The Payne Institute for Public Policy

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COMPLETION EQUIPMENT CONSTRAINTS

U.S. Oil & Gas Extraction Briefing - Second Quarter 2022

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The Payne Institute for Public Policy at the Colorado School of Mines produces a quarterly commentary series on the U.S. upstream oil and gas sector's financial health, activity levels, employment and outlook.

SUMMARY

Activity in the U.S. oil patch has reached the point of being supply constrained. Areas of tightness had been identified earlier in the year and include wellbore pipe (known as Oil Country Tubular Goods, or OCTG), hydraulic fracturing (frac) services and frac sand.

For now, the oilfield services providers are not yet focusing on adding meaningful amounts of capacity. They, like their oil company customers, have received clear messages from investors and lenders to prioritize financial returns over growth. And for at least some services, it is only with further price increases — and confidence that demand will persist — that the providers can justify investing in new equipment. Thus, it appears likely that the service industry will not spend in earnest to add capacity until 2023, particularly in the key area of frac equipment.

Efficiency in operations, which primarily translates to getting more hours per day out of equipment, continues to provide some basis for growth of oil and natural gas production. Further, the oil companies continue to refine their completions efforts to improve the productivity of their wells.

But it seems unlikely that efficiency gains can offset the dual challenges of a financial-return mindset for the industry and equipment constraints. U.S. hydrocarbon production growth appears likely to remain modest for the foreseeable future, including that the public O&G companies continue to target 3-5% production growth year-over-year in 2022.

The oilfield activity counts continued their now-lopsided climb in 2Q22, with the rig count up another 14% vs. the frac crew count up 4% from 1Q22. As suggested above, the frac crew count appears to be nearing a near-term peak, although there is opportunity to expand supply modestly without building new equipment; contract drilling companies have more potential to reactivate drilling rigs and that should allow the drilling rig count to continue to rise. Related, it is expected that the Drilled but Uncompleted (DUC) well count will reverse its downward slide and begin to rise in the second half of 2022.

With respect to inflation, the outlook has perhaps edged a little higher to 15-20% year-over-year in 2022, net of O&G company efficiency measures. Although OCTG and frac-related services are experiencing the greatest increases, there is some broadening of inflation to include other services, including drilling. **Including inflation, O&G company spending increases are expected to be 35-40% year-over-year in 2022 (with the rest of the spending growth funding more development activity).**

The Inflation Reduction Act (IRA) is unlikely to have an appreciable impact on onshore (or offshore) activity, despite its inclusion of mandated leasing activity. As has been addressed in previous quarterlies, the O&G industry has adequate access to Federal lands through existing leases and the vast majority of activity onshore occurs on privately-held land. Rather, the constraints are investor demands for spending discipline and, increasingly, availability of services as noted above. It seems plausible that there can be a more pronounced positive impact from the stipulations to streamline major infrastructure project approvals — recent years' stymying of new natural gas pipelines in the Northeastern U.S., for example, has suppressed natural gas development in that region.

Meanwhile, the threat of methane emissions charges in the IRA should spur investment in equipment and process changes to lower emissions and ongoing expenditure for monitoring and verification, even though the charges can only be applied to a fairly small set of large emitters. It is unclear how much of a burden this places on the industry and the IRA does appropriate over $1.5 Billion to help support such investment.

Please see pages 3-4 for recent activity discussion, pages 5-6 for discussion of service cost increases and pages 6-7 for an update on the impact of the IRA.

Reference Table – U.S. Oil & Gas and Activity Statistics

	2Q20	3Q20	4Q20	1Q21	2Q21	3Q21	4Q21	1Q22	2Q22
Oil Price (West Texas Intermediate, $/bbl)	$29.14	$40.94	$42.72	$58.14	$66.16	$70.55	$76.97	$94.86	$108.38
Nat Gas Price (Henry Hub, $/Mcf)	$1.70	$2.00	$2.53	$2.77	$2.95	$4.37	$4.72	$4.67	$7.49
Oil Production (Millions of Barrels per Day)	10.8	10.8	10.9	10.7	11.3	11.2	11.6	11.5	11.6
Nat. Gas Dry Production (Billions of Cubic ft per Day)	89.6	90.0	91.1	90.4	93.2	93.9	96.5	94.6	96.4
LNG Exports (Billions of Cubic ft per Day)	5.5	3.9	8.8	9.2	9.8	9.6	10.3	11.9	12.2
Drilled but Uncompleted Wells (DUCs)	8,816	8,439	7,673	6,880	6,149	5,529	4,818	4,398	4,245
Rig Count	378	240	293	374	436	484	544	620	704
Frac Spread Count	89	79	132	156	221	241	263	268	278
Direct Employment In O&G Extraction (Thousands)	362.5	340.3	333.4	329.8	345.0	354.5	369.0	382.5	403.2

