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Assessing Shale Producers' Ability to Scale-up Activity

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INTRODUCTION

The oil production targets agreed to at the November 30, 2016, OPEC meeting have created the firmest prospect in the past two years of a meaningful oil price recovery. Key producers' adherence to those targets remains in question, but a perhaps more important issue is the degree to which non-OPEC production, particularly US shale, will respond if prices sustain at a higher level. Indeed, US crude oil production declined by about 1 million barrels per day from June 2015 to July 2016, revealing a rather elastic response to lower prices. But OPEC and other key global producers, including Russia, now face the question, "How fast can US shale producers scale-up their activity levels if WTI crude prices rise and stabilize in the $60/bbl range?"[1]

This brief addresses that question and highlights the challenges US unconventional liquids producers will likely face during a scale-up. It also points out price and timing inflection points likely to broadly influence industry decision-making. Fundamentally, US shale producers are likely to commence higher activity levels in two broad, price-dependent phases: (1) bringing online drilled but uncompleted wells (DUCs, in industry parlance); and (2) scaling up drilling and completions of new wells if WTI prices can stay at or above a sustainable level, most likely $60/bbl. That said, the manner in which costs respond to any uptick in drilling and completion activity will serve as a check on pace, and not all regions will see the same level of interest as prices climb. The Permian Basin is already adding rigs and will likely continue to see a majority of new interest, but as prices stabilize other plays such as the Bakken, Eagle Ford, and Niobrara will follow.

PHASE 1: BRING DUCS INTO PRODUCTION AS CRUDE PRICES PERMIT

Baker Institute Center for Energy Studies research, as well as discussions with industry representatives, suggest the turnaround time on DUCs can be very fast: as little as three weeks from the time the frac begins until the first oil is brought to sales (Figure 1). The spud-to-sales times for new wells—in this case, Delaware Basin

FIGURE 1 — DELAWARE BASIN SPUD-TO-SALES TIMEFRAME (WOLFCAMP WELL, 10,000-FT LATERAL)

	Drilling	Completion	Commencing Sales	Total Est. Spud-to-Sales Time
DUC Case	N/A	10-14 Days	5-6 Days	15-to-20 days
Base Case	20-25 Days	10-14 Days	5-6 Days	35-to-45 days
Pessimistic Case	30 Days	10-14 Days Frac + ~30 Days to Fill Frac Pit	7-10 Days	80-to-90 days

SOURCE Compiled from company reports and discussions with an experienced Permian Basin completions engineer

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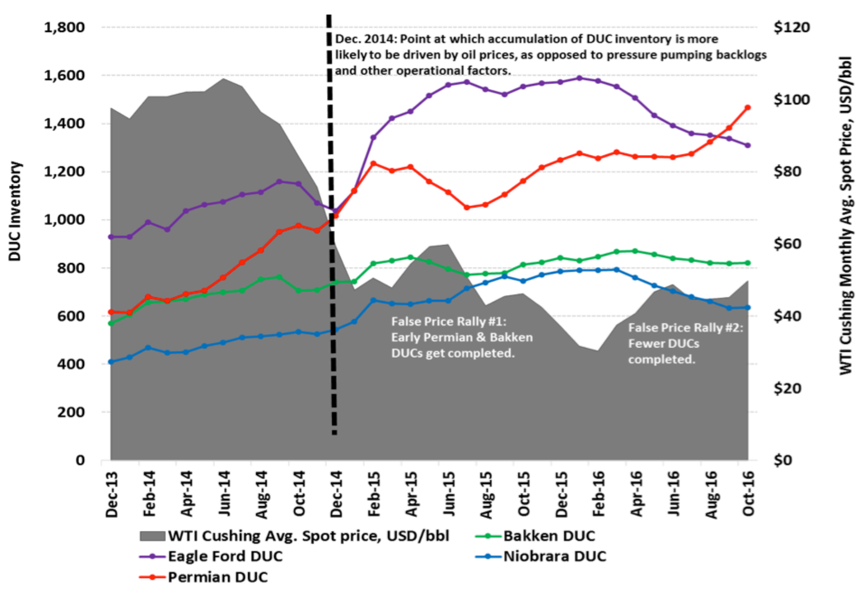
Wolfcamp horizontal wells with 10,000-foot laterals in the Permian Basin—are also remarkably fast, at an estimated 35 to 45 days for operators who already have power and takeaway infrastructure and proactively manage frac water supplies.

