Hardly a year passes in the energy sector that events cannot be categorized as tumultuous, uncertain, or unprecedented. The flow of information from an ever-expanding multiplicity of sources is daunting. Developments over the past 12-18 months continue to fit this pattern. The problem is not new and not simply a result of desktop technologies. A good argument can be made that it is intrinsic to the nature of energy developments and fuels. These have more connections, consequences and stakeholders than most economic endeavors. Their complexities and scope encompass many “factors” that intertwine, grow and shape developments in a boundless chessboard. This review begins with a reflection on this theme.

THE APEX OF ECONOMIC COMPLEXITY

A qualitative sense of how energy economics and fuels likely occupy a special position at the apex of economic complexity comes from appreciating a number of their special features. While singly they are not uncommon in many businesses, taken together they argue strongly for this dubious distinction. These features -- illustrated with a broad-ranging set of current and historical examples -- include:

- **Their impacts on customer, corporate and producer decisions.** These encompass a wide spectrum ranging from individual car purchases to far more consequential decisions, such as the choice of new power plants; and targeting of oil/liquids or dry gas exploration and production, all of which feed back into the supply-demand balance.

- **Their combining of societal and investor impacts.** This runs deep and has a long history. For those involved in oil and gas or environmental activism, the contentious debates over the Keystone and Dakota Access pipelines stand out (and there are many other projects where a permit can be withheld by a state or federal entity). Social oversight in the energy sector dates back to hydropower developments and the establishment of the Federal Power Commission (FPC, precursor to Federal Energy Regulatory Commission). The social connection was paramount in the establishment of rural, municipal and government-run power agencies (such as the Bonneville Power Administration and Tennessee Valley Authority), the birth of the nuclear power industry, regulation and de-regulation of interstate natural gas prices and gas usage (a complicated history, with restrictions on power sector use of natural gas lifted in 1987).1

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1 Regulation of pipelines is long-standing, e.g. the 1938 Natural Gas Act, with regulation of wellhead gas prices stemming from the Supreme Court’s 1954 Phillips decision affirming the FPC’s jurisdiction over prices delivered to interstate pipelines. This duality eventually led to alarming gas shortages of the winters of 1976-77 and 1977-78. In response, the expansive National Energy Act of 1978 was enacted in November 1978, containing within it both limitations on power sector natural gas use as well as the seeds of deregulation within the gas and electric sectors (discussed in the next section on the 1970s). With respect to nuclear power, at U.S. urging and with full support of President Eisenhower, the public...
Quasi-regulation of electric power reliability was handled voluntarily after the great Northeast Blackout of 1965, culminating in enforceable standards for the first time in 2007 by the North American Electric Reliability Corporation. Oil has not been left out, considering such things as the historical imposition of oil import quotas (which favored domestic production, enacted in 1959 to limit imports to 12.2% of domestic production and lifted in 1973) and the December lifting of restrictions on overseas crude oil exports. Throughout, public service commissions have long set electricity pricing (i.e., customer rates) in many parts of the country. A remarkable example of social oversight is the very recent mobilization of a constellation of local, state and federal agencies in response to the Aliso Canyon gas storage well leak (the active phase extended from October 2015 to February 2016). The public sector continues to modify the operations of both gas infrastructure and electricity assets in, or serving, southern California.

The impacts of these many activities can hardly be understated, steering the course and at times spawning new industries (e.g., nuclear power, independent power production, wind and solar power industries, private electricity transmission). The preceding list, while illustrative, would be woefully incomplete without mention of environmental regulations. At the highest level, there are such major influences as Corporate Average Fuel Economy standards (CAFE), Renewable Energy Performance standards (RPS), and regulations on acid rain, particulates, air toxics and ozone, accomplished through a variety of measures of which the formerly-proposed Clean Power Plan is only the most recent example. At the project level in oil and gas development, there is the laundry list of agencies affecting drilling programs and techniques, land use, local air quality, water management, reporting of frac fluids and so on. Getting permits and making go/no-go decisions often hinge on the timelines, cost and feasibility of navigating these requirements.

• **Their often-massive financial scale.** “Big dollars” in energy always brings up nuclear power. The few US nuclear plants now under construction have encountered financial hurdles reminiscent of the financial weight that burdened nuclear power’s growth in the 1970s. At present, Southern Company is struggling to complete its two-unit Plant Vogtle nuclear plant and SCANA Corporation (with others) their V C Summer nuclear plant, both dealing with

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2 Banned since 1977 (except mainly to Canada), crude exports climbed to 0.5 million barrels/day in 2015-2016, yet still remained about one tenth the level of petroleum product exports. A record 1.1 million barrels per day was reached in February 2017. These provide some relief to current oversupply of “light tight oil” which cannot be absorbed by domestic refineries, while aggravating global oversupply.

3 The names and costs associated with the turnback of nuclear plants in mid-construction in the early 1980s are legendary among those close to the industry. The list includes: Washington State Public Power Supply System Units 4 and 5, canceled in 1982 after defaulting on $2.25 billion; Public Service of Indiana’s Marble Hill Units 1 and 2, canceled in 1984 after $2.8 billion spent and 60% complete; Cincinnati Gas and Electric’s (principal owner) Zimmer unit, canceled in 1984 after $1.5-1.8 billion spent (converted to coal); and Long Island Lighting Company’s Shoreham plant, completed 1984, canceled 1989 after spending $4-6 billion.
significant cost overruns, schedule slippage, and Westinghouse’s resulting bankruptcy filing in March 2017 (bought by Toshiba in 2006). As of this writing (June 2017) the fate of the plants is not secure, with Toshiba’s liability for Vogtle capped at $3.7 billion provided an arrangement can also be made for the Summer plant.

Across the oil industry, the cost leader is LNG. At over $50 billion, Australia’s Gorgon facility serving the Northwest Shelf combines remoteness, obstacles and high costs. Likely in a similar ultra-cost ballpark is the very remote Western Siberian Arctic Yamal development requiring specialized construction to protect permafrost along with a fleet of ice-breaking LNG carriers. Brownfield LNG plants cost a fraction of those in remote regions.

Deepwater offshore platforms don’t approach Gorgon but are the highest cost investments in the sector. Examples include Chevron’s Tahiti, 2009, $2.7 billion, Jack/St. Malo, 2014-15, $7.5 billion and Big Foot, 2015, %5.1 billion (“Chevron Goes to Extremes in the Gulf of Mexico”, Brian O’Keefe, Fortune, June 9, 2014.)

Far cheaper but combining financial and societal dimensions is the now-emerging problem of whether and how to pay for the upkeep and operation of out-of-the-money nuclear power plants. Measures have been adopted in New York and Illinois and are pending in Ohio, Connecticut, New Jersey and possibly other states. The problem results principally from abundant natural gas and unexpectedly low-priced electricity, a problem that also plagues a number of coal-fired power plants. By pegging a value to zero emission power, additional money to retain two reactors in Illinois comprising 2,900 MW is set at $235 million per year over ten years. In this case (as well as in the case of nuclear plants both in the past and present), it is the financial impacts that usually command the most attention.