Sources: *Macrotrends.net, Energy Information Administration, Baker Hughes, Primary Vision, Haynes and Boone LLP, Bureau of Labor Statistics*

Notes:
– All reflect averages for the period except employment and DUCs, which are end of period
– Direct Employment is from the BLS' Current Employment Statistics; reflects Oil & Gas (NAICS code 211) and Support for Mining (213) segments. NAICS code 213 includes ~5,000-10,000 employees in the coal and non-energy sectors
–N/A = Not Available

SECOND QUARTER 2022 UPDATE

U.S. onshore activity rose again in 2Q22, with the drilling rig count averaging 704 in the quarter vs. 620 in 1Q22 (up 14%) and vs. its low of 230 set in August 2020. The U.S. onshore hydraulic fracturing (frac) spread count rose only 4% to average 280 in 2Q22 (see Reference Table and Exhibit 1). The rig and frac spread count averages in 2Q22 were 6% and 20% below late-2019 levels, respectively. For reference, as of August 5, 2022 the rig and frac crew counts were 748 and 289, respectively.

The continued faster growth of the rig count vis-à-vis the frac spread counts confirms earlier suspicion that there is tightness in frac equipment availability and that the Drilled but Uncompleted (DUC) well count may have found bottom. The DUC count did continue to decline in 2Q22, but at a much slower pace, falling by 153 wells to 4,245 at the end of June vs. an average decline of 700 wells per quarter in 2021 (see reference table). Given the rig count growth, it is plausible the DUC count starts to regrow in the second half of 2022.

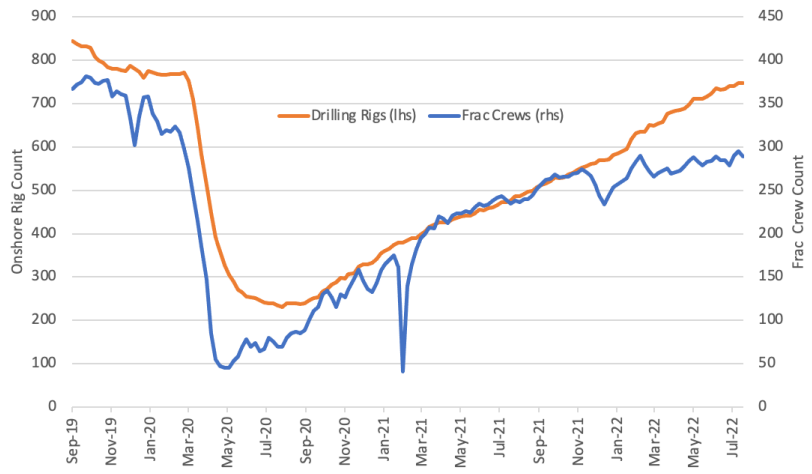
(Continued on next page)

For the second quarter, the growth in the count of rigs drilling for natural gas continued to outpace the growth in oil-directed rigs (20% sequentially in 2Q22 for gas-directed vs. 11% for oil). That growth remains somewhat localized, with the Haynesville, for example, continuing to add rigs at a faster pace than the Marcellus given the Haynesville's access to pipeline takeaway capacity and proximity to LNG (see Exhibit 2 and Appendix 1 for reference).

Production of oil and natural gas in 2Q22 recovered from winter weather-related constraints in 1Q22, to 11.6 Million barrels per day (Mbd) and 96.4 Billion cubic feet per day (Bcfd). LNG exports grew to 12.2 Bcfd in 2Q22 from 11.9 Bcfd in 1Q22 and 10.3 Bcfd in 4Q21 as strong overseas pricing and efforts to curtail use of Russian natural gas provide greater opportunity for export. Liquefaction facilities are now operating at or near peak capacity — including benefitting from debottlenecking efforts — and are seeking approvals for expansion (for more discussion on LNG capacity expansion plans, see our March 2022 quarterly report).