A 20-day turnaround is lightning fast in physical oil market terms. For perspective, consider that a supertanker steaming at 13 knots would need 22 days to get its cargo of oil from Ras Tanura, Saudi Arabia, to Zhoushan, a key Chinese oil storage and refining center south of Shanghai, and it would need 35 days to get an oil cargo from Saudi Arabia to the VLCC-capable Louisiana Offshore Oil Port.

$50 WTI is the Likely Price Threshold for DUC Completions in Multiple Shale Plays

If WTI prices settle at or above $50/bbl for a sufficiently long period (likely several weeks), upstream firms will move rapidly to complete their remaining inventories of DUCs. Whiting Petroleum and Continental Resources—both Bakken-focused operators—have recently indicated to investors that stable $50 WTI is a key activation point for accelerating DUC completions.[2] While some companies have been frac'ing their DUC inventories for over a year (Figure 2), at or above $50/bbl netback prices the majority of the DUC inventory across basins will be in the money, which will likely catalyze a more aggressive pace of completions.

FIGURE 2 — DUC INVENTORIES IN KEY SHALE LIQUIDS BASINS VS. WTI SPOT PRICE



SOURCE Energy Information Administration, authors' analysis

DUCs' Maximum Crude Oil Production Impact Likely to be Less than 250 kbd

Wood Mackenzie has provided one of the most prominent public views of potential DUC contributions to overall US oil output, estimating that as these wells are completed, they could bring a peak of up to 250,000 bpd of oil into the market through the end of 2017.[3] There is a material probability that the actual impact could be lower, given that operators in the Bakken and Eagle Ford have been periodically drawing down their DUC inventories throughout the last two years in response to periodic "false" price recoveries. Nevertheless, even at a plus 250 kbd net production impact, US liquids production from DUCs would offset only about one-quarter of the planned OPEC production cuts, assuming a 75% compliance rate across OPEC member nations.

Energy Information Administration (EIA) data reveal that the Bakken had 113 more DUCs in October 2016 than it did in December 2014. December 2014 is relevant because it is the month in which prices dropped low enough to incentivize producers to defer completions in the hope that oil prices would recover to a higher level. If we make an optimistic assumption that 80% of these DUCs are "high potential" wells, this leaves 90 wells from the Bakken that could materially impact production in the short term.

Following a similar logic, data from the Permian, Eagle Ford, and Niobrara indicate that up to 688 high-potential liquids wells await completion (Figure 2). The total number of DUCs in the major liquids basins was much higher in October 2016—4,232 to be precise.[4] Despite WTI prices being north of $100 per barrel in 2014, many of these wells were not completed when pressure pumping capacity caught up with demand. Then, as oil prices fell in late-2014 through early-2015, the wells remained uncompleted, suggesting they may be "dead DUCs" that will never be completed.[5]

Assessing the potential supply impact of the remaining high-potential DUCs invokes two core issues. The first—the speed at which DUCs can potentially be frac'ed and brought into production—has decent clarity. In its December 2016 Investor Update, Continental Resources (CLR) indicated it has two frac crews in its DUC zone in the Bakken, and had plans to have four working there by the end of 2016. Moreover, CLR said its stimulation crews can handle three to four wells per month each, meaning it could conceivably bring online 12 to 16 DUCs per month until the inventory is depleted.[6]