“Massive” also applies to the cost of compliance with regulations. By about 2010, a third of the cost of a new coal-fired power plant was devoted to environmental control systems. The cost of tighter ozone standards was estimated to eclipse the costs of nearly all prior environmental regulations, according to studies conducted in 2014 and 2015 by NERA Economic Consultants. A proposed rulemaking would have lowered the standard from 75

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4 Westinghouse 2017 filing is reminiscent of an event in July 1975 when Westinghouse declared it could not deliver on uranium fuel supply commitments to some 20 utilities to whom it had agreed to sell uranium for only $8 to $10 per pound U3O8. At the time, the price had risen to $26 per pound and soon reached $40. Westinghouse could only cover 50 million pounds out of 120 million it had committed to supply. The $2 billion obligation (about $5-6 billion in 2017 dollars) was a company-busting mistake, a liability estimated to be worth 70% of the company’s assets. A complicated legal tangle ensued, initially raising thin claims about unforeseeable price escalation and the Arab oil embargo. Finding evidence of an international uranium suppliers cartel, the case was largely resolved by 1981. “Commercial Impossibility. The Uranium Market and the Westinghouse Case”, Paul L. Joskow, The Journal of Legal Studies, January 1977. “Suit Ended on Supplies of Uranium”, Douglas Martin, New York Times, January 30, 1981.

ppb to 65-70 ppb ozone. Annual costs for a 65 ppb standard were estimated to average $80-100 billion per year ($2014) or $1.05 trillion over the period 2017-2040 ($2014, net present value; six times greater than EPA’s estimate). Additional impacts would be caused by cutbacks in natural gas production and accelerated coal plant retirements (*Economic Impacts of a 65 ppb National Ambient Air Quality Standard for Ozone, 2015*). The final standard issued October 2015 was set at 70 ppb.

Further illustrations of massive scale discussed below are some of the negative impacts of the collapse of oil prices on producers and, returning to the topic of customer savings reviewed last year, some of the positive impacts.

- **Their interconnectedness.** The flow of associated gas production into the already well-supplied natural gas market has become divorced in most circumstances from price signals for natural gas itself, responding instead to the forces controlling “light tight oil”, *i.e.*, shale oil (not necessarily technically “shale”), production. Coal’s fortunes are naturally tied to those of the electric power industry, yet too tied to the competitiveness of natural gas-fired generation and thus natural gas markets. Historically, regulations and pricing practices in the rail industry played a likely-forgotten but massive role in “opening up” coal produced in Wyoming’s Powder River Basin, greatly determining its competitiveness in distant regions. And while seemingly disconnected, there is even a link between coal mining regulations in China and the need for LNG in Europe (which, further, links to sales of US LNG into Europe). We expand on this connection in the discussion of the international coal price spike, below.

- **Their global reach.** “Energy” plus “international” means, foremost of all, oil; the past decade has seen unprecedented swings in notoriously cyclical charter rates for international shipping of LNG and dry bulk, the latter affecting coal, iron ore and grain; China’s industrialization has remained as a top driver of numerous commodities since the mid-1990s, affecting coal, iron ore, oil, and LNG imports, as well as steel, copper and other trade and commodities. While not a direct “energy”, there is an interplay of logistics between energy and infrastructure impacts from the massive container shipping industries (intermodal rail and ocean traffic), port developments, the Panama Canal expansion, and the rates applied to commodities vs. other shipments.

- **The ways that technologies or regulations periodically re-write the rules of the game.** Hydraulic fracturing, horizontal drilling, and related technologies, of course, are the most prolific and recent examples; deepwater drilling successes are likely to stand the test of time as the oil and gas industry’s singular most technologically sophisticated achievements [Norway’s Snøhvit and Australia’s Northwest Shelf LNG facilities have had to overcome both undersea and onshore development challenges, a technological and financial double-whammy]; remarkable advances in the performance and affordability of renewables technologies, particularly solar and wind; the stringency and impacts of clean air regulations on coal plant retirements, exemplified transparently by the retirement of some 45.6 GW of coal plants between 20111 and 2016, driven in large part by their inability to sustain the costs of complying with Mercury and Air Toxics Standards, per Center for Energy Economics, April 2017. And:
At the root, the still-hidden nature of earth’s secrets. New extensions, fields and plays must actually be “discovered”. Many questions still remain regarding the long-term production profile for today’s shale gas and oil plays, even though traditional exploration risk has been greatly transformed. Waste water disposal practices are getting well-deserved scrutiny, as many structures and stresses that could lead to induced seismic responses from wastewater disposal will remain unknown until regions are tested and thresholds of seismic activity, if this occurs at all, are revealed.

Give up? As long as thirty years ago, after ten years of organizing fuel conferences for the power industry, I described the challenges of change, uncertainty and complexity as dealing with a “smorgasbord of information”. Should one simply compile and take the average of different forecasts? Are the uncertainties simply so great that there is no payoff for taking the time and effort to think deeply? Such mechanistic or nihilistic postures run against the grain of a scientific organization, an inquiring mind, or the business intelligence function of any number of firms.

Much is to be gained from grappling with these challenges. Whereas corporations have a lot of internally-directed functions to master, functions related to energy economics usually force one to look outward, in a sense becoming the eyes and ears for developments far beyond one’s immediate geographic footprint and often beyond one’s specialty, training or experience. By their nature, understanding direct and indirect influences on fuels, power, and energy technologies’ penetration and turnover sweeps up a vast terrain and demands a hefty curiosity. The effort required is an investment, not in being right, but in judgment. It means getting semi-comfortable with feeling overwhelmed, carrying a healthy respect for uncertainty, and absorbing as much as possible.

THE TECH REVOLUTION IN OIL AND GAS: TAKING FOR GRANTED WHAT IS IN FRONT OF OUR FACE

Last year’s report provided a single focus on consumer savings in one year, 2015, from hydraulic fracturing (really many related technologies). The logic, which seemed bold at the time, appears to have become almost unassailable. Burgeoning supplies of shale gas drove down natural gas prices and held electricity prices in check, creating enormous savings for energy consumers. With profitability lagging in natural gas, the oil and gas industry turned to wet gas and shale oils, where the impacts of burgeoning supplies, already substantial for natural gas, led to domestic and international impacts, and savings, of almost unimaginable proportions. These savings are restated here.

Consumer Savings. Direct global consumers’ savings from hydraulic fracturing amounted to $755 billion in 2015. Savings from the pre- vs. post-shale era collapse of natural gas prices in

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6 I owe this theme to a recent discussion about shales with a prominent consultant and student of energy who remarked “Isn’t it interesting how people so easily take for granted what is happening around them?”
the United States amounted to $86 billion, counting both natural gas ($37.9 billion) and savings in the electric sector (cheaper gas, $27 billion; cheaper wholesale electricity, an additional $21.1 billion). Curiously, no direct electric sector savings of this magnitude ($48.1 billion) can be found, but we know from the operation of competitive power markets that savings of this general magnitude must exist. In presenting this work, we hope to spur other analysts to take up the challenge of estimating savings within the electric sector. Savings from the pre- vs post-shale era collapse of oil prices account for the bulk, 89%, of the $755 billion figure. These are comprised of price cuts for oil products and for natural gas/LNG, to the extent prices of the latter are set in relation to oil. Savings for US oil products amounted to $221 billion (bringing total US natural gas, electric and oil products savings to $307 billion in this one year). Global direct oil savings amounted to $366 billion, strictly for well-documented countries and those without subsidies complicating impacts. Turning to the fuels with oil-linked prices, savings for globally traded pipeline gas (excluding the US and Canada) amounted to $30 billion and for liquefied natural gas (LNG) $52 billion (thus, $448 billion in total outside of the US).

Reference. The 2016 report to the AAPG committee remains the fullest disposition of these calculations, including tables on individual countries. The findings were presented to AAPG’s joint Pacific and Rocky Mountains Section meeting held in Las Vegas, October 2016. AAPG’s Search and Discovery service posted the abstract and slides in April 2017 and provide the following reference:


Key Charts. Figures 1 and 2 present the weekly price and drilling trends since January 2007 for natural gas and oil, adding a price series for propane to the gas chart (Figure 1) since propane is a reasonably good approximation of EIA’s “natural gas liquids composite” price. This price relationship is plotted in Figure 3. The charts are updated through June 9, 2017.

