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INDUSTRY BRIEF

Energy Stat: What is the Outlook for U.S. Produced Oilfield Water and What Will It Mean for Investors?

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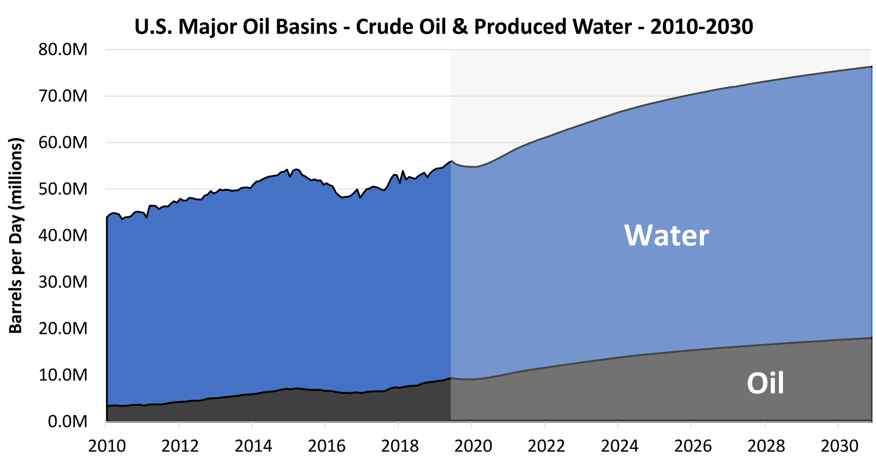
The massive U.S. energy renaissance over the past decade has brought with it a massive increase in the scale of overall oilfield logistics. In this week's "Stat" we will try to introduce investors to the issues and opportunities that will arise from the increased demand for water in completions (it is *hydraulic* fracturing after all), as well as the surge in supply of dirty, produced water which comes as a byproduct of crude production. With each completion using *thirty Olympic swimming pools* worth of water and with roughly four barrels of water produced for every one of crude, naturally two questions arise: "**Where will we get all the clean frac water?" and "What will we do with all of the dirty produced water?"**

Tapping sources of fresh water for fracking can compete with local needs, but keep in mind that water use by fracturing remains only a small fraction of total water demand. Nationwide, the USGS estimates that only 4% of all water is used for “mining” activity, which lumps in oil and gas, of which we estimate 15% is used in fracturing. Thus, at only ~50 basis points of U.S. water use, we believe that challenges on the "sourcing" side relate far more to difficulties *moving and storing* fresh water, rather than *finding* fresh water. Moreover, we expect that some of this fresh water used for fracking will be replaced by recycled "dirty" produced oilfield water.

While there is a very large logistical challenge in delivering water to the frac site, we believe there will be a more **sustained logistical problem with how the industry disposes of the dirty water that is produced by these shale wells**. In this week’s stat, we will spend more time framing the challenges and opportunities associated with these increasing volumes of produced water from shale wells. In fact, most investors are simply unaware of the fact that **as crude production grows, produced "dirty" water grows even faster.** This growing dirty water problem should create opportunities for investors through service companies which treat, recycle, or dispose of this dirty produced water. While much of this dirty water has historically been handled by E&P companies, we are already starting to see more outsourcing to service companies that can create economies of scale and with a more attractive cost of capital. We believe the disposing of produced water is gradually evolving to a model more similar to the Midstream model of "gathering and processing," with investment characteristics and return profiles closest to Midstream. While current public investment options are limited, we believe many may find their way to public markets over the coming years, through IPO and M&A. Accordingly, investors should start doing their homework now to get familiar with this evolving and growing subset of the oilfield sector. To help with this, **we have updated our dynamic Production by Play model to forecast future U.S. oilfield water production based on our U.S. oil supply model, for all major oil basins, on a month-by-month basis**, including a split for the Midland and Delaware basins (shown below).

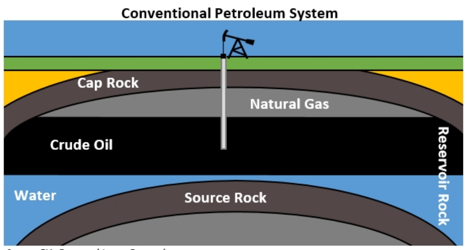


Source: EIA, Drilling Info, Baker Hughes, Raymond James Research

US. oilfield water production today is already a whopping ~50 million barrels per day. Given that the U.S. only produces about 15 million barrels of petroleum liquids each day, you can see that oilfield water production outpaces oil production by more than 4 to 1 on a national basis. For scale, this amount of water could cover over 8,000 football fields with a foot of water, *each and every day.* We estimate just under one-half of this water comes from today's horizontal basins, despite making up close to 80% of onshore crude production.

What is produced oilfield water and just how "dirty" is it?

For as long as we have drilled for oil and gas, water has also been a part of the produced mix. That is because the same reservoirs that hold hydrocarbons, also hold vast quantities of water, sitting thousands of feet below the fresh water table. Over a few million years of contact, the water trapped in these formations starts to look like the rock in which it sits, absorbing heavy metals, radiation from naturally occurring radioactive materials (NORM), and large amounts of salt. Essentially, this is ancient seawater that has simmered for hundreds of millions of years, resulting in overly salty water that is produced alongside oil and gas wells. The amount of contamination varies widely across different formations, and can even vary within a single field. As seen on in the simplified table below left, a petroleum system forms when both hydrocarbons and water are trapped together under an impermeable layer of rock.



Source: EIA, Raymond James Research

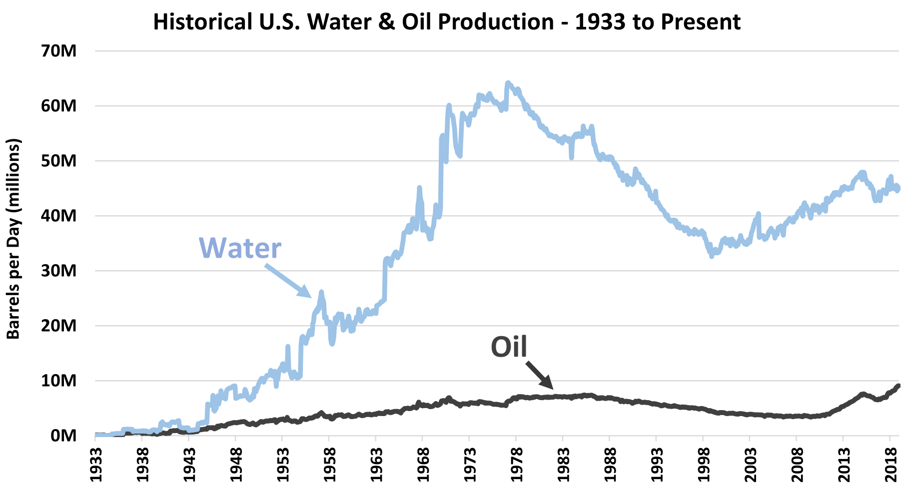
Depending on the reservoir, there can be more or less produced water upon initial completion. Over time, however, the typical water "cut" increases over the life of a well, making up to 95% of the recovered fluid for many older wells. The cut is typically measured as a "water-to-oil" ratio, with many old legacy wells putting off a WOR above 10x, whereas today's new wells often start at 1x to 6x. Oil and water production both decline over the life of a well, though typically water declines more slowly than oil will. This has the effect of increasing the water ratio over time, and explains why a majority of water comes from legacy oil basins.

