Staying-the-Course Despite Higher Prices

U.S. Oil & Gas Extraction Briefing

December 2021

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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

Restoring attractiveness to shareholders continues to dominate U.S. public oil and natural gas (O&G) industry mindset. Thus far, company commentary for 2022 is to “stay the course,” i.e., (1) maintain spending at current levels despite commodity prices that suggest they can earn (and therefore spend) much more money and (2) give back more money to shareholders than they have historically. That leaves the expectation that private oil companies will continue to raise their spending faster than their public peers – and that U.S. oil production will only gradually continue to recover. This discipline, as well as operating efficiencies, also imply that industry hiring recovery is likely to remain muted.

As with so many other sectors of the economy, the O&G companies are now facing inflation pressures, although they believe the impact can be partially offset via the efficiencies in well development that they have pursued over the last several quarters.

Finally, the recent global surge in natural gas prices adds impetus to efforts to develop more natural gas in the U.S. Any growth would build on what is already an export boom — ~10 Billion cubic feet per day (Bcf/d) in 2021 from 0 in 2014 and on its way to as much as 18 Bcf/d by 2030. It would also likely be sourced in basins including the Permian, Haynesville and Marcellus.

Please see pages 4-5 for recent activity discussion, pages 5-6 for inflation discussion and page 6-7 for an update on the impact on activity outlook of the recent global surge in natural gas prices.
## Reference Table – U.S. Oil & Gas and Activity Statistics

<table>
<thead>
<tr>
<th></th>
<th>4Q19</th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
<th>4Q20</th>
<th>1Q21</th>
<th>2Q21</th>
<th>3Q21</th>
<th>11/12/21</th>
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<tbody>
<tr>
<td><strong>Oil Price</strong></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>(West Texas Intermediate, $/bbl)</td>
<td>$56.87</td>
<td>$45.80</td>
<td>$29.14</td>
<td>$40.94</td>
<td>$42.72</td>
<td>$58.14</td>
<td>$66.16</td>
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<tr>
<td><strong>Nat Gas Price</strong></td>
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<td></td>
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<tr>
<td>(Henry Hub, $/Mcf)</td>
<td>$2.40</td>
<td>$1.90</td>
<td>$1.70</td>
<td>$2.00</td>
<td>$2.53</td>
<td>$2.77</td>
<td>$2.95</td>
<td>$4.37</td>
<td>$5.08</td>
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<tr>
<td><strong>Oil Production</strong></td>
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<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>(Millions of Barrels per Day)</td>
<td>12.8</td>
<td>12.7</td>
<td>10.8</td>
<td>10.8</td>
<td>10.9</td>
<td>10.7</td>
<td>11.3</td>
<td>11.2</td>
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<tr>
<td><strong>Nat. Gas Dry Production</strong></td>
<td>96.6</td>
<td>96.4</td>
<td>89.6</td>
<td>90.0</td>
<td>91.1</td>
<td>90.5</td>
<td>93.2</td>
<td>94.5</td>
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<tr>
<td><strong>Drilled but Uncompleted Wells</strong></td>
<td>8,365</td>
<td>8,513</td>
<td>8,826</td>
<td>8,770</td>
<td>8,046</td>
<td>7,269</td>
<td>6,416</td>
<td>5,629</td>
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<tr>
<td><strong>Rig Count</strong></td>
<td>797</td>
<td>763</td>
<td>378</td>
<td>240</td>
<td>293</td>
<td>374</td>
<td>436</td>
<td>484</td>
<td>559</td>
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<tr>
<td><strong>Frac Spread Count</strong></td>
<td>363</td>
<td>318</td>
<td>89</td>
<td>79</td>
<td>132</td>
<td>156</td>
<td>221</td>
<td>241</td>
<td>269</td>
</tr>
<tr>
<td><strong>Direct Employment</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>In O&amp;G Extraction (Thousands)</td>
<td>458.0</td>
<td>442.0</td>
<td>376.0</td>
<td>383.2</td>
<td>369.5</td>
<td>387.5</td>
<td>404.9</td>
<td>421.3</td>
<td>N/A</td>
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</tbody>
</table>