These charts illustrate the stepwise collapses of natural gas prices, the disenchanted with natural gas drilling at about a six-month lag, and the many years of uplift from liquids prices even when gas drilling rig counts fell into the low 300s at the time of the late 2014 oil price collapse. They also show the post-Recession and compelling climb of oil drilling as prices shot up to over $100 per barrel by early 2011 and stayed at these lofty heights for the next three and one-half years. Over the past year, i.e. from mid-2016 to June 2017, they show the much-touted climb of oil activity by some 400 rigs, notable because of the greater productivities now being achieved, and the climb of some 100 gas-directed rigs. Presenting similar information in their late 2016 paper, MIT’s Kleinberg et al (see Footnote 26) cautioned that the 2011-2012 increase in oil activity was greatly facilitated by natural gas’ decline, labeling it a “crossover”. Today, any substantial increase must be built from a greatly limited labor pool.

Figures 1 and 3 show the spike in propane prices caused in late-2013 by extensive crop-drying requirements and then later in the winter by the frigid “Polar Vortex”. Notably, the price-
depression of liquids vs. oil from 2012 onwards was reduced somewhat during 2016, attributed to a combination of propane (and ethane) exports and additional pipelining and processing capabilities for these products.

Figure 1. Natural Gas Drilling and Prices (Propane as Proxy for Natural Gas Liquids)

Figure 2. Oil Drilling and Prices (West Texas Intermediate)

Figure 3. Natural Gas, Oil (WTI), Propane and Natural Gas Liquids Price Relationships
Figure 4 tracks the increase in U.S. crude production and related impacts on the global oil markets. Notably, in the three years prior to the late 2014 oil price collapse, i.e. from 2011 to 2014, U.S. crude production climbed from 5.7 to 8.8 million barrels per day. Since then, it climbed further in spite of the price collapse in 2015, dropped back 2016, and is estimated by the Energy Information Administration’s Short Term Energy Outlook (STEO) of June 6, 2017 to reach 10 million barrels per day in 2018. Perhaps more importantly from a global trade and thus global oil price impact point of view, however, are the changes in imports and exports. In February 2017 the U.S. reached as much as 1.1 million barrels per day in crude oil exports. They averaged historic highs above 0.7 million barrels per day the other months from January through April, a change brought about by lifting the crude oil export ban in the US Congress’ Omnibus spending bill signed in December 2015, achieved in exchange for extending wind and solar tax credits on a declining scale through 2019.

![Figure 4. Crude Oil Production and Trade](image)

The bigger changes have taken place in reduced imports, a decline of 1.6 million barrels per day between 2011 and 2014, and increased petroleum products exports, up 0.9 million barrels per day over that period. The major changes in recent time periods is shown in Table 1.

Little attention has been given to the scale of changes that preceded the 2011-2014 surge. They didn’t precipitate Saudi Arabia’s November 2014 announcement to hold or increase its production, but they aggravated the preceding market balance. From 2007 to 2011, oil imports decreased by 1.1 million barrels per day, product exports increased by a huge 1.5 million barrels per day and products imports likewise decreased by 0.9 million barrels per day. Taking into account the trade in oil products as well a crude, the total effects on combined oil and products trade were nearly as great in the years preceding 2011 as after.

Measured against these two previous time periods, changes since 2014 have been minimal.
HISTORICAL PERSPECTIVE

To make these calculations of savings, we went back little more than ten years to calculate the “pre-shale era” of lofty natural gas prices over 2004-2007 and three years to 2014 to anchor oil before its collapse. The “fracking” phenomenon has thus emerged quite suddenly. Yet it looks even more improbable – and more important in a socio-economic context – if we consider it against some of the major energy events and turning points over the past forty to fifty years.

The nuclear era was well underway when the Arab Oil Embargo kicked off an era of energy insecurity. Government regulation was thought to be a solution to high cost gas and “windfall profits” before it was found to be a cause of shortages. The wave of high-cost nuclear and hard-to-time-exactly coal plants drove the search for solutions in theories of regulation and electric restructuring, where the social compact surrounding these non-gas plants (i.e. expensive yet vital) required compensation for “stranded assets”. Natural gas was conveniently cheap at the time, permitting the merchant energy industry to engage in wild excesses. The only good news on anything like the scale of fracking’s later successes was Powder River Basin coal. Then comes the Millennium. Oil is going nowhere and you couldn’t drill enough to still not find natural gas, inviting a proliferation of LNG regasification terminals. This takes us to the very eve of the shale era. It wasn’t the Barnett Shale, the grand-daddy of shales simmering almost out of sight under Fort Worth since 1981 (and an essential laboratory for decades), but rather it was Chesapeake’s moves in the Haynesville that ignited the big explosion.

**Historical Perspective: 1970s Fuel Insecurity**

**Oil Crises.** It is hard to truly appreciate the turnaround in U.S. energy circumstances without taking a long-term view. The 1970s sets the stage, a decade in which the United States entered an era of great fuel insecurity. The 1973-74 Arab Oil Embargo thrust energy supply and prices into public consciousness. The oil price nearly tripled between the end of 1973 and early 1974, and continued to climb. The Iranian Revolution pulled some 5 million barrels per day from the world market by early 1979 and led to a doubling of prices over 1979 into 1980, peaking with
the Iran-Iraq War in early 1981. This second event played into escalating inflation, which grew from 7% in early 1979 to 9% at year’s end and then to as high as 19% in 1981 (“Oil Shock of 19788-1979”, Laurel Graefe, Federal Reserve Bank of Atlanta). While their direct and indirect financial impacts cannot be understated, the 1970s were marked by more than these two oil crises.

**Uranium Price Shock.** Even as the Arab Oil Embargo was starting, uranium supply showed problems. Uranium (U3O8 or “yellowcake”) had been purchased by the Atomic Energy Agency’s (AEC) since 1950, with prices from 1962 through 1967 at $8 per pound. The commercial market (such as it was considering that this was a narrowly traded commodity) was established in 1968 and prices initially sank somewhat. By the end of 1973, simultaneous with the Arab Oil Embargo, prices had reached $7 per pound. Within a year they had doubled to $15 per pound and by December 1975 they had doubled again, e.g. to $35 per pound. The Westinghouse debacle was discussed previously. The company’s long position should probably be viewed less as a causative factor itself than as a trigger to sudden awareness of the underlying supply-demand imbalance. The situation was a matter of great concern in certain sectors of the utility industry and government, leading to questions of whether the country should pursue reactor designs that offered greater fuel efficiency. It also led the AEC in 1973 and its successor in 1974, the Energy Research and Development Administration’s (ERDA), to launch the National Uranium Resource Evaluation Program (NURE). This program was principally designed to acquire geochemical and radiological data and enable a more confident assessment of potential uranium supplies. The importance of the effort was underscored by its scale, estimated to require as much as $200 million over a period of years ($750-800 million in 2017 dollars). It is unclear whether the full amount had been allocated by the time the program wound down in 1983-1984, but the urgency and public commitment felt during the mid- to late-1970s is noteworthy.