The amount of contaminant (or dirtiness) in produced water is measured as "total dissolved solids" (TDS) and can range anywhere from an average of 35,000 mg/L to well beyond 300,000 mg/L. For reference, clean drinking water has less than 1,000 mg/L, and saltwater from the ocean has ~30,000 mg/L. The largest component of this TDS by far is salt. In addition to the high salt content, metals like iron & barium, and dissolved hydrocarbons (skim oil) are usually present. It goes without saying, produced water cannot simply be dumped in to our lakes and rivers.

Additionally, a large amount of water returns to the surface in the frac "flowback period," roughly the first two weeks after a well is fracked and brought on-line. This amount can be as much as 50% of the ~300k-600k/bbls that are injected during fracturing phase. However, very little of this is reservoir water; it is simply the water used in the frac coming back to the surface. TDS is very low in the initial flowback period, but TDS increases as more of the water comes from the reservoir rather than the frac. Frac sand, pieces of downhole tools, chemicals, and a high content of skim oil are all common components of flowback water, which make it unfit for dumping into rivers, despite lower TDS.

How much water does the U.S. produce and what do we with produced water?

Produced water is by no means a new problem. In fact, in the chart below, we see water production is still below the previous peak from the 1970s. Water, however has become one of the hottest topics in the U.S. oilfield, as produced water has grown from about 35 million bpd a decade ago to approaching 50 million bpd today. In fact, our most prolific basin, the Delaware, has **initial** WOR's of 4x to even 10x (more on this later).



Source: DrillingInfo, Raymond James Research. Excludes states without water data (OK, PA) and Gulf of Mexico

Traditionally, produced water was often reinjected into waterflood wells in the same formation with the remainder disposed into "disposal" wells. In large, vertical-wellbore developments, producers would often re-inject the water into adjacent wells drilled into the same formation to actively push undrained oil into producing wells in a process called "waterflooding." This works quite well in conventional reservoirs like the one at the top of the page. With old legacy wells producing WORs of 10x-30x, there was a steady supply of water for injection. A treadmill of recovering water, then reinjecting it, allowed the oilfield to economically handle all of these volumes.

With today's modern horizontal wells, there is less waterflooding and more disposal of the water into other empty formations that have been depleted. This is because today's horizontal "shale" wells are essentially drilled straight into low permeability rock, meaning waterflooding is no longer a viable method for enhanced oil recovery (or EOR). While we estimate about half of produced U.S. water is being used for water flooding nationwide, the **incremental barrel of water today comes from a horizontal well**, and thus waterflooding will continue to lose share. **In other words, the marginal barrel of produced water today is destined for a disposal well.** That means other disposal options will continue to see high growth rates. The remaining two disposal options for produced water are 1) salt water disposal wells, and 2) produced water recycling.

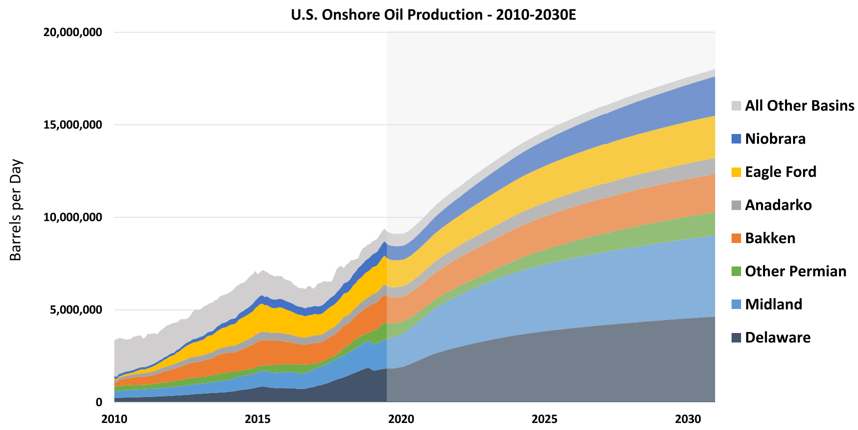
Salt water disposal (SWD) is the injection of produced water into depleted formations or other permeable layers of rock that do not produce oil. These formations are well below fresh water aquifers and drinking water, and in some instances even deeper than oil & gas formations. An SWD well, in many ways the identical inverse of an oil well, is drilled into these disposal formations. Water is pumped down from the surface, with thick and cement casing to prevent leakage. SWDs will have a daily permitted capacity, typically between 10k to 30k bbl/d, with 20-25k most common in the Permian. Water is transported to the SWD by truck or increasingly, by fixed pipe systems. New SWDs can have similar costs to new horizontal wells, and make money by charging per barrel fees for disposal, or are often owned internally by the E&Ps. Operators have historically in-sourced this activity, reported as part of their LOE (lease operating expense), though this trend is reversing.

It is also possible to remove contaminants from produced water, though this type of **recycling** is still in early stages of acceptance. In fact, we estimate SWD disposal volumes outnumber recycling volumes by nearly 20:1 today. This recycling requires a multi-step process to remove each part of the solution, (e.g. metals, salt), that is often cost prohibitive to convert into water fresh enough to drink. Fortunately, frac water does not need to be fresh enough to drink, so many are now starting to clean the dirty water only enough to reuse as frac water. Improving technology, as well as a constant demand for frac water, is allowing many operators to recycle their produced water into frac water. Since produced water is owned by the E&P, they can meet their needs for future completions by cleaning produced water, saving on both sourcing and transporting freshwater. This also obviously also carries the ESG benefits of preventing freshwater waste in fracs, and reducing SWD volumes, which can also have environmental concerns.

Where are produced U.S. water volumes going from here?