**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
- Winter storm Uri weighed on 1Q21 averages. Oil production, for example, was 11.1 million b/d in January and 9.9 million b/d in February
- N/A = Not Available
THIRD QUARTER 2021 UPDATE

With the continued recovery in oil and natural gas prices, the U.S. oil industry’s activity recovery also continued in 3Q21. The U.S. onshore drilling rig count averaged 484 in the quarter, vs. 436 in 2Q21 and its low of 230 set in August 2020. The rig count had risen to ~560 by mid-November 2021. Private companies are still driving the majority of the rig count growth. The U.S. onshore hydraulic fracturing (frac) spread count averaged 241 in 3Q21 (vs. its May 2020 trough of 45) and rose to ~270 by mid-November 2021 (see Reference Table and Exhibit 1). The rig and frac spread count averages in 3Q21 were 39% and 33%, respectively, below late-2019 levels.

Although the rig and frac spread count continue to rise in lockstep (see Exhibit 1), the ratio of 2 rigs per 1 frac spread supports a faster pace of completions than drilling of new wells. Hence, the Drilled but Uncompleted (DUC) well count continued to decline, falling to 5,385 by the end of 3Q21 from 6,136 at 2Q21-end and from a high of over 8,800 in 2020 (see Reference Table). This trend is supportive of production growth with a lower rig count. Given efficiencies in completing wells and to some degree larger frac crews, it is expected that production recovery could continue even with rig counts of ~550. However, the DUC count is thought to have a natural floor, suggesting that at some point additional production would require drilling more new wells and thus meaningfully higher rig counts.

Exhibit 1: Rig and Frac Crew Counts September 2019 – November 2021

As discussed in earlier quarterlies, the activity recovery has been led largely by private companies as public O&G companies are restraining their capital spending. The public companies are seeking to convince lenders and investors that they are disciplined stewards of capital. With this goal in mind, many have committed — and have already started — giving back to shareholders a specified fraction of the cash flow (a minimum of 40% or 50% is not uncommon). This return of cash is expected to proliferate (i.e. be executed by more companies) in 2022.

Even factoring in the drawdown of DUCs described above, this spending restraint is a significant factor in the modest recovery of oil and natural gas production over the last year. Further, although it is early in the 2022 planning cycle, commentary from the oil companies points more to flat production levels (relative to current production) next year rather than meaningful growth.

Per the Bureau of Labor Statistics, the upstream oil industry had added back 51,800 direct jobs, to
421,300, by the end of 3Q21 from its trough in 3Q20. These (re-)hires have predominantly been by the service sector, primarily as it staffs the rigs, frac crews and ancillary equipment at well sites as well as employs truck drivers to carry water and materials to and from locations. Oil company employment has grown by only ~6,000 to 142,000. Direct employment in the upstream remains 15% below the recent peak set in 1Q19 and nearly 35% below levels experienced in 2014 (see Reference Table).

Inflationary Pressure; Efficiency Can Partially Offset

The third quarter brought commentary by most of the U.S. oil companies regarding the acceleration of inflationary pressure for well drilling and completion activities. Companies estimated that the overall effect could be 10-15% higher well costs, all else equal, in 2022 than in 2021. The pressure is being driven primarily by higher costs for steel, fuel and labor, which weigh in on different elements of constructing a well. Equipment is selectively in short supply following shut-ins in 2020; overall there is enough tightness to give the service suppliers leverage in their efforts to raise prices to recover higher costs as well as recoup some of the pricing concessions they made in 2020.

The largest component of inflation to-date is in the steel piping that is placed in the wells (commonly referred to as Oil Country Tubular Goods, or OCTG), which comprises approximately 10% of a well’s cost. OCTG pricing has approximately doubled from the trough (see Exhibit 2) – and oil companies are being quoted delivery dates into 2022.