**Natural Gas Shortages.** Natural gas did not escape unscathed. The winter of 1976-1977 brought about natural gas curtailments in twenty states, drove 1.2 million people into unemployment during its peak in late January-early February⁸, and precipitated enactment of the Emergency Natural Gas Act of 1977. Aimed principally to facilitate natural gas transportation to where it was needed most, this was President Carter’s first bill, introduced on January 26th and signed one week later.⁹ Hardest hit were Ohio and New York. Temperatures in western New York averaged 10-11 degrees below normal from November through January, with January’s average in Buffalo being 13.8 °F when a crippling blizzard hit. Ohio’s average of

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11.9 °F was its coldest on record. Carter noted that half the pipelines in the U.S. had curtailed shipments to major industrial users, several pipelines had to curtail deliveries to private homes, and four thousand plants had been forced to close. The prior week (January 22nd), he had ordered the White House thermostats to be set to daytime temperatures of 65 degrees F, and he urged every American to do the same. He decried the lack of a national energy policy—which was to be addressed in a major way a little more than a year later, after another frigid winter, with the multi-part National Energy Act of 1978.

Industry experts had a full understanding of what was wrong with gas supply, namely long-regulated prices aimed at protecting consumers but failing to provide incentive to sustain supplies. This was only partially addressed by that part of the NEA, the National Gas Policy Act, with its 28 or more categories setting prices for old vs. new gas, and other distinctions. The tenor of fuel insecurity was baked into the legislation with Power Plant and Industrial Fuel Use Act. This intended to restrict utilities from using natural gas (or oil) as a boiler fuel by 1990 and prohibited construction of new gas-fired power plants unless they were cogeneration (combined heat and power) facilities, a feature which led to some new gas-fired plants with extremely small steam outputs. Within five years, industry representatives were complaining about difficulties in lowering prices, not raising them. Categories of regulated high-cost supplies had the perverse effect of injecting higher prices into the market regardless of declining demand during the recession years of the early 1980s. The political challenge was how to reconcile seemingly conflicting goals of equity, which through elaborate regulations had resulted in debilitating shortages, and market efficiency, which raised the specter of “windfall profits”.

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13 The Joint Economic Committee hearings on natural gas deregulation cited here is a 500+ page window into these debates. With testimony from some of the most well-known energy economists of the era, the transcripts and submissions combined dry data with extraordinary colorful imagery. On the first day of the hearings, Nicholas J. Bush, president of the Natural Gas Supply Association, described the effects of ultra-high-priced natural gas categories, such as the “deep gas” category which had received prices as high as $10/mcf ($25 in 2017 dollars) and averaged $7.53 in late 1982 to early 1983 ($15 in 2017):

“What has resulted from the Natural Gas Policy Act is a crazy quilt of distortions and inequities.... the law irrationally placed the greatest incentive for producers to explore for and develop the most difficult and most expensive gas first. It’s not altogether unlike telling a farmer to hire a helicopter and start picking his apples from the top of the tree.”
The period preceding the gas shortages of 1976-1978 did little to build confidence in gas supply, as reserves shrunk almost 30% between 1970 and 1978 and the reserves to production ratio fell to 10.4 from 13.3 years. Net reserve additions had been negative in most years since 1968, a calculation that quite visibly portrays the ill-ease leading up to the shortages. In very few years since 1950 have reserve additions exceeded annual production, notably the early 1950s and the period since 2007. **Figure 5, A and B.** The production peaks of over 60 Bcf/d (marketable gas) experienced from 1970-1973 were not exceeded until 2010-2011.

Professor Morris A. Adelman of MIT’s Department of Economics and Energy Laboratory provided comments on international distortions, having seen Canadian and Mexican natural gas priced at a $4.94 and $5.01 respectively ($12.50 in 2017 dollars), and Algerian LNG at $7.53 ($18.80 in 2017 dollars). At first, given momentum by the “second price explosion of 1979”, Canada reduced the level of allowed natural gas exports to the U.S. in order to obtain even higher prices, only to find over 1980-1983 that $4.94 was too high. He estimated the then “new gas” price of $3.50 or lower would prevail in a decontrolled market, and condemned the meddling and unsupported price expectations of governments who might prefer to keep their supplies “in the ground” in this manner:

“Holding oil or gas in the ground is partly a fetish, and a tribute to prejudice. Canadian gas is too good for the Yanks, Mexican oil or gas too good for *los gringos*, just as American (Alaskan) oil is too good for the Japanese, Scottish oil too good for the English, still less the Continental Europeans, etc., etc. Holding mineral assets in the ground makes economic sense if -- and only if -- the price is expected to rise at a rate faster than the rate of interest, Otherwise, the owner loses what he could have done in the interim with the proceeds, had he sold the mineral.”

The dysfunctions of the natural gas market in the early 1980s were also illustrated by a wave of negotiations over “take or pay” contracts in which volumes of higher-cost gas might be deferred in the then-shrinking market but there was considerable resistance to accepting prevailing, lower prices. As the debate on these matters wound down, involving Yale Professor Paul MacAvoy, the Consumer Energy Council of America’s Mark Cooper, and others, the chairman of the committee Senator Roger W. Jepson of Iowa reflected on the discussions:

“Some of the regulations have gone too far. It’s kind of like sticking your hand in a bucket of glue and then sticking it in a sack of feathers and then you try to shake the feathers off. To believe that regulation is going to solve all our problems is an approach that has not worked.”
Nuclear Power Implosion. Capping off this troublesome decade, the partial meltdown of one of the Three Mile Island Nuclear Plant reactors began on March 28, 1979. This resulted in enhanced designs, operations and inspections; however, when coupled with escalating costs, it marked the loss of appetite for new reactors in the US for about thirty years. 67 units that had been planned were canceled between 1979 and 1988. There were no new construction starts between 1977 and TVA’s 2007 decision to complete its Watts Bar 2 unit (on line in 2016). Rather, the 47 new reactors appearing in the late 1970s and 1980s had been approved by 1977 or earlier (World Nuclear Association “Nuclear Power in the USA”).

In sum, in little more than six years from 1973-1979 the U.S. energy mindset had shifted from “not on my mind” to great insecurity.

Historical Perspective: 1980s -1990s Gas Bubble, Coal, Environment, Boom

Natural Gas “Stability”. The complexities of the NGPA were gradually unwound over the next decade and a half -- decontrolling natural gas wellhead prices, addressing the problems of “take or pay” obligations between pipelines and producers, and transforming the role of pipelines from being combination gas marketers/transporters (a “bundled” merchant function) to serving instead as “open access” pipeline services companies. In April 1990, the New York Mercantile Exchange launched trading in natural gas futures, expanding methods for risk management. This was a function that had previously been served, at least in part, by pipeline’s long-term purchases of gas supplies backed up with decades of dedicated reserves. The futures market also increased short-term price transparency.

From the 1970s‘ concerns over scarcity, by the time of the 1982 recession natural gas supply entered a relatively stable period, although this was only apparent in retrospect. At the time,

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natural gas and residual fuel oil battled for market share in the electric power industry and uncertainty over natural gas supplies was tangible. With escalation of oil and gas finding costs, geologists could say “exploration in the conterminous 48 states is now like milking an old cow” and major electric utilities could question “is it really in our national interest to use a precious fuel like natural gas in a boiler?”

The coming stable period persisted until 2000. Annual average wellhead prices, expressed in 1Q2017 dollars, barely wavered from $3.00/mcf every year from 1987 through 1999. Figure 6 captures the trends in natural gas supply and consumption over the same long history as Figure 5. Declining overall natural gas demand from the mid-70s to mid-80s, especially industrial, and gradually increasing supplies supplemented by increasing imports (Canada) provided the foundation of price stability. This calm was dubbed “the gas bubble” and, by the early 1990s due to its persistence, “the gas sausage”.

This stability at relatively low prices also played into attractions of bringing the ideology of deregulation to the electric power industry.