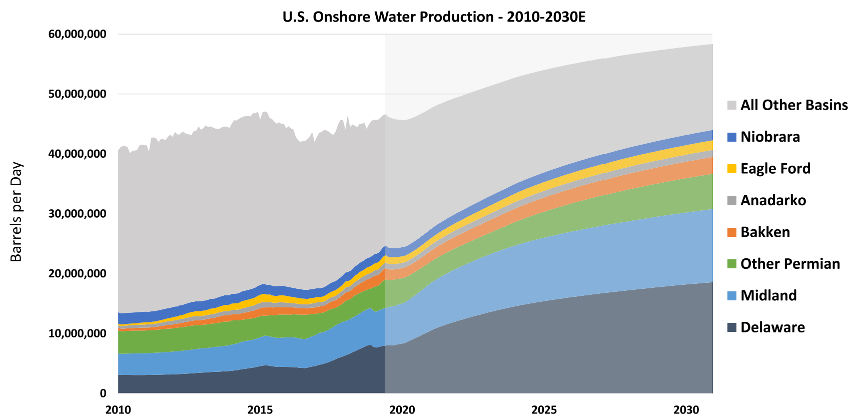
As water has gained more attention over the past 24 months, the question we get the most on produced water is, "how much produced water will there be?" Our U.S. oil model uses rig counts, well productivity, and type curves to model U.S. onshore oil production. Water production exhibits type curves similar to oil production, making water forecasting comparable to forecasting oil or gas. We have expanded our U.S. "Production by Play" model to cover produced water for the major shale basins - Delaware, Midland, Eagle Ford, Bakken, Anadarko, DJ, Haynesville, and Powder River - with monthly production by basin published through 2030. On the following page, we lay our our crude and produced water forecast. Additionally, modeling assumptions, type curves, and more detail can be found in the appendix of this piece.

Starting with our oil forecast, we project U.S. onshore crude-only production from just these major basins to grow from about 8 million bpd today to about ~17 million bpd by 2030. While this oil forecast has room for debate (well productivities, parent-child interference, quality of rock), with the U.S. as the marginal supplier of global crude, this type of growth will be crucial to feed global economic growth. In fact, this still leaves ~30% of expected global demand growth to be met by non-U.S. sources. However, this is (and has been) a debate for a different "Stat of the Week."

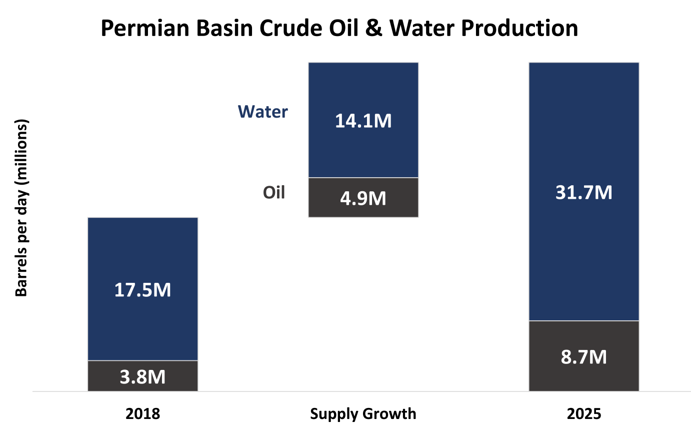


Source: EIA, Drilling Info, Baker Hughes, Raymond James Research

While the absolute growth rate of water will be dampened by legacy conventional fields declining in production, the concentration of water growth in the Permian basin and the lack of waterflooding for disposal, mean that spending and logistics on water, particularly disposal, are going to take a sharp ramp upwards over the next decade. <u>We project total U.S. water production reaches ~55 million bbl/d by 2025, and ~60 million bbl/d by 2030, with the Permian accounting for 32 million and 38 million bbl/d in the respective years.</u>



Source: EIA, Drilling Info, Baker Hughes, Raymond James Research



Source: EIA, Drilling Info, Baker Hughes, Raymond James. Estimates reflect year-end.

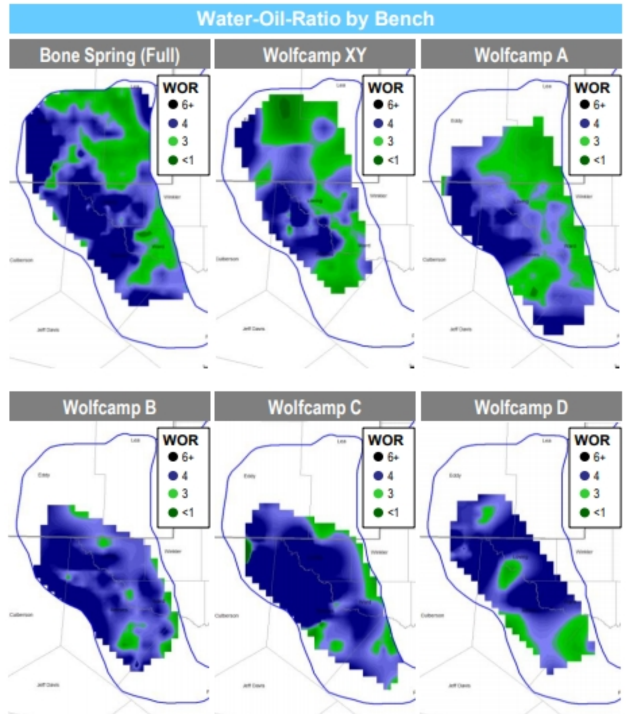
Permian leads the way with outsized water production - Particularly the Delaware

In our forecast and this piece, we have placed an undue focus on the Permian basin, particularly the Delaware. While most readers will know it is the heart of U.S. oil activity, there is a particular reason why it is top of mind for produced water. **New wells in the Delaware Basin are coming online with water-oil-ratios as high as 10-to-1, a level of water production typically exhibited in a decades-old conventional well. Across the basin, initial WORs of 4 or even 6-to-1 are viewed as "normal."** This is in contrast to other prolific shale basins such as the Midland, Eagle Ford, and Bakken, where WORs start at a 1-2x range, and expand slowly to 2-5x. In the graph on the left, we forecast water production grows to over 32 million barrels per day by 2025, for a CAGR of 10% over the period.

As the Permian basin shifts further into manufacturing mode, the water growth we project will create the need for nearly 1,000 additional salt water disposal wells by 2030. Even taking an impossibly bullish outlook with water recycling (100% of frac water coming from recycling)**, we will still need ~750 additional disposal wells in the Permian Basin** (more on this below). By 2030, we predict there will be a total need for ~1750 salt water disposal wells, assuming 80% utilization. While many companies involved in SWDs cite 80% as their target utilization, water pressure at the surface and in the formation can limit disposal capabilities, meaning demand for SWDs may be closer to 3,000 under realistic utilization assumptions. **This incremental demand for SWDs we estimate represents a $7-$9 billion dollar investment in the Permian Basin alone.**

Why The Delaware?

