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MACRO
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L48 PRODUCTION
The Treadmill Is Running Too Fast

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FOCUS

How far could onshore L48 production fall if the industry is forced to spend within cash flow? What is the cost to hold production flat across the major plays? What is the base decline rate of the L48 and its major plays?

KEY POINTS

- Production from the nine major L48 unconventional plays could fall by as much as 2.4 MMbbl/d of oil and 14.4 Bcf/d of gas, or 31% and 21% of current output, over the next 12 months if activity immediately drops to cash flow neutrality assuming flat $30/bbl WTI and $2.25/Mcf Henry Hub.
- If the industry were to instead hold production flat, a total outspend of $51 billion is required across the nine plays at the same price deck. This translates to an outspend of about 37%, an unlikely scenario given closed capital markets and strained balance sheets.
- Each $5/bbl and $0.25/Mcf move in both commodities shift our neutral cash flow case by about 0.6 MMbbl/d and 5 Bcf/d. These changes adjust the outspend in our stay-flat case by $13.4 billion.
- These numbers focus on the underlying cash flows and exclude the temporary shelter offered from hedges and the usual delay in production loss from dropped rigs. Including these would push back the timing but not the magnitude of our projections, we believe.
- We estimate $50/bbl is needed for the Bakken and Eagle Ford to hold current production flat and generate positive cash flow compared to $55/bbl in the Delaware, Midland and DJ. For the gas plays, the Haynesville requires $2.75/Mcf, the Marcellus $3.00 and the Utica $3.25.
- Record growth in L48 production over the last three years and the shift to inherently steeper-declining plays increased the overall base decline rates to 39% for oil and 27% for gas. These are respectively 7.1 and 4.4 percentage points higher than 2016 when WTI last fell below $30/bbl.
- To hold production flat, the industry would need to replace about 4.1 MMbbl/d of oil and 27.2 Bcf/d of gas over the next 12 months. The nine major unconventional plays account for 3.6 MMbbl/d and 23.3 Bcf/d of the total annual decline.

GENERAL

In light of the energy commodity price crash, the upstream industry will struggle to maintain production. Capital markets are tighter than 2016 when WTI last fell below $30/bbl and the underlying base decline is much steeper (**Figure 1**). In other words, the treadmill is running faster while operators' capacity to outspend cash flow is more restricted.