Figure 6. Natural Gas Trends: Production, Net Imports, Consumption, Prices

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18 NG Overview/Consumption, EIA MER: [https://www.eia.gov/totalenergy/data/monthly/](https://www.eia.gov/totalenergy/data/monthly/)
*The Turn to Coal and to the “PRB”.* After alternative generation options were pinched off (oil, obviously risky and becoming prohibited; natural gas, maybe not even available; nuclear, simply too costly), coal was essentially the only one left. Coal plants were brought on at a rate of about 10 gigawatts per year from 1980 to 1985, a rapid pace of development that had in fact been going on without interruption since 1967. Yet coal was becoming complicated. It was abundant, but its quality was coming into question as concerns grew about acidic precipitation ("acid rain") and the availability and premium needed for lower-sulfur coals. Concerns about acid rain started to grow in the early 1980s, eventually culminating in the Clean Air Act Amendments of 1990 which imposed phased reductions in SO2 emissions by 1995 and 2000. These gave further impetus to using lower sulfur coals, as companies whether to comply by “scrubbing” (installing flue gas desulfurization equipment) or “switching” (using lower-sulfur coals). The emergence of the Powder River Basin (PRB) as an abundant source of low-sulfur coal was made-to-order.

Exploitation of the 90-foot thick, surface mineable seams of Powder River Basin coal started from scratch in about 1970. By the 2000s, the region supplied 40-50% of all the coal used for electric generation (on a tonnage basis). This is one of the most significant developments in the U.S. energy industries in the past fifty years, much less being a significant counterpart to the drama of gas industry deregulation, the gas bubble, or efforts at electric restructuring during the 1980-1990 period.

The trajectory of the region’s growth is shown in Figure 7. Between 1985 when Wyoming production was about 140 million tons (short tons) and 2008 when it reached 466 million tons (PRB’s peak) total coal consumption in the electric sector had climbed from 694 to 1,041 million tons. (We refer to the state of Wyoming’s data when making comparison to the Basin’s early years, whereas EIA’s “Powder River Basin” category starting in 2000 actually shows somewhat higher tonnages.) The longer trend shows that the region’s coal captured 94% of the growth in electric sector coal use between 1985 and its peak.\(^\text{19}\) PRB production hit 400 million tons in 2003 and exceeded this level every year until 2015. Moreover, it achieved an extraordinarily wide geographic distribution, Figure 8.\(^\text{20}\)

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\(^{19}\) Wyoming coal growth, 1985-2008: 140 to 466 million tons, increase of 326 million tons (somewhat more than this if continuous statistics on EIA “Powder River Basin” were available for the earlier year); electric sector coal consumption, 694 to 1,041 million tons, increase of 347 million tons.

How much energy does 400 million tons represent? PRB coal specs are mostly 8800 Btu per pound, with some at 8,400 Btu per pound. Using a reasonable estimate of 17.2 million Btu per ton (short), each ton contains the equivalent of 16.7 mcf of natural gas (assuming 1,030 Btu per cf). 400 million tons translates to almost 6.7 trillion cubic feet or 18.3 billion cubic feet per day. (In electric terms, that’s enough gas to fire 130 gigawatts operating at 70% capacity factor at an annual average 8,600 Btu per kWh heat rate.) Gas consumption in the entire electric sector did not reach this level until 2007. In its peak year, referring to EIA’s 496 million ton statistic, the equivalent is 8.3 trillion cubic feet. In spite of these successes, the region has faced sharp declines. By 2015, production (EIA’s tracking) had fallen almost 100 million tons off its peak to 399 million tons. It fell a further 85 million tons in 2016.

The region’s growth looks inexorable, but it was not automatic or assured. PRB coal’s higher ash, moisture and lower heat content caused some deratings of the level of power production from individual generating units not initially designed for the fuel, but this drawback could usually be minimized with equipment modifications at many power plants and/or with blending.
it with higher sulfur coals.

The importance of the coal comes across in these numbers, which translated into lower-cost electricity in much of the country. An indirect effect should also be mentioned. By contributing significantly to the success of Clean Air Amendments of 1990, namely by lower costs of compliance significantly, this geologic phenomenon is a principal reason why “cap and trade” has achieved prominence in existing and proposed schemes control carbon (carbon dioxide) emissions (e.g. the Regional Greenhouse Gas Initiative spanning Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont or the U.S.’s very seriously proposed “Clean Power Plan”).

**Electricity Demand Growth: Slower but Relentless.** Standing back from the PRB phenomenon, it is important to place coal and other generation growth in the context of overall U.S. electricity demand growth. Post-war demographics and electrification caused average annual growth of 9.2% from 1949 to 1961. This dropped to 7.5% over the next twelve years from 1962 to 1973. 1974 with the Arab Oil Embargo was the watershed year in this progression. Overall growth from 1975 to 1990 averaged 3.3% -- a significant change from historic trends and a significant factor in concerns about overbuilding of generation capacity, who must pay for it, and the need to do something about it. Growth levels continued to weaken, averaging 2.4% from 1991 to 2000, as the decade ended with the “dot com” bubble and the next opened with the California electricity crisis of 2000-2001. Over this long period in the 1980s and 1990s while rates of annual electricity growth declined dramatically, the country nevertheless consumed 819 billion kWh or 41% more electricity in 1990 than 1978 (the year of the NGPA) and 755 billion kWh or 27% more in 2000 than 1990. These figures are highlighted on Figure 9.

Figure 9. Electricity Consumption and Growth Rates
The Gas-Fired Capacity Building Boom (and Bust). The decade of the 1990s ended just as an incredible building boom took off in natural gas-fired generation. This involved construction on a massive scale of two different kinds of equipment. One was “simple cycle” combustion turbines (basically giant stationary jet engines) used for peaking services. The other was a combination of combustion turbines plus a steam cycle, in which the hot flue gases from the combustion turbine are used to operate a steam cycle, resulting in a “combined cycle”. Figure 10 shows this period of investment along with all the other major types of electric generating stations over the long history in this review. It also brings some perspective to the turn to coal. By the end of the 1980s, activity practically came to a halt with the exception of a small surge in gas-fired units that extended into the mid-1990s. This mini-boom is attributed mostly to non-utility entities who had entered the electric sector as rivals to investor-owned utilities and who could obtain “avoided costs” for their generation. Figure 11 provides the split between simple and combined cycle additions during the construction boom. From 1999 to 2005 about 200 gigawatts of gas-fired were constructed according to these data.

Much of the animal spirit came from independent power producers who, by this time, were able to sell into the grid due to electric power deregulation which, like open access for pipelines, had created open access for electric transmission. Deregulation in the electric sector started with the Energy Policy Act of 1992. It gained momentum from a combination of factors, among them low natural gas prices, advances in gas-fired generation technology performance, relatively low capital costs, ability to add capacity in small increments, and short lead times. To this must be added the profit motive on the part of the developers and savings on the part of major energy consumers to take advantage of these economies while escaping the burden of fixed costs (which contributed to elevated costs of incumbent generators). These factors happened to coincide with political winds in favor of such things as greater retail competition.