In the Delaware basin, the target formations for most wells are the Wolfcamp and the Bone Spring plays (also known together as the "Wolfbone"). These formations are estimated by the USGS to hold over 45 billion barrels of recoverable oil, in addition to +60 billion BOE of gas and NGLs. Unfortunately, this resource has water oil-ratios far greater than encountered in the Bakken or the Eagle Ford, shown in the table on the right. This comes with higher water management costs, which cut into profitability over the life of the well. This also creates a major opportunity set, both for E&P operators to optimize water logistics for lower costs, and for midstream-style businesses to pipe and dispose of water.



Source: DrillingInfo

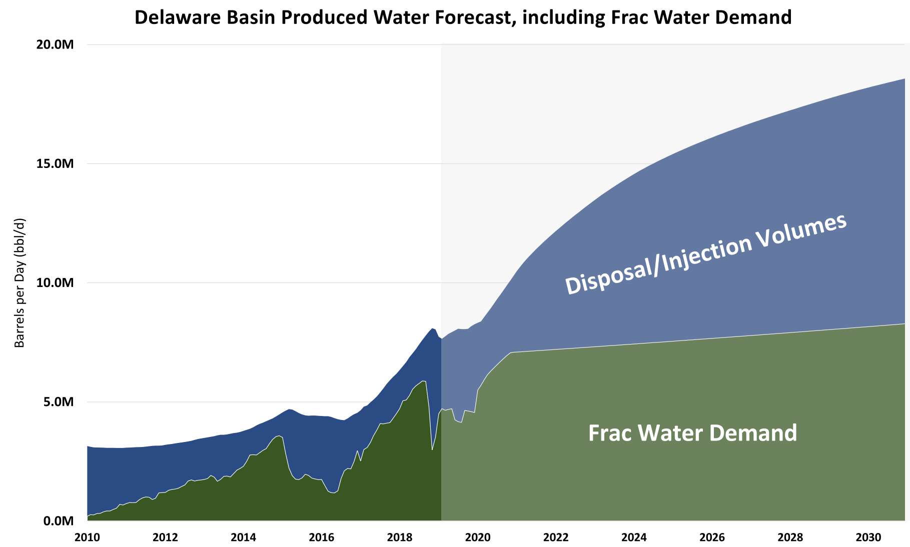
Recall, SWD wells were typically in-sourced at E&Ps. They owned individual SWDs and with the evolution of pad drilling larger operators could invest in systems of pipe to link systems of SWDs together, or to link their wellpads directly to the SWDs. This avoids much more costly option of trucking the water, which may add $2-3/bbl to disposal costs. While it may seem like a no-brainer to move this water through fixed pipes, **the average barrel of produced water still moves via truck at some point during the disposal process.** This is because dispersed, one well, vertical locations didn't usually lend themselves to disposed water infrastructure. Trucking dominates certain basins like the Bakken and Eagle Ford. The Delaware leads the way in fixed pipe systems, and operators we spoke to estimate a slight majority of SWD volumes arrive via pipe today, a percentage which operators are working to expand.

These fixed pipe systems were once owned by E&Ps themselves, but a round of asset dropdowns and sales have kicked off outsourcing of SWD activity. Diamondback's spinout of its water assets through Rattler Midstream (RTLR/Outperform), asset sales like Encana's water system to H2O Midstream or Concho's SWDs and pipes to Waterbridge can be win-win situations for the operator and midstream water disposal company. **For E&Ps the benefits are three-fold. First, as an internal cost center, investors are giving little value to these assets in valuation, though they can be sold at higher multiples than the E&P business itself trades.** For example Diamondback (FANG) currently trades at 5.3x 2020 EBITDA, while its SWD and G&P dropdown Rattler Midstream (RTLR) trades at 8.2x after an IPO in May. **Second, these water assets are relatively capital intensive additions to the balance sheet, which if sold off, could reduce leverage or free up cash flow for further development. Finally, scale matters in piped water disposal. If a disposal network is independent of just one operator, they can solicit other nearby producers to cost effectively attach to their existing disposal grid.** Thus far, we believe attractive valuation and capital reduction have both played a role in E&Ps dropdowns, and will push even more E&P asset sales in the future to the host of private equity backed water midstream entities willing to purchase these assets. In the future, multi-client scale may become a bigger driver.

For the midstream company, the incentives are also clear. By signing "dedicated acreage" agreements with E&Ps, they can ensure a steady supply of produced water to be gathered on their systems. These multi-year contracts are key to making disposal business similar to midstream in their risk profile. Furthermore, additional pipelines can be built to service third-parties, increasing returns compared to a single E&P customer. We see continuing consolidation of E&P assets, as well as mergers for scale, and predict several IPOs may be coming sooner than investors think.

"But we won't need SWD's, because all this water will be recycled!"

One pushback we commonly get on our bullish view of water disposal is that the growth of recycling will cannibalize SWD volumes. While this is directionally accurate, there is a limit to the need for this "less dirty" recycled water. So, let's test how large an effect this could possibly represent. Recycling, particularly in the Permian, is still in its infancy, with fresh water still the source for a vast majority of frac jobs. While recycling *flowback* water, the water that returns to the surface after a frac, is commonplace today, recycling *produced* water is still not viewed as economic by many operators because of the much higher cost associated with cleaning the dirtier produced water. Flowback recycling generally makes much more sense, as the water is already on location of the frac pad, and is generally lower TDS than produced water.



Source: EIA, Drilling Info, Baker Hughes, Raymond James Research

In the chart on the left, we compare daily water production to the potential frac water required for completions under our oil forecast. Even with our bullish view of future U.S. activity, the amount of water needed for Delaware fracking falls well short of the increase in produced water. In other words, **there will be a demand for SWDs no matter how much water is recycled.** Keep in mind that the graph assumes 100% of frac water demand in the Delaware will come from recycled water. To be sure, logistical challenges and costs of water recycling mean this "100% recycled" scenario is a pipe-dream to begin with.

In less watery basins we do concede that recycling could eat more meaningful share of SWD volumes, however current regulation and economics makes this somewhat unlikely. For example in the Bakken, operators are not permitted to store produced water in open surface pits prior to recycling, the TDS that must be removed is very high, and low-cost surface water for fracturing is abundant. These barriers limit the incentives to recycle produced water to "ESG benefits", rather than a true cost savings. In a bullish outlook, we could see produced water recycling maybe increasing to 60-70% of fracturing demand, though this would also require billions of dollars in investment build to recycling facilities and infrastructure to store and transport recycled water to the needed destinations.