Crews in the Permian Basin are even faster, with Diamondback Energy revealing in early August 2016 that its frac crews working the Delaware Basin could complete "basically five 7,500 to 10,000-foot wells per frac crew per month."[7] Applying this Permian operator's frac rate to the national liquids DUC stock suggests the following: if operators nationwide choose to run through the total "fraclog" of slightly less than 700 "high-potential" DUCs over a six-month period and the average frac crew completes four wells per month, the existing stock of liquid-dominant DUCs would require roughly 30 frac crews. At an average frac spread size of 25,000 hydraulic horsepower, this would be equivalent to approximately 8% of currently active US pressure pumping capacity—a surge that would be "doable" but would likely drive up service costs and slow activity at a given price level.[8]

The second issue—how much production DUC wells bring onto the market in a given timeframe—is bracketed with a much higher degree of uncertainty. Factoring into this is the fact that shale wells are naturally very heterogeneous, and predicting the behavior of any single well is fraught with difficulty. Moreover, the extent to which observed well productivity has been changing is remarkable, but this is due to both improvements in drilling efficiency and high-grading of acreage in a low-price environment. So if DUC completions were held off because those wells are in less productive acreage, then the impact may not be that material. Uncertainty on this front abounds.

At least one dataset suggests that between 2012 and 2015, the average decline rates of shale wells in the Permian Basin and Bakken slowed significantly, giving the newer wells a flatter production profile than their older shale cousins, which tended to yield a large upfront production spike and then tapered rapidly.[9] Slower decline rates could stem from a number of factors—including operators only drilling their most productive locations during low price periods and more operators deciding to choke back initial well flows to capture some near-term cash flow while deferring some more for the future in hope of higher prices—but the data on a national level remain preliminary.

PHASE 2: RAMPING UP DRILLING AND COMPLETION OF NEW WELLS

Barring any unexpected demand or supply-side oil shocks in the next 12 months, even moderate compliance (say 50% to 75%) with the targeted OPEC output reductions begins to make a WTI price of $60/bbl a realistic possibility. When spot crude oil prices stabilize near $55/bbl for WTI and the forward curve allows future sales at or above $60, shale oil producers with high-quality acreage in the Permian Basin are likely to begin adding rigs and significantly ramping up operations.[10] In the Bakken, Continental Resources—which is a reasonable proxy for the play at large given its expansive operations in the region—says WTI stabilizing at $60/bbl is the activation point at which it believes adding rigs becomes justified.[11]

Basins, such as the Permian and Eagle Ford, that are located closer to well-developed pipeline infrastructure and major markets will reach the price activation point for increased drilling and completion activity sooner than basins, such as the Bakken, that have a relative dearth of infrastructure. For instance, Continental's realized oil price (i.e., netback price) in 2016 for its

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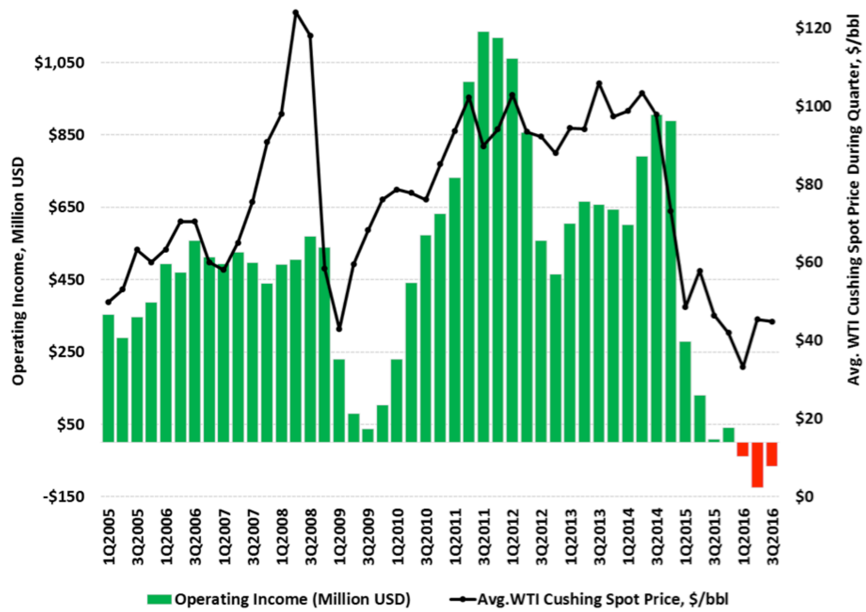
FIGURE 3 — HALLIBURTON NORTH AMERICA OPERATING INCOME (BY QUARTER, 2005Q1–2016Q3)