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It is hard to believe that any industry with such generally-high capital costs and public oversight as the electric power industry could find itself massively overbuilding generating capacity. In 2000, risks from overbuilding were becoming increasingly apparent, but the jury was out on whether through some process of checks and balances the worst could be avoided. Convening a workshop on the topic, the Electric Power Research Institute heard in early 2000 that over 200 gigawatts of new gas-fired capacity appeared quite likely to be constructed between the summer of 1999 and the next four years or so. Many (in Texas and California) would replace less efficient gas and oil equipment, yet many would add to total capacity and create new demand for natural gas. Among the results, the authors concluded that “Denial that cycles can
exist is one of several characteristics that leads to boom-bust.”23 The building spree caused a
credit collapse across the merchant energy industry. According to Standard and Poor ratings,
between 2001 and 2003 a dozen once-well-known names moved from investment grade to
below or well-below investment grade (junk, speculative, high yield): AES, Allegheny, Aquila,
Calpine, Dynegy, Edison Mission Energy, El Paso, Mirant, NRG, PG&E NEG, Reliant and
Williams.24

The psychology and dynamics of boom/bust plague many industries, as varied as aircraft
engines and insurance. Many are documented in John Sterman of MIT’s authoritative (and
disturbing) book.25 The mortgage debacle leading to the Great Recession of 2008-2009 reads
like a textbook example. Studies of real estate bubbles going back a hundred years had shown
that even bankers, normally a check on excess, can pour fuel on the flames. The oil and gas
industry is so notoriously afflicted with cycles that they simply appear to be a part of the DNA.
Overproduction, as we’ve now seen with shale gas and then shale oil and condensate, has
almost become a steady-state.

It’s an open question what actors in these industries can learn from the pressures and
responses in other industries. The main tools seen in the “bust” phase in the oil/gas, oil field
services and other extractive industries appear to be cost control (many aspects ranging from
people layoffs and equipment layups to high-grading, winnowing of assets, and supply
chain/logistics management), strategic acquisitions and divestiture, stopgap hedging, skills and
products differentiation and technical innovation (not unrelated to cost control).

**Historical Perspective: The End of the Bubble**

The bubble came to an end with a bang (the California Electricity Crisis of 2000-2001). 1999
average spot prices (Henry Hub) averaged $2.27 per million Btu (mmBtu) and jumped 90% to
$4.31 in 2000. In 2017 dollars, this was equivalent to increasing from $3.20 in 1999 to $5.94.

**Much Effort, Little Gain.** The backdrop was the long period of balancing the market with
Canadian imports and lackluster creep of production (Figure 6). Industrial demand had started
to sag and reserve additions had been minimal (Figure 5.) A close look at the effort-yield is
shown in Figure 12. Our “end of bubble” theme directs attention to the long period of what
might be called normalcy, as contrasted to the post-Great Recession rig decline when natural
gas production broke all the rules.26

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23 Prospects for Boom/Bust in the U.S. Electric Power Industry, Website accessed and public report

24 Peter Rigby, Standard and Poor’s, speaking to EPRI-EEI Power-Gas Seminar, November 13, 2003. J.
Platt personal files.


26 Rigs plummeted to historic lows (2016). Increasing associated gas and the diversity and dynamic
nature of costs in a declining market explain much. See Robert Kleinberg and others: “Tight Oil
Development Economics: Benchmarks, Breakeven Points and Inelasticities” MIT CEEPR WP 2016-12.
Over most of the 1990s, drilling moved erratically upward from 300-400 to over 500 rigs per month, and production moved up only 3 billion cubic feet per day (Bcfd). Mid-1990 rigs hit a low of about 360 in May 1999 before rocketing to 1,060 in two years, and then falling back until April 2002. This is the small interim blip in the upward drilling trajectory on the chart. Years of continuously increasing effort followed. The count hit 1,500 in 2007. Production, which had inched up to 53.7 Bcfd for 2001, drifted down or flat for the next six years, and despite all the drilling it was still about 1 Bcfd short of its peak in 2007.

**Desperate Measures.** It was this experience, oblivious of the scale of production which could emerge from shales, that led to conclusions about the necessity of importing LNG and, as well, of arrange to construct an Alaskan gas pipeline which might supply 4 Bcfd. This mindset was reinforced by five expensive years (2003-2007) in which prices averaged $6.75/mmBtu (Henry Hub spot) or $8.27 (2017 dollars).

**The Crest of High Price Expectations.** The idea that natural gas prices had reached some kind of stable plateau in the $6.00-$8.00 range gave confidence to the backers of a group buying the Texas utility TXU, announced in February 2007. $6.00 would translate into sufficiently high power prices (rule of thumb: $60 per megawatt hour) to drive profitability. The leveraged buyout, estimated to cost $45 billion and labeled the largest in history by that time, was

Rev. December, 2016. This reference kindly brought to author’s attention by Frank Vellastro, Center for Strategic and International Studies. [Authors Robert L. Kleinberg, Sergey Paltsev, Charles K. Ebinger, David Hobbs, and Tim Boersma]

arranged by Kohlberg Kravis Roberts & Co., Texas Pacific Group and Goldman Sachs. As part of the dealmaking, TXU’s plans for building 8 of 11 planned coal-fired power plants were scrapped.

**New Price Regime Recorded in Forecasts.** Toward the end of that year, the EIA was finishing its 2008 Annual Energy Outlook, in which it anticipated LNG imports to the US of 3.3 Bcfd by 2010 and 5.8 Bcfd by 2015 (and continuing to increase thereafter). Private research reached much the same conclusions but upped the numbers by a factor of two to 5.7 Bcfd in 2010 and 11.8 Bcfd in 2015 (and rising thereafter). The author presented these findings to an AAPG forum in April 2008.²⁸

The tenor of the times during this post-bubble period is captured in the record of accessible government natural gas price forecasts. **Figure 13** compiles EIA’s forecasts from 1985 to 2010, all translated into 2008 dollars. They show the downward trend of longer term expectations as the realities of the bubble sank in during the 1990s, and the reverse to much higher prices post-2000.

![Figure 13. LBNL Compilation of EIA Natural Gas Price Forecasts through 2010](image)

**Historical Perspective: Hello, Shales! July 2008 Triggers New Thinking**

For many, one or two publications in July 2008 introduced the possible scale and affordability of shale gas. The first was a study prepared by Navigant Consulting, sponsored by the American Clean Skies Foundation.²⁹ This organization ostensibly had an educational mission, although it was set up by Aubrey McClendon, the CEO of Chesapeake Energy with deep roots in the discovery and exploitation of shale gas in the Haynesville shale. Because of these connections, one wasn’t sure at first what to make of it.

**Figure 14** shows a projection from this report – and what happened. The forecast looked impossibly optimistic. Nine years after its release, the study’s estimates of production for the seven “big shale plays” turned out to be exceeded by about ten percent, even though the roles of identities of the leading shales changed considerably. The Marcellus became a monster play, the Haynesville and Fayetteville grew considerably but fell short of the projection, and the Barnett – the only major source in early 2008 – lost some ground. As to other areas and types of shales not considered, these increased the contribution from shales by almost half again as much as had been estimated.

The second publication, appearing two and one-half weeks later, was a report by a respected financial institution, Deutsche Bank.\(^3\) It too included a stunning projection, although it extended only through 2011. This is shown in **Figure 15** – and what happened. Again, projections for the main four shales proved to be a bit too cautious – in particular, the Haynesville actual production overshot expectations, leading the group’s production to reach its forecast target a year and some months earlier than projected. The other shales greatly exceeded expectations and additional sources entered the picture that had not been included, such as the Eagle Ford and Permian. As for Navigant’s study, these other shales ended up increasing the total contribution from shales by half as much.

**Figure 14.** Navigant’s Estimated Production from Big Gas Shale Plays in Ten Years

This historical retrospective is hardly a complete list of “what’s important to remember” when thinking about the role of shale gas and oil in the U.S. and world economies. The main purpose of this review is to remind ourselves of the conditions and concerns, most of which represented constraints, that preoccupied the energy industries and public policy over the many decades leading up to the shale era.

