Energy Economics and Technology Committee 2020 Report
May-June 2020

Article # 141905

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Zenith to Nadir: Oil's Woes in the Throes of Pandemic

A sense of unease was penetrating the oil and gas industry way back in 2018 when the industry broke records in production and exports, only to be eclipsed by further peaks in 2019. This unease had two sources. From *within*, it was a growing awareness that many if not most companies defining the "shale era" were floating on a sea of debt, an unsustainable financial proposition, and that henceforth the activities of the industry – drilling, completions, production – would need to generate "free cash flow", namely revenues sufficient to both cover a much larger portion of costs and yield profitable investment. From *without*, this unease came from growing awareness that concerns over climate change would sooner or later, quite possibly sooner, cause societies to turn away from fossil fuels. The latter could proceed in discrete steps already underway, such as state renewable performance standards within the electric sector. Societies could adopt modest national proposals such as heightened R&D on carbon capture and the like. Or they could advance bolder moves such as embodied by the Green New Deal proposed in early 2019 after the Democratic takeover of the U.S. House of Representatives in the November 2018 election. Such was the prelude to 2020.

The crisis posed by the pandemic – by the extraordinary, punishing direct and indirect impacts of the novel coronavirus and societal responses – throws the preceding, enormous, essentially existential tensions confronting the oil and gas industry into even greater turmoil and uncertainty. As of May 2020, and little over two months into it (in the U.S.), the new challenges make the impossible-enough production/profitability/climate conundrum look almost quaint.

The period since early March, 2020 has been marked by moments of singular significance. This review begins with a tally of these most recent events and then dives into the pricing pressures driving project economics, reserve write-downs, impairments and bankruptcies. For several years, natural gas liquids have offered a kind of life raft to for certain wells and production portfolios able to take advantage of them. Guest authors expand on market swings in liquids and on the squeeze taking place on lease operations, the very nub of shut-down decisions.

The Moments of March and April 2020

The Saudi Arabia-Russia Oil Price War. Prior to the weekend of March 7-8, OPEC attempted to gain Russia's support for strengthening cuts in oil production. Cracks in OPEC resolve appeared on March 5 when Brent settled below $50 per barrel "for the first time in nearly three years"[1]. The OPEC group had already been operating under cuts of 1.7 million barrels per day (bpd), slated to expire at the end of March, and was aiming to expand cuts by 600,000 bpd and as much as 1 million bpd[2]. CSIS analysts have calculated pre-existing cuts as being 2.1 million bpd[3]. Motivations in February and early March, prior to understanding the global spread of the virus, were soft global demand and a possible European economic recession. The meeting concluded on Friday without Russia's buy-in, triggering a further ~10% cut in Brent prices and, the next day, Saudi Arabia's offering cargoes at discounts of $6-8 off Brent[4]. In northwest Europe, the discount for Arabian Light rose to $10.25 off Brent.

While the ostensible rationale and immediate trigger was Russia's apparent intransigence to further cuts, U.S. shale producers, essentially all with substantially higher physical costs of production, lay in the crosshairs and had long been a focus of both Saudi Arabian and Russian anti-shale actions. Essentially yielding to the reality of burgeoning US tight oil (and product) supplies and shrinking imports, Saudi Arabia took a significant step with their November 2014 announcement to seek market share, accelerating and strengthening the oil price collapse which has persisted to the current day. Russia's actions began earlier. Their global disinformation campaign against "fracking" has roots that go back to 2011. Curiously, it was documented by one of the more authoritative sources on the matter, Fiona Hill, a U.S. expert on security

[1] "OPEC Tries to Force Russia Into Deeper Cuts as Oil Price Slumps", *Bloomberg*, March 5, 2020, by Grant Smith, Nayla Razzouk and Matthew Martin: https://www.bloomberg.com/news/articles/2020-03-05/opec-meets-in-effort-to-bridge-saudi-russia-divide-on-oil-cuts?sref=nfGWux2z

[2] "OPEC leaning toward larger oil cuts as virus hits prices, demand: sources", *Reuters*, February 28, by Alex Lawler and Dmitri Zhdannikov: https://www.reuters.com/article/us-oil-opec/opec-leaning-towards-larger-oil-cuts-as-virus-hits-prices-demand-sources-idUSKCN20M1MB

[3] "Is the Oil Market Crisis Over? Not at All", Center for Strategic and International Studies, April 3, 2020, by Sarah Ladislaw and Ben Cahill: https://www.csis.org/analysis/oil-market-crisis-over-not-all

[4] For example, "OPEC+ Talks Collapse, Blowing Hole in Russia-Saudi Alliance", March 6, *Bloomberg*, by Nayla Raszzouk, Grant Smith, Natalia Kniazhevich and Golnar Motevalli: https://www.bloomberg.com/news/articles/2020-03-06/opec-fails-to-reach-deal-as-russia-refuses-deeper-oil-cuts?sref=nfGWux2z, and "Saudis Plan Big Oil Output Hike, Beginning All-Out Price War, *Bloomberg*, March 7, by Javier Blas and Anthony Di Paola: https://www.bloomberg.com/news/articles/2020-03-07/saudis-plan-big-oil-output-hike-beginning-all-out-price-war?sref=nfGWux2z

matters dealing with Russia, in her testimony during the 2019-2020 impeachment proceedings against U.S. President Donald Trump[5]. Russia also targeted Europe[6].

Price swings most directly related to the price war were quite dramatic as it began and quite muted as it ended, although it is perhaps too soon to finalize the price war's obituary due to the many weeks in March and April of heightened production, stock building and filling of cargoes. The price effects at the beginning and close of the price ware are shown in this table, with the key weekends highlighted. At the beginning, the price war was big news. When it ended, after an intense week of 3-way discussions involving not only Russia and Saudi Arabia but also the U.S. (which pointed to looming production cuts across the U.S. industry) the math was dominated by pandemic global economic and energy demand destruction[7].

6-9 March : Talks Collapse			9-13 April : Agreement		
		WTI Spot $/bbl			WTI Spot $/bbl
M	2-Mar	46.78	M	6-Apr	26.21
T	3-Mar	47.27	T	7-Apr	23.54
W	4-Mar	46.78	W	8-Apr	24.97
Th	5-Mar	45.90	Th	9-Apr	22.90
F	6-Mar	41.14	M	13-Apr	22.36
M	9-Mar	31.05	T	14-Apr	20.15
T	10-Mar	34.47	W	15-Apr	19.96
W	11-Mar	33.13	Th	16-Apr	19.82
Th	12-Mar	31.56	F	17-Apr	18.31
F	13-Mar	31.72	M	20-Apr	-36.98

Pandemic Declared. On March 11, citing 118,000 cases of COVID-19 in 114 countries with a death count of 4,291, the World Health Organization's Director-General Dr. Tedros Adhanom Ghebreyesus declared the disease a pandemic[8]. Dr. Tedros was motivated by the disease's extent and severity as well as by apparent insufficient resolve for dealing with it, even though "over 90%" of the cases had been found in just four countries (including China and South Korea)". Just two days later, the U.S. Federal Emergency Management Administration declared the disease a national emergency[9]. By Monday, March 16, the first U.S. "stay at home" policies were issued across a number of counties in the San Francisco Bay area, a week that concluded with an expansion to the rest of the state of California and similar policies from the state of New York, in turn kicking off further restrictions in much of the rest of the U.S. (*San Francisco Chronicle* front page, below.) It is the restrictions against non-essential business and travel that have had such an extraordinary impact on the oil and refining industries.

WHO's timeline on the coronavirus reminds us how much has been learned since a cluster of cases of pneumonia in Wuhan City, China, was brought to their attention on December 31, 2019. By the end of January, human-to-human transmission had been observed outside China,

[5] "Impeachment Testimony Describes Putin's Propaganda War On American Fracking", *Forbes*, December 2, 2019, by Dan Eberhart: https://www.forbes.com/sites/daneberhart/2019/12/02/kremlin-meddling-shows-value-of-natural-gas-supplies-fracking/#45309147462a and "Putin's Next Move in Russia: Observations from the 8th Annual Valdai International Discussion Club", Brookings On the Record, December 12, 2011 by Clifford D. Gaddy and Fiona Hill: https://www.brookings.edu/on-the-record/putins-next-move-in-russia-observations-from-the-8th-annual-valdai-international-discussion-club/

[6] "Russia 'secretly working with environmentalists to oppose fracking'", *The Guardian*, June 19, 2014, by Fiona Harvey: https://www.theguardian.com/environment/2014/jun/19/russia-secretly-working-with-environmentalists-to-oppose-fracking

[7] "Oil Nations, Prodded by Trump, Reach Deal to Slash Production", NYT, April 12, 2020, by Clifford Krauss: https://www.nytimes.com/2020/04/12/business/energy-environment/opec-russia-saudi-arabia-oil-coronavirus.html

[8] "WHO Director-General's opening remarks at the media briefing on COVID-19 – 11March 2020": https://www.who.int/dg/speeches/detail/who-director-general-s-opening-remarks-at-the-media-briefing-on-covid-19---11-march-2020

[9] "COVID-19 Emergency Declaration, March 13, FEMA": https://www.fema.gov/news-release/2020/03/13/covid-19-emergency-declaration

the COVID-19 genetic code had been distributed by China, and WHO had declared the situation a "Public Health Emergency of International Concern"[10].

San Francisco Chronicle

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CORONAVIRUS PANDEMIC

STAY AT HOME

6 Bay Area counties order nearly 7 million people to shelter in place

By Erin Allday

Six Bay Area counties announced "shelter in place" orders for all residents on Monday — the strictest measure of its kind yet in the continental United States — directing everyone to stay inside their homes and away from others as much as possible for the next three weeks in a desperate move to curb the rapid spread of coronavirus across the region.

The directive was set to begin at 12:01 a.m. Tuesday and involves San Francisco, Santa Clara, San Mateo, Marin, Contra Costa and Alameda counties — a combined population of more than 6.7 million. It is to stay in place until at least April 7. The three other Bay Area counties — Sonoma, Solano and Napa — did not issue similar mandates.

Just outside the Bay Area, Santa Cruz County late Monday also announced a "shelter in place" order for its 275,000 residents.

The orders — which are all similarly worded — fall just short of a full lockdown, which would forbid people from leaving their homes without explicit permission. The orders (read

Gabrielle Lurie / The Chronicle

Kathryn Sandretto, manager of Acote, closes the clothing store after learning that all non-essential businesses must close.

"Stay At Home" Order, March 16, 2020. San Francisco Chronical front page, March 17, 2020.[11]
Photo Credit Jeremy Platt, May 19, 2020.

IMF: Global GDP Collapse**.** Historical perspective on the scale and scope of the pandemic and/or the necessary responses to the pandemic is captured in the International Monetary Fund's dramatic recalibration of global GDP. A selection of GDP annual growth statistics from 2000 through their 2020 estimate is presented in the following chart. Beyond these countries, the organization's World Economic Outlook anticipates global growth to sharply swing to -3.0% for the full year compared to +3.6% and +2.9% in 2018 and 2019. While impacts in the U.S. and Europe are particularly severe along with the U.K. and Japan, many other countries will experience dire effects such as Russia, -5.5%; Brazil and Mexico, -5.3% and -6.6%; and Nigeria and South Africa, -3.4% and -5.8%, according to the IMF's assessments.

[10] "WHO Timeline – COVID-19": https://www.who.int/news-room/detail/08-04-2020-who-timeline---covid-19
[11] https://www.sfchronicle.com/bayarea/article/Bay-Briefing-Stay-at-home-15136262.php

GDP Annual Growth (%)									Great Recession												Pandemic
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
U.S.	4.1	1.0	1.7	2.9	3.8	3.5	2.9	1.9	-0.1	-2.5	2.6	1.6	2.2	1.8	2.5	2.9	1.6	2.4	2.9	2.9	-5.9
Euro Area-19	3.8	2.2	0.9	0.6	2.3	1.7	3.2	3.0	0.4	-4.5	2.1	1.7	-0.9	-0.2	1.4	2.1	1.9	2.5	1.9	1.2	-7.5
Germany	2.9	1.7	-0.2	-0.7	1.2	0.7	3.8	3.0	1.0	-5.7	4.2	3.9	0.4	0.4	2.2	1.7	2.2	2.5	1.5	0.6	-7.0
France	3.9	2.0	1.1	0.8	2.8	1.7	2.4	2.4	0.3	-2.9	1.9	2.2	0.3	0.6	1.0	1.1	1.1	*2.3*	*1.7*	*1.3*	-7.2
Italy	3.8	2.0	0.3	0.1	1.4	0.8	1.8	1.5	-1.0	-5.3	1.7	0.7	-3.0	-1.8	0.0	0.8	1.3	1.7	0.8	0.3	-9.1
Spain	5.2	3.9	2.7	3.0	3.1	3.7	4.1	3.6	0.9	-3.8	0.2	-0.8	-3.0	-1.4	1.4	3.8	3.0	*2.9*	*2.4*	*2.0*	-8.0
UK	3.4	3.0	2.3	3.3	2.4	3.2	2.8	2.4	-0.3	-4.2	1.9	1.5	1.5	2.1	2.6	2.4	1.9	1.9	1.3	1.4	-6.5
Japan	2.8	0.4	0.1	1.5	2.2	1.7	1.4	1.7	-1.1	-5.4	4.2	-0.1	1.5	2.0	0.4	1.2	0.5	2.2	0.3	0.7	-5.2
S. Korea	8.9	4.9	7.7	3.1	5.2	4.3	5.3	5.8	3.0	0.8	6.8	3.7	2.4	3.2	3.2	2.8	2.9	3.2	*2.7*	-	-
China (PRC)	8.5	8.3	9.1	10.0	10.1	11.4	12.7	14.2	9.7	9.4	10.6	9.6	7.9	7.8	7.3	6.9	6.7	6.8	6.6	6.1	1.2
India	*3.8*	*4.8*	*3.8*	*7.9*	*7.9*	*9.3*	*9.3*	*9.8*	*3.9*	*8.5*	*10.3*	6.6	5.5	6.4	7.4	8.2	7.1	*6.7*		4.2	1.9

Source: (1) OECD Statistics: https://stats.oecd.org/index.aspx?queryid=60702# and **IMF est.**

(2) IMF (2020 est., April 14 2020): "The Great Lockdown: Worst Economic Downturn Since the Great Depression"

https://blogs.imf.org/2020/04/14/the-great-lockdown-worst-economic-downturn-since-the-great-depression/

While the Saudi Arabia/Russia oil price war was still in full swing, noted oil analyst Amy Myers Jaffe, now Senior Fellow with the Council on Foreign Affairs, underscored the significance of sharply reduced oil revenues to both large and small petrostates, where capital flows into the international banking sector, very helpful in the past from Qatar and Abu Dhabi, and from China to Iran, Venezuela, and producers in Latin America and sub-Saharan Africa may all be imperiled[12].

***IEA: Global Oil Demand Collapse, 29 million bpd*.** The International Energy Agency's monthly *Oil Market Report* is one of the "go to" sources for tracking near-real-time global oil developments, particularly for OECD countries and several others[13]. They introduced their Global Energy Review (publicly available, of which the OMR is a part) with the observation:

> The coronavirus pandemic has triggered a macroeconomic shock that is unprecedented in peacetime. … About 4.2 billion people or 54% of the global population, representing almost 60% of global GDP, were subject to complete or partial lockdowns as of the 28th of April and nearly all the global population is affected by some form of containment measures. … [In effect in 187 countries, these measures] include partial or complete lockdowns, daytime curfews, closure of educational institutions and non-essential businesses, and bans on public gatherings.
>
> … during the lockdown phase economies can expect a 20% to 40 % decline in economic output, depending on the share of the most affected sectors and the stringency of measures. At the global level, this translates into a 2% drop in expected annual GDP for each month of containment measures.[14]

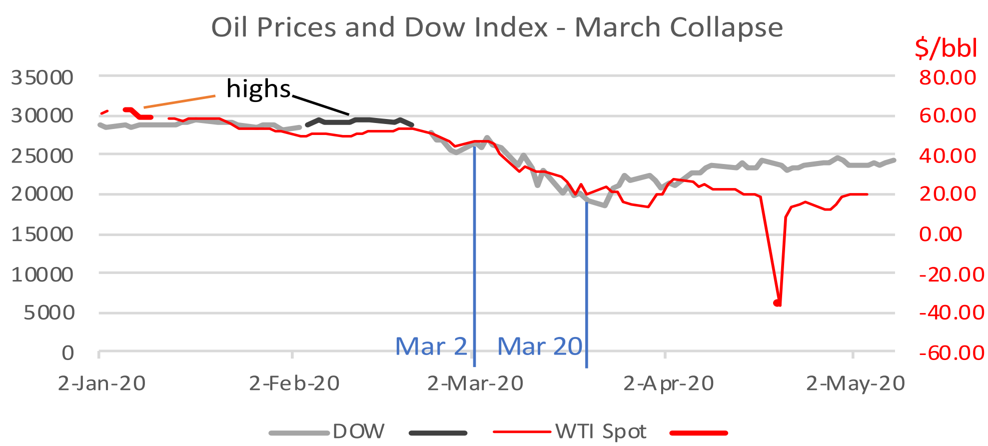
[12] "Emerging Petrostates Are About to Melt Down – Collapsing Oil Prices Risk Igniting a Sovereign Debt Crisis", Amy Myers Jaffe, *Foreign Affairs*, April 2 2020: https://www.foreignaffairs.com/articles/2020-04-02/emerging-market-petrostates-are-about-melt-down

[13] *OMR*: https://www.iea.org/reports/oil-market-report-april-2020

[14] *Global Energy Review* references: https://www.iea.org/reports/global-energy-review-2020 and https://webstore.iea.org/download/direct/2995

Against global oil supply/demand in the neighborhood of 100 million barrels per day (bpd), IEA estimated *April demand would fall 29 million bpd* year-on-year and 23.1 million bpd over the April-to-June quarter. They estimated 187 countries were under restrictions. On the supply side, the apparent resolution to the Saudi Arabia-Russia oil price war would see demand fall by an ostensible 9.7 million bpd, or perhaps 10.7 million bpd (the latter measured against the April production surge preceding the May 1 agreement date). U.S. and Canada could contract 3.5 million bpd. Industry capital expenditures could contract about $155 billion or 32%. The *OMR* forecasts trends to the end of the year, yet the uncertainties surrounding current events lead us to place greater emphasis on the near-term calculations rather than convey the full year forecasts. How might the market come to balance, considering this great discrepancy of demand and supply? In addition to maxing storage fill, a dim outlook for U.S., Canada, and many other producers is inevitable.

U.S. Stock Market Shock and Oil Skid. The U.S. stock market has had a kind of resilience not dissimilar to the U.S. oil and gas industry with its success of geosteering, horizontal drilling, and hydraulic fracturing. It has survived skepticism, collapses of natural gas and oil prices, and near elimination of drilling of any kind. But the events over several perilous weeks in March, 2020 appear to mark a turning point from which there is no return – not for oil, not for economies – anytime soon. Forces larger than oil pummeled the stock market essentially coincidentally with the breakdown of OPEC/Russia talks, as that was exactly when global impacts of the pandemic were becoming ever more apparent. This period in March as an importance not apparent at the time. Without clairvoyance regarding April's negative oil-pricing event (its negative posting on April 20), the basic outcomes of the new financial and oil (im)balance were essentially arranged in full over the few weeks between March 2nd and 20th. The timeline of these shifts since January are shown in this Oil Prices, Dow Index chart.