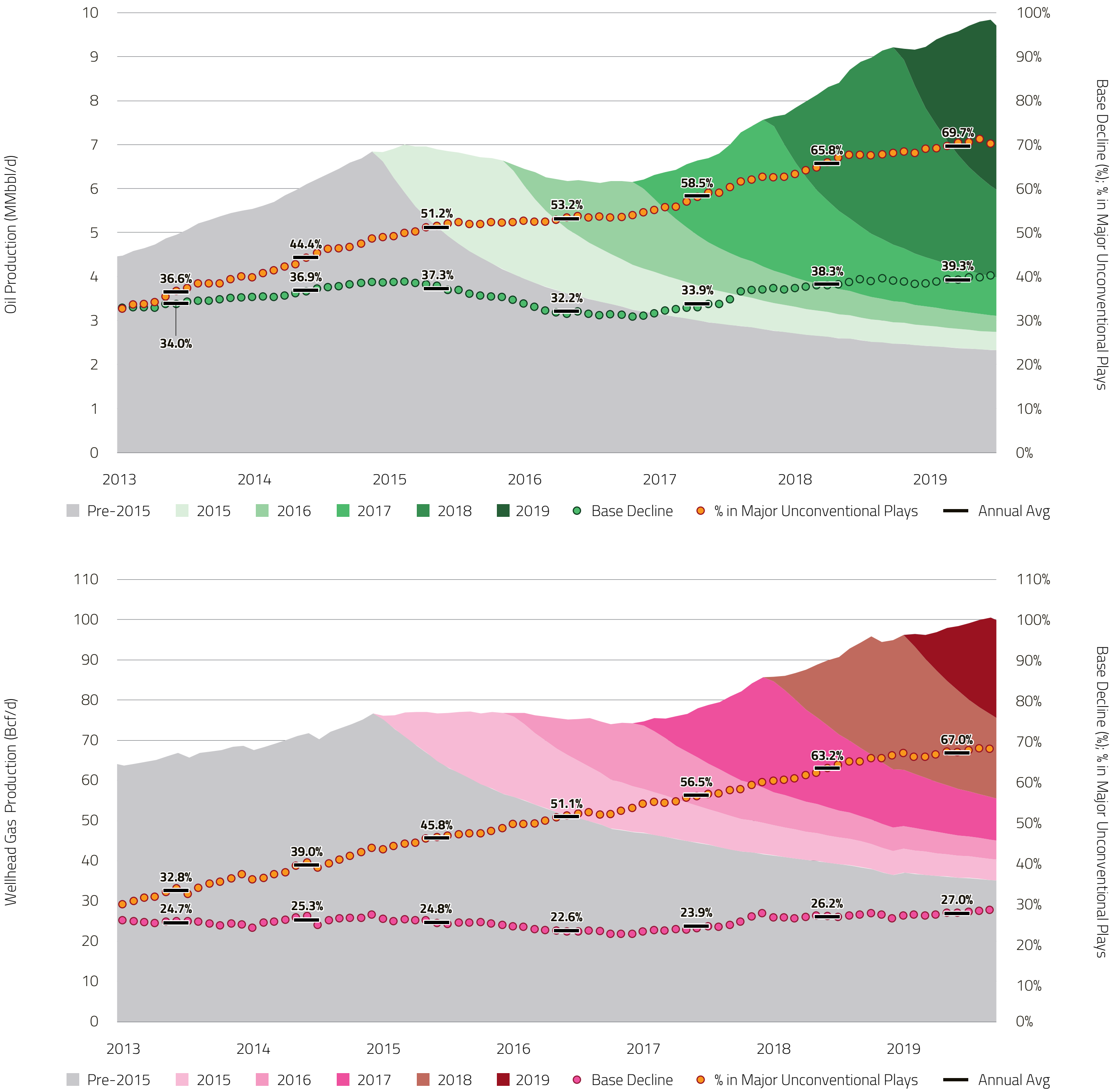
L48 onshore production grew to record levels over the last three years, rising ~55% for oil and 40% for gas. The gains were driven by the major unconventional plays that now account for around 70% of total oil production and 67% of gas, up from 53% and 51% in 2016. This rapid growth from inherently steeper-declining plays make it harder to sustain production during a downturn in drilling and completion activities. We estimate L48 onshore oil and gas base declines are ~39% and ~27%, respectively up 7.1 and 4.4 percentage points from 2016. To hold production flat, the industry would need to replace about 4.1 MMbbl/d of oil and 27.2 Bcf/d of gas, an unlikely scenario given the latest capital cut announcements.

Hedges offer many operators cover from low commodity prices, but the shelter is temporary. This report looks at the true, unhedged cost to hold production flat from today's levels at various commodity prices. We also estimate the 12-month decline outlook if operators in these key plays immediately start spending within cash flow.

NEED TO KNOW

The base decline rate is the percentage production will drop over the next 12 months if no new wells are brought online.