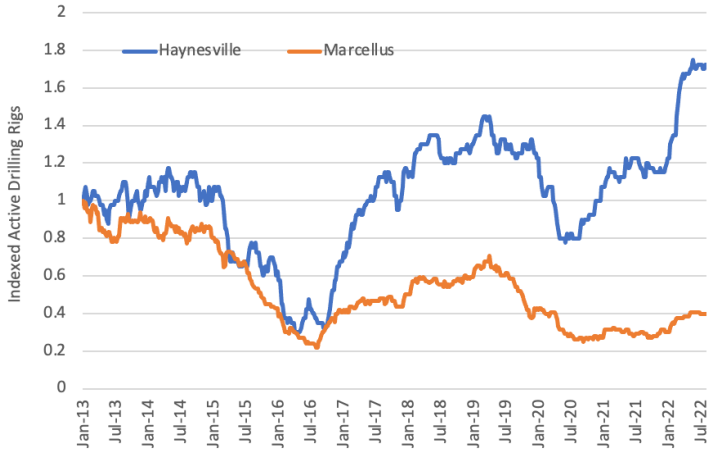
Direct upstream industry sector employment rose by 20,700 in 2Q22 to 403,200 and is now ~25% above the post-COVID trough. Direct employment in the upstream remains nearly 20% below the recent peak set in 1Q19 and 35% below levels experienced in 2014 (see Reference Table).

Exhibit 1:
Rig and Frac Crew Counts
September 2019 – July 2022



Note: *February 2021 crew count impaired by ice storms*
Source: *Baker Hughes, Primary Vision*

Exhibit 1:
Haynesville vs. Marcellus Indexed Rig Counts
2013 – July 2022



Source: *Baker Hughes*

THEMES

INFLATION AND SERVICE COMPANIES' SUPPLY RESPONSE

At this point, the vast majority of the publicly-traded U.S.-centric oil companies have set their spending expectations higher for 2022, reflecting (generally) upward pressure in the pricing of goods and services related to their hydrocarbon development programs. The degree to which capital spending budgets were raised varied, but +/- 10% was not uncommon. This incremental spend points to the oil companies spending 35-40% more on developing oil and gas than they did in 2021.

For the O&G companies, higher realized selling prices for oil and natural gas more than offset this higher spending, resulting in both higher profitability in 2Q22 and commitments to give even more cash back to investors.

The oilfield service companies (the oil companies' suppliers) echoed the sentiment that a combination of rising input costs and market tightness (i.e. little excess capacity) had given them the ability to raise prices, as well as to secure work commitments from their oil company customers for the future. As had been previously cited by the industry and discussed in Payne's last quarterly, the most acute increase relates to steel, and particularly for wellbore pipe known as Oil Country Tubular Goods (OCTG), and frac services, although price increases have broadened to other service areas, including drilling, as well.

Although OCTG comprises less than 10% of a well's cost, pricing, which industry consultant Pipelogix has indicated is over $3,500 per ton, has now roughly tripled from the COVID-induced trough and is more than double its average through the prior decade.

For frac services, which can comprise ½ of a well's cost, it is harder to calibrate pricing moves. Pricing is determined

by (expected) utilization, contract length, alternate fuel-source (such as dual-fuel capability with natural gas or electrified fleets) and broader service-provision (including sand or related completion services along with the frac), all of which make apples-to-apples pricing comparisons more difficult. To offer some perspective, however, pricing is likely to be up more than overall oil company inflation in 2022. Thus plausibly overall frac pricing has risen 20-25%, although so-called leading edge pricing is likely up far more.

"Frac service pricing is up ~20-25% from trough but is still likely to be 15% below pre-COVID levels by year-end 2022."

How the services industry responds to supply constraints remains uncertain. As noted in the previous quarterly, OCTG constraints were exacerbated both by plant closures during the 2020 downturn and cessation of imports from Russia and Ukraine.

As for frac equipment, the answer appears more complicated. On the one hand, the service companies

appear to feel the same pressure from investors to improve their financial returns, rather than pursue growth. Further, as one frac service provider has indicated, pricing by the end of 2022 is still likely to be 15% below pre-COVID levels and published profitability would suggest it is prudent for the industry to secure even higher prices before ordering (a lot of) new capacity. Finally, the use of alternate fuels to power the frac equipment appears to allow the frac service companies to charge higher pricing given fuel savings to the customer. On the other hand, as has been noted in recent quarterlies, industry dynamics regarding utilization — such as the use of simulfrac completion techniques — appears to afford more profit potential at lower pricing. In addition, the frac service industry has consolidated through the recent downturn, leaving current providers likely more comfortable that the industry is less likely to overbuild. Nevertheless, it is tempting to guess that pricing (average and leading edge) will have to rise for a couple more quarters at least and the companies will have to secure visibility on work through 2023, if not further out, before the industry commits significant capital to grow the fleet.