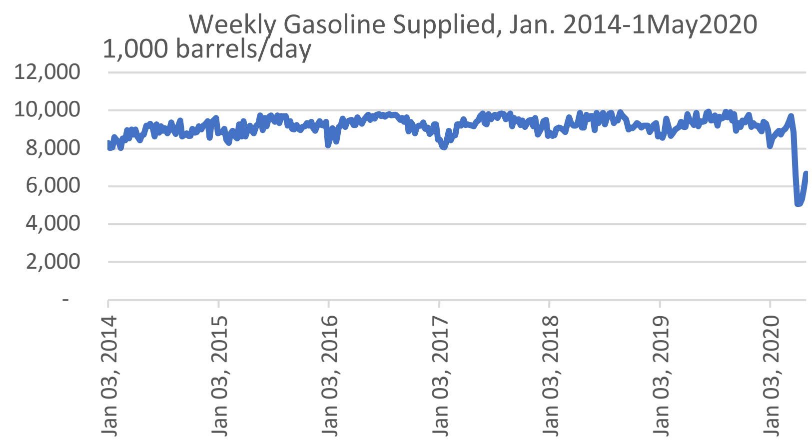


		WTI Spot $/bbl	DOW
M	2-Mar	46.78	26,703
T	3-Mar	47.27	25,917
W	4-Mar	46.78	27,091
Th	5-Mar	45.90	26,121
F	6-Mar	41.14	25,865
M	9-Mar	31.05	23,851
T	10-Mar	34.47	25,018
W	11-Mar	33.13	23,553
Th	12-Mar	31.56	21,201
F	13-Mar	31.72	23,186
M	16-Mar	28.96	20,189
T	17-Mar	26.96	21,237
w	18-Mar	20.48	19,899
Th	19-Mar	25.09	20,087
F	20-Mar	19.48	19,174
M	23-Mar	23.33	18,592
T	24-Mar	21.03	20,705
W	25-Mar	20.75	21,201

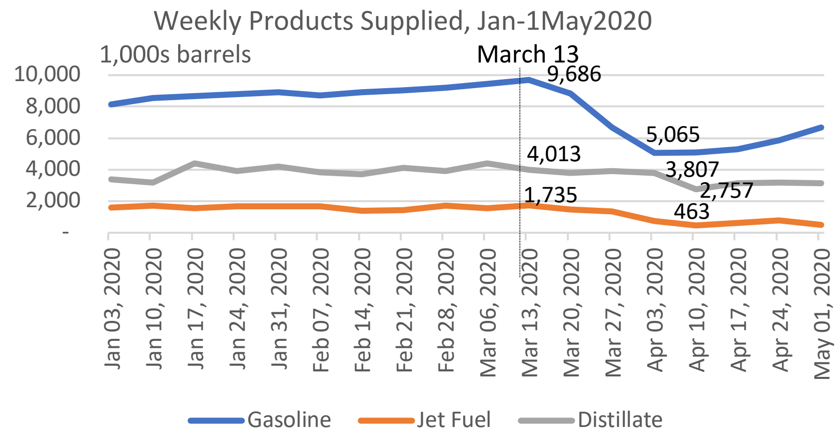
The IEA's *Global Energy Review* address a range of energy topics including up-to-date trends in electricity use in response to coronavirus lockdown measures. After a period of weeks, the greatest decline has been seen in Italy, on the order of 25%. Reductions elsewhere have been 20-25% in India, ~20% and more recently lessening in France and Spain, about 10% in Germany with a possibly brief dip to 20%, and 15% to over 20% in the UK.
For treatment of electricity: https://www.iea.org/reports/global-energy-review-2020/electricity#abstract and https://www.iea.org/reports/weekly-electricity-data-as-of-27-april-2020

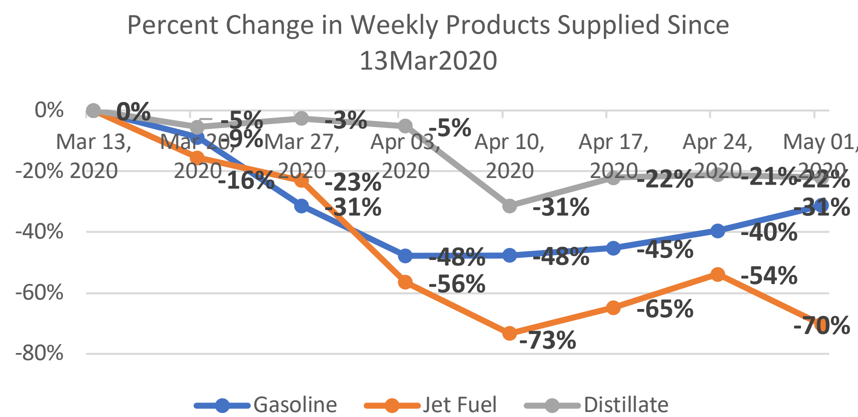
Oil prices were highest at the start of the year, averaging $60.84 per barrel over the first full week. The DOW hit new records a month later, closing near or above 29,000 continuously for nearly three weeks through February 21st, an average of 29,254. By the beginning of March, oil had drifted down to $46.78, $44.06 or 23% off the high. The DOW dipped at the end of February, closing March 2nd 2,550 or 9% off its high. By the 9th, the price war knocked $10 or more off oil. By the 20th, it had dropped to $19.48, $27.30 or 58% below March 2 level – and $41.36 per barrel or a remarkable **68%** below its early January mark. Oil has struggled in the teens or near $20 per barrel through early May. The DOW has not suffered quite the same fate, although its shifts represent vastly greater swaths of the economy than any single industry. From early March, by the 20th it fell to 19,174, a decline of 7,529 points or 28%. And measured against its February records, its principally-COVID-19 related losses amounted to 10,080 points – a drop of **34%**.

The Fall-Off of Demand. The collapse in demand for U.S. transportation fuels is thrown into high relief in the following three charts – the first, the trend in weekly gasoline supplied since 2014; the second, the trend in supplies of gasoline, jet fuel and diesel since January 2020; and the third, the relative declines in use of gasoline, jet fuel and diesel since the baseline week of March 13, 2020 through May 1. The first just makes the point about how starkly the collapse in demand (in that case, motor gasoline) stands out historically. The second chart, dating to the beginning of the year, captures the drop-offs but also gives the relative size of each product segment. Air travel has been hammered, for example, but it represents only about 11% of the combined transportation fuels market. The third chart illustrates clearly how early and steep the declines were, with 9% and 16% declines in gasoline and jet fuel the very first week. By the third week, gasoline had declined a remarkable 48% and the following week jet fuel reached what may be its lowest point, a spectacular 73% decline.



Motor Gasoline Supplied	million bpd
13-Mar	9.7
3-Apr	5.1
3-wk decline	-4.6
% decline	-48%

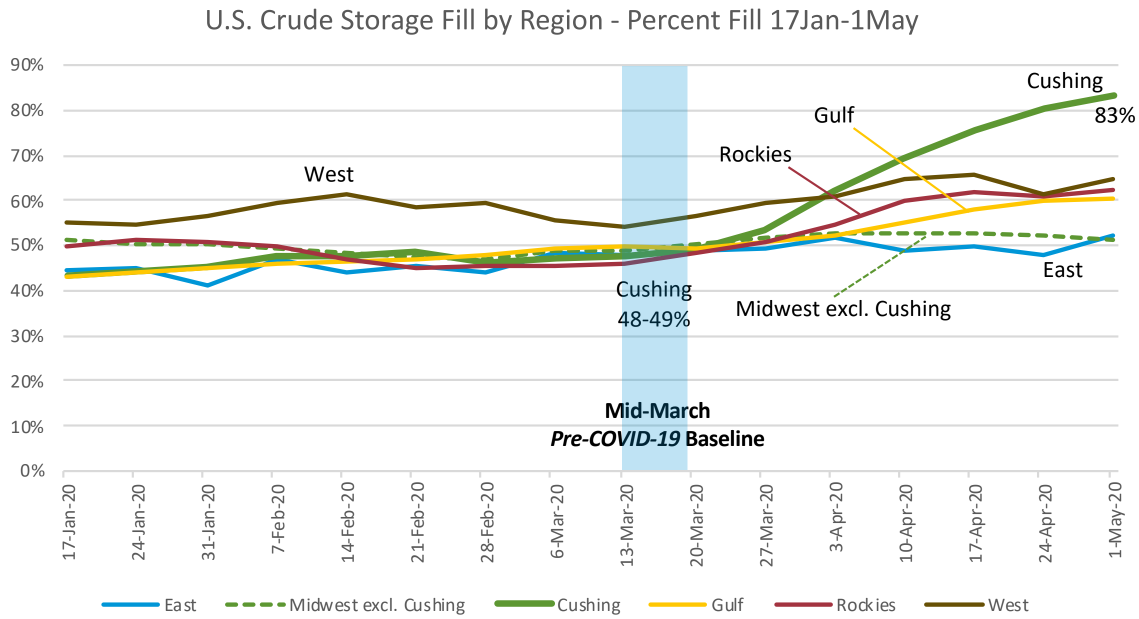


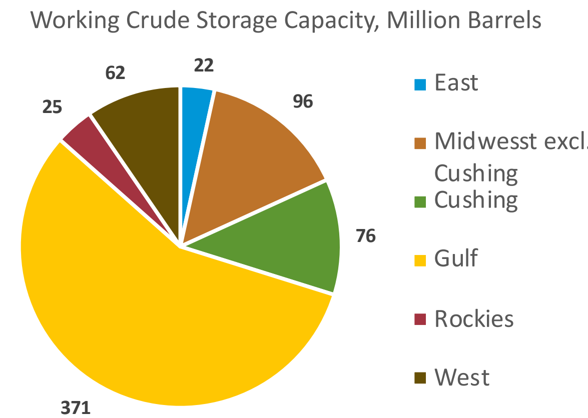


Without systematically documenting the retail price effects, it may be sufficient to offer the following photograph. 98-cent gas was found in the Midwest after gasoline demand had fallen nearly 50% for three weeks.

Photo Credit. Booth Platt. Citgo Station, April 18, 2020. Detroit, MI, corner of Mack Ave. and Conner St.

The Cushing, Oklahoma Crude Oil Storage Choke Point. Market observers, financial analysts, traders and all stakeholders in the oil and gas industry are watching the filling of storage capacity in the key oil trading hub of Cushing, Oklahoma, with horror and fascination, since once the region reaches so-called “tank tops”, there is essentially no choice but to shut down production (although some will flow to the Strategic Petroleum Reserve). The anomalous fill rate at Cushing, relative to the other regional storage capacity (here focusing on “working” storage capacity), is shown in the next chart. By May 1, it had reached 81%. The area has an outsize importance in price formation compared to its actual size – compared to other regions in the pie chart.





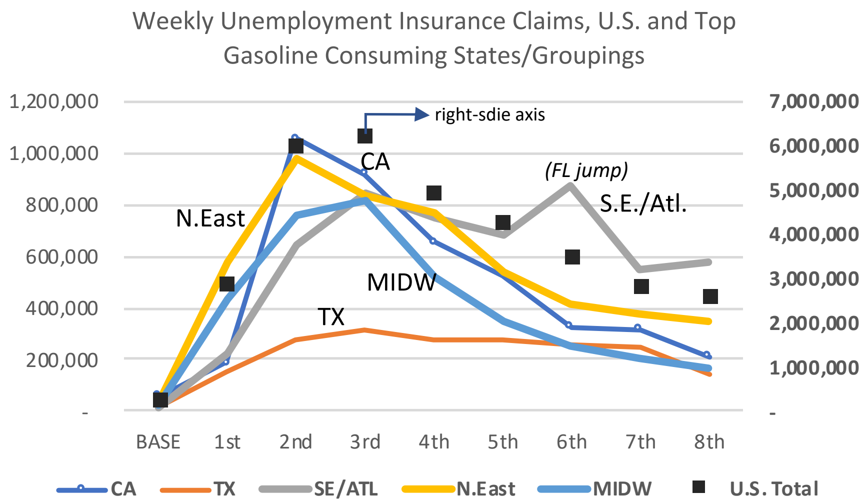
U.S. Unemployment Insurance Filings—Consumption and Production Views. Every Thursday, the U.S. Department of Labor issues a state by state accounting of unemployment insurance claims for the week ending the preceding Saturday. The next week, the initial "advance" claims are adjusted slightly. The charts provided here illustrate the weekly, claims (on a seasonally unadjusted basis) for the weeks ending March 14th through May 9th. The first week is referred to as a "baseline" because sharply restrictive "stay at home" measures had not been enacted until the following week. Against that baseline, the very first (next) week saw a record filing of 2.9 million claims. Filings exceeded 6 million the 3rd and 4th weeks, and dropped below 3 million by the 7th and 8th weeks after the "Baseline".

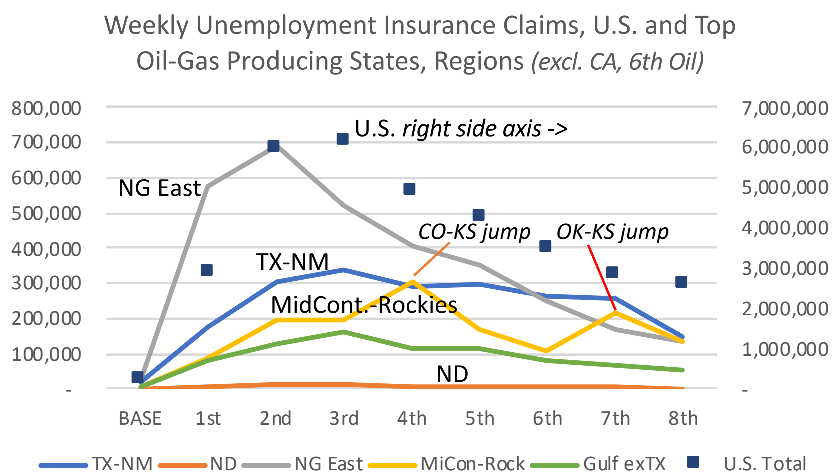
These levels far exceed the distress experienced directly within the oil and gas industries, yet they offer a different lens from which to understand vast, cross-sector impacts of such consequences as reduced travel, gasoline and jet fuel consumption, and the like.

Data have been condensed as follows: (a) Total filings plus those from just the largest gasoline-consuming states, and (b) Total filings plus those from just the top ten oil and top ten natural gas-producing states. The relevant tables are provided in the Appendix. In the second chart, the huge levels of unemployment within California (the largest gasoline-consuming and 6th largest oil-producing state) is removed to allow for easier discrimination of the other regions.

Looking at the combined weekly filings since the baseline week, the subset of the top 12 gasoline-consuming states represents 53% of typical annual gasoline consumption (reference usage in 2018) and 58% of total filings over the 8 weeks (i.e., 19.6 of 33.6 million filings). By contrast, the 14 states comprising the top ten oil and natural gas producer, many of which are more sparsely populated (N. Dakota is the #2 oi producer), account for only 35% of total filings (i.e. 11.7 of 33.6 million filings).

The scale of economic impacts reflected in jobs lost gives a sense of the challenges, length and uncertainties around reopening and recovery. Oil futures too are a signal – at the end of May, CME Group's NYMEX WTI crude oil futures do not reach $40 per barrel until the summer of 2022 and $50 until late 2026 or early 2027. Changes in work and travel lead to delayed "new normals" of modestly- to significantly-less motor fuel and jet fuel use, spanning a wide band of uncertainty in various forecasts.

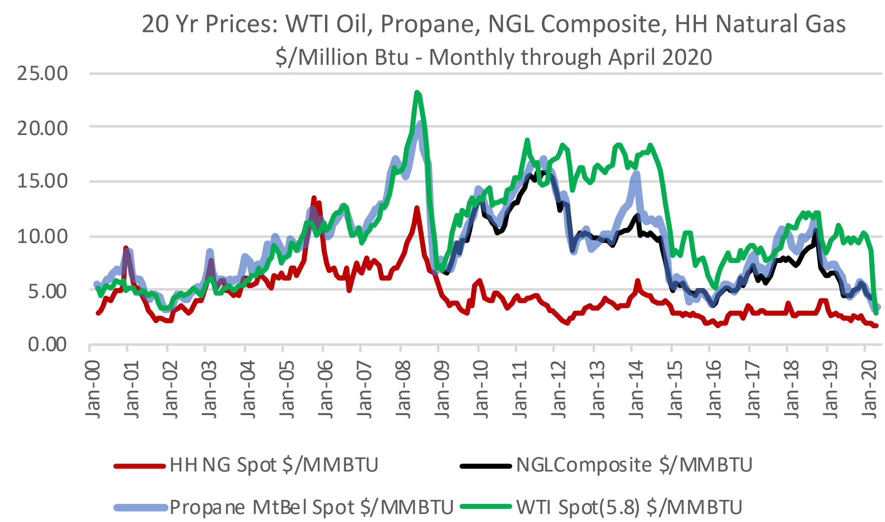




Natural Gas Liquids

NGL Background: Not Necessarily a Reliable Profit Engine for the Wet Gas and Associated Gas Producer, and Deeply Reliant on Exports to Manage Oversupply

Our discussion of promise, bright spots and low points for natural gas liquids (NGLs) begins with a portrayal of pricing over 20 years for natural gas, oil, and several reference NGLs – namely propane and an NGL "composite" price. The latter is calculated by EIA using volumes reported to EIA and product prices obtained by EIA from Bloomberg. Volumes of the NGLs ethane, propane, butane, isobutane and natural gasoline (not a complete list) have heat contents intermediate between natural gas and oil and thus their prices usually, but not always, fall somewhere in the middle. The data are translated into dollars per million Btu, although such prices are rarely used in NGL commerce where prices are quoted in dollars and cents per gallon.

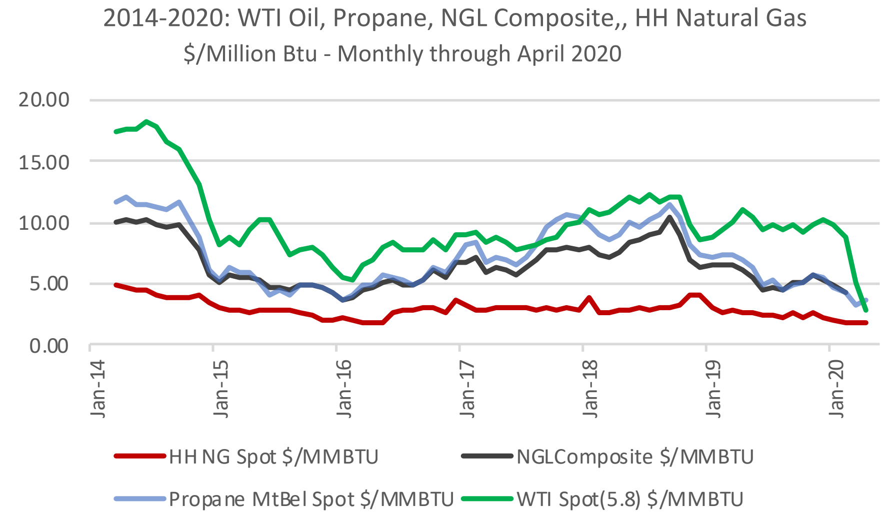


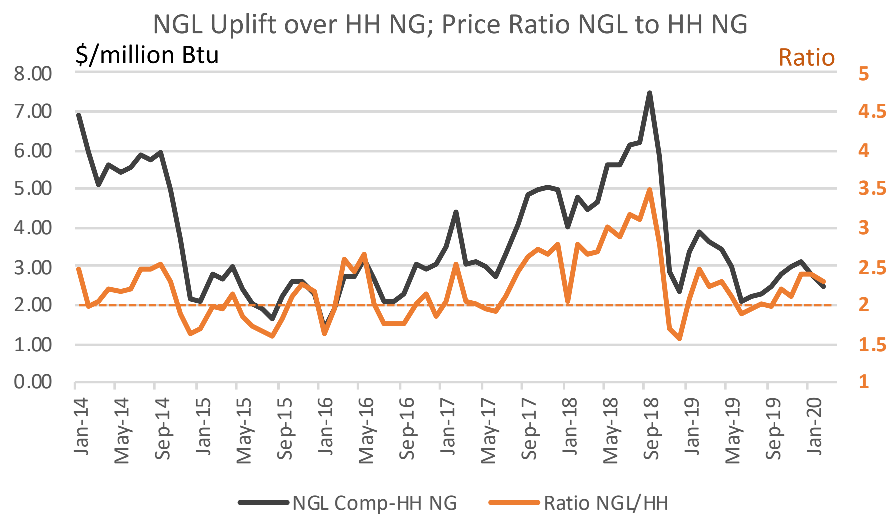
NGL prices tracked oil prices quite closely until after 2009. That was also the year that NGL field production (from NGL processing plants), which had been relatively flat, crept up to 2 million bpd for the first time since 2000 and began an inexorable rise over the next decade. (Production summarized further below.) After the mild winter of 2011-2012, propane and the NGL composite prices began to diverge more sharply from oil and have largely been discounted since then. The exceptional late-2013 crop drying requirements followed by an early cold winter made for the notable propane price spike of 2013-2014.[15] The only time propane prices have actually exceeded oil are last five months of 2017 and April into May 2020, at the time of writing this review. The trade literature did not appear to make much of the 2017 aberration,

[15] In January, 2014, monthly WTI and propane prices were \$16.31 and \$15.25 per million Btu (\$94.62/barrel, \$1.40 per gallon).

but at the present time, spiking ethane and propane prices are getting attention. The concern in 2020 is that the decisive oil price collapse and pullbacks in oil production will drive down Texas/New Mexico associated gas production (Permian, Eagle Ford) as well as NGL-rich associated gas (although produced in smaller volumes) from North Dakota (Bakken). This will be compounded by cuts of generally high-cost Appalachian wet gas production (Marcellus, Utica/Point Pleasant), already suffering from sub-$2.00 prices. NGL price support, then, must come from chemical and other domestic and international users. Useful background on this emerging phenomenon can be obtained from at RBN Energy blog series.[16]

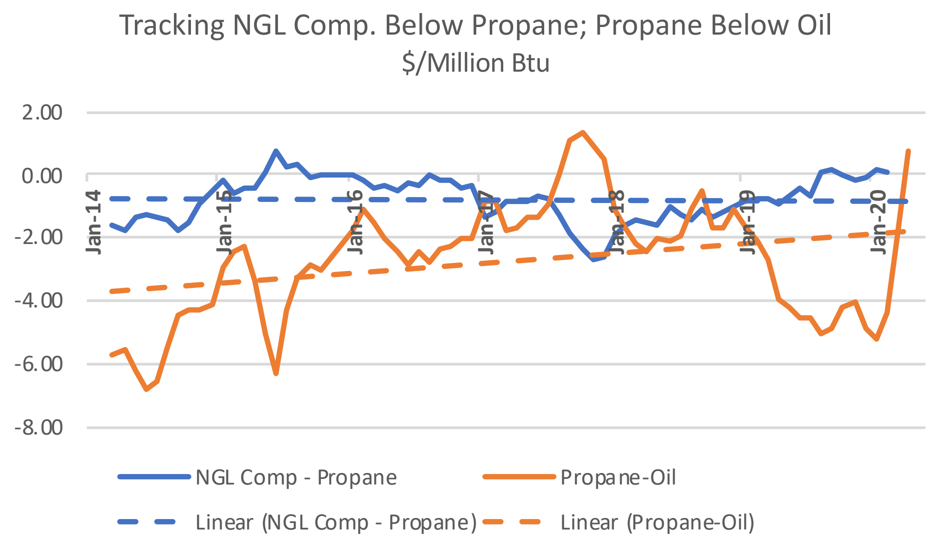
From 2009 to though most of 2014, NGL prices offered a substantial uplift compared to far-lower natural gas prices. More recent price dynamics and periods of very compressed uplift are examined in the next three charts, covering the period since January 2014 when oil prices were still in their heyday. The late 2014 and ensuing oil price collapse, unsurprisingly, drove NGL composite and propane prices into overlapping lows in the $5.00/million Btu range for several years. Propane especially gained ground through 2018. This was a time when NGLs were increasingly eyed as a means to contribute to well profitability. For example, in mid-2016, NGLs offered barely $2.00 per million Btu value above sub-$3.00 natural gas prices. This margin or "uplift" climbed quite steadily to near or above $6.00, peaking near $7.50 over natural gas, between July and October 2018. 2019 started a very different story, with uplift average $2.58 between June 2019 and February 2020. The first chart below gives a blow up of the actual monthly prices. The second chart shows the NGL composite uplift over Henry Hub natural gas prices. Admittedly, in regions with crushing basis differentials, even very modest NGL prices may be helpful to well economics, provided the NGL stream can cover its own extra processing and transportation costs.