Produced water infrastructure should be a win-win - and getting Water right can be a huge win for E&Ps

E&P ultimately bear the costs of produced water, though this is not new problem and it may have a happy ending. E&Ps that have invested thus far in water assets may be able to monetize them in this environment where water midstream companies are expanding their footprints and still get lower water disposal costs. Additionally, we view these transactions as value creating from both a capital reduction and a cost reduction view. By signing agreements which rationalize up-front spending for fixed pipe rather than trucking, E&Ps can lower their effective LOEs and thus decrease their breakeven price of oil production. In the Delaware basin, where water may outnumber oil 6:1, this will be vital. With trucking costing $2-3/bbl of water, trucked SWD volumes could increase operating costs by $12-18/bbl of oil, which would be a massive blow to profitability.

The first major public players in water midstream are NGL Energy Partners LP (NGL/Outperform) and Rattler Midstream LP (RTLR/Outperform). Both own water systems which link operator acreage to owned-SWDs, as well as water sourcing and delivery systems for completions. While the partnerships also engage in traditional midstream services as well, both are expected to produced a majority of EBITDA from water in the coming year. While pure-play water midstream exposure is currently non-existent, these two players come the closest.

Some of the largest players in this space to date have been private companies, many backed by private equity. We expect to see a wave of IPOs, particularly of Permian SWD operators in the coming years, part of the reason we are highlighting the issue to investors today. So far the list of private water "super-system" owners includes WaterBridge Resources, Hillstone Environmental, Goodnight Midstream, Solaris Water Midstream, H2O Midstream, Gravity Oilfield Services, Radius Water Resources, and Oilfield Water Logistics. Also in the private company world, Pilot Flying J has leveraged its large tanker fleet and logistics expertise to offer water hauling to its network of SWDs and pipelines. While this list is by no means exhaustive, it does show that this is a sector that public investors, particularly in Midstream, will need to comprehend.

We would also be remiss if we did not mention the important role of oil service firms in the water industry. Two companies under our coverage that are clear winners in a rising water world are Tetra Technologies (TTI/Market Perform) and National Oilwell Varco (NOV/Outperform). Tetra offers integrated water management solutions, much of which involves pre-frac water sourcing or flowback operations. However, it has become one of the largest water recyclers and a technology and automation leader. Second, as fixed pipe systems grow in size and number, disposal companies have realized they need pipe which can handle the corrosive mix of produced water, with the pressure rating of steel pipe. These competing needs are best met by fiber glass pipe, where NOV is a leading supplier in the oilfield. Its patented Red Thread fiber glass has seen a pickup in large orders, particularly for wide diameter pipes that form the backbone of these water super-systems.

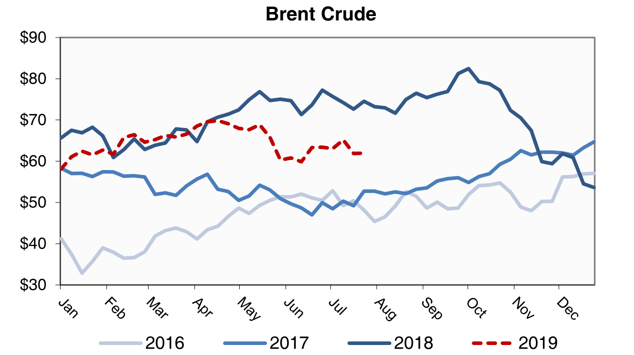
Conclusion - As long as oil production continues to grow, so will water (and the market for disposing of it!)

U.S. will be producing a whopping 54 million barrels per day of dirty produced water by 2025 under our outlook for oil production. With disposal/treatment costs typically around $1.00/bbl, this represents a $20B annual market for water recycling, disposal and treatment. This will be a ~$12B market in the Permian basin alone, where over 60% of the water will be produced. This also represents an annual CAGR of 10% for Permian water spending over the next 6 years, making it one of the fastest growing slices of the U.S. oilfield. We expect a rising tide of water companies come to markets that allow for public investment in water disposal, with similar economics to traditional Midstream. Additionally, public E&Ps can appease investors by releasing capital from water assets at high valuations in today's markets. We expect water gathering will become a mainstay of Midstream investing over the coming years, and expect investors can benefit from what is likely to be a under-appreciated investment.

Raymond James Weekly Oilfield Review

For the week ending: 7/26/2019

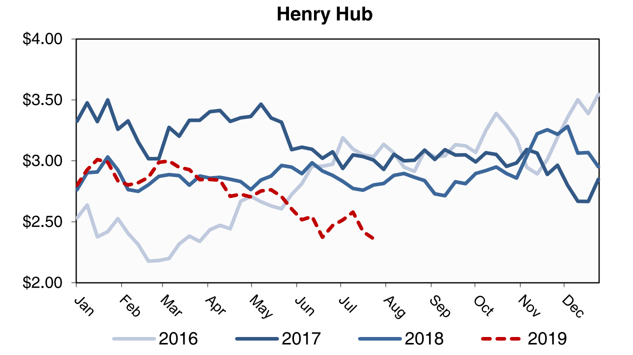
12 Month Oil Calendar Strip



	This Week	Last Week	YTD	Last Year
Price	$61.98	$61.87	$58.35	$74.52
Percent Change		0%	6%	-17%

Source: Bloomberg, Raymond James

12 Month Gas Calendar Strip



	This Week	Last Week	YTD	Last Year
Price	$2.36	$2.42	$3.32	$2.80
Percent Change		-2%	-29%	-16%

Source: Bloomberg, Raymond James

	This Week 7/26/2019	Last Week 7/19/2019	Last Year 7/27/2018	Change From: Last Week	Change From: Last Year
U.S.Rig Activity - Onshore					
U.S. Oil	776	779	861	-0.4%	-10%
U.S. Gas	169	174	186	-2.9%	-9%
U.S. Total	**945**	**953**	**1047**	**-0.8%**	**-10%**
U.S. Horizontal	823	829	922	-0.7%	-11%
U.S. Directional	67	69	64	-2.9%	5%
U.S. Offshore - Gulf of Mexico					
U.S. Offshore	25	26	16	-3.8%	56%
Fleet Size	73	73	78	0.0%	-6%
# Contracted	37	37	36	0.0%	3%
Utilization	51%	51%	46%	0.0%	10%
Canadian Rig Activity					
Rig Count	127	118	223	7.6%	-43%
Stock Prices					
OSX	77.25	76.35	149.66	1.2%	-48%
S&P 500	3,025.86	2,976.61	2,818.82	1.7%	7%
DJIA	27,192.45	27,154.20	25,451.06	0.1%	7%
Alerian MLP Index	253.19	254.25	274.90	-0.4%	-8%
S&P E&P	3,722.78	3,732.49	6,429.87	-0.3%	-42%
Inventories					
U.S. Gas Storage (Bcf)	2,569	2,533	2,272	1.4%	13%
Canadian Gas Storage (Bcf)	429	418	464	2.6%	-8%
Total Petroleum Inventory (k)	1,308,542	1,315,229	1,196,007	-0.5%	9%
Spot Prices (US$)					
Oil (Brent)	$63.33	$62.99	$74.29	0.5%	-15%
Oil (W.T.I. Cushing)	**$56.19**	**$55.95**	**$68.69**	**0.4%**	**-18%**
NGL Composite	$19.78	$20.56	$35.36	-3.8%	-44%
Gas (Henry Hub)	$2.17	$2.26	$2.82	-3.8%	-23%
Residual Fuel Oil (New York)	$10.36	$9.98	$11.56	3.8%	-10%
Gas (AECO)	$0.62	$0.34	$0.68	82.4%	-9%