Other factors and developments of daunting magnitude have also entered the picture and have reshaped, or are reshaping, the chessboard we referred to earlier when discussing the “apex of economic complexity”. Among the most significant and durable of these are (1) China and what it has meant in terms of globalization, oil, coal, metals and LNG markets, shipping, etc. and (2) renewables technologies costs and performance, the outcomes of which have been intimately linked with China’s “factory floor” and represent in inevitability as sure as that of hydraulic fracturing.

ISSUES OF THE DAY

**Surprise Price Spike: International Coal.** Last summer coal prices in China took off, with some surprising worldwide implications that demonstrate how seemingly small triggers in one place can impact developments across the planet. This is isolated example of the interconnectedness and complexity of energy matters, wherein what you thought was somebody else’s business is suddenly your business. China implemented a policy in May 2016 to help support rock-bottom coal prices. The mechanism was to reduce the number of days per year permitted to mine coal.
from 333 to 276. By August, Chinese total coal imports had climbed about 50%, prices of thermal coal imports had jumped similarly, and those of thermal coal had climbed 250%.

To put this event in context, Figure 16 shows the path of thermal coal prices from five years preceding the global commodities supercycle of 2008 to April 2017 (June in the case of currency). By mid-2016, coal prices (traded in US dollars per metric ton) had been falling continuously for five and a half years. The high point during 2010-2011 was set by the shortages caused by floods in Queensland. Exchange rates hovered near one-to-one against the US dollar during most of this decline but started falling sharply in late 2014. Just like the weak rouble has shielded Russia from the worst effects of falling oil prices, the weak Australian dollar did the same for Australia’s coal exports. With falling prices coupled with falling currency, Australia received fewer US dollars but essentially the same level of Australian dollars for every ton. The exchange rate has hardly moved over the past year. This detail helps answer the question whether, apart from China, financial factors might have, somehow, suddenly pressured Australia to seek higher prices.

Figure 16. Australia Thermal Coal Price and Currency Trends Since 2003

Figure 17 narrows the focus to the period since 2014, while bringing in data on Central Appalachian coal prices and European natural gas prices, which sets the stage for understanding the surprising reach of China’s problem. All prices are in dollars per million Btu. The markers on the curves show the low and high price points. These were reached in November for Australian coal, after which some relief came from relaxing the policies. The gap between European gas prices and Australian coal held at about $2.00 per million Btu over most the year and sank below $1.00 in October and November as coal prices rose faster. From trough to peak, Australian thermal coal rose 200% (coking went up about 300%), and only 25% for Central Appalachian coal (which typically increases in partial sympathy with metallurgical coal prices). The proximity of Europe’s imported coal and natural gas prices is what’s significant.

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Timera Energy tracks fuel and power developments with a particular focus on Europe. Figure 18 is taken from their April 2017 analysis of the impact of these higher imported coal prices on gas demand in Europe. While natural gas prices had crept up $0.25/million Btu, coal prices had increased so much that, through “coal switching”, the power sector consumed an additional 20 billion cubic meters (700 billion cubic feet). This relationship is of more than academic interest to US gas markets and competitiveness of US LNG exports. In the authors’ words: “As the LNG glut grows, power sector switching will be a key mechanism allowing surplus LNG volumes to be absorbed by European hubs.”

**US Tight Oil/Shale Oil Still Major Influence on Global Oil Prices.** 2016 did not herald a significant pull-back from US pressure on global oil markets, with the 0.5 million barrels per day

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increase in crude imports mostly offset by the 0.4 million barrels per day increase in products exports (Figure 4). News during the first half of 2017 was taken up with the strength of US tight oil production and questions about whether OPEC would extend its January to June production cuts. Some of the headlines on the former tell the story:

(a) April 17: “Citi Sees Oil Surging $10 as OPEC Combats Roaring U.S. Shale”
(b) April 23: “Shale’s the Wild Horse OPEC Can’t Tame”
(c) May 4: “Oil’s OPEC-Driven Gain Wiped Out as Shale Boom Offsets Cuts”

The role of shales is better seen by attempting to avoid confirmation bias, i.e. by not looking for just the news you want to see. Comprehensive summaries of the forces at play in balancing the market are available from such organizations as the Center for Strategic and International Studies (CSIS), where analysis sheds light on the inundation from statistics (our “smorgasbord”). They show how US conventional oil production climbed in the last quarter of 2016 and into 2017 while tight oil remained essentially flat since the first quarter. They underscore the price-depressing overhang of stocks, exacerbated by US oil producers “irrational exuberance”. CSIS latest commentary brings a needed, wider perspective on trends and uncertainties, noting – in addition to the role of U.S. “quick cycle” unconventionals - such things as obsession over short term (often sketchy) statistics and “boycotts, trade wars, escalation in regional conflicts, a failed state or two, and the investment choices of the financial community”.

**Bankruptcy Surge in 2016 and Other Negatives.** The oil price collapse didn’t fall far from the norm until the last quarter of 2014, and many companies had financial arrangements (e.g. hedges) which could tide them over for a time. Moreover, in late spring, the prices improved for a time. This pushed the agony into 2016 when continued low oil prices took their greatest toll, accompanied by the lowest natural gas prices seen since the mild winter of 2011-2012.

The law firm Haynes and Boone LLP established a “bankruptcy monitor” and continues to track one measure of impacts in the oil/gas sector. While far from a complete reckoning of impacts, it captures the pattern shown using other measures. Their results are summarized in Table 2. Of the $124 billion in debt, two-thirds was incurred in 2016 and two-thirds within the E&P sector.

(b) Julian Lee, Bloomberg Gadfly: https://www.bloomberg.com/gadfly/articles/2017-04-23/u-s-shale-s-the-wild-horse-that-opec-just-can-t-tame
34 This they announced on May 25th, extending cuts of 1.8 million barrels per day through March 2018. OPEC’s share is 1.2 million barrels per day, non-OPEC countries including Russia, approximately 0.6 million barrels per day. Alex Lawler, Rania El Gamal and Ernest Scheyder, “OPEC, non-OPEC extend oil output cut by nine months to fight glut”, Reuters. May 25, 2017. Website accessed June 29, 2017.
35 CSIS point out that OPEC apparently accused US producers of exuberance. (The term came into the vernacular in a 1996 speech by Federal Reserve Board Chairman Alan Greenspan.)
36 Frank A. Verrastro, Adam Sieminski, Larry Goldstein and Albert Helmig, “Bulls and Bears Converge: Sentiment Shifts and Misperceptions in the Oil Market”, CSIS Commentary, June 29, 2017.
Table 2. Bankruptcies Across E&P, Oilfield Services and Midstream Companies

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<td>2015</td>
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<td>E&amp;P</td>
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<td>Midstream</td>
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<td></td>
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Source: Haynes and Boone LLP

Bureau of Labor Statistics showed a loss of 150,000 extraction and support services jobs between the peak of about 535,000 in September 2014 and November 2016. The “big four” oilfield services companies (OFS) are said to have laid off 30% to 40% of employees, mostly in North America, and the two major drillers 50%. Globally, the top fifty OFS companies are alone estimated to have laid off 300,000.

We indicated in Figure 4 the unprecedented scale of negative net natural gas reserve additions in 2015, eclipsing all (few) previous downturns. This step represents the effect of Securities and Exchange Commission financial reporting requirements, which call for evaluating reserves against prices on the first day over twelve months. As collateral shrinks, so too does a company’s borrowing capability, impinging further on capital spending.

The Markets and Finance section of EIA prepares annual assessments of performance for a large group of US and international oil and gas companies. The larger population is now about 89 companies and the US portion is a group of 44 “onshore-focused oil producers”. Several indicators of two years of financial distress and recent glimmers of improvement are illustrated in Figure 19. This shows quarterly capital expenditures and sources of cash, the latter comprised of cash from operations (a large source when prices/revenues are high), raising equity (issuing shares – a large share in the first quarter of 2015 and reappearing again throughout most of 2016), selling off assets (usually a desperate move; it was big in the last half of 2014 and again during the last quarter of 2016), and borrowing (debt). Debt was very high.