Yet several of the companies, including EOG Resources, Pioneer Natural Resources, Diamondback Energy, and Ovintiv to name a few, expect that ongoing efficiency efforts, as well as securing longer term contracts for services, can partially or even largely offset these inflationary pressures (on a cost-per-barrel-of-oil-equivalent basis). These efficiency measures, which have also been addressed in previous quarterlies (e.g., see here), include:

Exhibit 2:
OCTG Pricing
December 2009 – October 2021

Source: Pipelogix
• the drilling of longer horizontal sections of wells, which saves time relative to drilling more wells to access the same amount of hydrocarbon-bearing rock
• the hydraulic fracturing of two wells at the same time, which saves time vs. fracturing the wells sequentially
• optimization of hydraulic fracturing techniques, which yields greater production per well

NATURAL GAS OFFERS LONGER-TERM GROWTH POTENTIAL

The advent of unconventional (i.e. shale) development in the U.S. unlocked oil deposits previously thought uneconomic to develop, which spurred the oil renaissance in the country. What perhaps is less well known is that shale development also dramatically raised the country’s ability to produce low-cost natural gas. Despite growth in demand for natural gas for power generation (displacing coal) and for liquefaction to ship overseas, this plentiful capacity resulted in several years of low natural gas prices. Low prices, in part, led to the O&G’s industry’s investment focus shifting from natural gas (it was the dominant target for U.S. upstream development 20+ years ago) to oil — as an illustration, the drilling rig count has been ¾ + oil-directed (vs. natural gas-directed) since the Summer of 2012.

With respect to recent activity, the companies that are focused on natural gas development face the same pressure from investors and creditors to be more capital disciplined, which along with low price has contributed to a muted recovery from 2020’s industry collapse. Using the rig count again as a means to illustrate this point, the oil-directed drilling rig count fell 76% from the beginning of 2018 to its trough in August 2020 while the gas-directed rig count fell 62% in the same period. However, the oil rig count has since risen 150% from that trough (to 450 rigs) while the gas rig count has risen only 45% (to 100 rigs) (see Exhibit 3). Dry natural gas production has risen gradually through 2021 to nearly 95 billion cubic feet per day (BCFD) in 3Q21 (see Reference Table).

The path for the O&G industry to grow natural gas production (over a multi-year timeframe) appears to lie in more (liquefaction and) export. Recent strength in natural gas prices globally should bolster the impetus to develop more export capacity, given (1) the plausible geopolitical lessons for Europe of its dependence on Russia (Russia provides ~40% of European gas) and (2) the value of additional LNG to cushion temporary disruptions of primary sources of power; natural gas is also an available alternative to coal in the medium term in the fight against climate change.

Exhibit 3:
Oil, Natural Gas and Gas Region Rig Count Trends 2018-Present

Source: Baker Hughes
With that said, the export market has already grown dramatically over the last several years, to ~10 BCFD on average in 2021 (11% of average natural gas production) from 0 in 2014 (see Exhibit 4). And there are already additional liquefaction projects in the planning stage that would, if all completed, add another 8 BCFD/8% of current production to demand by 2030.

The incremental natural gas production required for this export demand appears most likely to come from three core areas in the U.S. that currently comprise ½ of the country’s production (see Exhibit 5 and Appendix 1):

1) The Marcellus shale, which is largely in Pennsylvania but includes Ohio, West Virginia and New York. The Marcellus comprises 26% of total U.S. dry natural gas production;
2) The Haynesville shale in Northeast Texas/North West Louisiana (11% of U.S. production)
3) The Permian basin in Texas and New Mexico (14%). Much of Permian production is associated gas; there is varying Oil-to-Gas composition across wells in the basin.

The Haynesville has seen stronger recovery vis-à-vis the Marcellus from the 2020 trough — again using rig count as a proxy, the rig count in the Haynesville has risen 40% from the trough vs. the rig count in the Marcellus up 12% — given its proximity to export markets and the pipeline capacity constraints in the Appalachia region. See Exhibit 3 on previous page.
ABOUT THE AUTHOR

Brad Handler is a Senior Fellow at the Payne Institute and is the Principal and Founder of Energy Transition Research LLC. At Payne he is researching the Oil & Gas industry’s role and vulnerability in the global transition to lower-carbon energy as well as how finance can catalyze that transition. He has recently had articles published in the Financial Times, The Washington Post, Nasdaq.com, Petroleum Economist, POWER Magazine 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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