SOURCE Company reports, Energy Information Administration

It could take several quarters for service companies to rebuild a sufficient human capital base to support a substantial ramp-up in drilling and completion activity.

Bakken production was typically lower that the WTI crude oil price by $7/bbl to $8/bbl, suggesting that company statements indicate it plans to add rigs with netback prices in the low $50s.[12] Top Permian Basin operators enjoy more favorable pricing, with their realized prices for crude typically trailing the NYMEX price by approximately $2.35/bbl to $3.50/bbl as of third quarter 2016.[13] While the netback price at $60/bbl WTI is typically higher in basins with greater take-away capacity, higher drilling and completions activity risks triggering supply chain challenges that raise costs and slow the pace of activity.

Delays from Bringing Stacked Equipment Back Into Service

When the price downturn decimated demand for oilfield services, companies across the supply chain mothballed equipment. These commercially rational actions set the stage for delays in ramping operations back up because drilling rigs, pressure pumping equipment, and other key tools and machinery have been "cold stacked"—taken out of service for an extended period and "generally not considered to be part of marketable supply."[14] Cold stacking creates challenges if activity levels rise quickly because equipment often requires various maintenance and repairs after being out of service for an extended period, which in the case of pressure pumping equipment can mean delays of at least two months as units are prepared for re-entry into service.[15] In cases where equipment was cannibalized for spare parts during the downturn, delays could be longer, and in more extreme cases, cannibalization may have been so extensive that the original equipment is effectively knocked out of the market.

Replacing People Likely Much Tougher than Bringing Iron Back into Service

In the 2011–2012 timeframe, oilfield service companies scrambled to plug labor force gaps. Some even went so far as to assemble a labor force from across the country and house the workers at hotels rented under a multi-year contract by the company, as Halliburton did in Whites City, NM, on the northern edge of the Delaware Basin.[16] In the Permian Basin, demand for hotel rooms in nearby Carlsbad, NM, drove rates to as high as $400/weeknight by late summer 2014. This state of affairs was mirrored in the Midland-Odessa area as well.

Yet when oil prices began falling in late 2014 and into early 2015, many of the same service providers who had frantically hired staff to meet oilfield labor demand began mass layoffs. For example, Halliburton moved from leasing entire hotels to house workers in 2012 to reducing its workforce headcount by 40% since the beginning of 2015 in response to the global oil price downturn.[17] It is difficult to assess precisely how former oilfield laborers will respond if the companies that released them at some point during the last 18 to 24 months reach back out. That said, we expect a palpable impact from shortages of experienced oil field hands, especially for drilling and pressure pumping. It could take several quarters for service companies to rebuild a sufficient human capital base to support a substantial ramp-up in drilling and completion activity.

How Significantly Could Rising Service Costs Affect Breakeven Prices?