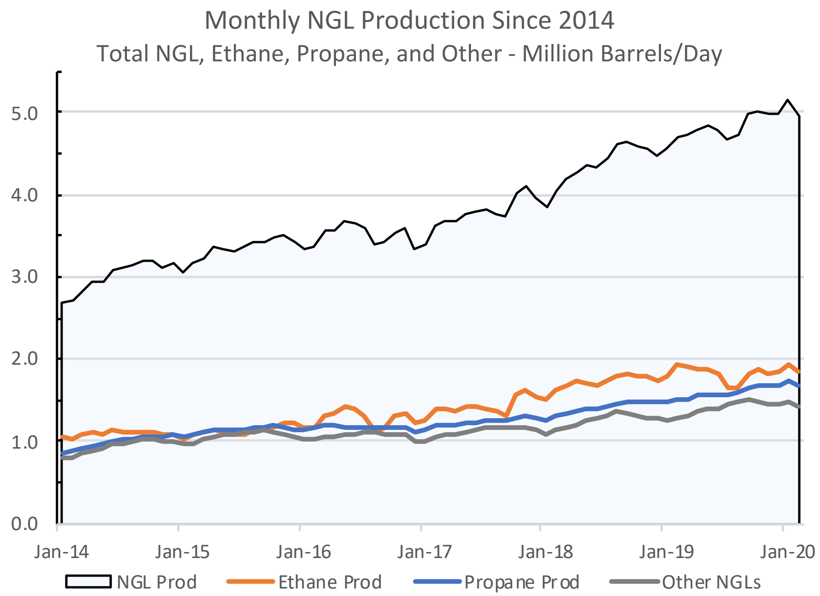
16 "One Thing Leads to Another -0 Big Changes Impacting Ethane and LPG Markets", RBN Energy, April 28, 2020 by Housely Carr and "Can't Get Enough of It – Are We on the Verge of a Propane Supply Shortfall?", RBN Energy, May 11, 2020, by Rusty Braziel.

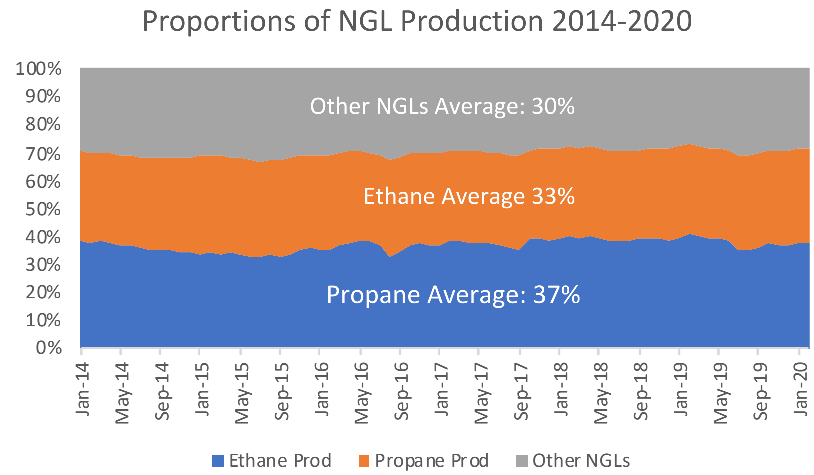
The next chart in this series is somewhat of a technical nature, aimed at whether propane prices could essentially substitute for NGL composite prices, or vice versa. Perhaps surprisingly, the NGL composite averages about 78 cents below propane prices over this period, almost never matching the propane price but also not diverging very much. The variance of propane below (or above) oil prices is more considerable, with the late 2017 (Hurricane Harvey impacts) and current, anomalously high, propane prices standing out.



Turning to production trends, in the five years from 2009 to early 2014, total NGL production gradually grew from 2 million bpd to 3 million bpd. Since early 2014, production expanded much more quickly by 2 million bpd. Fortunately, it appears that much of this recent increase in production was able to be accommodated by the rapid expansion of export facilities – all aimed at the U.S. global price advantage for such products which has both pulled investment into U.S. Gulf-based petrochemical infrastructure as well as allowed U.S. feedstocks to compete against oil-based (i.e. naphtha-based) feedstocks in international facilities. This latter advantage is coming under serious attack during the present collapse of global oil prices.

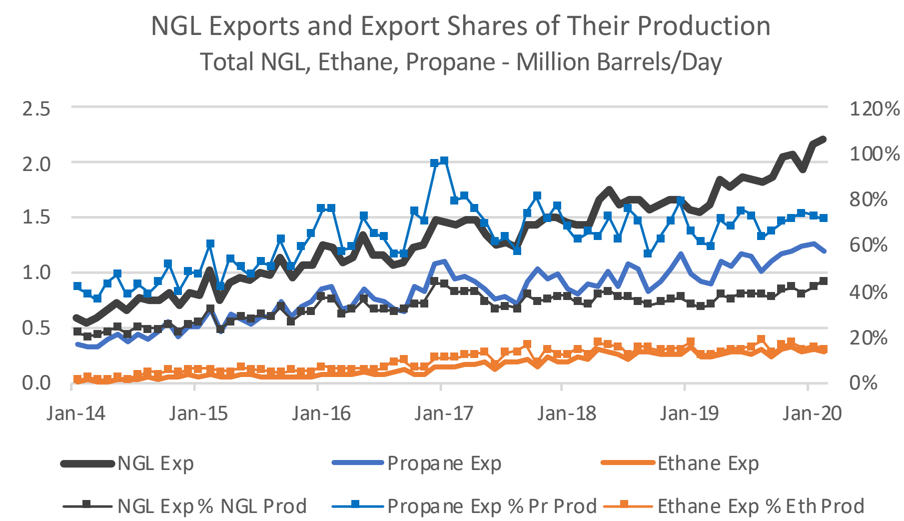
First illustrated (next page): the climb in U.S. field production of NGLs. Volumes of ethane have slightly exceeded those of propane, but the proportions of the two leaders and the rest are roughly equal when grouped in this manner. Just how equal the shares are is shown in the accompanying breakdown.





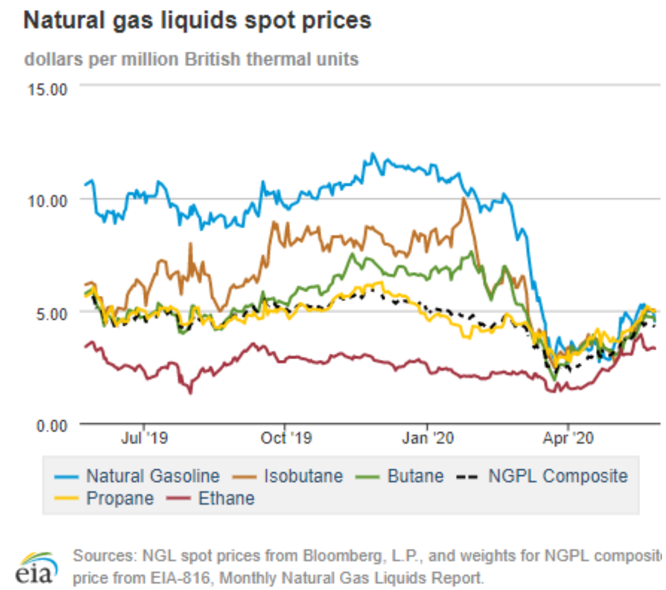
The final chart in the series portrays the growth of exports. Over the period since January 2014, total NGL production grew from 2.7 to 5.0 million bpd (it hit 3.0 million bpd that April) while NGL exports grew from 0.6 to 2.2 million bpd.

Exports are important to very different degrees to the different products. Since mid-2019, 70-75 % of propane production has been exported, while the figure for ethane is 14-19%.



Drilling Down on Ethane and Propane – The Dead Weight of "Rejection" Dampens Excitement even in the COVID Era. The section below is authored by Nathan Schaffer, a decades-long member of Houston's Groppe, Long and Littell consultancy and current Vice President of Petrochemicals, for the Wood Mackenzie energy (oil, gas, coal, renewables) and metals consultancy. Mr. Schaffer was part of the instructional team for AAPG's planned June 2020 workshop and field trip to Enterprise Products Partners Mont Belvieu NGL fractionation, storage and transshipment facility, only about 35 miles east of downtown Houston. An Associate of the Energy Economics and Technology committee (AAPG Energy Minerals division), he offers insights into propane and ethane market trends, the motivations and *status quo* of ethane "rejection", and the likelihood that a meaningful boost in ethane prices may be more a matter of the past few (April-May 2020) turbulent months than a market driver which producers can go to the bank on, looking ahead.

We preface Mr. Schaffer's contribution with a picture of budding excitement over an upturn in NGL prices presented in EIA's May 2020 *Natural Gas Weekly Update*.

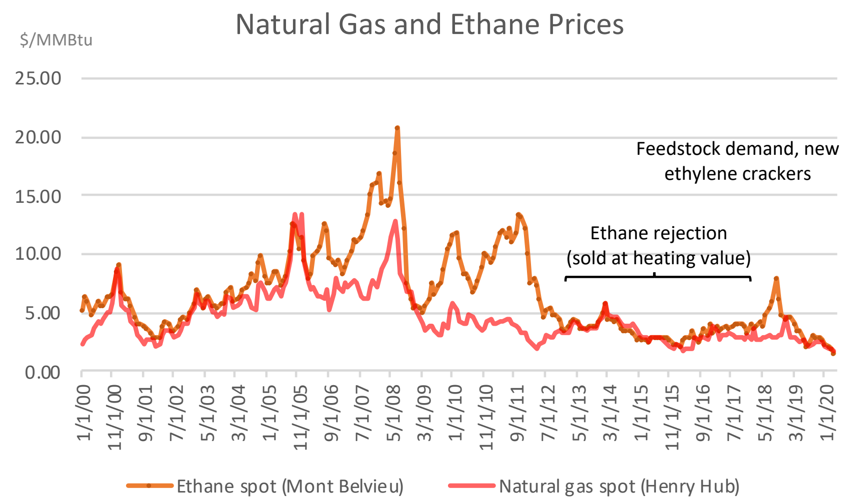


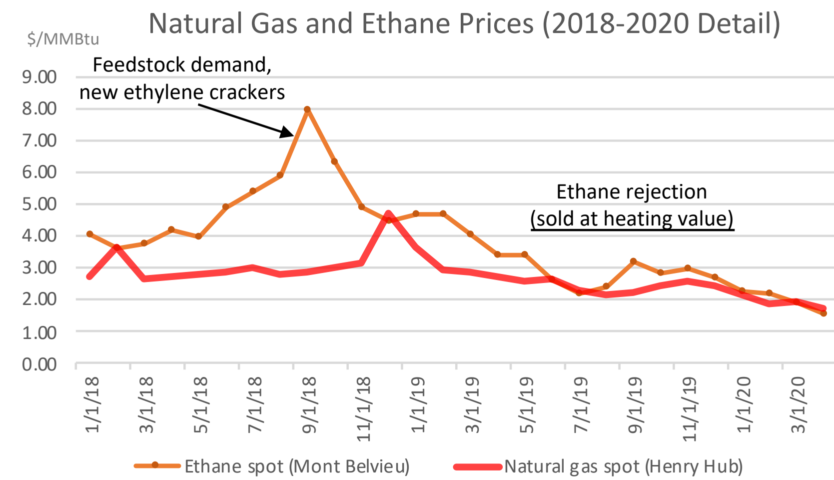
Source: EIA *Natural Gas Weekly Update* for week ending May 27, released May 28,2020. EIA notes these are spot prices set at Mont Belvieu, Texas, obtained from Bloomberg, with monthly volumes based on EIA's Form 816. EIA further notes that "natural gasoline" is a trader's term for "pentanes plus", i.e. mainly pentanes and hexanes.

U.S. Ethane and Propane – Upside Limited by Fundamental Factors
Prepared by Nathan Schaffer, *Wood Mackenzie*, May 24, 2020.

Ethane. It is worthwhile to expand on some of the NGL market factors described earlier especially as these fundamentals will partly steer future market developments. Production of ethane is one area with some complex, or at least not-so-obvious, attributes to unpack. Reported production from EIA in early 2020 was roughly 1.9 million bpd, however this essentially represents only the portion of ethane actually recovered at gas processing plants. Overall U.S. natural gas as produced at the wellhead, from gas wells and associated production from oil wells, has significantly more ethane although much of it is never recovered. Instead a portion of the ethane is "rejected", i.e. is left in the natural gas stream (which is comprised mostly of methane), depending on processing economics and limited only by pipeline dew point specifications.

The charts below compare ethane and natural gas prices over the last 20+ years on a $ per million Btu basis. The price uplift collapsed in 2012 amid the surge in U.S. production of shale gas and later tight oil. Since then large portions of ethane have been rejected with no financial incentive to recover. Most estimates put the level of ethane rejection at nearly 1 million bpd as 2019 ended (versus 1.9 million bpd recovered).

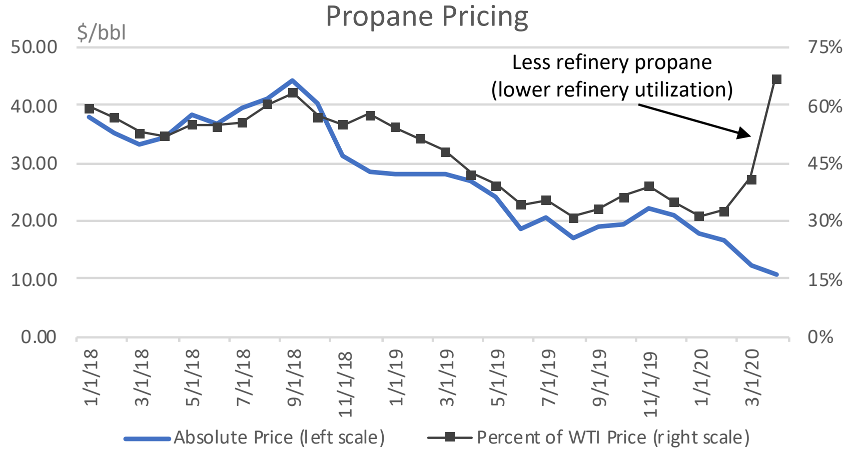




The recent collapse in oil prices and lingering low natural gas prices – resulting in severe pressure on E&P companies – have raised the question of whether ethane prices could rise as a result of slowing upstream activity. That is unlikely to happen given the sizeable cushion created by ethane rejection. Put another way, slowing upstream activity will likely reduce but not eliminate ethane rejection, i.e. leaves a smaller cushion but still a cushion rather than a tightening of ethane supply. To be clear, ethane prices could increase with an increase in natural gas prices as the established "floor", but any sizeable widening of the uplift seems unlikely at this stage.

Ethane consumption is unlikely to tighten the market balance either. Nearly all ethane is consumed as feedstock for the production of ethylene – a basic chemical building block for plastic polymers like polyethylene, PVC, polystyrene and polyester all of which we encounter on a daily basis. The decline in ethane prices, from a peak of over $20 per million Btu (138 cents per gallon) in July 2008 to below $4 per million Btu by the end of 2012, spurred a wave of new investment in ethylene producing capacity all of which uses "cheap" ethane as feedstock. Since 2012 US ethylene capacity has increased by more than 35 percent. Most of the new capacity was installed along the US Gulf Coast but ethane exports have also increased to supply ethylene crackers overseas. As the feedstock demand for ethane rapidly increased, the price uplift for ethane widened with an interim peak in September 2018. However, U.S. natural gas production – and along with it available ethane supply – continued to outpace feedstock demand, again collapsing the spread. "Cheap" ethane remains available but U.S. ethylene producers face increased pressure from overseas competitors that use naphtha for feedstock. The sharp decline in oil prices has also made naphtha a "cheap" feedstock. Further, all ethylene producers worldwide are currently facing the challenge of lower demand for their end products as a result of the pandemic response and fallout.

Propane. The pandemic response is also a factor in recent developments around propane. Like ethane, propane is recovered at gas processing plants but it is also a product of oil refining with 15-20 percent of U.S. production from the latter. Travel restrictions and stay-at-home orders to reduce the spread of coronavirus have resulted in large reductions in demand for transportation fuels, e.g. jet fuel, gasoline and diesel, as documented earlier. Refineries in turn have reduced overall utilization rates – and reduced propane supply as a side effect.



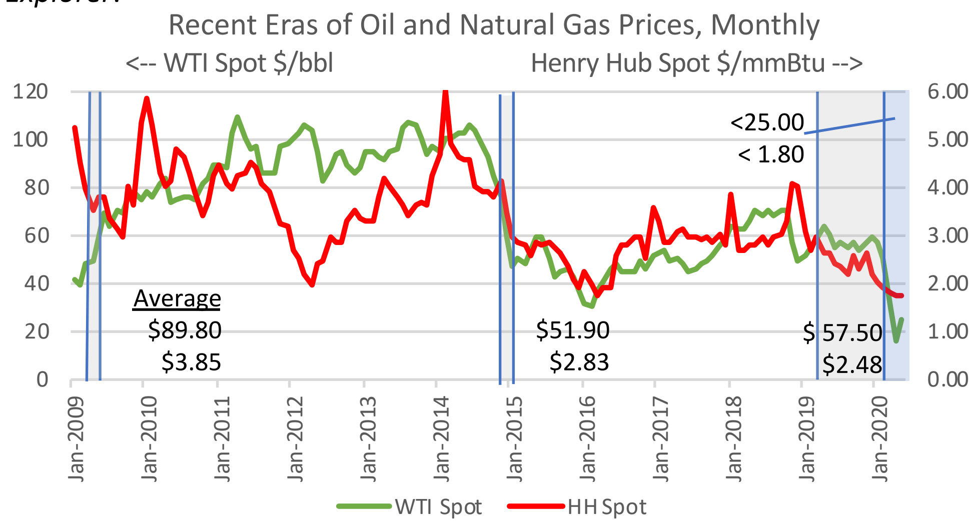
The chart above shows absolute prices for propane in $ per barrel since the start of 2018 along with the price of propane relative to the price of WTI crude. Absolute prices have declined but much less so than the price of crude. As a result, the relative price has strengthened from around 30 percent in the second half of 2019 to nearly 70 percent in April 2020. The future trajectory hinges on refinery utilization and hence timing of a recovery in transport fuel demand. As that happens, relative propane prices will likely turn lower; however, we could see support from waning supply from gas processing plants – the 80-85 percent portion facing a slowdown in E&P activity. [17]

Natural Gas Prices in the Doldrums

Price Eras After the 2008-2009 Financial Collapse. The current financial predicament of the oil and gas industry has roots that go back to natural gas' initial, dramatic collapse to sub-$4.00/million Btu prices in March 2009. The global commodities supercycle had crested the year before and the Great Recession was in full swing. Natural gas prices had never sunk so low (on a monthly basis) since October 2002 – a 7 ½ year period when natural gas averaged an extraordinary $6.92/million Btu. Shale had hardly revealed its potential in actual terms, although seminal (yet incredible-sounding) forecasts had been issued by Navigant and Deutsche Bank in 2008. 2008 brought the first major climb in shale gas production, bringing its total to 9.3 9.3 Bcf/d, yet total supply had only crept up to an average of 55.1 Bcf/d. This is how the stage was set before we look at what happened from then to the present.

[17] *Editor's Note:* Evidence of such firming, at least in the short run, is the further upward turn in absolute propane prices by mid-May 2020 to January levels, e.g. above 40 cents/gallon (e.g. 45 cents, $19/barrel, $4.90/mmBtu).

There are two basic periods that demarcate the 2009 to 2019/20 period. We block these out in the chart below, presenting current year or nominal prices. The Appendix illustrates inflation-adjusted prices in the brief article “How Bad Is It?”, which appeared in AAPG’s May 2020 *Explorer*.



This first period ends November 2014, the last month that natural gas prices averaged above-$4.00 (and when oil prices were in the middle of their rapid 2014-2015 descent to levels comparable to those at the start of this period). Natural gas experienced several winter spikes, which is par for the course, and a major movement in the opposite direction, also related to weather, the mild winter of 2011-2012. The distinguishing characteristic of this period is the fact that, whatever was happening with natural gas prices, oil prices were always very robust.

The second period blocked out on the chart falls into two parts, “bad” and “worse-than-bad”, running up to the March 2020 Saudi-Russia “skid” and unfathomable pandemic problems described at the outset of this review. The first part is the period from January 2015 through January 2019. From a natural gas perspective, it began with prices hitting and descending below $3.00 for a prolonged period and ended when prices last held above $3.00. The oil price collapse was the main event, sending shock waves through the industry and the oilfield services sector.[18] By 2018, oil’s fortunes had improved substantially, both from efficiency gains and price levels near or above $70 per barrel from May to October. Like the prior period, natural gas swerved with mild and severe winters. Nevertheless, average oil prices were almost $30 per barrel lower and natural gas prices a full dollar lower (i.e. $2.83 vs. $3.85) than the preceding period.

