, 2013, *Times of India.*