Given the headlines about frac sand inflation, it is worth repeating the view that sand constraint or pricing appears unlikely to be an important factor for long in oilfield activity. As discussed in our last quarterly, in-basin availability, perhaps boosted by mobile units, points to adequate availability and much lower-than-historical prices (even if recent higher prices hold) in the medium term.

INFLATION REDUCTION ACT

The recently passed Inflation Reduction Act (IRA or the Act) contains provisions that may impact U.S. extraction operations. The positives for the industry specifically related to extraction include additional lease sales and directives to streamline permitting of infrastructure projects, including fossil fuel pipelines. The negatives are aligning royalty rates with state levels, the threat of

"The Inflation Reduction Act (IRA) is unlikely to have an appreciable impact on onshore (or offshore) activity, despite its inclusion of mandated leasing activity."

charges on methane emissions and, for companies with over $1 Billion in income, the alternative minimum tax on corporations. These are discussed below.

The IRA provides for both onshore and offshore lease sales in specific ways. For onshore, the Act requires the Department of the Interior (DoI) to host a lease sale within four months of issuing new onshore wind and/or solar Rights of Way. For offshore, the Act requires DoI to (1) award the high bidders their leases from Gulf of Mexico Lease Sale 257 held last November and (2) conduct lease sales in Alaska's Cook Inlet (Sale 258) by the end of 2022 and in the Gulf of Mexico (Sales 259 and 261) by 2023. Further, the Act requires that at least one offshore oil and gas lease sale that offers at least 60 million acres be held within the year prior to a new offshore wind sale.

IRA includes provisions intended to streamline permitting of major infrastructure projects. These include creation of a project list of "strategic national importance", which is to include fossil fuels among other project types; setting a two year maximum timeline for environmental review for major projects and one year for minor projects; such reviews must have a single inter-agency review document; and steps to limit roadblocks, including shortening the statute of limitations for court challenges.

The Act increases the royalty rate for all new onshore and offshore fossil fuel leases from 12.5% to a minimum of 16.6% (vs. state-land royalty rates of 18.75% in New Mexico and North Dakota, 16.67% in Wyoming, Utah, Montana and 20% in Colorado). The legislation also eliminates noncompetitive leasing, establishes a minimum bid on federal parcels and creates a new per-acre fee for submissions of expressions of interest for onshore oil and gas leases. Royalties must also be paid on all gas produced from leases on Federal lands even if it is lost (to flaring, venting or other releases) subject to certain exceptions.

With respect to methane emissions, the IRA includes a charge from specific facilities, including onshore (and offshore) petroleum and natural gas production, among other oil and natural gas system facilities. The charge would start at $900 per metric ton of methane ($36 per metric ton of CO2 equivalent or MTCO2e) and rise to $1,500/ton after two years.