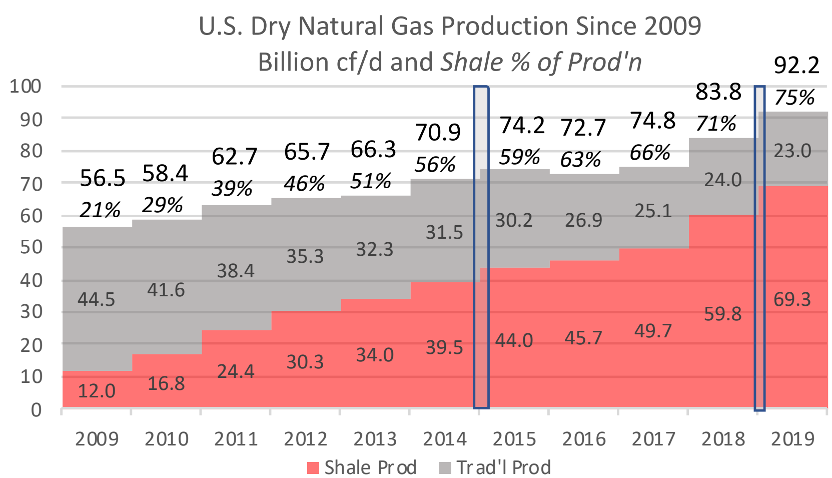
The second or “worse-than-bad” part, particularly from a natural gas perspective, essentially coincides with the single year of 2019 with natural gas averaging only $2.69 in February and dropping to $2.02 through January 2020. First, sub-$4.00 was the major demarcation. Then,

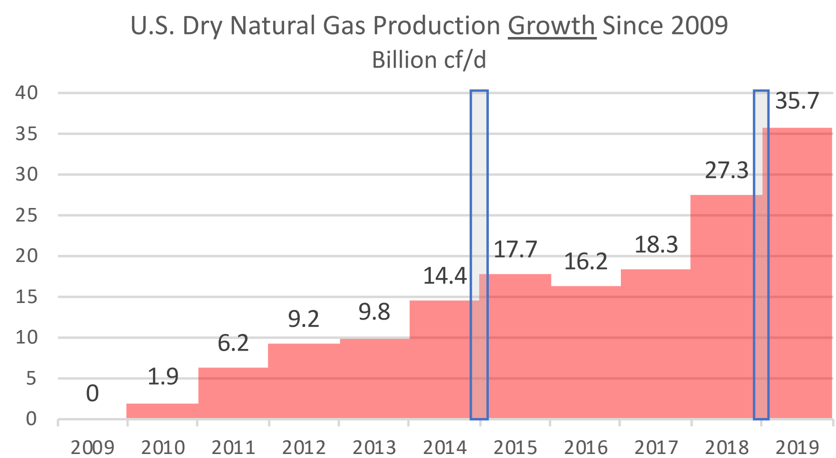
[18] Reflecting on the 2014-2015 price collapse, the 2015 Committee report observed it was principally an inevitable response to the global effects of the rapid rise of U.S. tight oil and oil products production combined with reduced U.S. oil and products imports. Those realities were then aggravated, in a move similar to that seen in March 2020, by Saudi Arabia’s November 2014 to maintain production and counter U.S. shale.

sub-$3.00. While 2019 oil prices maintained near $60, natural gas moved steadily downward. The pain is magnified when we consider most regional pricing hubs face a negative adjustment off these already-low prices. And all this does not even represent the low point when we realize oil prices in the $15-35 range and natural gas sub-$2.00 were still to come.

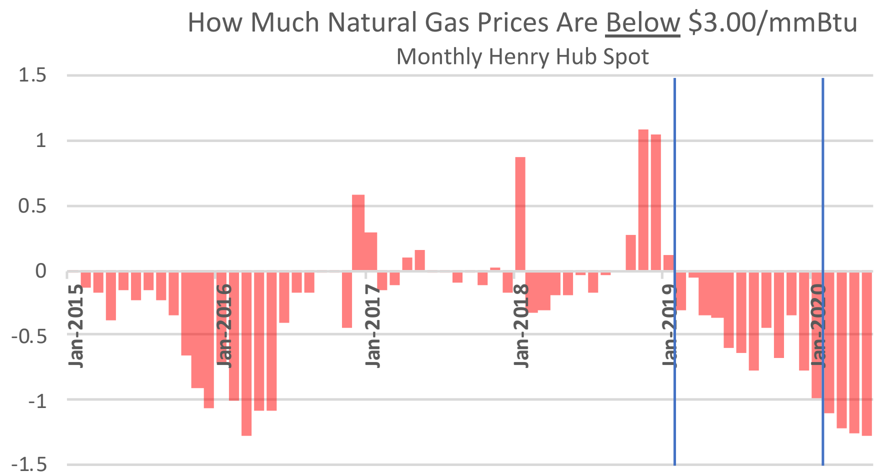
Production Defying Gravity. The accompanying charts plot natural gas production and, more visibly, growth in production over these different post-Financial Crisis periods. Notably, production continued to grow with the single exception of 2016, by which time record low sub-$40 oil and sub-$2.00 natural gas exerted an influence. Growth in 2015, the first year of the price collapse, was somewhat protected by price hedging. The degree to which shale gas not only added to total production but also cannibalized traditional sources over the entire period is evident. Within this ten year stretch since 2009, shale gas' share of production rose from 21% to 75% and total production grew 63% or 35.7 billion cf/d.

The continued growth, even acceleration, of production is explained principally by relatively hefty oil prices allowing associated natural gas to continue to be produced, even if at a loss. This actually occurred in stunning fashion during 2019 (e.g. the Permian Basin Waha hub).





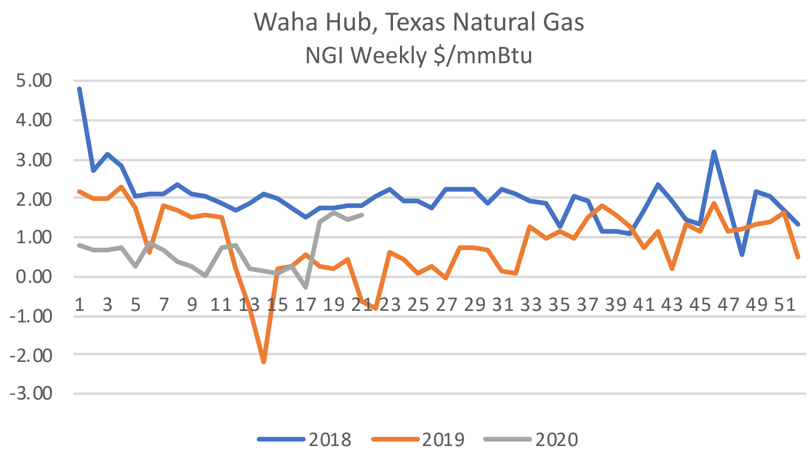
But before examining regional prices, the next chart gives a graphic illustration of how much below the $3.00 level prices have been in the second "price era", i.e. from 2015 to the present. While it is a play-specific and property-specific matter, $3.00 can be viewed as a water level index, below which regional prices are stressed and many gas-specific producers would be "underwater" or not achieving intended revenue targets.



Defying Gravity Finally Coming to an End. While the pullback in production appears to be only just beginning at a macro level or for the entire Permian Basin, a closer look shows regional pullbacks across shales which were less protected by oil prices. The table indicates each shale's individual peak, most toward the end of 2019 and some in much longer-term decline. We see that U.S. total shale production peaked in November 2019 and declined by 1.7 billion cf/d as of April 2020. However, measuring each play's decline against its own peak (or its January 2019 output in cases where declines have been going on for years), the shale plays as a group have cut back nearly double the nominal amount, or 3.3 billion cf/d.

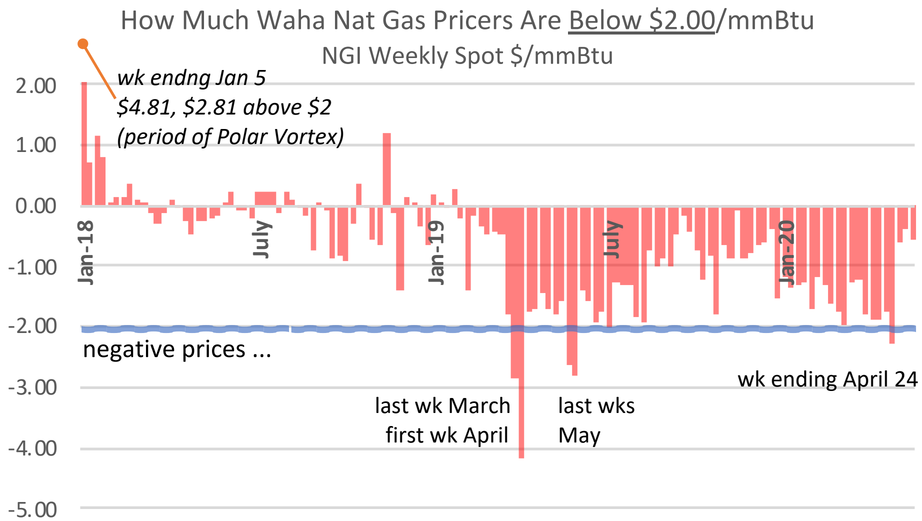
EIA Shale Play Categorization	Peak Production	Month	April 2020 Production	Decline Since Peak	Comment
Shale Plays Total	**72.990**	**Nov-19**	**71.280**	**-1.710**	
Marcellus (PA, WV, OH & NY)	23.895	Nov-19	23.137	-0.758	
Permian (TX & NM)	11.266	Feb-20	11.124	-0.142	
Utica (OH, PA & WV)	7.840	Sep-19	7.172	-0.668	
Haynesville (LA & TX)	9.698	Dec-19	9.546	-0.152	
Eagle Ford (TX)	4.522	Dec-19	4.372	-0.15	
Barnett (TX)	2.453	Jan-19	2.126	-0.327	In decline since 2011
Woodford (OK)	3.146	Oct-19	2.799	-0.347	
Bakken (ND & MT)	2.095	Nov-19	2.002	-0.093	
Niobrara-Codell (CO & WY)	2.875	Dec-19	2.728	-0.147	
Mississippian (OK)	2.926	Oct-19	2.603	-0.323	
Fayetteville (AR)	1.323	Jan-19	1.139	-0.184	In declne since 2012-
Rest of US 'shale'	2.562	Sep-19	2.527	-0.035	
Decline since individual peak or Jan. 2019				**-3.326**	

Regionality of Natural Gas Prices: Even $2.00 Might Look Good? The Henry Hub, shown above, only fell below $2.00 (on a monthly basis) over a period of a 6 months at the end of 2015 to May 2016 and, now, ever since December 2019. Prices on a weekly basis provided by Natural Gas Intelligence allow us to review other regions experiencing the lowest prices. We recall that $3.00 never used to look very good and $2.00 never looks good, yet several regions have experienced such prices for quite a long time. The most *extreme* low-price events (actually negative natural gas prices) have been in the West Texas Permian Basin (Waha Hub), chasing additions of pipeline infrastructure as recently as April of this year (2020). The *longest-running* sub-par prices in recent time have impacted Marcellus/Utica production. The stress within the Permian is shown in the next chart along with summary statistics: $1.98 2018 average dropping to only $0.86 in 2019, and lower still the first months of 2020.



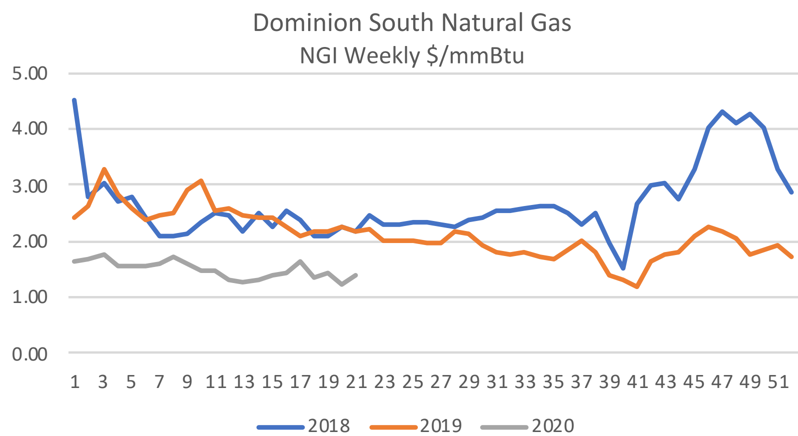
	To Wk 21	Full Yr
2018	2.20	1.98
2019	0.83	0.86
2020	0.63	

In a manner similar to the earlier chart on how much the Henry Hub has fallen below $3.00/million Btu, the next shows the Permian measured against only $2.00. Obviously, these are not sustainable prices in today's low oil-price world, the opposite of what prevailed when the Permian moved into negative territory just a year earlier in 2019. Negative price events are set off by the "water line".

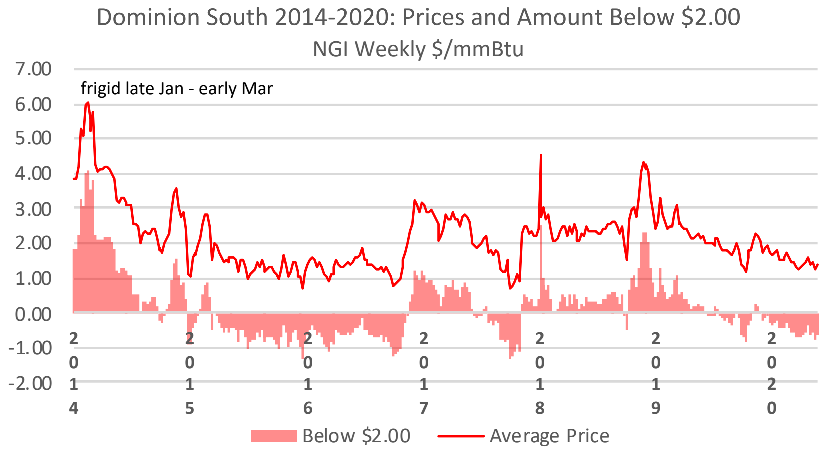


The stress on Marcellus/Utica production is evident in the next chart, with overlapping years comparable to the topmost chart on the Permian. Dominion South is in southwestern Pennsylvania near both Ohio (Utica) and northern West Virginia. The price slide below $2.00 is well underway by mid-2019, well above Permian prices but lacking as much support from condensate and other liquids.

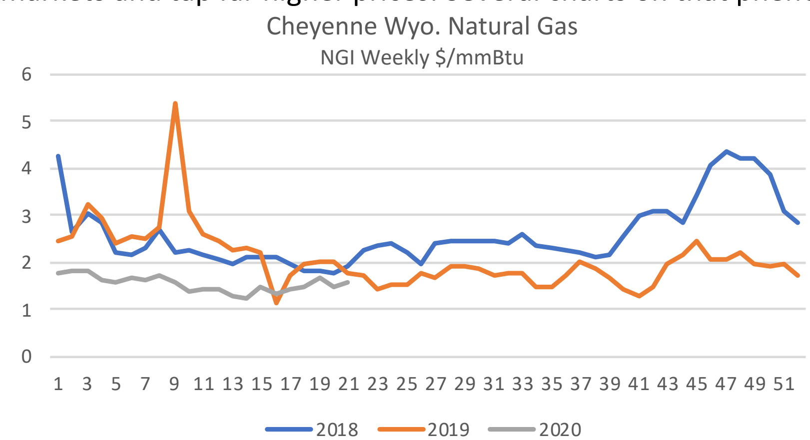
The fact that underpricing of the Marcellus has been long-lasting is illustrated in the second chart. Prices have been below $3.00/mmBtu almost the entire time since the cold winter of 2013-2014, at or below $2.00 20 weeks in 2017 and almost continuously since June 2017. This is no small thing, what with Marcellus/Utica representing 42.5% of U.S. shale production (71.3 Bcf/d, above table) or 2.7 times the output of the Permian.



	To Wk 21	Full Yr.
2018	2.49	2.67
2019	2.51	2.12
2020	1.71	



A third producing area with quite a long history of infrastructure-driven underpricing is the Rockies. The Cheyenne Hub, a bit closer to the DJ Basin than Opal, is roughly comparable in trading volumes to the Opal Hub and exhibited prices on average $0.22/mmBtu cheaper since January 2018. It is a reference point for Niobrara production. Its price chart, surprisingly, is somewhat similar to that for the Marcellus. The Opal Hub, on the other hand, has a storied history going back to the initial motivations during the 2000-2010 decade to reach eastern markets and tap far higher prices. Several charts on that phenomenon are provided in the Appendix.



	To Wk 21	Full Year
2018	2.31	2.60
2019	2.49	2.08
2020	1.56	

These three regions stand out among the low-price "leaders" and they give a deeper appreciation of price depression at a regional level. Other regions tend to track the Henry Hub much more closely, with the exception of California and New England prices which have particular constraints. The major Haynesville play sees prices averaging about $0.15 lower, whether they be in northern Louisiana, east Texas or along routes to Missouri. The Eagle Ford may see price differences from the Henry about half that much across south Texas generally and essentially matching the Henry Hub (again on a longer-term average accounting) at the Katy Hub just west of Houston. As we've mentioned, when Henry Hub prices themselves have cratered, the benefits of closing the basis gap become more or less moot.

Wellhead Economics: Permian and Haynesville Best Wells in Worst of Times

In this section we expand on how the broader changes in supply-demand imbalances and regional circumstances affect decisions at the wellhead. This perspective is that of *lease operations*, a type of assessment that is the bread and butter of project valuation. By tradition, it leaves some things out, such as land costs or an allocation of a company's G&A to a specific well. But the pressures illustrated in these examples definitely roll up into companies' overall performance, which we address in the final section.

The examples provided here were prepared by Michael Link, Director of Engineering at Dallas' Haas Engineering. Firms such as this make assessments for a variety of reasons, including estimating well value to support borrowing decisions and the valuation of reserves. He is a petroleum engineer with industry experience for Devon Energy, DTE Gas & Oil/Atlas Energy, and Atlas Energy/Chevron Michigan LLC (E. Texas to the Northeast and elsewhere). He's a participant on the Potential Gas Committee which has estimated U.S. natural gas resources for about 40 years (esp. important during the decades of lean years, pre-shale, when it might have been easy to dismiss the role that natural gas could play in the energy economy); and he's an Associate with the Energy Economics and Technology Committee (AAPG Energy Minerals Div.).

Impact of Changing Prices – Regional Examples
Prepared by Michael Link, *Haas Engineering*, June 12, 2020

As previously discussed, natural gas basis differentials can vary widely by delivery point. It should also be understood that these differentials have inherent volatility of their own, which can have a significant impact on economic returns. Examples from various basins can help us understand what has transpired, and perhaps, some of what may lie ahead. The examples are taken from the Permian Basin in West Texas and the Haynesville Play in East Texas/N. Louisiana. Profitability can be compared by measures such as internal rates of return, i.e., the wells' IRRs.

***Permian Basin - Western Delaware Basin Example*.** Significant volumes of associated gas have been developed in recent years in the Permian Basin. As the first example illustrates, even in the gassiest portions where recent development has taken place, oil production is the majority of the revenue. With recent decreases in oil prices, gas and NGL's comprise an increasing share of revenue.
The first panel defines and illustrates the chief well performance specifications, categories of costs (both fixed and variable), product yields (e.g. NGL composite barrels), prices and their basis differentials from the reference hubs. The analytical platform allows the assessor to examine any number of sensitivities.

Input	Value	Notes
Ownership		
Working Interest	100%	
Net Revenue Interest	75%	Implies a 25% Royalty. This is common in Texas.
Lateral Length	7,500'	
Production Profile		
Initial Production - Gas	220,000 MCF/Mo.	
Initial Production - Oil	25,000 BO/MO	
Estimated Ultimate Recovery - Gas	6.6 BCF	
Estimated Ultimate Recovery - Oil	460,000 BO	
Estimated Ultimate Recovery		
Gas Shrinkage	35%	Volumetric reduction of gas due to gas processing, fuel, line loss, etc.
NGL Yield	100 BBL/MMCF	
Investment	$8,250,000	Includes costs for Drilling, Completion, Facilities for 1 well. Does not include acreage costs.
Operating Expenses		
Fixed Expense ($/MO)	Declining LOE: $25k/Mo to $5k/Mo over 4 years	Declining Lease Operating Expenses (LOE); fixed expense model.
Variable Expens ($/BO)	$3.00/BO	Variable expense model
Reference Prices		
Natural Gas Price	$2.00/MCF	Reference price from Henry Hub
Oil Price (West Texas Intermediate)	$40.00/BO	Reference price from Cushing, OK
Price Adjustments		
Natural Gas - Basis Differential	-$0.50/MCF	Typical Basin Level Basis Differential for Delaware Basin
Natural Gas - Transportation, Treating, Marketing	-$0.35/MCF	Typical transportation costs for the Delaware Basin
Total Natrual Gas Price Adjustment	***-$0.85/MCF***	
Oil - Transportation	-$3.00/BO	Typical transportation costs for the Delaware Basin

The first set of inputs results in a 23%+ Internal Rate of Return (the first full page panel below) – even at a relatively low and flat received WTI price (adjusted for transportation) of $37/barrel. This core well may be a viable development opportunity for many operators. However, short term volatility, as we have seen in the WAHA oil price and NGL differentials, can have a significant impact on project economics.

The second full page panel is a price sensitivity case for the same well. Natural gas basis differential prices are increased from normal expectations, -$0.50/MCF, to -$1.50/MCF and NGL differentials are increased from 30% of WTI (representing the combined value of all the NGLs produced) to only 20% of WTI for the first 18 months of this wells producing life. Oil prices are kept unchanged. As illustrated by the calculation of discounted cash flow, the 16%+ Before-Tax IRR has decreased by ~ 30%, which makes this project much less attractive and unlikely to be developed under these conditions.