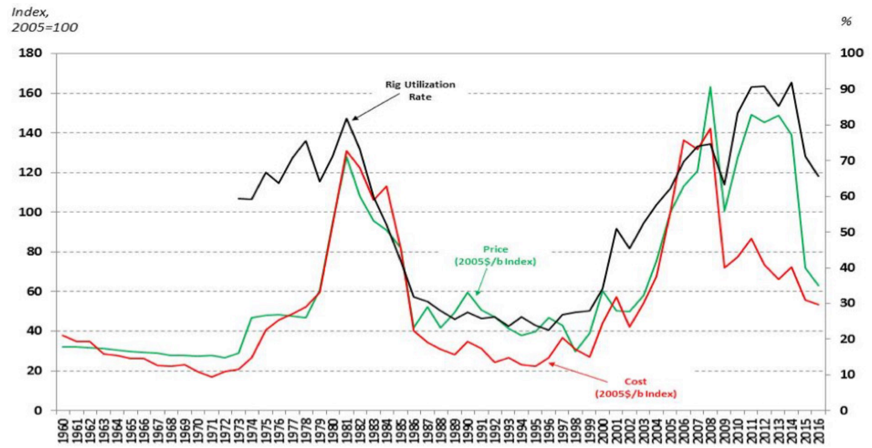
The first three quarters of 2016 hit service company bottom lines hard. Halliburton—the largest global provider of pressure pumping services—suffered consecutive quarters of negative operating income in its core North American business for the first time in more than a decade (Figure 3). Even during in late-2008 to late-2009, when crude oil prices plummeted from $145/bbl to $34/bbl before recovering in the back half of 2009, Halliburton's reported North American operating income never went negative.

Service cost inflation due to shortfalls in equipment and personnel deserves significant attention as it holds the potential to affect breakeven economics for upstream operators on two distinct levels. First, as well service costs rise, total well costs will generally rise, thus potentially rendering some prospects uneconomic. Second, any delay caused by lack of availability of drilling and/or completion service capacity negatively affects well program economics and risks stranding capital.

Costs to drill and complete wells tend to move with the underlying price environment (Figures 4 and 5), which is a signal of the impact of changes in demands for rigs, oil field services, and personnel. As prices rise, interest in upstream investment also rises, which tends to stress supply chains and drive up costs. Indeed, there is a strong positive correlation between costs and rig utilization. This basic point naturally begs the question, "To what extent will costs rise if drilling ramps up again in the US Lower 48?"

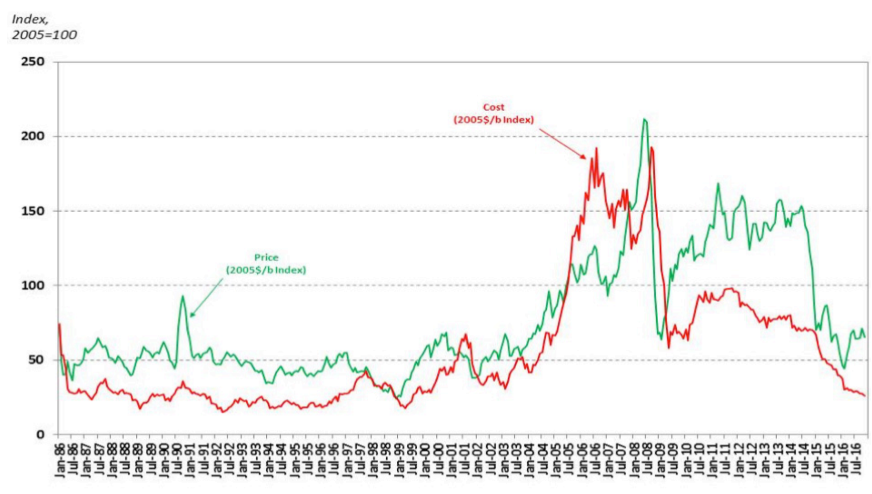
The answer to this question is not obvious. Analysis of monthly data in Figure 5 reveals that the dollar *per barrel* cost declined by 63% from November 2014 through November 2016. By contrast, the dollar *per well* cost (Figure 6) declined by 34% over the same time period. This indicates, as seen in Figure 6, that production per well drilled increased during that two-year window. Indeed, well productivity improved by about 77%. Altogether, productivity gains accounted for an estimated 69% of the *per barrel* cost reduction while actual service and material cost reductions accounted for 31%.