FIGURE 1 | Lower 48 Onshore Oil and Gas Production and Base Decline Rates



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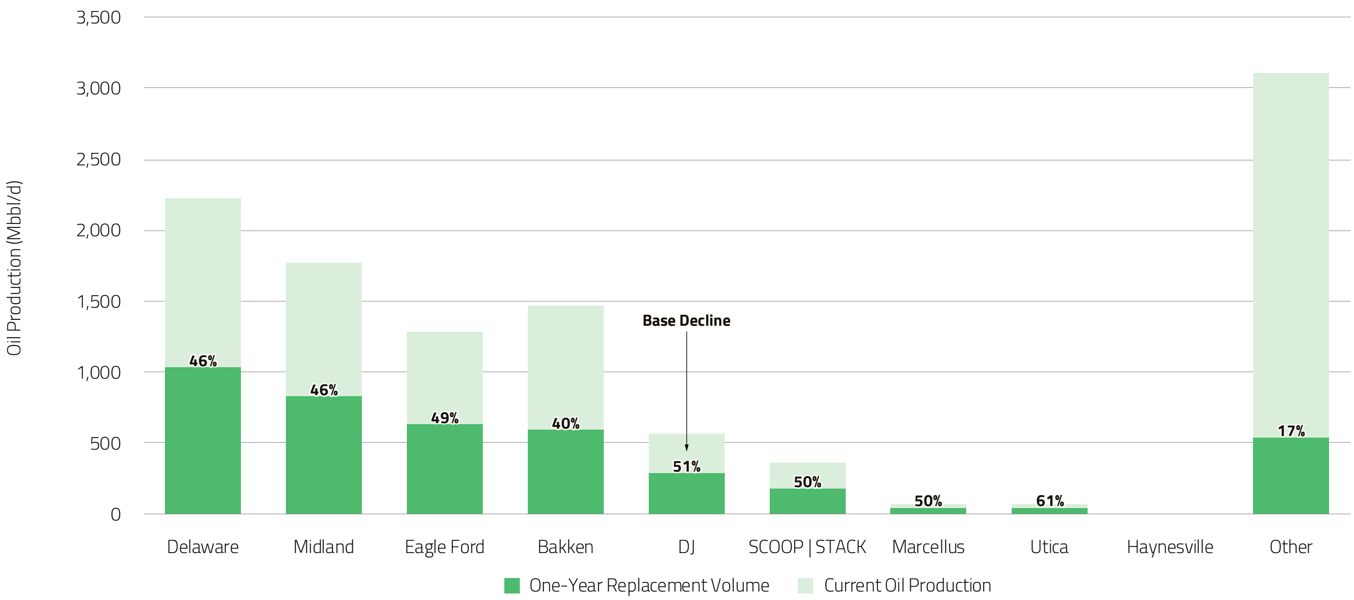
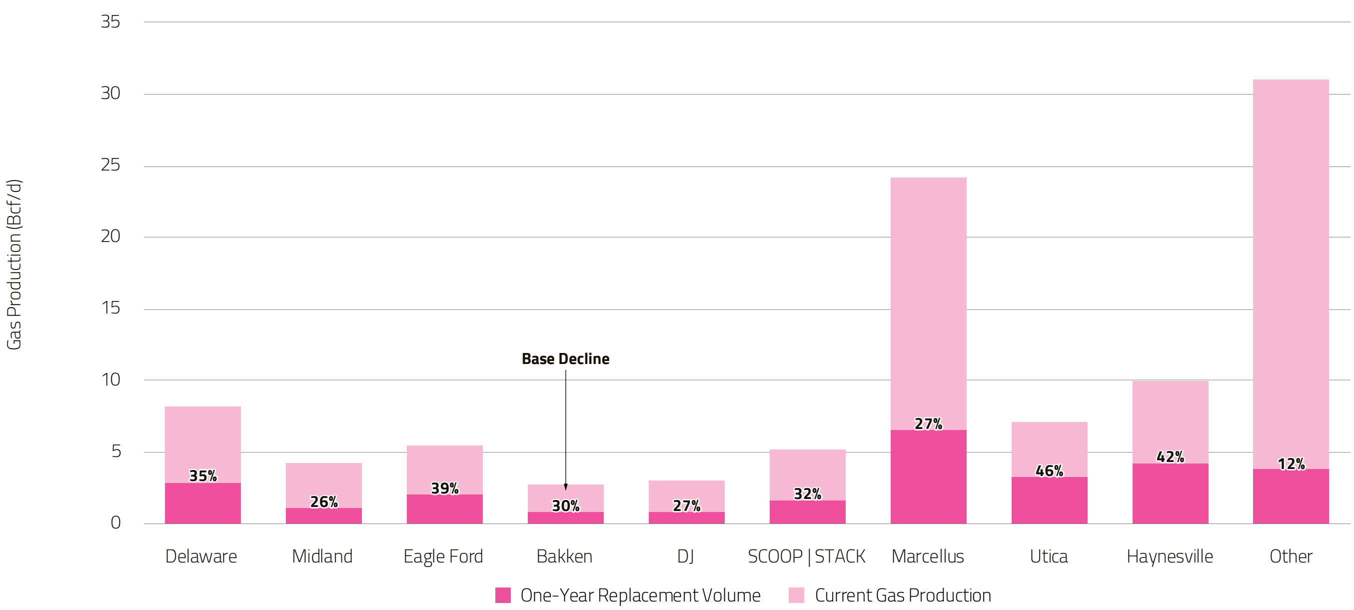
PLAY BREAKDOWN