ECONOMIC PROJECTION

NEW

EXAMPLE DEL - WCWEST BLEND 7,500'

Discount Rate : 10.00

As of : 05/01/2020

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	89.83	958.64	67.38	467.34	37.00	1.15	3,030.35	862.78	419.50	253.18	8,250.00	-5,029.56	-5,015.01
2021	74.67	1,004.14	56.00	489.52	37.00	1.15	2,635.00	903.73	464.01	226.80	0.00	2,847.92	-2,452.43
2022	40.95	602.95	30.71	293.94	37.00	1.15	1,474.38	542.65	302.85	128.51	0.00	1,585.68	-1,157.92
2023	28.37	432.35	21.28	210.77	37.00	1.15	1,029.71	389.12	235.12	90.19	0.00	1,093.52	-347.67
2024	21.79	338.15	16.34	164.85	37.00	1.15	794.15	304.33	155.36	69.74	0.00	873.39	240.13
2025	17.61	276.50	13.21	134.80	37.00	1.15	643.73	248.85	112.83	56.62	0.00	723.13	682.72
2026	14.81	234.41	11.11	114.27	37.00	1.15	542.49	210.97	104.44	47.77	0.00	601.24	1,017.20
2027	12.78	203.45	9.59	99.18	37.00	1.15	468.82	183.11	98.35	41.32	0.00	512.26	1,276.25
2028	11.27	180.20	8.46	87.85	37.00	1.15	413.87	162.18	93.82	36.50	0.00	445.73	1,481.12
2029	10.03	160.93	7.53	78.45	37.00	1.15	368.65	144.83	90.10	32.53	0.00	390.86	1,644.41
2030	9.06	145.73	6.80	71.04	37.00	1.15	333.13	131.15	87.18	29.41	0.00	347.69	1,776.46
2031	8.26	133.15	6.19	64.91	37.00	1.15	303.86	119.84	84.78	26.83	0.00	312.08	1,884.21
2032	7.61	122.90	5.71	59.91	37.00	1.15	280.06	110.61	82.83	24.74	0.00	283.10	1,973.06
2033	7.02	113.54	5.26	55.35	37.00	1.15	258.40	102.18	81.05	22.83	0.00	256.70	2,046.29
2034	6.53	105.76	4.90	51.56	37.00	1.15	240.45	95.18	79.58	21.25	0.00	234.80	2,107.18
Rem.	80.18	1,301.49	60.14	634.48	37.00	1.15	2,954.73	1,171.34	1,749.33	261.16	0.00	2,115.58	296.77
Total 39.8	**440.79**	**6,314.28**	**330.59**	**3,078.21**	**37.00**	**1.15**	**15,771.76**	**5,682.85**	**4,241.14**	**1,369.37**	**8,250.00**	**7,594.12**	**2,403.95**
Ult.	**440.79**	**6,314.28**											

Major Phase :	Oil		
Initial Rate :	25,000.00	bbl/month	
Abandonment :	110.54	bbl/month	
Initial Decline :	96.000	%/year	b = 1.00
Initial Ratio :	8.800	Mcf/bbl	
Abandon Ratio :	16.233	Mcf/bbl	
Abandon Day :	02/23/2060		

Eco. Indicators

Return on Investment (disc) :	1.296
Return on Investment (undisc) :	1.920
Years to Payout :	3.19
Internal Rate of Return (%) :	23.63

	Initial	1st Rev.	2nd Rev.
Working Interest :	1.00000000	0.00000000	0.00000000
Revenue Interest :	0.75000000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	**5.00% :**	**4,228.65**	**PW**	**20.00% :**	**449.38**
PW	**8.00% :**	**3,023.68**	**PW**	**30.00% :**	**-612.61**
PW	**10.00% :**	**2,403.95**	**PW**	**40.00% :**	**-1,294.04**
PW	**12.00% :**	**1,886.87**	**PW**	**50.00% :**	**-1,772.64**
PW	**15.00% :**	**1,252.10**	**PW**	**60.00% :**	**-2,128.36**

Permian Core Sensitivity Discounted Cash Flow

ECONOMIC PROJECTION

NEW

EXAMPLE DEL - WCWEST BLEND 7,500'

Discount Rate : 10.00

As of : 05/01/2020

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	89.83	958.64	67.38	467.34	37.00	0.15	2,563.01	575.19	419.50	199.26	8,250.00	-5,730.57	-5,690.20
2021	74.67	1,004.14	56.00	489.52	37.00	0.15	2,145.48	602.49	464.01	170.32	0.00	2,113.64	-3,787.94
2022	40.95	602.95	30.71	293.94	37.00	1.65	1,621.35	542.65	302.85	143.20	0.00	1,717.95	-2,385.51
2023	28.37	432.35	21.28	210.77	37.00	1.65	1,135.10	389.12	235.12	100.73	0.00	1,188.37	-1,504.96
2024	21.79	338.15	16.34	164.85	37.00	1.65	876.58	304.33	155.36	77.98	0.00	947.57	-867.21
2025	17.61	276.50	13.21	134.80	37.00	1.65	711.13	248.85	112.83	63.36	0.00	783.79	-387.50
2026	14.81	234.41	11.11	114.27	37.00	1.65	599.63	210.97	104.44	53.49	0.00	652.67	-24.41
2027	12.78	203.45	9.59	99.18	37.00	1.65	518.41	183.11	98.35	46.28	0.00	556.89	257.20
2028	11.27	180.20	8.46	87.85	37.00	1.65	457.79	162.18	93.82	40.89	0.00	485.26	480.24
2029	10.03	160.93	7.53	78.45	37.00	1.65	407.88	144.83	90.10	36.45	0.00	426.16	658.28
2030	9.06	145.73	6.80	71.04	37.00	1.65	368.65	131.15	87.18	32.96	0.00	379.66	802.47
2031	8.26	133.15	6.19	64.91	37.00	1.65	336.31	119.84	84.78	30.08	0.00	341.29	920.30
2032	7.61	122.90	5.71	59.91	37.00	1.65	310.01	110.61	82.83	27.73	0.00	310.06	1,017.61
2033	7.02	113.54	5.26	55.35	37.00	1.65	286.08	102.18	81.05	25.60	0.00	281.61	1,097.95
2034	6.53	105.76	4.90	51.56	37.00	1.65	266.22	95.18	79.58	23.82	0.00	258.00	1,164.86
Rem.	81.75	1,326.87	61.31	646.85	37.00	1.65	3,335.76	1,194.18	1,827.19	298.60	0.00	2,404.16	331.35
Total 41.0	**442.35**	**6,339.66**	**331.76**	**3,090.58**	**37.00**	**1.19**	**15,939.38**	**5,116.86**	**4,319.00**	**1,370.74**	**8,250.00**	**7,116.51**	**1,496.21**
Ult.	**442.35**	**6,339.66**											

Major Phase : Oil
Initial Rate : 25,000.00 bbl/month
Abandonment : 102.48 bbl/month
Initial Decline : 96.000 %/year b = 1.00
Initial Ratio : 8.800 Mcf/bbl
Abandon Ratio : 16.233 Mcf/bbl
Abandon Day : 05/15/2061

Eco. Indicators

Return on Investment (disc) : 1.184
Return on Investment (undisc) : 1.863
Years to Payout : 4.41
Internal Rate of Return (%) : 16.58

	Initial	1st Rev.	2nd Rev.
Working Interest :	1.00000000	0.00000000	0.00000000
Revenue Interest :	0.75000000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	**5.00% :**	**3,441.86**	**PW**	**20.00% :**	**-534.56**
PW	**8.00% :**	**2,152.50**	**PW**	**30.00% :**	**-1,603.51**
PW	**10.00% :**	**1,496.21**	**PW**	**40.00% :**	**-2,270.27**
PW	**12.00% :**	**952.69**	**PW**	**50.00% :**	**-2,726.38**
PW	**15.00% :**	**291.24**	**PW**	**60.00% :**	**-3,056.98**

***Haynesville Example*.** Some basins have lower differentials and generally less variability. One such example is the Haynesville, located in E. Texas & NW Louisiana. Recent improvements in well performance in core areas (De Soto, Caddo, etc. Parishes, Louisiana) of the Haynesville and modest improvements in gas price, as well as lower basis differentials create commercial opportunities in the Haynesville. An example well from its core exhibits the following:

Input		Value	Notes
Ownership			
	Working Interest	100%	
	Net Revenue Interest	80%	Implies a 20% Royalty. This is common in Louisiana.
Lateral Length		7,000'	
Production Profile			
	Initial Production - Gas	625,000 MCF/Mo.	
	Initial Production - Oil	NA	No oil production
	Estimated Ultimate Recovery - Gas	13 BCF	
	Estimated Ultimate Recovery - Oil	NA	No oil production
Estimated Ultimate Recovery			
Gas Shrinkage		NA	No shrinkage
NGL Yield		NA	No NGL Yeild
Investment		$8,500,000	Includes costs for Drilling, Completion, Facilities for 1 well. Does not include acreage costs.
Operating Expenses			
	Fixed Expense ($/MO)	$3k/Mo	
	Variable Expens ($/MCF)	$0.23/MCF	Variable expense model
Reference Prices			
	Natural Gas Price	$2.00/MCF	Reference price from Henry Hub
	Oil Price (West Texas Intermediate)	NA	No oil production
Price Adjustments			
	Natural Gas - Basis Differential	-$0.15/MCF	Typical Basin Level Basis Differential for Haynesville.
	Natural Gas - Transportation, Treating, Marketing	-$0.30/MCF	Typical transportation costs for the Haynesville
	Total Natrual Gas Price Adjustment	***-$0.45/MCF***	***Total***
	Oil - Transportation	-$3.00/BO	Typical transportation costs for the Haynesville.

HENRY HUB GAS PRICE ($/MMBTU)	IRR (%)
$1.75	<0
$2.00	9.5
$2.25	21.9
$2.50	35.5
5 Yr Strip	30.5
NYMEX Strip 5.29.2020 (Avg $2.43/MCF)	

Results from discounted cash flow analysis are shown in the next full-page panel. As the discounted cash flow above illustrates, as well as the adjoining, short summary table of this example under various Henry Hub pricing scenarios (right corner, this page), the Haynesville Core is commercial at average Henry Hub prices over $2.25/MCF.

ECONOMIC PROJECTION

Haynesville Type Curve Economics
HAYNESVILLE EXAMPLE - 7,000'
Discount Rate : 10.00
As of : 05/01/2020

Year	Oil Gross (Mbbl)	Gas Gross (MMcf)	Oil Net (Mbbl)	Gas Net (MMcf)	Oil Price ($/bbl)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Misc. Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF (M$)
2020	0.00	2,953.47	0.00	2,291.89	0.00	1.30	2,979.46	0.00	682.53	224.61	8,500.00	-6,427.68	-6,368.12
2021	0.00	3,195.93	0.00	2,480.04	0.00	1.30	3,224.05	0.00	755.08	243.04	0.00	2,225.92	-4,374.56
2022	0.00	1,712.66	0.00	1,329.03	0.00	1.30	1,727.74	0.00	421.35	130.24	0.00	1,176.14	-3,422.42
2023	0.00	1,067.51	0.00	828.39	0.00	1.30	1,076.90	0.00	276.19	81.18	0.00	719.53	-2,895.57
2024	0.00	730.80	0.00	567.10	0.00	1.30	737.23	0.00	200.43	55.58	0.00	481.22	-2,576.80
2025	0.00	529.19	0.00	410.65	0.00	1.30	533.84	0.00	155.07	40.24	0.00	338.53	-2,373.90
2026	0.00	401.86	0.00	311.84	0.00	1.30	405.39	0.00	126.42	30.56	0.00	248.41	-2,239.15
2027	0.00	315.55	0.00	244.87	0.00	1.30	318.32	0.00	107.00	24.00	0.00	187.33	-2,147.18
2028	0.00	254.98	0.00	197.86	0.00	1.30	257.22	0.00	93.37	19.39	0.00	144.46	-2,083.00
2029	0.00	209.27	0.00	162.40	0.00	1.30	211.11	0.00	83.09	15.91	0.00	112.11	-2,037.91
2030	0.00	175.29	0.00	136.02	0.00	1.30	176.83	0.00	75.44	13.33	0.00	88.06	-2,005.86
2031	0.00	148.96	0.00	115.59	0.00	1.30	150.27	0.00	69.52	11.33	0.00	69.42	-1,982.98
2032	0.00	128.47	0.00	99.69	0.00	1.30	129.60	0.00	64.91	9.77	0.00	54.93	-1,966.60
2033	0.00	111.37	0.00	86.42	0.00	1.30	112.35	0.00	61.06	8.47	0.00	42.82	-1,955.04
2034	0.00	97.72	0.00	75.83	0.00	1.30	98.58	0.00	57.99	7.43	0.00	33.16	-1,946.93
Rem.	0.00	382.86	0.00	297.10	0.00	1.30	386.23	0.00	287.69	29.12	0.00	69.42	13.65
Total 20.3	**0.00**	**12,415.87**	**0.00**	**9,634.71**	**0.00**	**1.30**	**12,525.13**	**0.00**	**3,517.12**	**944.20**	**8,500.00**	**-436.19**	**-1,933.28**
Ult.	**0.00**	**12,415.87**											

Major Phase :	Gas		
Initial Rate :	625,000.00	Mcf/month	
Abandonment :	4,236.69	Mcf/month	
Initial Decline :	67.000	%/year	b = 0.50
Initial Ratio :	0.000	bbl/Mcf	
Abandon Ratio :	0.000	bbl/Mcf	
Abandon Day :	08/08/2040		

Eco. Indicators

Return on Investment (disc) :	0.769
Return on Investment (undisc) :	0.949
Years to Payout :	0.00
Internal Rate of Return (%) :	< 0

	Initial	**1st Rev.**	**2nd Rev.**
Working Interest :	1.00000000	0.00000000	0.00000000
Revenue Interest :	0.80000000	0.00000000	0.00000000
Rev. Date :			

Present Worth Profile (M$)

PW	**8.00% :**	**-1,697.16**	**PW**	**30.00% :**	**-3,416.46**
PW	**9.00% :**	**-1,818.28**	**PW**	**35.00% :**	**-3,640.11**
PW	**15.00% :**	**-2,430.70**	**PW**	**40.00% :**	**-3,829.46**
PW	**20.00% :**	**-2,827.04**	**PW**	**50.00% :**	**-4,129.76**
PW	**25.00% :**	**-3,149.59**	**PW**	**60.00% :**	**-4,352.98**

Furthermore, this opportunity demonstrates IRR's of over 30% at a recent 5-year NYMEX strip price. However, it should also be understood that profitability is vulnerable to sustained declines in price of as little as $0.25-0.50/MMBTU, which have occurred over the past 18 months. Moreover, not all portions of this play may be commercial, but the Core certainly appears to be.

This may also be true for prolific areas of others dry gas plays, such as the Marcellus. Thus, we might expect to see an increase in activity in these areas. Conversely, in areas with significant recent natural gas basis volatility as well as a recent drop in oil prices, we might expect lower level of activity in the gassier portions of such prominent oil plays as the Permian Basin.

Industry Financial Considerations: Troubles Precede the Oil Price War and Pandemic

The industry's current financial stresses have roots that well-predate the oil price war or the pandemic. Insights into this history come real-time tracking by the financial community. The resources drawn upon are principally reporting since 2017 by the Wall Street Journal; reporting by the financial journalist Bethany McClean released in a booklet during the 3rd quarter of 2018; and analysis made available by the large-institutions advisor Sanford Bernstein/Alliance Bernstein (first in September 2018 and updated in July 2019. As we come to the present, insights into changing sources of capital available to the oil and gas industry are drawn from Haynes and Boone, LLC (of oil/gas bankruptcy monitoring fame) surveys of borrowers (producers, oil field services) and lenders (financial institutions, private equity).

Industry Financial Performance/Warning Signs – A Slow Drip, Beginning Late-2017. Reporting over time from the *Wall Street Journal* documents the gradual emergence of financial discipline across oil and gas producers. The industry consistently overproduced, weakening both natural gas and oil prices and revenues, and it required strong levels of capital expenditures to drive production. Executive compensation had long been linked to achieving production targets, such that by September 2017 a large group of investors had essentially reached the breaking point. Through letters delineating their dissatisfactions with financial performance and pressuring company boards to reform compensation, the shift in rhetoric dates to the last 3-4 months of 2017, a time when oil prices were markedly improving. The advantage of seeing these changes through such reporters' eyes is their access to analysts, investor advisory firms, business statistical services, companies' management, and other sources. One of the most informative articles on this period was issued in early December, 2017.

"Wall Street Tells Frackers to Stop Counting Barrels, Start Making Profits – The shale-oil revolution produces lots of oil but not enough upside for investors", by Bradley Olson and Lynn Cook. *WSJ*, released Dec 7, updated Dec 13, 2017.
Backdrop: This article delineates the September meeting of 12 major investors (e.g. "portfolio managers and fund officials holding a total of nearly 5% of shares in 20 large shale companies".) For context, citing Wood Mackenzie, the article notes that 30 companies account for 70% of U.S. shale oil production. The article also draws comments from the meeting moderator; investor presentations from Anadarko Petroleum, Devon Energy Corp., and Apache Corp.; communications with Harold Hamm, then CEO of Continental Resources; and others.

> "As a group, U.S. shale companies have been forecasting they are on the brink of generating free cash flow—taking in more revenue from operations than they spend on new investments—for the first time since 2014, when oil traded at over $100 a barrel. Since then, they have largely repeatedly moved those goal posts back."

An accompanying chart shows free cash flow of traditional oil production ranging near $1 barrel over most of the time from 2010 to 2Q2017 (and near $0 or negative only 6-7 quarters of the 30 total), whereas shale oil was near zero or positive only 5-6 quarters and negative $2 or more 15 quarters, showing modest improvement with the spending contractions forced by the late 2014 oil price collapse.
We will return to the topic and trends in free cash flow in the next segment, as it has shifted from being a watchword to being something of a cudgel. Capital spending on drilling and completions on existing acreage, considered "organic" as it is tied directly to production, must always follow the general trend of revenues, which in turn always follow the general trend of price. A wildcard is additional capital spending, namely that on acquisitions. But weather too is a wildcard. The greatest mismatch of organic capital spending occurred, for example, after the dramatic collapse of natural gas prices caused by the very mild winter of 2011-2012, extending over multiple quarters. Particular opportunities may also impede companies' ability or inclination to adjust capex to changing circumstances. In that regard, this article gives comments from Apache's CEO several months earlier as an example – the company was in the midst of exploiting a major discovery.

Additional warning signals in the article are the observations that many companies leave out land acquisition costs when reporting "break-even" prices and that the U.S. Securities and Exchange Commission's rules for evaluating costs of reserves leave out not only land costs but also those of pipelines, other infrastructure and overhead.
https://www.wsj.com/articles/wall-streets-fracking-frenzy-runs-dry-as-profits-fail-to-materialize-1512577420

"Oil Market Conquers Its Fears Over Shale – Worries producers will flood market ease, lifting crude prices", by Alison Sider and Stephanie Yang. *WSJ*, Jan 15, 2018.
Backdrop: Strong WTI prices, up ~50% to near $65; strong global demand outlook; shrinking OECD oil inventories. These positives could be offset by a surge in shale production, but the reporters found companies might respond with discipline:

> "Investors are also trying to rein shale producers in—pushing the companies to spend within their means and focus on generating free cash flow rather than growing production at any cost. That pressure from investors, coupled with rising costs of equipment and manpower, could keep a lid on shale's growth, some analysts and investors said."

They also reported that producers at a recent Goldman Sachs conference, according to Goldman analysts, had said "they planned to use extra cash to pay down debt and return cash to shareholders".
https://www.wsj.com/articles/oil-market-conquers-its-fears-over-shale-1516021201

"Frackers Could Make More Money Than Ever in 2018, If They Don't Blow It – Oil companies, listening to investors, promise modest drilling as oil prices rise, but skeptics remain", by Bradley Olson. WSJ, Jan 22, 2018.

Backdrop: 2018 began with oil prices moving above $60/barrel. It was the first prolonged improvement since the 2014-2015 collapse (June 2017 average was ~$45). Production growth was poised to set new records above 10 million bpd, in part based on lags (momentum) from prior drilling. With hindsight, we learned the industry set new records in 2018 across the board – a key theme in our 2019 review. Larger companies had announced spending cutbacks, smaller companies had announced slower rates of growth – and all this in an improving price environment. It would truly be news if this were accompanied by actual profits. The article laid out this tension.

> "Production continues to increase because of past and continuing investment, but companies are pulling back on future spending. That puts U.S. oil companies on track in 2018 to generate more cash than they spend, a first in the age of shale.
>
> "…Shale-company executives have been preaching the gospel of moderation since 2014, when oil prices plummeted because of a global glut of crude that fracking helped create. Yet **the companies behind the U.S. oil boom together have spent $265 billion more than they generated from operations since 2010**, according to a Wall Street Journal analysis of FactSet data."

https://www.wsj.com/articles/frackers-could-make-more-money-than-ever-in-2018-if-they-dont-blow-it-1516536000

"**Déjà vu: Oil Investors Could Relive 2014's Swings – It's 'naïve' to think that U.S. oil producers will show discipline this time around, one analyst warns",** by Alison Sider. WSJ, Feb. 2, 2018.

Backdrop: After three years of low oil prices, Citigroup's global head of commodities research, Ed Morse, became one of the skeptics about producer discipline. Quoting Mr. Morse:

> "The animal spirits that drive these companies overshadow any commitment to having discipline," Mr. Morse said. "Only the most naïve of analysts or investors actually believe that's going to happen."

A further point of vulnerability, so evident in the current global oil market saga, was how long OPEC would continue to help prop up prices by displaying discipline:

> "OPEC and other major exporters have been holding oil off the market for more than a year in an effort to reduce a glut and lift prices. Oil's trajectory this year largely depends on how long producers like Saudi Arabia will be willing to sit by and watch U.S. producers take their market share, Mr. Morse said."

https://blogs.wsj.com/moneybeat/2017/04/20/deja-vu-for-oil-traders-amid-concerns-about-tepid-demand/?mod=searchresults&page=1&pos=10

"Oil Is Above $70, but Frackers Still Struggle to Make Money – Most of the top 20 shale-oil producers spent more than they made in the first quarter", by Christopher M. Matthes and Bradley Olson. *WSJ,* May 17, 2018.

Backdrop. Prices continued to climb, hovering around $70 from June through November. This improvement came as quite a surprise, with many companies hedged at lower prices unable to take advantage of the moment. Expected new financial discipline had yet to bear fruit through the first quarter.