FIGURE 4 — OIL PRICE, DEVELOPMENT COSTS, AND RIG UTILIZATION (ANNUAL, 1960–2016)



SOURCE Data compiled from the Bureau of Labor Statistics, the Energy Information Administration, and the Bureau of Economic Analysis; Data analysis by authors

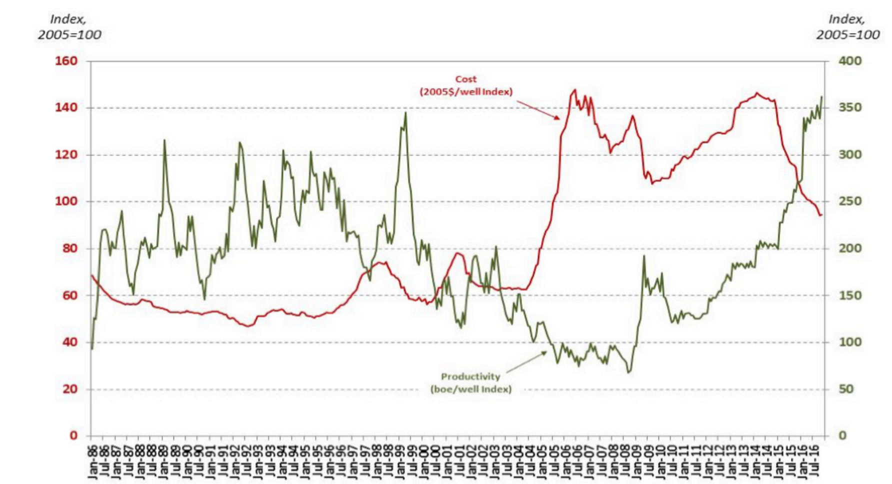
FIGURE 5 — OIL PRICE AND DEVELOPMENT COSTS (MONTHLY, JAN. 1986–NOV. 2016)



SOURCE Data compiled from the Bureau of Labor Statistics, the Energy Information Administration, and the Bureau of Economic Analysis; Data analysis by authors

However, a large proportion of the cost reductions that came from productivity improvements occurred as operators simultaneously moved into better acreage in an effort to maintain profitable operations and employed different completion techniques (longer laterals, more water and sand, etc.). So if oil prices increase and operators reverse trend by moving into more marginal acreage, it is thus far unclear to what extent the productivity gains realized over the last two years will persist.

FIGURE 6 — AGGREGATE WELL PRODUCTIVITY AND PER WELL COSTS (MONTHLY, JAN. 1986–NOV. 2016)



SOURCE Data compiled from the Bureau of Labor Statistics, the Energy Information Administration, and the Bureau of Economic Analysis; Data analysis by authors

NOTE As constructed, in the very short term productivity will generally shift when the number of active rigs rises and declines as a matter of construction because production does not change as rapidly as rigs lay down. This contributes to the observed "choppiness" in the data but does not persist over a long period.

The data suggest that if all productivity gains are maintained going forward, as drilling and completions activity ramps up, *per barrel* costs could rise by 52% from their current levels. If, however, productivity gains were to be completely lost as drilling activity ramps up, then per barrel costs would fully reverse, thereby increasing by 169%.[18] In other words, less than a third of the *per barrel* cost decrease realized over the last two years is reversed if productivity gains can be maintained, which would convey a relatively minor impact to the profitability of new wells drilled. *Hence, the degree to which productivity persists is a critical element in understanding the responsiveness of shale to price increases.*

Confounding matters even more, the potential impact of rising service costs on well breakeven economics is likely to be unevenly distributed, with the larger and more efficient shale developers the most insulated. For instance, EOG Resources reported in November 2016 that in its core Delaware Basin Wolfcamp oil play, almost three-quarters of the net savings realized over recent quarters in its completed well cost arises from efficiency gains, with only 27% coming from service cost reductions.[19] These results are remarkably similar to the aggregate US data presented in Figures 5 and 6 and discussed above.