The major unconventional plays typically decline two to three times faster than the "Other" play wedge, comprised predominantly of conventional production (**Figure 2**). Nearly half of the oil volumes, or 3.6 MMbbl/d, in the major plays need to be replaced next year to hold production flat with all base decline rates above 40%.

The Utica and the Haynesville rank as the steepest-declining gas plays with base declines of 46% and 42%, respectively. By comparison, the Marcellus is in-line with the L48 onshore average of 27%. Combined, the major plays need to replace ~23 Bcf/d to hold gas production flat.

FIGURE 2 | Current Production, One-Year Replacement Volume and Base Decline Rates by Play





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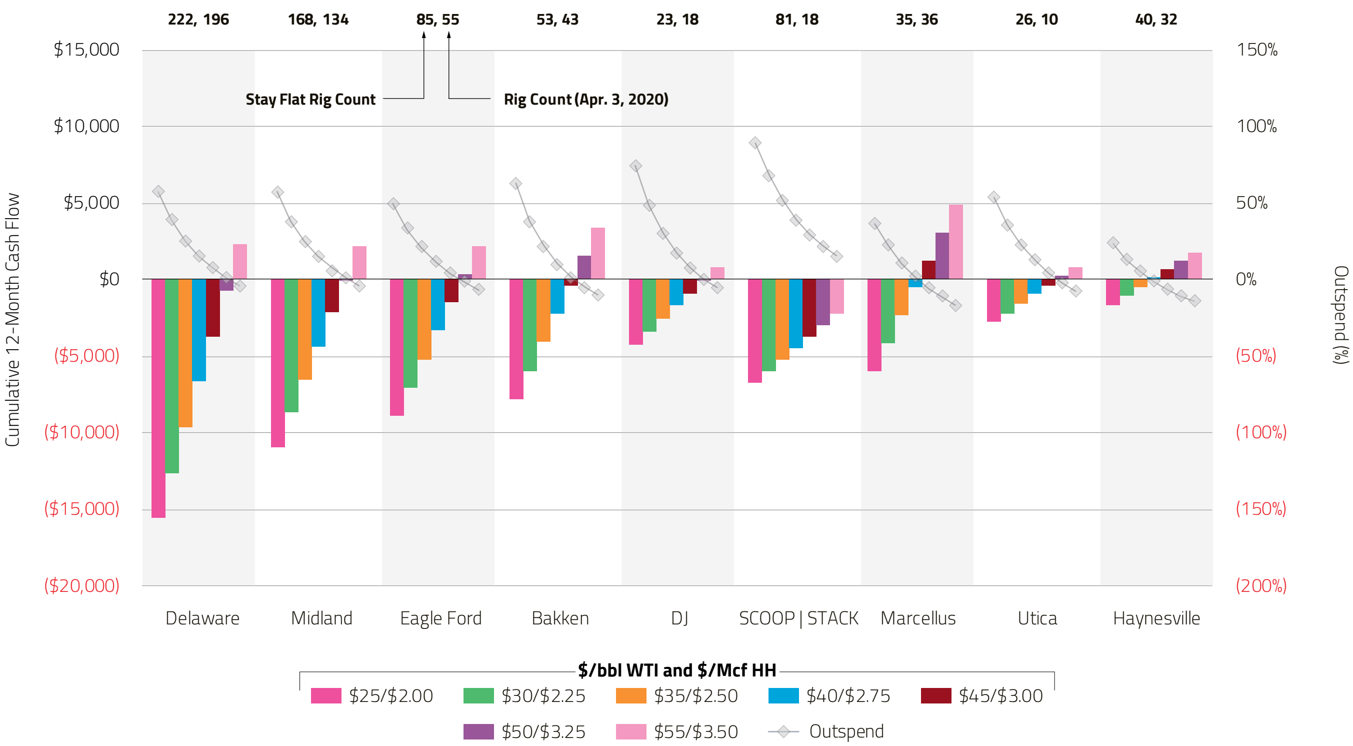
THE COST TO STAY FLAT