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for particular quarters in 2012 and 2013, and spiked in the last quarter of 2014. This may have been a move to build flexibility in case conditions soured further. Debt has remained a nearly negligible tool since early 2015.

**Capital Expenses and Sources of Cash for Onshore-Focused US Oil Producers**

![Graph showing capital expenses and sources of cash](image)

Figure 19. US Oil Producer Financial Metrics: Capital Expenditure and Sources of Cash
Source: EIA

As gruesome as this picture is, it is important to provide a fuller story of the winners and losers from these dramatic events. Collective data are more useful than single company snapshots, which is why we have emphasized some of the largest datasets here. Even in combination with the consumers savings discussed previously, this still conveys only part of the scope of impacts ... pluses in petrochemicals and fertilizers, minuses in tax revenues, and the list goes on.

**So Many Questions.** Shifts in the industry and, to some extent, in the regulatory arena have been or promise to be dramatic. Among the major developments which deserve fuller treatment, and some helpful references, are the following.

1. *The Permian – All Eggs in One Basket?* This old and revitalized region is getting the lion’s share of attention at this late stage of the industry downturn. It has absorbed about 60% of the increase in US oil-directed rigs since the drilling lows of 2016 (Figure 2). From producing about 1 million barrels per day at the start of 2011, it now (June 2017) produces over 2.4 with almost 30% of the increase occurring since the start of 2016. As goes oil, so goes its associated gas, adding about 2 billion cubic feet per day and leaving operators wondering

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how to get it to market. This has spawned myriad investments in the midstream sector including activity aimed at moving supplies into Mexico, pipeline reversals, and changing pricing dynamics within the region. This has been likened to the problems of takeaway capacity that caused negative “basis” (underpricing compared to local hubs or the Henry Hub marker). A good education on these topics comes from the periodic reports issued by RBN Energy.41

Managing sand has also become a major logistics enterprise. Within a few years (2019), it is expected that a third of all sand being used in the U.S. and Canada will be used just in the Permian region.42

One of the leading producers in the Midland sub-basin is Pioneer Natural Resources. Their internal estimates indicate a recoverable resource of about 100 billion barrels oil-equivalent remaining in the Midland and Delaware sub-basins, which when combined with 35 billion barrels past production approaches the size of the Saudi Arabian Ghawar field (largest recoverable resource in the world at 150-160 billion barrels, citing Wood Mackenzie). While all investor presentations need to be scrutinized for hyperbole, these are often gleaned by analysts for well performance data and the like. In Pioneer’s case, their appendix includes some excellent slides on the geologic setting, depositional model and well logs of the stacked reservoir. Two of these are included here, in part because the author has had difficulty locating timely information of this type in the geologic literature but also because of their quality (Figure 20 and Figure 21).43 Figure 21 shows how the Midland play makes up in depth what it lacks, as compared to the Marcellus for example, in area.

2. Technology Miracles – Enlarging the Resource or Producing Faster/Cheaper? The downturn has brought out remarkable efficiencies. There has been a combination of sustainable changes in technologies and approach which will serve well in unlocking production regardless of the price regime and changes related to the business cycle such as labor.
contraction and bare-bones quotes for services which cannot support operations over the long term. New records have been set in intensity of development, such as one and one-half to two-mile laterals and escalating tonnages of proppant (25 tons of sand in a 1.8 mile Chesapeake well), and speed, such as drilling a mile in a day. There are clues in the literature of increases in EURs (Estimated Ultimate Recoveries) which can be viewed as the resource potential over acres, which is quite different from how much hydrocarbon can be pulled out of a hole in some period of time. Greater intensity of extraction along a lateral and closer spacing of laterals without cannibalizing one another can increase total recovery. One innovation is to conduct frac operations in coordinated batches rather than drill, frac, drill, sequentially, as this method may not only incur efficiencies but also optimize rock stresses and gains in EUR.

Related to EUR is the matter of high-grading. The literature is beginning to provide quantitative insights into the major factors that have supported sustained production with surprisingly low rig counts, and concentration on the best prospects within a portfolio has been essential. When the industry returns to “normal”, high-grading will have exhausted these sweet spots, so the question then will be how much the new approaches will have upgrade the economics of the remaining targets, in effect converting some Tier 1 prospects to Core or some Tier 2 to Tier 1 in an endless process of winnowing.

Lastly, while we cannot do justice to it here, we again recommend Kleinberg (footnote 26) to stimulate thinking and bring order to thinking about “breakeven economics”.

3. **LNG export quantities and economics.** 2016 saw Cheniere begin LNG exports from Sabine Pass. The company has become “with just the three trains operational ... the single largest, physical gas consumer in North America”. By the end of April 2017 it had shipped about 400 billion cubic feet on “more than 100 cargoes” to 20 countries. Three trains are operational, and a fourth train at this facility is expected to go online by the end of the year. Cheniere’s contracting approach brought a major innovation to global LNG contracting, with two components. The first is a fixed fee of $2.25 to $3.50 per million Btu (the Sabine facility has contracts at both levels; the company’s Corpus Christi facility under construction has contracts at $3.50). The second component is the cost of gas, 115% of Henry Hub. The significance of this approach is its total departure from oil-linked pricing.

A number of organizations provide a wealth of information on the LNG business. The simple story is that Australia and the U.S. are adding substantially to global LNG capacity to the end of the decade, contributing to an expected “glut” until such time as demand picks up. The US is on a path to exporting 6 Bcfd by 2019 and perhaps over 8 Bcfd by the end of the year, from 6 facilities. Low prices are now making potential developers wary of making new FIDs, or final investment decisions. This is a characteristic investment within the industry and could lead to improved prices in the 2020s until new capacity will have been sanctioned and constructed.

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The pattern of mounting US sales estimated by Energy Ventures Analysis (EVA) is shown in Figure 22. The U.S. export pricing dilemma, also calculated by EVA, is shown in Figure 23.

The dilemma is that US exports can compete on a variable cost basis but low oil price-influenced LNG prices prevent full cost recovery. Shipping rates as indicated are quite low, e.g.

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45 Figures 22 and 23 are used by permission. Michael Schaal, June 2017. EVA LNG Quarterly is a new service provided by EVA.
$0.45 to Europe or $1.20 to Asian markets. Shipping costs are at an extreme cyclical low, as shown by Poten & Partners’ assessment in Figure 24. The stability of these factors is questionable.

Figure 24. LNG Vessels and Charter Rates
Source: Poten & Partners

Going forward, US customers are concerned that overseas demand will drive up US prices. A question is to what degree and under what scenario, say of oil prices, this could become a problem. A consideration is whether the problem is to some degree self-correcting, i.e. as US gas prices increase, they squeeze the margins, perhaps again serving as a disincentive and permitting limited contributions toward fixed costs. Knowledge of prices at different destination hubs will become an important piece of information, and is yet another example of the widening horizons of information needed to manage decisions and risks in the complex energy markets. Several additional references in the LNG realm are the International Gas Union’s 2017 World LNG Report and the International Group of Liquefied Natural Gas Importers (GIIGNL) Annual Report 2017: The LNG Industry in 2016.

Conclusion. The drama continues in and this review can touch on only part of it. One thing is clear, the technologies of horizontal drilling and massive hydraulic fracture have, most improbably, given the U.S. far more flexibility in how to serve its energy needs than had ever been thought possible.