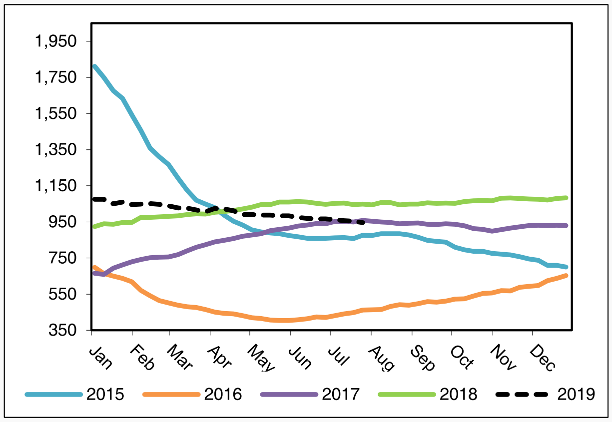
Sources: Baker Hughes, ODS-Petrodata, API, EIA, Oil Week, Bloomberg, Raymond James

U.S. Rig Count Breakdown	7/26/2019	7/19/2019	W/W ∆	YTD ∆	YTD % ∆	Y/Y ∆
Total Count						
U.S. Rig Count	**946**	**954**	**(8)**	**(137)**	**-13%**	**(102)**
By Basin*						
Permian	437	434	3	(46)	-10%	(41)
Eagle Ford	80	81	(1)	(12)	-13%	(10)
Cana Woodford	63	65	(2)	(27)	-30%	(34)
Marcellus	52	54	(2)	(5)	-9%	1
Haynesville/Bossier	51	51	0	(2)	-4%	4
Bakken	47	55	(8)	(9)	-16%	(10)
DJ Basin	26	24	2	1	4%	4
Gulf of Mexico	23	25	(2)	2	10%	5
Powder River Basin	23	21	2	4	21%	8
San Joaquin Basin	15	14	1	4	36%	4
Utica	15	17	(2)	0	0%	(6)
Pinedale	10	9	1	(2)	-17%	(1)
Uinta	7	6	1	1	17%	1
Piceance Basin	5	5	0	(2)	-29%	(2)
Mississippi Lime	5	4	1	(8)	-62%	(6)
Arkoma Woodford	4	3	1	(3)	-43%	(3)
Barnett	2	2	0	(1)	-33%	(1)
Granite Wash	2	2	0	(4)	-67%	(11)
Other	79	82	(3)	(28)	-26%	(4)
Drill For						
Oil	776	779	(3)	(109)	-12%	(85)
Dry Gas	90	88	2	(8)	-8%	2
Wet Gas	79	86	(7)	(21)	-21%	(19)
Miscellaneous	1	1	0	1	0%	0
Trajectory						
Horizontal Oil	674	679	(5)	(112)	-14%	(88)
Horizontal Gas	149	150	(1)	(10)	-6%	(10)
Horizontal	823	829	(6)	(122)	-13%	(99)
% Horizontal	87%	87%	0%	0%		-1%
Vertical/Directional Oil	102	100	2	3	3%	3
Vertical/Directional Gas	20	24	(4)	(19)	-49%	(7)
Vertical/Directional	123	125	(2)	(15)	-11%	(4)

Source: Baker Hughes, Inc, Raymond James research

Includes all trajectories

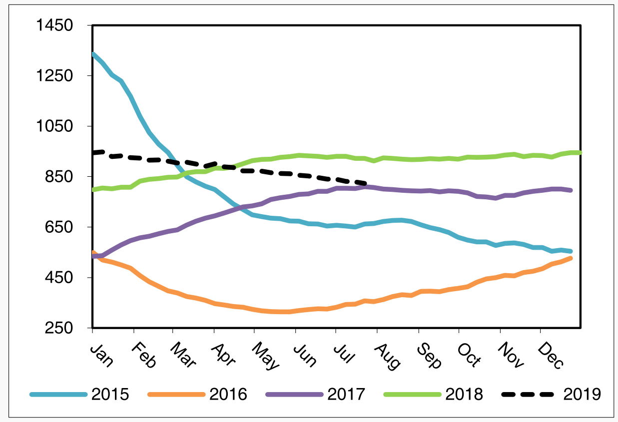
Total U.S. Rig Count



	This Week	Last Week	Beginning of Year	Last Year
Rig Count	946	954	1075	1046
Percent Change		-0.8%	-12.0%	-9.6%

Source: Baker Hughes

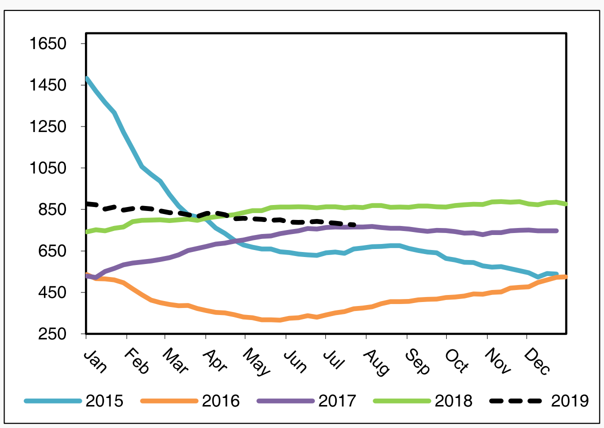
Horizontal Rig Count



	This Week	Last Week	Beginning of Year	Last Year
Rig Count	823	829	945	922
Percent Change		-0.7%	-12.9%	-10.7%