At flat prices of $30/bbl WTI and $2.25/Mcf HH, we estimate major L48 plays need to outspend cash flow by $51 billion over the next 12 months to sustain production – an average outspend of 37% (**Figure 3**). Although some operators have 2020 hedges in play, we consider this overspend an unrealistic scenario given tightened financial markets and strained balance sheets. All major plays will see production declines with commodity prices at the current levels and industry capex spend is limited to operator cash flow.

At $50/bbl WTI, the Bakken and the Eagle Ford start to generate positive cash flow while holding flat production on average. By comparison, the Delaware, Midland and DJ each require $55/bbl. On the gas side, the Haynesville crosses the positive cash flow mark at $2.75/Mcf HH, the Marcellus at $3/Mcf and the Utica at $3.25/Mcf.

Our model assumes ¾-cycle economics. It includes interest but excludes dividends and the impact of hedging. Other key inputs can be found in the Economic Assumption section.

FIGURE 3 | Cumulative 12-Month Cash Flows Assuming Flat Production at Various Price Decks



Source | RSEG, raw data provided by Baker Hughes

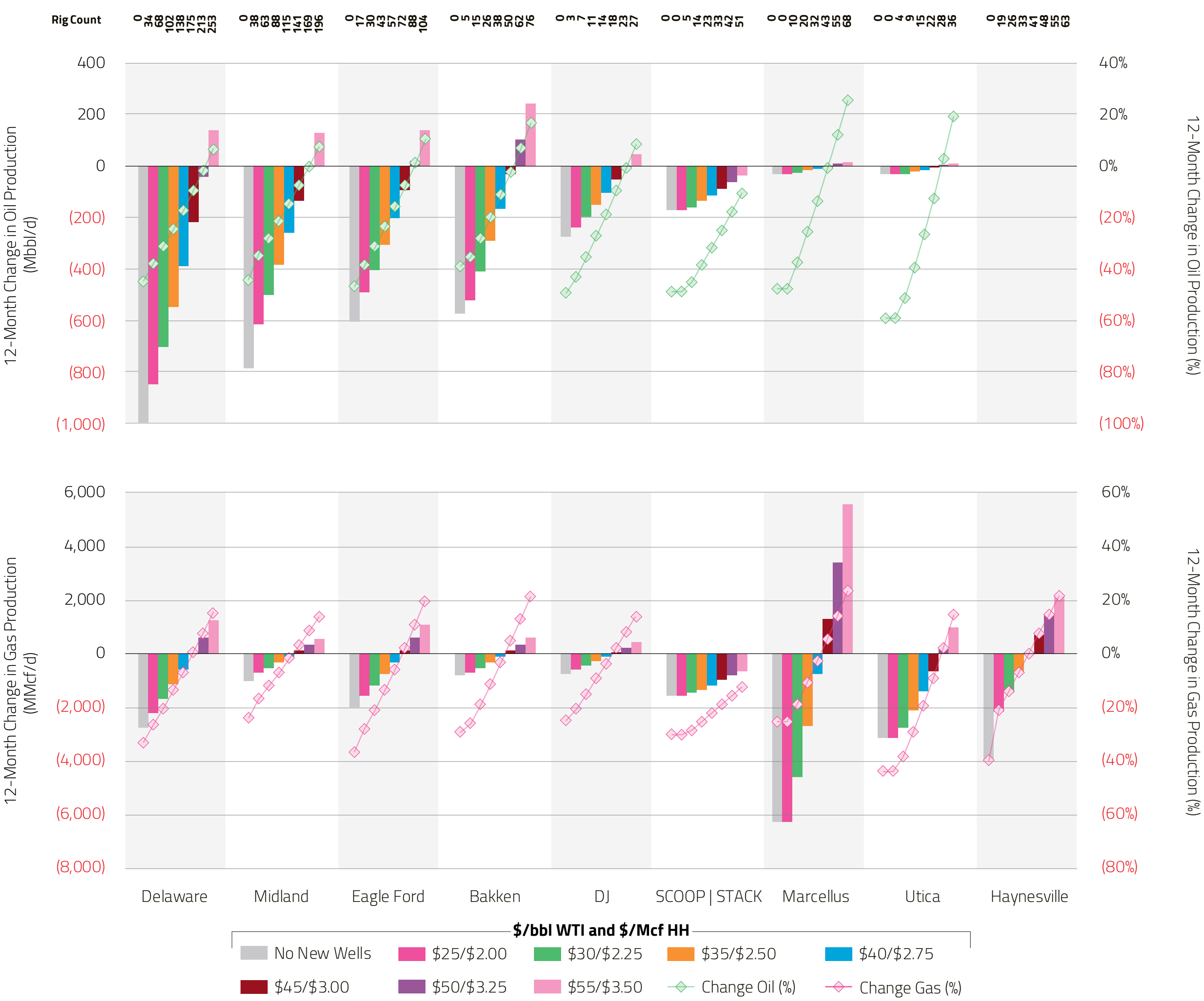
SPENDING WITHIN CASH FLOW

Figure 4 examines each play's change in 12-month production if activity immediately drops to cash flow neutrality. Under normal market conditions, a rig removed today will not impact production for five to six months due to the lag in spud-to-sales time. Given today's abnormal commodity price environment, we wanted to see the outlook if a significant amount of completions halted immediately.