If a large portion of cost reductions are structural—related to improved completion techniques, for example—then they are likely to remain even if we see a rapid increase in drilling and completion activity. Moreover, if innovations in the approach to production continue, productivity need not decline as new and more marginal acreage is developed. For example, greater use of multi-well pads in the Midland and Delaware Basins will enable wells to be fracture-stimulated and brought into production more quickly thereby reducing service costs *per barrel* of oil produced. Concho Resources reports that in 2017 it plans to use multi-well pads for more than 70% of its drilling program, as opposed to 50% in 2016 and 15% in 2014. This is an example of a durable structural change that will lend advantages to operators with the scale and logistical base to implement it.

BOTTOM LINE

Given recent statements by industry participants, it is reasonable to expect that if WTI crude prices stabilize at or above $60/bbl, major parts of the US shale sector that are currently dormant will ramp up. The extent to which this occurs depends upon the extent to which the productivity gains observed over the last couple of years can persist. A significant ramp-up in development would likely induce crunch points in the long and complex shale supply chain and impact costs *per well*. But operators' moves to capture economies of scale can help blunt the impact of such headwinds. Examples include the 19,000-ton unit train of frac sand that Halliburton and US Silica moved into the Eagle Ford region in October 2016 and the frac jobs in the Delaware Basin that now sometimes exceed 30 million gallons of water—enough to fill more than 45 Olympic swimming pools.[20]

As the benefits of such structural shifts percolate through the industry, if and when oil prices reach a sufficient level to stimulate broader drilling and completions activity, logistics will matter as much as geophysics in driving production forward. Indeed, near-term constraints on equipment and personnel could force extended lead times for those not fortunate enough to have long-term agreements or vertically integrated supply chains already in place. Thus, the pace at which shale responds to a higher price could become as much a function of logistics and oilfield service capabilities as it is geology and mineral rights. In sum, many factors must be elastic in the short-run for shale production response to be robust.

Hence, the degree to which productivity persists is a critical element in understanding the responsiveness of shale to price increases.

ENDNOTES

1. Continental Resources, one of the largest Bakken producers, cites $60 WTI as the point at which it will begin putting additional drilling rigs to work (John D. Hart, chief financial officer, treasurer, and senior vice president, at the company's first quarter 2016 earnings call on May 5, 2016). The Bakken shale is a useful proxy for overall US shale liquids activity because if producers in that remote play believe oil from the play's premium acreage can overcome high transportation costs and be profitably marketed, oil from quality acreage in the more favorably situated Eagle Ford and Permian Basin will also generally be "in the money."

2. James J. Volker, chairman, president and CEO of Whiting Petroleum, at the company's second quarter 2016 earnings call, July 28, 2016. See also http://www.wsj.com/articles/energy-producers-edge-closer-to-tapping-drilled-but-uncompleted-wells-1477139848.

3. See, for instance, "DUC and recover: the backlog of L48 uncompleted wells," Wood Mackenzie, October 13, 2016, https://www.woodmac.com/analysis/DUC-and-recover-backlog-L48-uncompleted-wells; Jonathan Garrett, "US Shale: Winning in a volatile environment," Wood Mackenzie, October 2016, http://www.spegcs.org/media/files/files/759d9ea6/US_Shale_Winning_in_a_Volatile_Environment_WSG_October_19_2016_l97Zzmt.pdf.

4. Note that we focus on October 2016 data, as that is the month for which data is last reported by EIA at the time of this report.