Source: Baker Hughes

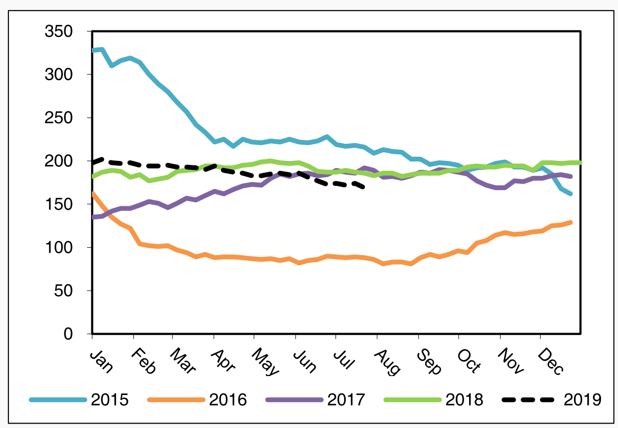
Oil Rig Count



	This Week	Last Week	Beginning of Year	Last Year
Rig Count	776	779	877	858
Percent Change		-0.4%	-11.5%	-9.6%

Source: Baker Hughes

Gas Rig Count



	This Week	Last Week	Beginning of Year	Last Year
Rig Count	169	174	198	187
Percent Change		-2.9%	-14.6%	-9.6%

Source: Baker Hughes

Produced Water Overview

- Every bbl. of oil comes with +4 bbl. of dirty, saline water, known as produced water or "brine"
- Produced water is often saltier than seawater, with various heavy metals and radioactive material
- Disposal typical occurs through injection into old, inactive oil wells, called Salt Water Disposal (SWD)
- A new use case is emerging for re-use in future hydraulic completions, though the water still requires some treatment prior to re-use

Produced Water Modeling

- **Much like oil, water production declines over the life of a well. This decline curve can be modeled fairly reliably after initial months or years of production data.**
- **Like our U.S. oil model, our water model uses rig counts, well completions, initial productivities, and type curves to model the decline of existing wells, and add new wells as they are drilled.**
- **Our forecast models the 6 of the major EIA basins (Permian, Eagle Ford, Bakken, Anadarko, Niobrara, Haynesville), as well as 3 additional sub-basins (Delaware, Midland and Powder River Basins).**

Delaware Basin – Heart of the H2O Boom

- **We modeled all major U.S. shale oil basins, though placed particular focus on the Delaware due to high water cuts.**

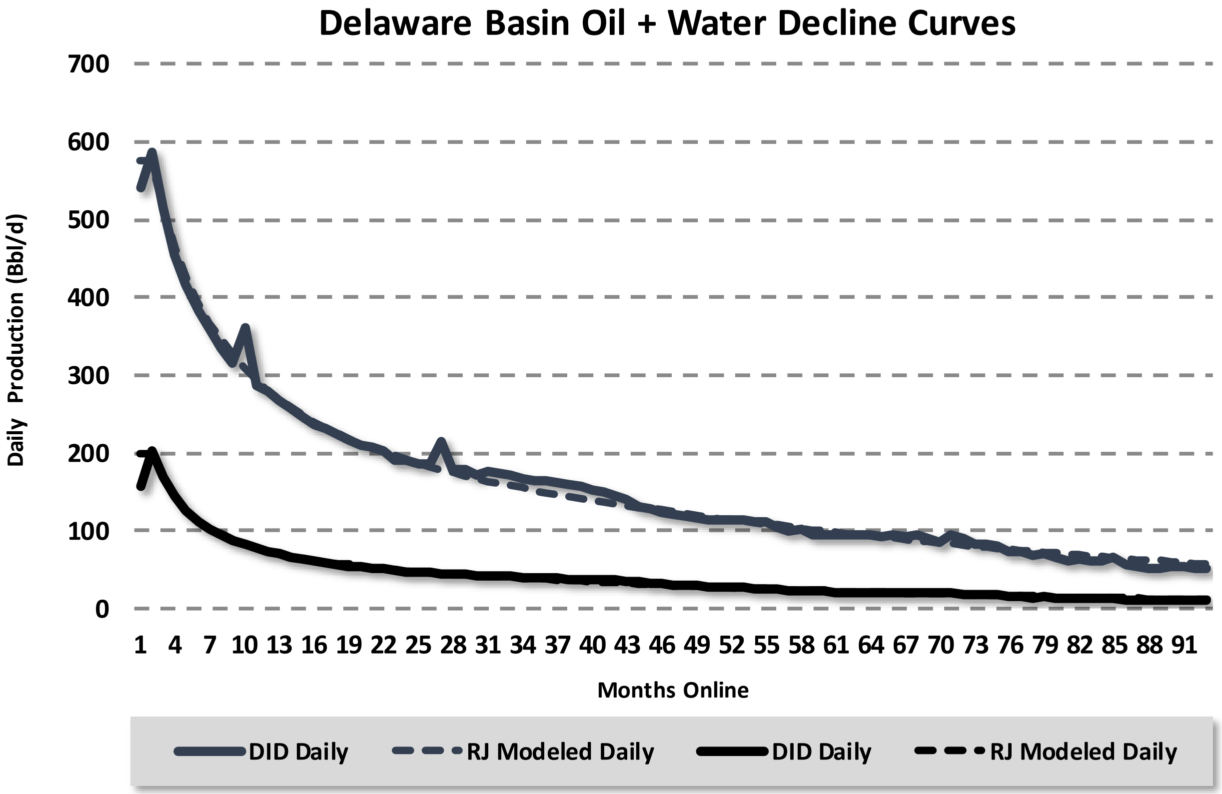
- **We constructed separate type curves for Delaware wells. Our type curves include modern horizontal wells, early horizontals, and legacy verticals.**

  - **Delaware defined as: Eddy, Lea, NM, Reeves, Loving, Ward, Pecos, Winkler, Culbertson TX counties**

  - **Specialized versions of the model, for specific basins/counties, type curves, or rig counts are available upon request**

- **All in, produced water in the Delaware has an 9.2% annual CAGR from 2010-2030.**