At $30/bbl WTI and $2.25/Mcf HH, we estimate oil production will fall by around 31% and gas by ~21% over 12 months if operators spend within cash flow. This translates to production drops of 2.4 MMbbl/d and 14.4 Bcf/d from a rig count around a third of where it is today. Every $5/bbl and $0.25/Mcf change in both commodities shifts our estimates by about 0.6 MMbbl/d and 5 Bcf/d.

Note that 2020 hedges will prop up cash flows and certain operators will outspend, helping to curb some of our estimated decline.

FIGURE 4 | 12-Month Change in Oil and Gas Production Assuming All Cash Flow is Reinvested



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ECONOMIC ASSUMPTIONS

Our model assumes ¾-cycle economics and the average 2019 type curve by play. The cost structure is based on 2019 play averages from RS Core™ (**Figure 5A** and **5B**). Today's commodity environment is bringing significant downward pressure on capital costs, although it's uncertain how much more operators can squeeze out. To capture this dynamic, we assume 2019 average D&C cost in our $55/bbl WTI scenario and decrease this baseline by 3% for every $5/bbl drop in WTI.

Each operator has a unique situation and won't necessarily follow the play-wide trend. The model also does not assume any type curve high-grading, which would lower the stay-flat capital cost and reduce the amount of production decline in our spend within cash flow scenario.