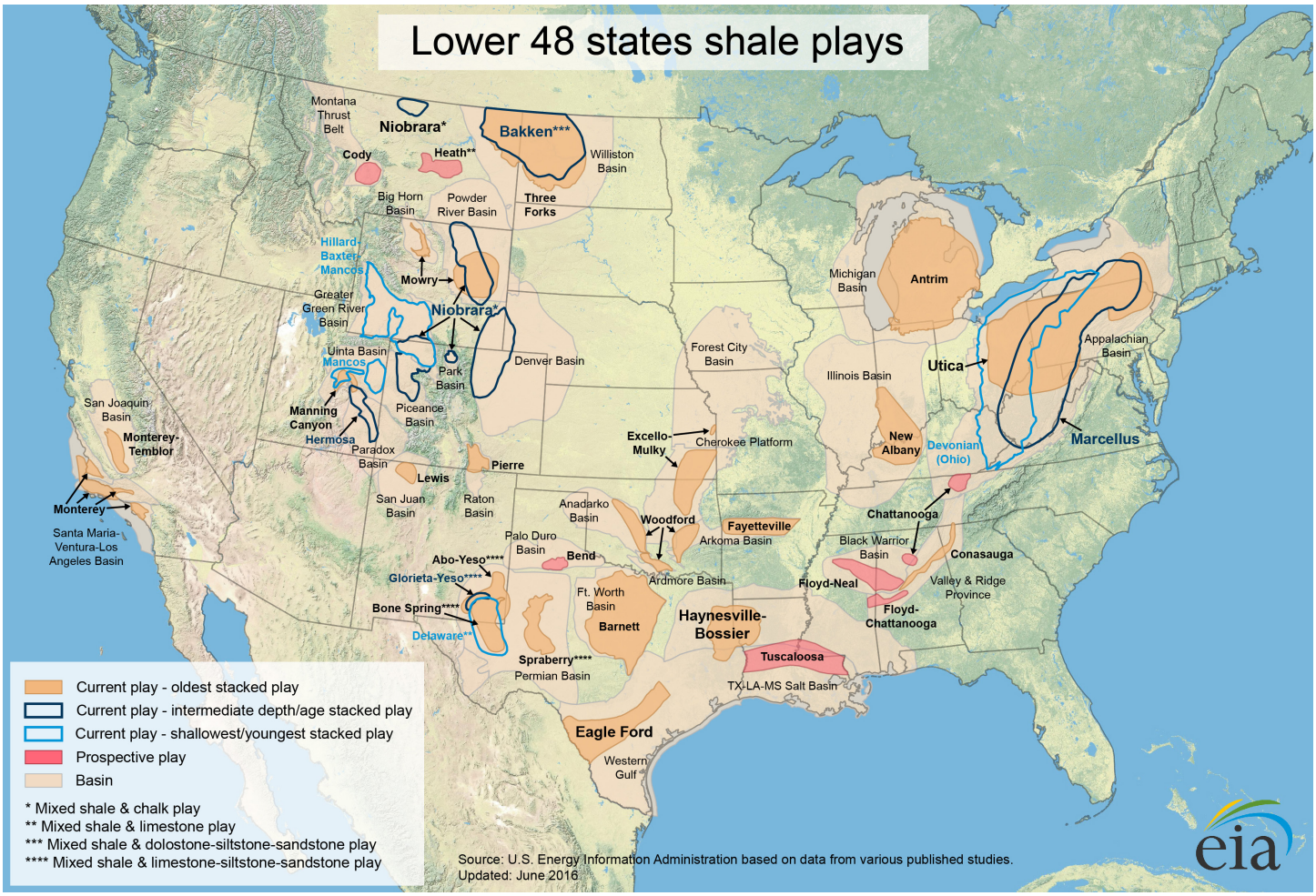
Specific conditions limit the number of facilities and volumes for which the charge could apply — facilities must emit at least 25,000 MTCO2e and the charge only applies to emitted tons that exceed 0.2% of the natural gas sent to sale from the facility. As a result, estimated methane emissions from onshore oil and natural gas production, gathering and boosting systems subject to the charge is 43 Million MTCO2e vs. 66 Million MTCO2e reported to the Environmental Protection Agency (EPA) (based on 2019 data).

More generally, the IRA provides for exemptions from charges if EPA regulations yield as much or more reduction in methane emissions. The EPA proposed regulations for the same facilities in November 2021, but such regulations have not been finalized. With that said, it is thought that the evaluation (to be performed by the EPA) of whether the EPA's rule results in as much methane reduction will be complex and controversial. Such likely paring back of the breadth of the emission charges has led to the view that they would result in a very modest (<1%) increase in natural gas prices paid by residential consumers.

However, whether in response to the threat of these charges for emissions or to EPA regulations, there is to be some burden imposed on the industry to replace equipment and adjust processes to limit methane emissions. The cost of such action would be very site specific. The IRA does include appropriations of $850 Million to help affected facilities cover such costs and of $700 Million to address methane emissions from "marginal conventional wells."

APPENDIX 1

Map of U.S. Unconventional Hydrocarbon Plays



Source: U.S. Energy Information Administration

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Brad Handler is a researcher and heads the Payne Institute's Sustainable Finance Lab. He is also the Principal and Founder of Energy Transition Research LLC. He has recently had articles published in the Financial Times, Washington Post, Nasdaq.com, Petroleum Economist, Transition Economist, WorldOil, POWER Magazine, The Conversation and The Hill. Brad is a former Wall Street Equity Research Analyst with 20 years' experience covering the Oilfield Services & Drilling (OFS) sector at firms including Jefferies and Credit Suisse. He has an M.B.A from the Kellogg School of Management at Northwestern University and a B.A. in Economics from Johns Hopkins University.

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