5. See, for instance, Tanya Andrien, "A Guide to American DUCs (Drilled Uncompleted Wells)," *Forbes*, June 27, 2016, http://www.forbes.com/sites/drillinginfo/2016/06/27/american-ducs-drilled-uncompleted-wells/2/#524a1b3b3474 .

6. Hart, earnings call, May 5, 2016.

7. Michael L. Hollis, Diamondback Energy's chief operating officer and vice president of drilling, at the company's second quarter 2016 earnings call on August 3, 2016.

8. Vela Addison, "North American Frack Demand Falls, Cold-Stacking Could Carry Into 2016," *Hart Energy E&P Magazine*, December 22, 2015, http://www.epmag.com/north-american-frack-demand-falls-cold-stacking-could-carry-2016-832641#p=full. The story reports that 9.1 million hydraulic horsepower was out of service in the US market at year-end 2015, accounting for 52% of total capacity. Hence this analysis assumes 9 million hydraulic horsepower are currently available in the US marketplace.

9. Ernest Scheyder and Terry Wade, "U.S. shale oil's Achilles heel shows signs of mending," *Reuters*, July 1, 2016, http://www.reuters.com/article/us-usa-shale-declinerates-idUSKCN0ZH3RQ.

10. See, for instance Steven Gray, RSP Permian's chief executive officer and director, second quarter 2016 earnings call on August 9, 2016: "At $55 oil, we would be

comfortable ramping up to five operated rigs where we would expect to grow production by approximately 30% or more."

11. Hart, earnings call, May 5, 2016.

12. Continental Resources Reports Third Quarter 2016 Results," November 2, 2016, http://bit.ly/2k1Xplz.

13. Citing 10-Q reports from Concho Resources, Diamondback Energy, and RSP Permian, all of which maintain substantial operations in both the Delaware and Midland Basins.

14. For an explanation of "cold stacking" vs. "warm stacking," see Monitor Systems, "COLD STACKED RIGS: What is the difference between warm stacked and cold stacked drilling rigs?," http://www.monitor-systems-engineering.com/cold_stacked_rigs.html.

15. Vela Addison, "North American Frack Demand Falls, Cold-Stacking Could Carry Into 2016," *Hart Energy E&P Magazine*, December 22, 2015, http://www.epmag.com/north-american-frack-demand-falls-cold-stacking-could-carry-2016-832641#p=full.

16. Zachary Toliver (Energy Media Group) and Jon Lofquist (Carlsbad Current Argus), "Oil Patch Workers Drive Carlsbad Hotel Growth," Permianshale.com, August 18, 2014, http://permianshale.com/news/id/104800/oil-patch-workers-drive-carlsbad-hotel-growth/. See also George Watson, "What is the Economic Impact of Oil, Gas in the Permian Basin?" Texas Tech University, September 4, 2014, http://today.ttu.edu/posts/2014/09/what-is-the-economic-impact-of-oil-gas-in-permian-basin.

17. See Halliburton's 10-Q SEC Filing for third quarter 2016, October 28, 2016.

18. This is based on a fairly rudimentary calculation meant to convey a *ceteris paribus* result; it follows if the *per well* costs rise from current levels to November 2014 levels (index value of 94.4 in November 2016 to 143.6 in November 2014), but well productivity remains constant at its current level (index value of 362.5 in November 2016 versus 205.1 in November 2014). If we hold productivity constant, we get a 52.1% increase in *per barrel* costs (index value increase from 26.0 to 39.6). Notably, this is smaller than if we allow all productivity gains realized since November 2014 to be erased, which results in a *per barrel* cost increase of 169% (index value of 26.0 increasing to 70.0).

19. Company Investor Presentation, Delivered at Bank of America Merrill Lynch Global Energy Conference, 17 November 2016.

20. "Halliburton and U.S. Silica break record for moving largest sand unit train in North America," Halliburton Press Release, October 13, 2016, http://www.halliburton.com/public/news/pubsdata/press_release/2016/halliburton-us-silica-break-record.html.

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