> "Of the top 20 U.S. oil companies that focus mostly on fracking, only five managed to generate more cash than they spent in the first quarter, according to a Wall Street Journal analysis of FactSet data.

"…the top 20 companies by market capitalization collectively spent almost $2 billion more in the quarter than they took in from operations, largely due to bad bets hedging crude prices, as well as transportation bottlenecks, labor and material shortages that raised costs."

https://www.wsj.com/articles/oils-at-70-but-frackers-still-struggling-to-make-money-1526549401

"Big Fracking Profits at $50 a Barrel? Don't Bet on It", by Bradley Olson and Rebecca Elliott. *WSJ*, Dec 4, 2018.
Backdrop. Oil price dropped precipitously the last two months of 2018, from $70.75 per barrel (October average) to $49.52 (December). How well the industry could perform after this turnaround was an open question, but the prospects were dim. Looking ahead, 2019 was not terrible for oil, prices averaging $57. Natural gas was a disaster.

"From 2012 to 2017, the 30 biggest shale producers lost more than $50 billion. Last year, when oil prices averaged about $50 a barrel, the group as a whole was barely in the black, with profits of about $1.7 billion, or roughly 1.3% of revenue, according to FactSet.

"…Estimates by consulting firm R.S. Energy Group peg break-evens excluding land costs and overhead at about $37 for the Permian Basin of West Texas and New Mexico, $42 for the Eagle Ford in South Texas and $47 for the Bakken in North Dakota.

"But companies require much higher oil prices in order to come out ahead if more of those necessary expenses are taken into account, the consulting firm's data show. **All-inclusive break-evens are about $51 in the Permian, $57 in the Eagle Ford and $64 in the Bakken**, according to R.S. Energy."

https://www.wsj.com/articles/big-fracking-profits-at-50-a-barrel-dont-bet-on-it-1543919401?mod=article_inline

"Frackers Secret Problem – Oil Wells Aren't Producing as Much as Forecast. Data analysis revels thousands of locations are yielding less than their owners projected to investors; 'illusory picture' of prospects", by Bradley Olson, Rebecca Elliott and Christopher M. Matthews. *WSJ,* Jan. 2, 2019.
Backdrop. 2019 kicked off with a disturbing analysis potentially undermining claims about the net worth of many shale producers. This had little to do with price but rather expected production from future wells, based on actual production falling short of company forecasts made between 2014 and 2017. The analysis was conducted by the *Wall Street Journal* using data from Rystad Energy and others.

"Two-thirds of projections made by the fracking companies between 2014 and 2017 in America's four hottest drilling regions appear to have been overly optimistic, according to the analysis of some 16,000 wells operated by 29 of the biggest producers in oil basins in Texas and North Dakota.

"Collectively, the companies that made projections are on track to pump nearly 10% less oil and gas than they forecast for those areas…."[19]

The article describes mis-hits by individual companies and gives many reasons for disparities. These chiefly revolve around production levels being large or larger, although for some companies and regions the difference was found to be over 50%. Among the reasons, projections of well productivity and decline rates (i.e. "type curves") might be made from fewer than 10 wells, which themselves might be a highgraded sample, although up to 60 is called for on statistical grounds. Life of wells is uncertain, with only the Barnett Shale offering long histories. Such evidence suggests well lives of less than 25 years, with most the production the first 10. 30 years is the benchmark used by Rystad. 50 years is chosen by one of the companies. Complications also arise from changes in schools of thought about how close wells can be spaced

[19] WSJ's -10% figure was revised to -15% in an updated analysis at the end of the year. "As Shale Wells Age, Gap Between Forecasts and Performance Grows", by Rebecca Elliott and Christopher M. Matthews. *WSJ*, Dec. 29, 2019.

together without non-constructive interference (some may actually enhance recovery over acreage).[20] This article also addresses the use of Estimated Ultimate Recovery figures (EURs), pointing out the concept came into vogue during the tight-money days after the 2014 oil price collapse. Companies turned to EURs as a means to unlock value beyond the 5-year period set by SEC asset valuation rules. In addition to these many reasons, the reporters also found that value from natural gas liquids may or may not be included (excluded from *WSJ*'s analysis).

Most of these problems are highly technical and reflect irresolvable uncertainties, sufficiently so that some companies are discontinuing the practice. It is not clear whether they have any immediate effect on valuations. But the article does include a scorecard for the group of 29 companies.

> "Shale companies have attracted huge amounts of capital from Wall Street over the past decade. So far, investors have largely lost money. … The 29 companies in the Journal's analysis have spent $112 billion more in cash than they generated from operations in the last 10 years, according to data from FactSet, a financial-information firm."

This record may stand on its own as a criticism of industry practices. Yet a less critical posture may be justified when considering how successive acquisition of land and pursuit of development played out in region after region, driving a rapid climb in capital requirements in a highly competitive industry, all compressed over a period of little more than ten years.
https://www.wsj.com/articles/frackings-secret-problemoil-wells-arent-producing-as-much-as-forecast-11546450162?mod=article_inline

"Frackers Face Harsh Reality as Wall Street Backs Away", by Bradley Olson and Rebecca Elliott. WSJ, Feb. 23. 2019. Leader: Key lifeline for smaller operators fades, as losses pile up and prospects dim for big investment returns
Backdrop. By February, systematic statistics on 2018 lending to shale producers had become available. Sources of capital were running in the opposite direction of prices. Data in the article offer a complete history of "equity and debt offerings to shale companies" in the shale era. It is unclear how much was public vs. private and the specific companies summarized.

> "Frequent infusions of Wall Street capital have sustained the U.S. shale boom. But that largess is running out. New bond and equity deals have dwindled to the lowest level since 2007. Companies raised about $22 billion from equity and debt financing in 2018, less than half the total in 2016 [$56.8 B] and almost one-third of what they raised in 2012 [$63 B], according to Dealogic.
>
> "…Banks have provided financing when producers spend more cash than they take in from operations, something that has happened every year since 2010."

The article notes that lending terms had been tightened by the U.S. Treasury Department in 2016, specifically in response to the growing wave of bankruptcies in the shale sector. They did this by restricting total debt to a factor of 3.5 times earnings (excluding interest, taxes and other items). In practice, lenders had become even more cautious, preferring to see debt below a factor of 2.5.

Returning to Dealogic's lending trend (next page), debt and equity issuance grew from about $11 billion in 2004 to nearly $40 billion in 2009-2010, essentially flattening those years of recovery from the Great Recession.

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[20] M. Link, Haas Engineering. Personal conversation, week of June 1, 2020.

The equity share remained about $10 billion during the early shale era, from 2007-2012, the year the debt share exploded from $25 B the year before to $52 billion.[21] Debt bounced down and up to a still hefty $39 billion in 2014. The next year, after the oil collapse, even more might have been needed but instead its share began to shrink to $27 billion in 2017 and $20 billion in 2018. Equity issuances made up much of the difference through 2016. From its ~$10 billion level in 2012, equity doubled the next two years, pulling back only slightly the first full year of oil collapse (2015), and exploded nearly 1.5 times the next year to $34 billion. This was the only year equity approached or exceeded 50% of the debt-equity total since 2004.

Distaste for equity issuance came into full force in 2017, the year that attention to free cash flow was emerging. It dropped like a rock from its record peak to $7 billion and then nearly vanishing at only $3 billion in 2018.

Debt and Equity Issuances, Shale Group

	Debt	Equity	Total	Debt % of Total
1995	2.31	3.01	5.32	43%
1996	5.59	4.01	9.60	58%
1997	8.54	1.67	10.21	84%
1998	14.54	5.71	20.25	72%
1999	11.19	3.81	15.00	75%
2000	3.74	4.25	7.99	47%
2001	15.75	1.51	17.26	91%
2002	9.77	1.25	11.02	89%
2003	4.68	3.64	8.32	56%
2004	5.87	5.90	11.77	50%
2005	5.81	7.64	13.45	43%
2006	12.38	5.92	18.30	68%
2007	12.21	8.83	21.04	58%
2008	14.68	11.89	26.57	55%
2009	29.04	9.12	38.16	76%
2010	28.06	11.41	39.47	71%
2011	24.72	9.04	33.76	73%
2012	52.26	10.69	62.95	83%
2013	27.90	14.72	42.62	65%
2014	38.57	19.59	58.16	66%
2015	27.69	17.94	45.63	61%
2016	22.61	34.24	56.85	40%
2017	27.63	7.38	35.01	79%
2018	19.80	3.00	22.80	87%
2009-2018	298.28	137.13	435.41	70%

Source: Dealogic/WSJ "Frackers Face Harsh Reality …"
B. Olson and R. Elliott. Feb 23, 2019

"Shale Companies, Adding Ever More Wells, Threaten Future of U.S. Oil Boom", by Christopher M. Matthews, Rebecca Elliott and Bradley Olson. *WSJ*, March 3, 2019.
Leader:
"Newer wells drilled close to older wells are generally pumping less oil and gas and could hurt output leading frackers to cut back on the number of sites planned and trim overall production forecasts"
Backdrop. This second, early 2019 bombshell from the same group of *WSJ* reporters also involved a highly technical facet of shale, namely the question mentioned previously about well-spacing. The reporters conclude that well-spacing was and is no small thing, but rather a key factor that buoyed expectations with the promise of getting something almost for nothing. Importantly, though, like the uncertainties around forecasting production, the questions have no one answer and companies are pushing the envelope and backing off. Well-spacing is also no small thing simply because of scale:

> "The number of child wells in the Permian now makes up 50% of all wells there and will grow steadily, according to Schlumberger Ltd., the world's largest oil field services company. In other basins there are already more child wells than parent wells, Schlumberger estimates."

Much was learned in 2018 about "parent-child" wells, documented in the article. The problems were one of the reasons behind *WSJ*'s group of 29 companies' reduced well performance. Production growth from the Permian Basin might have to be trimmed 1.5 million bpd, according to a study by Wood Mackenzie. Studies issued by the Society of Petroleum Engineers estimated a 70-80% chance child wells would produce

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[21] Dealogic's data in the article also provide support to the notion that the industry's growth was greatly enabled by cheap debt. Shale companies' debt doubled between 2008, $14.7 billion, and 2009, $29 billion, when interest rates plummeted to combat the Financial Crisis/Great Recession.

less (per foot) and, in the Permian, as much as 15-50% less – not to mention impacting parent well output, estimated by Rystad to be 10-12% less from child interference.

Whether foreknowledge would have changed historical investment is hard to say. Nevertheless, the reporters concluded that:

"…rosy forecasts [of the benefits of 'bunching wells in close proximity'] helped fuel investor interest in shale companies, which raised nearly $57 billion from equity and debt financing in 2016, according to Dealogic, even as oil prices dipped below $30 a barrel. That was up from nearly $34 billion five years earlier, when oil topped $110 a barrel."

https://www.wsj.com/articles/shale-companies-adding-ever-more-wells-threaten-future-of-u-s-oil-boom-11551655588

"Banks Get Tough on Shale Loans as Fracking Forecasts Flop – Oil and gas companies face tightened credit after wells produce less than projected", by Christopher M. Matthews, Bradley Olson and Allison Prang. WSJ, Dec. 23, 2019

Backdrop. 2019 saw basically flat oil prices (near $60/barrel) and a steady, deep decline in natural gas prices except where prices were already below $2/mmBtu, e.g. the west Texas Waha hub, reviewed above. This alone would be a disincentive to lending, whereas over prior years debt from all sources, and especially banks, had been a reliable source of capital. Producers and lenders alike were losing their taste for issuing equity (most especially private equity, unless lending became part of a different sort of arrangement involving shared risk, i.e., joint ventures). And with the bell ringing since 2017, the role of cash flow from operations was getting even larger.

The exemplar of low-price-driven shrinking asset base, referred to in the article, was the announcement by Chevron:

"The tightening financial pressure on shale producers is one of the reasons many are facing a reckoning going into next year. Chevron Corp. said Dec. 10 that it plans to take a charge of $10 billion to $11 billion[22], roughly half of it tied to shale gas assets, which it said won't be profitable soon."

Citing "people familiar with the matter", the lending situation was found to be darkening – not exactly falling off a cliff but certainly belt-tightening:

"Banks have begun to tighten requirements on revolving lines of credit, an essential lifeline for smaller companies, as these institutions revise estimates on the value of some shale reserves held as collateral for loans….

"Some large financial institutions … are likely to decrease the size of current and future loans to shale companies linked to reserves as a result of their semiannual reviews of the loans.

[22] "Chevron, Facing Fossil Fuels Glut, Takes $10 Billion Charge – Oil giant cuts the value of its holdings, including shale, citing low prices caused by oversupply", by Christopher M. Matthews and Rebecca Elliott. *WSJ*, Dec. 10, 2019.Between 2010 and 2011, Chevron obtained a ~$6 billion stake in Appalachian gas when prices were over $4.00/mmBtu. The company was choosing not so much as to abandon shale but to concentrate on its assets in the Permian Basin. An offshore Gulf project and its share of the planned Kitimat LNG export project were part of the write-down. As for the Permian, both Chevron and Exxon had announced in March, 2019 their intentions to reach production of 900,000 and 1 million "barrels of oil and gas a day" (natural gas and liquids breakdown unclear), a major expansion. "Chevron, Exxon Mobil Tighten Their Grip on Fracking – Chevron to double production in Permian Basin in next five years; Exxon to boost Permian output to one million barrels a day by as early as 2014", by Bradly Olson. WSJ, March 5, 2019.

> "…Banks have extended billions of dollars of reserve-backed loans, though the exact size of the market isn't known. JPMorgan said in a regulatory filing in September that it has exposure to $44 billion in oil and gas loans….
>
> "…Banks have typically lent as much as 60% of [the value of reserves]. But **some are now discounting the value by as much as 20%**."

https://www.wsj.com/articles/banks-get-tough-on-shale-loans-as-fracking-forecasts-founder-11577010600

"U.S. Shale Companies Are Turning the Oil Tap Back On", by Rebecca Elliott. WSJ, June 7, 2020.
Backdrop. Almost two months after the April WTI price plunge, the outlook hinged on what the reporters recognized as the "remarkable recovery" of oil prices to near $40/barrel, measures to bring back least-cost production (existing wells), continuation of OPEC+ production cuts (agreed days before to extend another month to July), gradually increasing driving/travel, the record-low rig count…

The reporter addresses the combined effects of all these factors, citing IHS Markit's forecast that U.S. oil production would shrink to 10 million bpd by year end (from peaking at 13 million bpd Jan 24 through March 20) and the International Energy Administration's (IEA) that global June demand would remain at only 86 million bpd (an unprecedented 13% decline but not as bad as the 29 million bpd, ~30% figure first anticipated). So, what might $40 mean? Elliott offered a recent break-even cost metric:

> "Current prices remain below the levels many companies need to drill new wells profitably. But the bounceback is sufficient for many to start up existing wells. The average price required to cover **operating expenses on existing wells ranges from $23 a barrel to $36 a barrel** in the U.S., depending on the region, according to a recent Federal Reserve Bank of Dallas survey."

https://www.wsj.com/articles/u-s-shale-companies-are-turning-the-oil-taps-back-on-11591542000?mod=searchresults&page=1&pos=4

Comment. This compendium covers the period principally from late 2017 to the end of December, 2019. It firmly establishes that the oil and gas industry's financial woes predate the severe pressures triggered by the oil price war and the global economic contractions associated with the pandemic. The problems mostly stem from overproduction associated with the incredible technical success of hydraulic fracturing and horizontal drilling techniques. Capital is seen as both a lifeline to companies and an enabler of too-aggressive campaigns. The current state of affairs remains a precarious act of taming production and seizing the smallest opportunity.

The compendium is by no means a comprehensive history nor a sufficient warning of troubles to come. Oil, always the elephant, takes the headlines. Natural gas, already beleaguered, faces further escalating problems – in particular, the global LNG glut where exports have been the principal means of bleeding off excess supplies. And for further context, despite the oil focus, we should recall that the shale era began with both technical and financial innovations in the gas patch. The latter have played a particularly perverse role in expanding supplies in falling markets.

Whereas safeguards around debt and asset valuations are locked into prices, thus presumably a disincentive to overproduction (albeit ineffective, as documented time and again above), even the veneer of safeguards is not so clear in certain kinds of joint venture arrangements. By 2010-2011 and thereafter, and motivated by new entrants' desires to obtain promising acreage or by existing players to shuffle positions, these arrangements involved up-front cash payments and commitments to drill or reimburse drilling costs (called "**drill carries**"). They had a vital yet unsung role in "defying gravity", although in some cases buyers negotiated an "out", namely not to drill if prices fell below a floor. The floor was as high as $4 per million Btu in a prominent, multi-billion-dollar agreement entered into in 2011 between Noble Energy and Consol Energy for Marcellus assets).[23] Positions in the Permian (and elsewhere) were also obtained in this manner. We anticipate the voluminous financial literature will bring more transparency into this phenomenon in the future. A sense of their continuing importance comes from Haynes and Boone's *Redeterminations Surveys*, the last segment below.

The Boom-Bust Psyche: Are Oil-Gas Industry Finances a Ponzi Scheme?

We brought attention to Bethany McLean's 2018 booklet, *Saudi America: The Truth About Fracking and How It's Changing the World*, in the Committee's November 2018 mid-year report. She is a financial journalist who covered the Enron crisis (co-author of *The Smartest Guys in the Room: The Amazing Rise and Scandalous Fall of Enron*) and the 2008 financial crisis (*All the Devils Are Here: The Hidden History of the Financial Crisis*, 2011 and *Shaky Ground: The Strange Saga of the U.S. Mortgage Giants*, 2015). Her slant is neither technological nor environmental, taking aim instead at what had become apparent by then, the squarely shaky or unsustainable financial practices of the industry. It is an informative and entertaining read, with vignettes on Aubrey McClendon (founder of Chesapeake) and on other innovators, such as Mark Papa (CEO of the Enron spinoff Enron Oil and Gas, now "EOG", which she refers to as both the "anti-Enron" and the "anti-Chesapeake", Harold Hamm (CEO Continental Resources), and the Sheffields of Pioneer Natural Resources. Papa was one of the first to leap to oil from gas (to the Bakken) due to natural gas' weak prices and oversupply. She writes that he "realized that natural gas prices would be low for several decades".

She dates the financial warning signs to the 2015 Ira W. Sohn Investment Research Conference, knows as "the Super Bowl of the hedge fund industry", where David Einhorn of Greenlight Capital (and famous for shorting Lehman Brothers) gave a scathing presentation on the shale companies. Other attendees had more nuanced views, such as SailingStone Capital Partners, whose own detailed research confirmed Einhorn's general pessimism but also proved that "not all oil frackers are alike".

Her book takes us through the 2014 oil price collapse -- a vignette on the Saudi oil minister Ali Al-Naimi, the principal behind their "Thanksgiving Day" decision not to reduce output, and the decision to reintroduce production cuts two years later. She covers the radical shift in U.S. policy at the end of 2015 to allow oil exports; notions (or delusions) of "energy dominance; and the bloom of the Permian. The future of the latter is apparently not assured. In her interview with the current CEO of EOG, Bill Thomas, she writes "[he] says that even in the much celebrated Permian, the rock is much more variable than optimists seems to believe, and the 'core' – really good rock – is smaller". The downer continues. "By 2020, he says that even in the Permian, the best acreage will be mostly drilled, and after that he predicts a sizeable dropoff". This leaves open many questions about what's next, including hints that both politically and from geotechnical perspectives, oil and gas are very different.

[23] "Consol, Noble Energy end shale partnership", by Anya Litvak. Pittsburgh Post-Gazette, Oct. 31, 2016. https://www.post-gazette.com/business/pittsburgh-company-news/2016/10/31/Consol-and-Noble-call-it-quits-on-Marcellus-Shale-partnership/stories/201610310189

A running theme behind her review, perhaps influenced by her deep familiarity with the Financial Crisis, is the connection between the shale era and the particular opportunities brought about by the Financial Crisis. For those who have tracked George Mitchell's efforts from the early 1980's onward[24], this may seem somewhat overstated, but it nevertheless holds a lot of weight and as we've seen gets a lot of Wall Street attention. She puts it this way:

> "The most vital ingredient in fracking isn't chemicals, but capital, with companies relying on Wall Street's willingness to fund them. If it weren't for historically low interest rates, it's not clear there would even have been a fracking boom."

We can't test how things would have turned out without easy money, or at least easy debt, but it is possible the results would have been quite stunning since the industry's overall growth has been stratospheric. She writes:

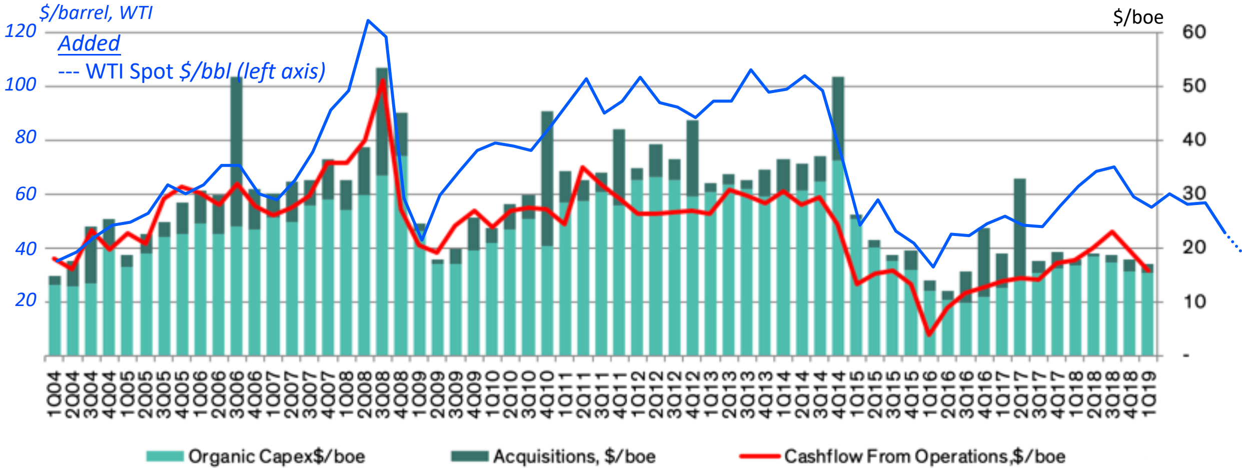
> "Another investor puts it this way: 'If companies we forced to live within the cash flow they produce, U.S. oil would not be a factor in the rest of the world, and would have grown at a quarter to half the rate that it has."