FIGURE 5A | Assumptions and Outputs by Play

	Delaware	Midland	Bakken	DJ	Eagle Ford	SCOOP | STACK	Haynesville	Marcellus	Utica
Type Curve									
Peak Calendar-Month Rate (boe/d)	1,463	865	961	606	1,194	991	2,905	2,323	3,057
Ratable 12-Month Exit, gross (boe/d)	826	541	670	446	654	593	2,195	1,555	2,190
Oil EUR (Mbbl/1,000')	77	46	55	27	40	32	0	4	7
WH Gas EUR (MMcf/1,000')	387	168	148	216	223	375	1,841	1,728	1,070
Single-Well Model Economic Inputs									
DC&T ($MM, @ $30/bbl WTI)	$8.1	$6.9	$7.0	$4.5	$5.8	$6.5	$11.1	$7.1	$8.6
DC&T ($MM/1,000', @ $30/bbl WTI)	$0.97	$0.74	$0.71	$0.53	$0.81	$0.86	$1.43	$0.82	$0.79
10% Non-D&C Capex ($MM, @ $30/bbl WTI)	$0.8	$0.7	$0.7	$0.4	$0.6	$0.6	$1.1	$0.7	$0.9
Net Opex ($/boe)	$7.92	$7.47	$8.44	$4.53	$8.19	$8.63	$4.23	$7.09	$7.81
Net Interest Expense ($/boe)	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$1.50	$1.50	$1.50
Net G&A ($/boe)	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$1.00	$1.00	$1.00
Oil Differential to WTI ($/bbl)	$0.0	$0.0	($5.0)	($5.2)	$1.1	($1.8)	($9.7)	($6.6)	($5.3)
NGL Realization (% of WTI)	27%	27%	20%	20%	26%	35%	26%	28%	34%
Gas Differential to HH ($/Mcf)	($0.7)	($0.7)	($0.7)	($0.8)	($0.1)	($0.3)	($0.1)	($0.3)	($0.3)
Oil Severance Tax (%)	6.7%	5.6%	10.0%	7.2%	5.6%	5.8%	11.0%	3.4%	2.6%
NGL Severance Tax (%)	8.8%	8.5%	10.0%	7.2%	7.3%	5.8%	2.7%	3.4%	2.6%
Gas Severance Tax (%)	8.8%	8.5%	10.0%	7.2%	7.3%	5.8%	2.7%	3.4%	2.6%
Royalty Rate (%)	25%	25%	20%	18%	24%	20%	23%	18%	18%
NGL Yield (bbl/MMcf)	114	117	92	92	112	109	4	25	32
Gas Shrink (%)	29%	30%	18%	18%	22%	26%	1%	4%	6%

Source | RSEG, company disclosures, raw data provided by Baker Hughes

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FIGURE 5B | Assumptions and Outputs by Play

	Delaware	Midland	Bakken	DJ	Eagle Ford	SCOOP | STACK	Haynesville	Marcellus	Utica
Current Production Split									
Oil (%)	54%	64%	70%	45%	50%	24%	0%	1%	4%
NGL (%)	22%	18%	12%	22%	22%	31%	2%	10%	13%
Gas (%)	24%	18%	18%	33%	28%	45%	98%	89%	83%
Netback Sensitivity ($/bbl WTI and $/Mcf HH)									
$15/$1.50 ($/boe)	($1.5)	($0.1)	($4.4)	($1.3)	($0.6)	($3.8)	$1.2	($2.6)	($3.2)
$20/$1.75 ($/boe)	$1.6	$3.4	($0.8)	$1.6	$2.5	($1.6)	$2.7	($1.1)	($1.6)
$25/$2.00 ($/boe)	$4.8	$6.9	$2.7	$4.5	$5.6	$0.5	$4.2	$0.4	$0.0
$30/$2.25 ($/boe)	$7.9	$10.4	$6.3	$7.3	$8.6	$2.7	$5.6	$1.9	$1.6
$35/$2.50 ($/boe)	$11.1	$13.9	$9.9	$10.2	$11.7	$4.9	$7.1	$3.4	$3.2
$40/$2.75 ($/boe)	$14.2	$17.5	$13.4	$13.0	$14.7	$7.1	$8.5	$4.9	$4.8
$45/$3.00 ($/boe)	$17.4	$21.0	$17.0	$15.9	$17.8	$9.3	$10.0	$6.4	$6.4
$50/$3.25 ($/boe)	$20.5	$24.5	$20.5	$18.8	$20.8	$11.5	$11.4	$7.9	$8.0
$55/$3.50 ($/boe)	$23.7	$28.0	$24.1	$21.6	$23.9	$13.7	$12.9	$9.4	$9.6
Well Count and Rig Assumption									
Wells per Month to Hold Production Flat	200	183	105	99	170	85	27	67	25
Rig Efficency (Wells/Rig/Month)	0.9	1.1	2.0	4.3	2.0	1.1	0.7	1.9	0.9
Rig Count to Hold Production Flat	222	168	53	23	85	81	40	35	26
Rig Count as of Apr. 3, 2020	196	134	43	18	55	18	32	36	10

Source | RSEG, company disclosures, raw data provided by Baker Hughes

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