Cash Flow from Operations vs. Capital Expenditures = Elusive Free Cash Flow.
Courtesy of Bob Brackett, Sr. VP and Senior Analyst, North American E&P with Bernstein Research (Sanford C. Bernstein, NY), we can provide a lengthy historical trend of Cash Flow from Operations vs. Capital Expenditures for a very large sample of shale companies. Dr. Brackett first presented their calculations at the Energy Information Administration's September, 2018 Workshop on Financial and Physical Oil Market Linkages. The population of 55 US and Canadian companies comprises about half of U.S. production as well as U.S. capital expenditures.[25] Revenues from oil, natural gas and natural gas liquids are all included in the summary "boe" calculations (barrels of oil equivalent).

[24] Founder of Mitchell Energy. Considered the father of fracking based on prolonged efforts to assess and get gas out of the Barnett Shale, the first major shale play. His company was acquired by Devon Energy in 2001 for $3.1 billion.

[25] By oil production, the largest U.S. oil companies in the group are Conoco Phillips, EOG, Occidental and Anadarko and Devon. By natural gas, they are EQT, Conoco Phillips, Cabot, Antero and Chesapeake. Top Canadian energy companies in the group are Suncor, Canadian Natural Resources and Imperial Oil.

Chart: Cash flows from Operations and Capex, 2004-1Q2019



Source: Bernstein Research, citing FactSet, Company reports, Bernstein analysis, and Bloomberg
Used by permission, July 12, 2019. WTI quarterly oil price trend added, through 2Q2020 (June average estimated at $38.[26]

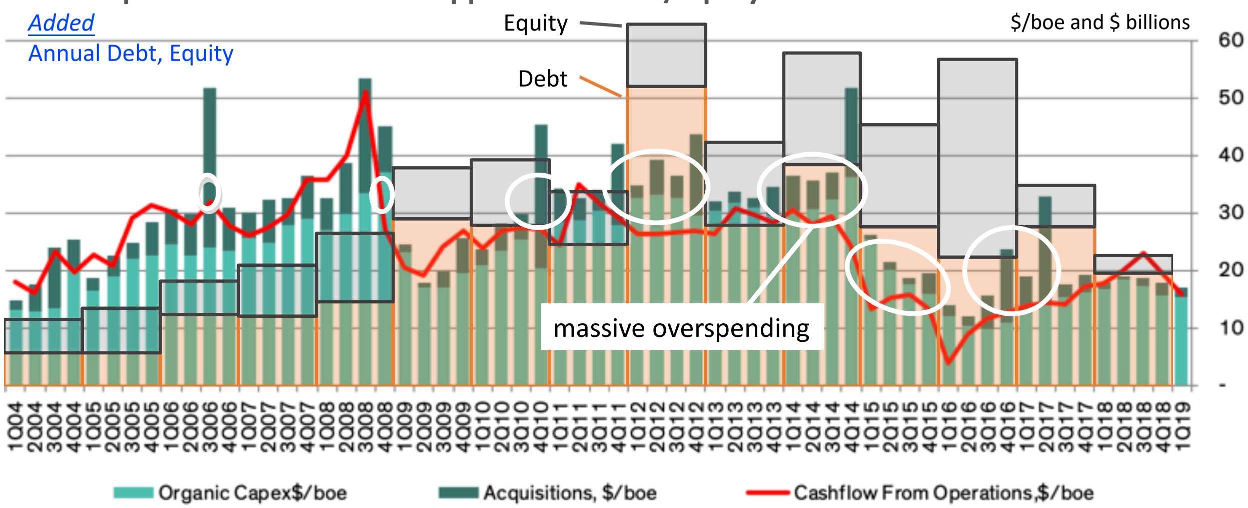
While the current focus is on free cash flow, where the combination of organic capex and acquisitions does not exceed cash flow from operations (CFO), the first thing that jumps out is the inexorable connection of levels of organic cash flow (that involved in E&P, i.e. not acquisitions) and oil prices. Beyond this, acquisitions, which might be considered as "one off" events, have a quite irregular pattern and usually take up a small share of total capex with some notable exceptions.

Leaving the costs of acquisitions out of the picture, expenditures rarely exceeded CFO until after the Great Recession. The opposite occurred until several years after the oil price collapse, e.g. 3Q2016. From this chart, discipline appears to have been pretty good ever since, even when including the cost of acquisitions (which have been minimal). This recent period looks quite different, though, when contrasting larger and smaller companies – the latter have been deeply in the red over essentially the entire period. As for more gas-oriented vs. oil-oriented companies, both have kept expenditures in check since 2017, with oil-oriented companies getting a market boost from higher oil prices over much of 2018. Gas-oriented companies as a group did not appear to benefit much from the gas price spike toward the end of that year. Yet summary charts miss a lot of valuable granularity, such as SailingStone Capital learned when it combed over company data back in 2015. The Bernstein analysis showed 9 of the 55 companies obtaining CFO substantially in excess of their capex in the specific quarter the chart was prepared (1Q2019).

[26] Bernstein N. American Oil & Gas Exploration/Production quarterly report: "E&P State of the Business 1Q19: Hard to win the fight for discipline if E&Ps stay summer soldiers and sunshine patriots". Published June 17, 2019.

Another angle on the chart is the requirement that something (borrowing, issuances of equity, sales of assets, or other arrangements) must make up the difference when capex exceeds CFO. The correlation of negative free cash flow and borrowing is apparent when we superimpose Dealogic's annual debt/equity data onto Bernstein's chart.

Chart: Capex Exceedances Drive Appetite for Debt/Equity Issuances



Not to be forgotten is that debt has a cumulative effect and that equity issuances have a dilutive effect in addition to shrinking the asset base. Cumulative additions to debt from 2009 through 2018 amounted to $298 billion dollars; equity issuances, $137 billion. How much is that? How much might an improvement in crude, natural gas and liquids prices make a difference?

The following panel, a simple and perhaps simplistic thought experiment, gives some perspective into how long a "rising tide" might have to last for this now-mountainous legacy to resolve itself. Assuming a $5/barrel boost in oil prices, $0.50/mcf in natural gas and $0.05/gal in NGPL could happen, the boost to industry revenues would be $38 billion/year. Production levels are assumed to approach those of recent years, though not the peak levels. The simple/simplistic result, all else being equal, is the revenue boost would allow the accumulated debt to be paid off in 7.8 years. This assumes many other fanciful things, such as zero interest rates and sole use of the extra revenues for debt repayment. While the amounts are huge and the experiment very generous, it is possible it overstates the problem in that some portion has been paid off.

Production X Price Boost = Revenue Boost

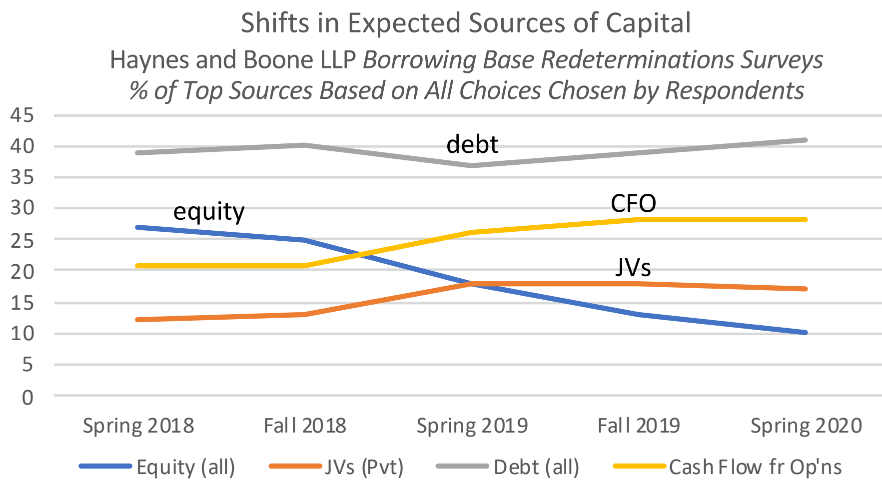
	Crude Oil	Nat Gas	NGPL
	Production		
2015	3.445 B bbls	27.065 B mcf	1.210 B bbls
2019	4.465 B bbls	33.657 B mcf	1.800 B bbls est.
A.	**Proposed Quantites**		
	4 B bbls	30 B mcf	1.5 B bbls
B.	**Proposed Price Boost**		
	$5/bbl (10% of $50)	$0.50/mcf*	$0.05/gal, ~$2/bbl
	$10/bbl	$1.00/mcf*	(10% of $.50/gal)
C.	**Revenue Boost (A X B)**		
	$20 B	$15 B	$3 B
	$40 B	$30 B	

*NG % of low prices are larger, e.g. $0.50: 25% of $2, 16.6% of $3.

***Cash Flow from Operations Becomes a More Tangible Part of Industry Financial Planning*.**
A recent shift in sentiment toward sources of capital is evident from a time series of Haynes and Boone LLP's Borrowing Base Redeterminations Surveys, initiated in 2018 and conducted twice a year. Kraig Grahmann, Partner out of the firm's Houston office, provided a set of these to support our search for a change in sentiment.[27]

In broad brush strokes, expectations for use of debt have been remarkably consistent, although there are changes in composition of this under the surface.

[27] Memorandum Grahmann to Plat. June 4, 2020.



Expected Sources of Capital, Coming Year

	Equity (all)	JVs (Pvt)	Debt (all)	CFO
Spring '18	27	12	39	21
Fall '18	25	13	40	21
Spring '19	18	**18**	37	**26**
Fall '19	13	**18**	39	**28**
Spring '20	10	**17**	41	**28**
	- ~60%	+ ~40%	~unch.	+ 33%

Selling equity shares became ever more unpopular, moving from the #2 to the last position through 2019 and into the spring of 2020. Preferences for reliance on cash flow from operations did not advance until the spring of 2019, when it moved sharply upward, rising again and holding after the subsequent survey. Not all equity is being shunned. Joint ventures with private equity jumped between fall 2018 and spring 2019, right along with the popularity of CFO. In the past, deals involving such things as drill carries were described as joint ventures. We do not have insight into what obligations comprise the current wave of JVs.

Taking a closer look at details, capital markets for debt and equity look largely closed-off. Non-bank lending has stepped up to fill the gap, just as JVs (with private equity) have filled the gap from the sharp falloff in capital expected from private equity.

Haynes & Boone: Q. Where are producers planning to source capital in (spring: current year; fall: next year)?

	Equity fr. Captl Mkts	Equity fr Prvt Eq Firms	JV w/ Prvt Eq	Debt fr Cap'l Mkts	Debt fr Banks	Debt fr Alt. Cap'l Prov'rs	Debt fr. Prvt Eq Firms	CFO	Other	SAMPLE n=	# borrow sources cited	ave. # choices per response
Spring 2018	8	19	12	11	20	-	8	21	1	108	365	3.4
Fall 2018	8	**17**	13	12	**20**	-	8	**21**	1	123	459	3.7
Spring 2019	4	14	**18**	8	**21**	-	8	**26**	1	121	364	3.0
Fall 2019	2	11	**18**	3	**20**	16	-	**28**	2	221	670	3.0
Spring 2020	2	8	**17**	4	17	20	-	**28**	4	207	578	2.8

Source: Haynes and Boone LLP; Used by permission.

Reviewing this, one should remain mindful that these surveys represent before-the-fact expectations, spanning opinions from a range of stakeholders (producers, oilfield services, financial institutions, private equity and other professionals). What actually happens is borne out in the actual lending statistics such as that compiled by Dealogic, Bernstein and many others. Yet even when operating at an historic low ebb, stakeholders expect producers will continue to draw upon a wide range of sources of capital.

Appendices

Appendix A - How Bad Is It? Oil and Gas Price Collapse Measured Over Twenty Years

This material appeared in the May *AAPG Explorer*, at the conclusion of David Brown's article "Where is the Industry Going to Get its Capital? Negative oil prices hit exploration investment particularly hard"[28]. It converted recent low prices into constant dollars, stretching back 20 years or longer. This serves as a yardstick against which to measure today's rock-bottom prices. In 20 years, monthly prices have never matched the lows seen recently.

– – –

The current dramatic price collapse across both oil and natural gas has little precedent. Today's collapse has some ingredients of prior periods, such as cracks in the OPEC+ cartel as Saudi Arabia and Russia aimed to retain market share at the expense of each other and U.S. shale hydrocarbons. But any such normal oil-related geopolitical tensions are thrown out the window when cheap oil is prevented from spurring demand by today's nearly-unimaginable global pandemic. The month of March saw oil plummet first to the $40s per barrel under geopolitical tensions and then to the $20s as the pandemic reached more deeply into economies and consciousness. Natural gas, in the doldrums of sub-$3.00 per million Btu throughout 2019, broke $2.00 – not to mention sharp discounts far below that Henry Hub marker price in many regions.

Against this backdrop, the charts here compare apples-to-apples today's price levels to those over the past twenty years. The first level of low points after the late-2014 oil price collapse was $47.22 in January 2015, equivalent to $52.27 in February 2020 dollars. Only in January and February 2016 did prices break below $40 per barrel in February 2020 dollars, reaching $31.68 ($34.59 adjusted) and $30.32 ($33.08 adjusted) – until this March. Looking back farther, the November 2001-February 2002 low point was December's $19.39 per barrel, $30.15 in February 2020 dollars. While off the charts shown here, the historic oil price collapse of the mid-1980s was July 1986 plummet to $9.25 "first purchase price", equivalent to $21.85 on an adjusted basis and thus a match to some of the most recent daily lows.

Turning to natural gas, only twice in the post-2000 era did prices puncture or come close to puncturing the $2.00 per million Btu threshold. This was $1.95 in April 2012 after the mild winter of 2011-2012, or $2.19 on an adjusted basis, and the stretch of low prices from Nov-Dec 2015 through May 2016, when the March low of $1.73, $1.88 adjusted, represents the only time that today's $2.00 value was actually breached on a price-adjusted basis (and notably over a full month). With adjusted oil prices near or exceeding $100 per barrel from November 2010 through September 2014, the oil sector offered a hefty life-raft during the first low points and a value close to $50 per barrel during most of the remaining period – until this March. There is no candy-coating the current and quite possibly worsening situation.

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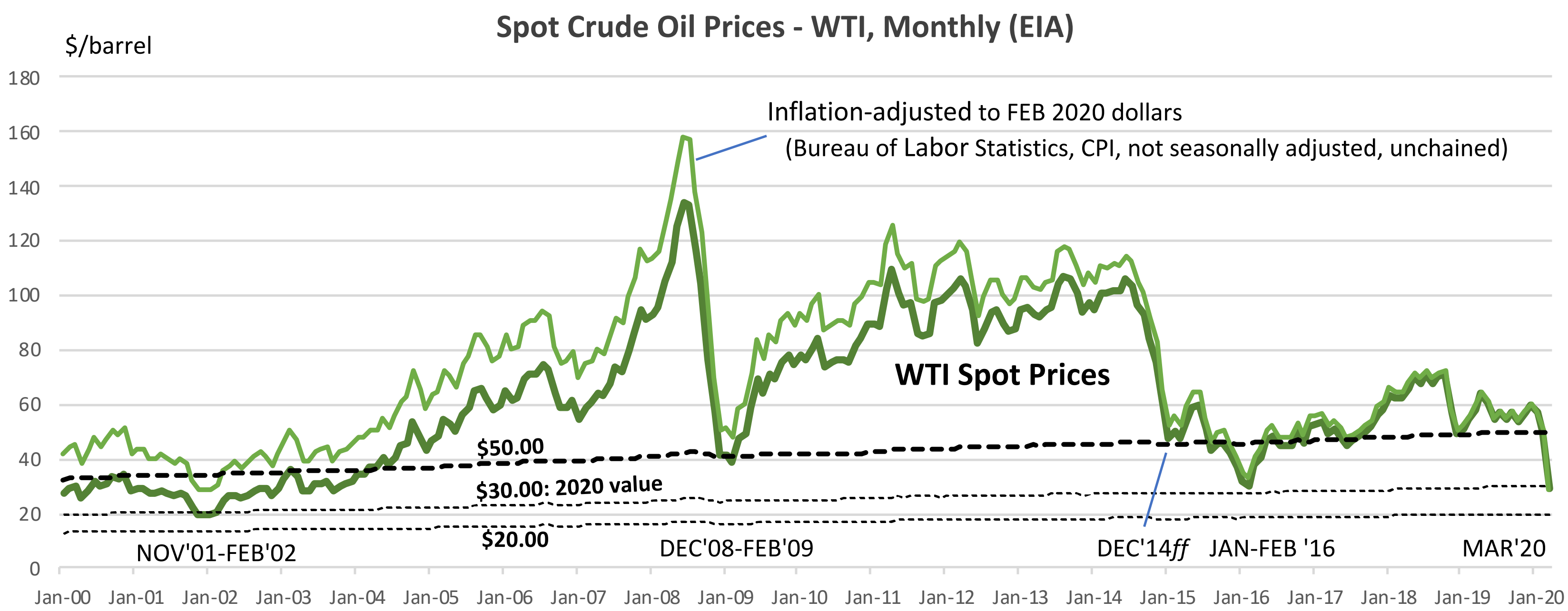
[28] AAPG member link: https://explorer.aapg.org/story/articleid/56970/where-is-the-industry-going-to-get-its-capital?utm_medium=website&utm_source=1


Spot Crude Oil Prices - WTI, Monthly (EIA)
$/barrel
180
160
140
120
100
80
60
40
20
0
Inflation-adjusted to FEB 2020 dollars
(Bureau of Labor Statistics, CPI, not seasonally adjusted, unchained)
WTI Spot Prices
$50.00
$30.00: 2020 value
$20.00
NOV'01-FEB'02
DEC'08-FEB'09
DEC'14ff
JAN-FEB '16
MAR'20
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
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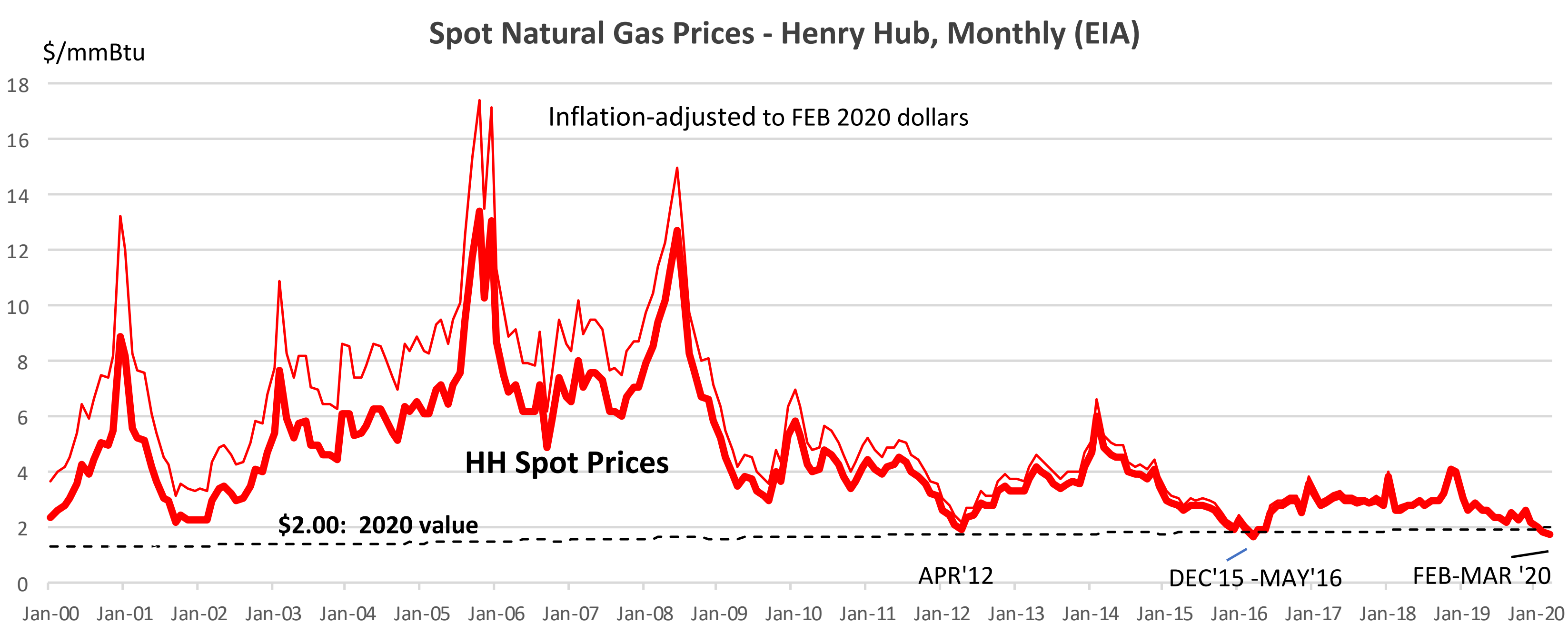
Jan-18
Jan-19
Jan-20


Spot Natural Gas Prices - Henry Hub, Monthly (EIA)
$/mmBtu
18
16
14
12
10
8
6
4
2
0
Inflation-adjusted to FEB 2020 dollars
HH Spot Prices
$2.00: 2020 value
APR'12
DEC'15 -MAY'16
FEB-MAR '20
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20

Appendix B: Unemployment Insurance Claims by State or Region. Two views: (1) Top Gasoline-Consuming States and (2) Top Oil- and Natural Gas-Producing States.

Source: U.S. Department of Labor, claims; EIA, state energy statistics.

(1) Top Gasoline-Consuming States

Department of Labor Weekly Unemployment Insurance Claims: Top Gasoline Consuming States View

Weeks Ending Dates March 14 (Baseline) to May 9, 2020 (8th week since Baseline).

Note: Reports are issued Thursdays after each "week ending" date. That count is revised the next week.

Gasoline Use											
2018											
Transport Sector											
(Million Barrels)		Rev.	Rev.	Rev.	Rev.	Rev.	Rev.	Rev.	Rev.	Advance	*Increase*
TOP 12 STATES		**BASELINE**	**1st**	**2nd**	**3rd**	**4th**	**5th**	**6th**	**7th**	**8th**	*Total Wks 1-8*
		14-Mar	**21-Mar**	**28-Mar**	**4-Apr**	**11-Apr**	**18-Apr**	**25-Apr**	**2-May**	**9-May**	
3405.1	**<- US Total ->**	**251,416**	**2,920,160**	**6,015,821**	**6,211,399**	**4,964,568**	**4,281,648**	**3,495,703**	**2,855,560**	**2,614,093**	***33,610,368***
	State/Rank										
349.1	CA/1	57,606	186,333	1,058,325	918,814	655,472	528,360	325,343	316,257	214,028	*4,202,932*
337.9	TX/2	16,176	155,426	276,185	315,167	274,257	280,761	254,084	243,935	141,672	*1,941,487*
	S.E./Atl.										
210	FL/3	6,463	74,313	228,484	169,885	180,419	247,003	433,103	174,860	221,905	*1,729,972*
115.6	GA/6	5,445	12,140	133,820	390,132	319,581	247,003	266,565	228,352	241,387	*1,838,980*
108.4	NC/8	3,533	94,083	172,145	137,422	140,155	106,266	98,941	85,956	56,193	*891,161*
94.4	VA/11	2,706	46,277	112,497	147,369	104,619	82,729	72,488	59,631	53,396	*679,006*
	SubTotal	18,147	226,813	646,946	844,808	744,774	683,001	871,097	548,799	572,881	*5,139,119*
	N.East										
131.9	NY/4	14,272	79,999	366,595	344,451	394,701	205,184	219,413	195,110	200,375	*2,005,828*
111.1	PA/7	15,439	377,451	404,677	277,640	234,868	194,594	127,896	94,445	75,557	*1,787,128*
89.8	NJ/12	869	115,815	206,253	214,836	141,420	140,139	71,966	88,326	68,685	*1,047,440*
	SubTotal	30,580	573,265	977,525	836,927	770,989	539,917	419,275	377,881	344,617	*4,840,396*
	MIDW										
116	OH/5	7,046	196,309	274,288	226,191	159,317	109,830	93,599	61,487	50,548	*1,171,569*
109.2	IL/9	10,870	114,114	178,421	201,041	141,160	102,936	81,596	74,476	72,993	*966,737*
108.8	MI/10	5,338	128,006	304,335	388,554	222,207	136,707	82,004	67,399	47,438	*1,376,650*
	SubTotal	23,254	438,429	757,044	815,786	522,684	349,473	257,199	203,362	170,979	*3,514,956*
1882.2*	**Subset**	**145,763**	**1,580,266**	**3,716,025**	**3,731,502**	**2,968,176**	**2,381,512**	**2,126,998**	**1,690,234**	**1,444,177**	***19,638,890***
55.30%	Share of U.S.	58%	54%	62%	60%	60%	56%	61%	59%	55%	58%

(2) Top Producing States

Department of Labor Weekly Unemployment Insurance Claims: Top Producing States View

Weeks Ending Dates March 14 (Baseline) to May 9, 2020 (8th week since Baseline).

Note: Reports are issued Thursdays after each "week ending" date. That count is revised the next week.

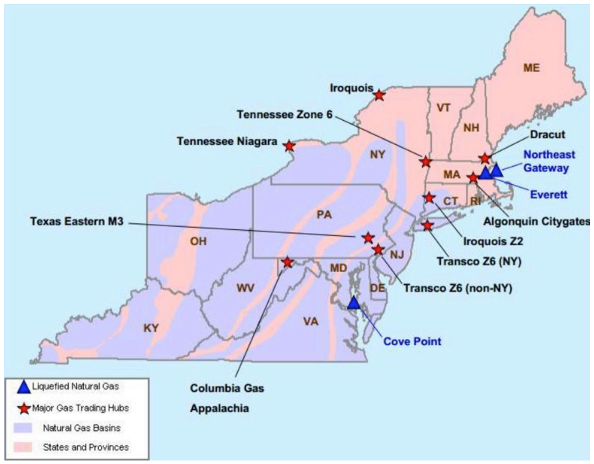
Production		**Rank**												
Oil*	**Onshore Nat Gas**	**Oil**	**Onshore Nat Gas**											
2019	2018	2019	2018		Rev.	Rev.	Rev.	Rev.	Rev.	Rev.	Rev.	Rev.	Advance	*Increase*
Million barrels/d	Billion cf/d	Top 10 of Each			**BASELINE**	**1st**	**2nd**	**3rd**	**4th**	**5th**	**6th**	**7th**	**8th**	*Total Wks 1-8*
					14-Mar	**21-Mar**	**28-Mar**	**4-Apr**	**11-Apr**	**18-Apr**	**25-Apr**	**2-May**	**9-May**	
12.23	**83.8**			**<- US Total ->**	**251,416**	**2,920,160**	**6,015,821**	**6,211,399**	**4,964,568**	**4,281,648**	**3,495,703**	**2,855,560**	**2,614,093**	***33,610,368***
				State										
				TX-NM										
5.07	18.7	1	1	TX	16,176	155,426	276,185	315,167	274,257	280,761	254,084	243,935	141,672	*1,941,487*
0.93	3.7	3	9	NM	869	18,105	27,849	26,132	19,043	13,621	12,093	13,675	8,850	*139,368*
				SubTotal	17,045	173,531	304,034	341,299	293,300	294,382	266,177	257,610	150,522	*2,080,855*
1.4	1.5	2	11	ND	415	5,662	11,818	15,125	9,502	8,065	6,274	4,044	3,225	*63,715*
				NG East										
0.02	16.8	16	2	PA	15,439	377,451	404,677	277,640	234,868	194,594	127,896	94,445	75,557	*1,787,128*
0.08	6.4	11	5	OH	7,046	196,309	274,288	226,191	159,317	109,830	93,599	61,487	50,548	*1,171,569*
0.05	4.5	14	7	WV	3,435	3,536	14,523	14,494	14,944	46,755	29,818	13,227	5,842	*143,139*
				SubTotal	25,920	577,296	693,488	518,325	409,129	351,179	251,313	169,159	131,947	*3,101,836*
				MidCon--Rock										
0.58	7.4	4	4	OK	1,836	21,926	47,744	60,534	54,481	46,696	33,041	93,885	32,794	*391,101*
0.51	4.6	5	6	CO	2,320	19,774	61,838	46,326	104,572	67,639	38,662	28,360	22,493	*389,664*
0.28	4.3	7	8	WY	517	3,653	6,396	6,543	5,794	4,381	3,497	2,854	2,686	*35,804*
0.1	0.8	9	12	UT	1,305	19,690	28,533	33,040	24,037	19,649	11,738	8,992	7,135	*152,814*
0.09	0.5	10	14	KS	1,755	23,563	54,330	49,306	116,277	30,596	24,483	82,435	69,069	*450,059*
				SubTotal	7,733	88,606	198,841	195,749	305,161	168,961	111,421	216,526	134,177	*1,419,442*
0.44	0.5	6	13	CA	57,606	186,333	1,058,325	918,814	655,472	528,360	325,343	316,257	214,028	*4,202,932*
				Gulf exTX										
0.12	7.6	8	3	LA	2,255	72,438	97,400	100,621	79,653	91,923	66,141	50,941	40,268	*599,385*
0.01	1.6	20	10	AR	1,382	9,275	27,756	62,086	35,629	25,404	17,671	13,448	12,416	*203,685*
				SubTotal	3,637	81,713	125,156	162,707	115,282	117,327	83,812	64,389	52,684	*803,070*
9.68	**78.9**			**<-Subset->**	**112,356**	**1,113,141**	**2,391,662**	**2,152,019**	**1,787,846**	**1,468,274**	**1,044,340**	**1,027,985**	**686,583**	***11,671,850***
79%	94%			Share of U.S.	45%	38%	40%	35%	36%	34%	30%	36%	26%	35%

*Oil: excludes AK and Federal offshore

Appendix C: Map Supplement for Natural Gas Trading Hubs including FERC May 21, 2020 Price Summary for Selected Regions

Source: Federal Energy Regulatory Commission, FERC Market Assessments, citing data from Bloomberg and Waterborne (LNG); EIA.

Appalachia: Marcellus and Utica

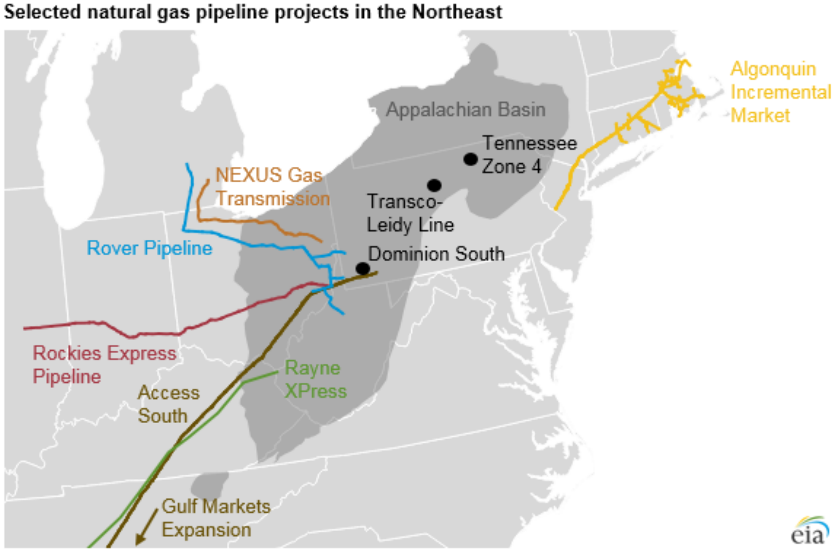


	Average Day Ahead Prices ($/MMBtu)	Algonquin Citygates	Transco Zone 6 NY	Transco Zone 6 Non-NY	Columbia Applachia	Henry Hub
2017	**Annual**	3.86	3.01	2.98	2.22	**2.96**
	Summer	2.60	2.46	2.56	1.99	**2.97**
	Winter 2017/2018	8.01	6.80	6.14	2.60	**2.97**
2018	**Annual**	4.99	4.43	4.19	2.53	**3.12**
	Summer	3.19	2.82	2.81	2.20	**2.91**
	Winter 2018/2019	5.62	4.08	3.64	3.19	**3.33**
2019	**Annual**	3.30	2.61	2.43	2.33	**2.51**
	Summer	2.17	2.01	2.01	2.11	**2.39**
	Winter 2019/2020	3.19	2.16	2.12	1.85	**2.07**
2020 YTD	**Annual**	2.11	1.73	1.71	1.67	**1.81**
	Summer	1.60	1.47	1.46	1.63	**1.70**
	Winter 2020/2021					

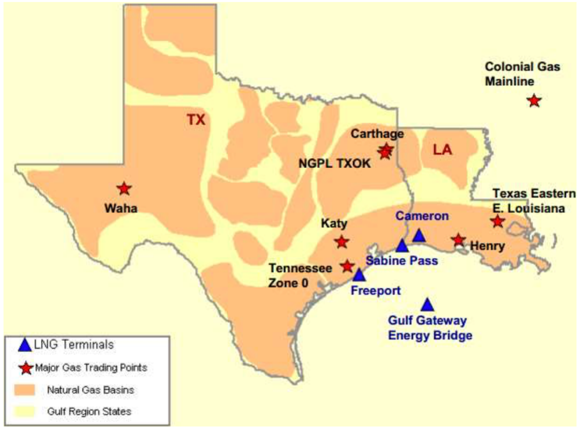
Additional Key Appalachia Hubs: Dominion South (SW PA/E. Ohio/N. WV), Tennessee Zone 4 (N. Central PA)

Map source: "Natural gas pipeline projects lead to smaller price discounts in Appalachian region", *Today in Energy*, EIA, August 16, 2017.
By Terry Yen and Naser Ameen.

Selected natural gas pipeline projects in the Northeast



Gulf: Permian, Eagle Ford (Texas); Haynesville, Henry Hub (Louisiana)

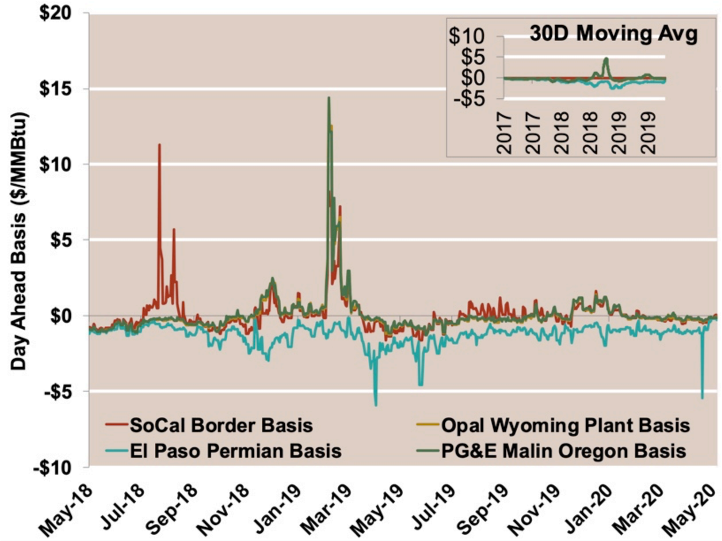


	Average Day Ahead Prices ($/MMBtu)	Houston Ship Chnl	Katy Texas	Waha Hub	Carthage TX	Henry Hub
2017	Annual	2.98	2.97	2.67	2.87	**2.96**
	Summer	3.01	3.00	2.66	2.88	**2.97**
	Winter 2017/2018	3.04	3.01	2.44	2.87	**2.97**
2018	Annual	3.20	3.17	1.94	2.98	**3.12**
	Summer	3.01	2.99	1.83	2.77	**2.91**
	Winter 2018/2019	3.32	3.29	1.51	3.18	**3.33**
2019	Annual	2.45	2.46	0.82	2.31	**2.51**
	Summer	2.33	2.35	0.47	2.16	**2.39**
	Winter 2019/2020	1.99	1.99	0.79	1.93	**2.07**
2020 YTD	Annual	1.76	1.76	0.55	1.69	**1.81**
	Summer	1.66	1.66	0.66	1.60	**1.70**
	Winter 2020/2021					

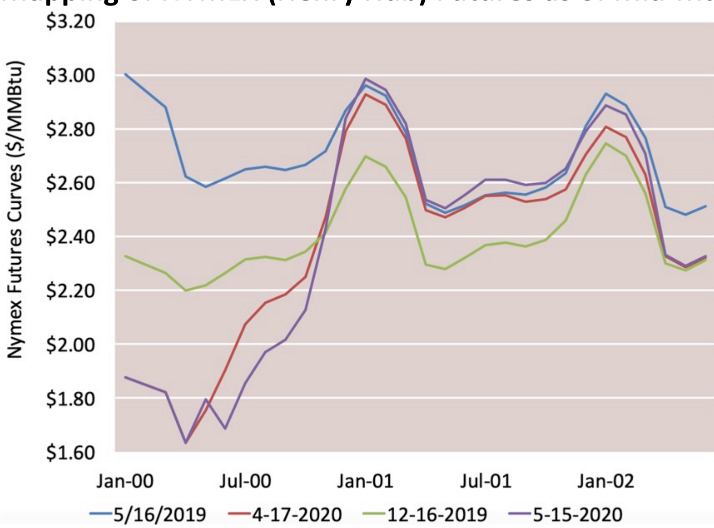
West, Southwest, Rockies, NW

	Average Day Ahead Prices ($/MMBtu)	SoCal Border	Opal Wyoming Plant	El Paso Permian	PG&E Malin Oregon	Henry Hub
2017	Annual	2.86	2.69	2.62	2.74	**2.96**
	Summer	2.82	2.65	2.60	2.70	**2.97**
	Winter 2017/2018	2.74	2.55	2.36	2.54	**2.97**
2018	Annual	2.92	2.75	2.03	2.77	**3.12**
	Summer	2.74	2.33	1.88	2.37	**2.91**
	Winter 2018/2019	4.01	4.64	1.93	4.68	**3.33**
2019	Annual	2.67	2.78	1.11	2.83	**2.51**
	Summer	2.10	1.97	0.79	2.02	**2.39**
	Winter 2019/2020	2.17	2.23	1.06	2.27	**2.07**
2020 YTD	Annual	1.68	1.70	0.88	1.74	**1.81**
	Summer	1.48	1.49	0.91	1.52	**1.70**
	Winter 2020/2021					

West, cont'd: Price Anomalies – Summer heat waves (CA); Pipeline failure, Winter freeze (NW/Canada)



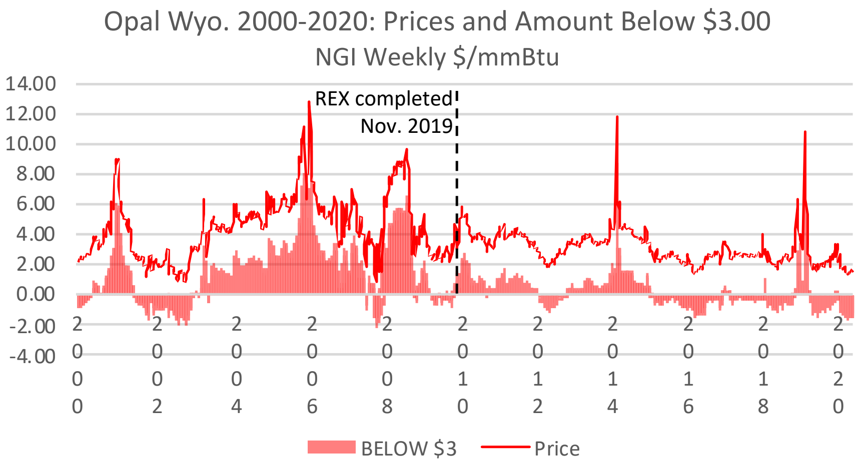
Mapping of NYMEX (Henry Hub) Futures as of Mid-May 2020: Beyond the Pandemic Price Trough

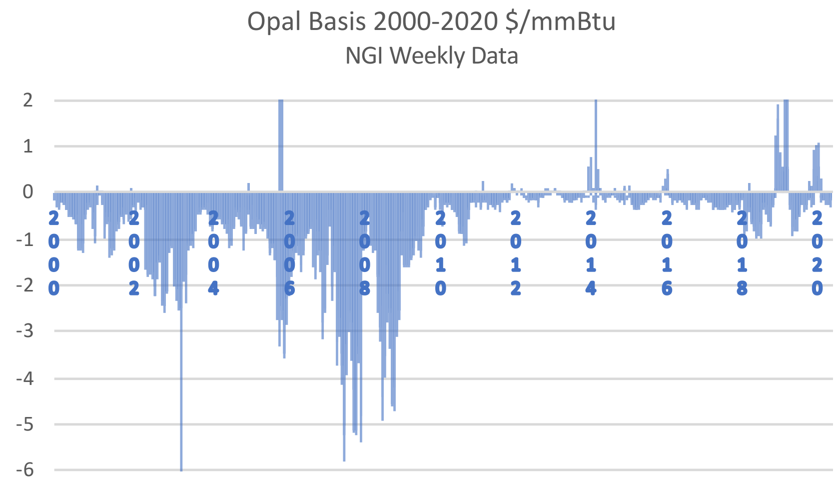


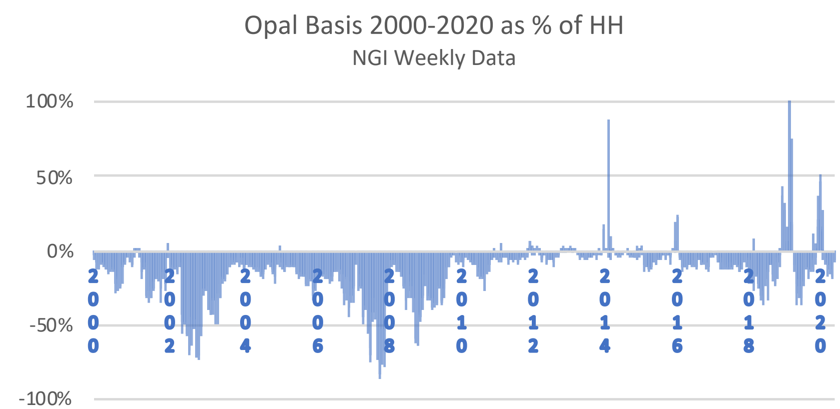
Reference: *2020 Summer Energy Market and Reliability Assessment*, Federal Energy Regulatory Commission (FERC), May 21, 2020. https://www.ferc.gov/market-assessments/reports-analyses/reports-analyses.asp and https://www.ferc.gov/market-assessments/reports-analyses/mkt-views/2020/05-21-20.pdf

Appendix D. Snapshot of Opal, Wyoming Pricing – Overcoming Supply-Infrastructure Imbalance

These charts illustrate the price effects of the multi-phase Rockies Express pipeline (REX) constructed between 2007 and 2009. For years, Opal could be considered the “granddaddy” of negative basis. The initial effects were to greatly reduce the degree that Rockies natural gas was discounted to, for example, the Henry Hub. While it succeeded in reducing basis many years, it ultimately crashing into the sub-$3.00 prices of the past 5-6 years. The more recent price spikes were principally linked to Canadian pipeline issues affecting Northwest and Rockies supplies.







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