2010-2016 Delaware Basin Well



Source: *DrillingInfo, Raymond James Research*

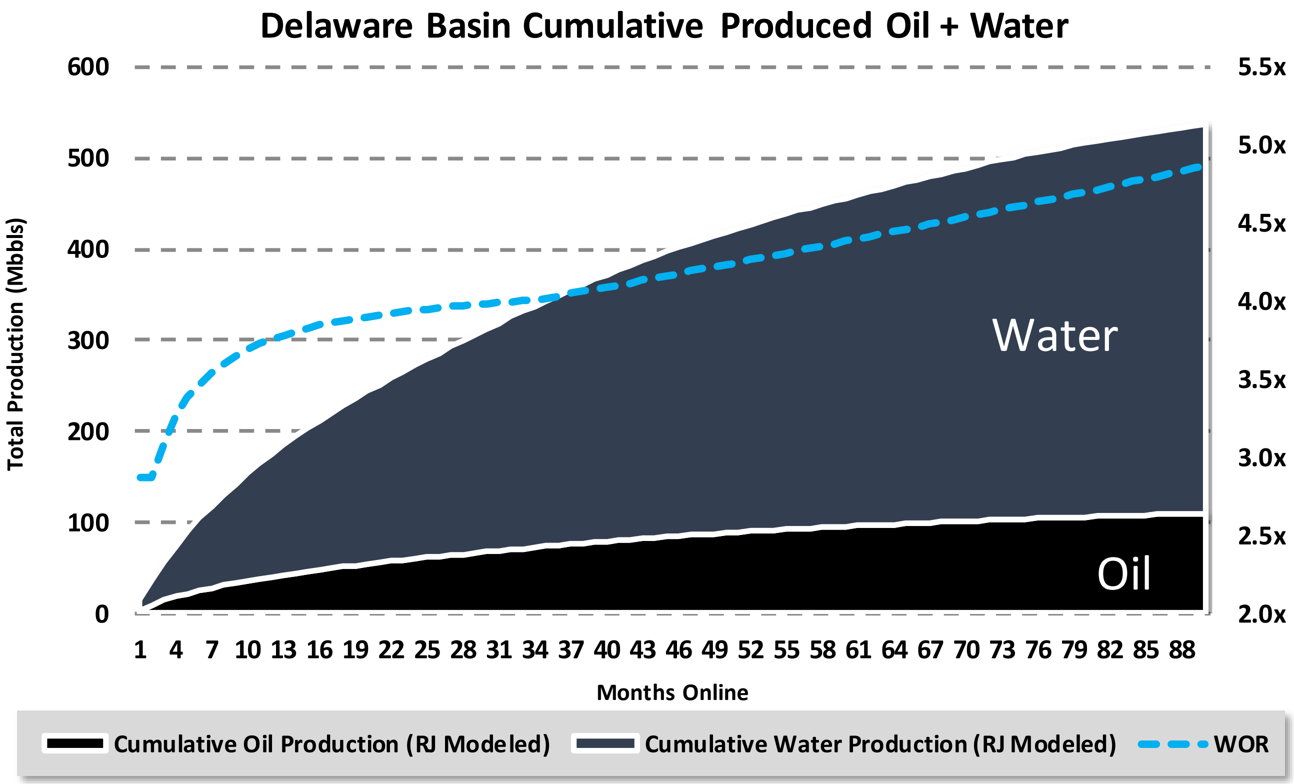
Well Parameters:

- Delaware Basin
- 2010-2016
- Horizontal, Vertical
- Wolfcamp, Bone Spring Formations
- Avg. Lateral: 6,120

Oil IP30: 200 bbl/d
Oil IP360: 75 bbl/d
Water IP30: 575 bbl/d
Water IP360: 280 bbl/d

Water-to-Oil Ratio of 2010-2016 Delaware wells starts at close to 3.0x, reaching 4.0x after 24 months, 5.0x at ~8 years, and 6.0x at ~12 years

2010-2016 Delaware Basin Well



Source: *DrillingInfo, Raymond James Research*

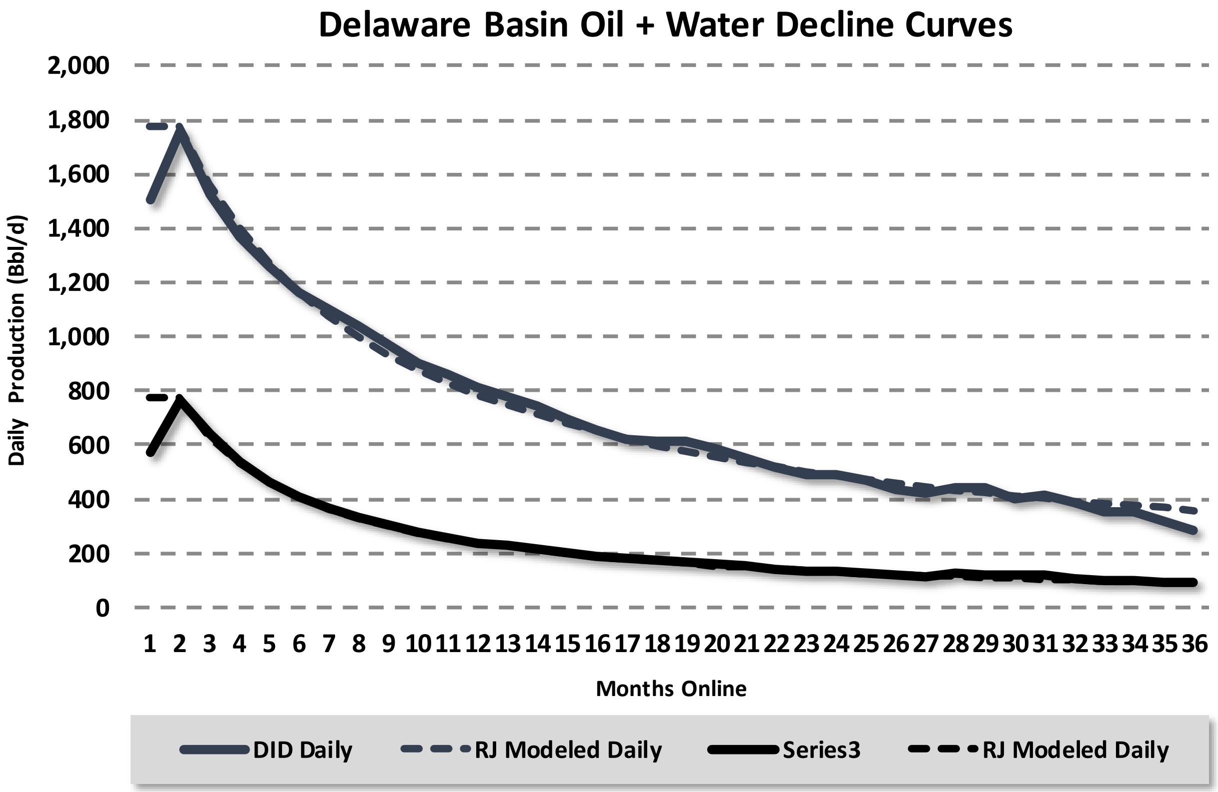
Well Parameters:

- Delaware Basin
- 2010-2016
- Horizontal, Vertical
- Wolfcamp, Bone Spring Formations
- Avg. Lateral: 6,120

Oil IP30: 200 bbl/d
Oil IP360: 75 bbl/d
Water IP30: 575 bbl/d
Water IP360: 280 bbl/d

Water-to-Oil Ratio of 2010-2016 Delaware wells starts at close to 3.0x, reaching 4.0x after 24 months, 5.0x at ~8 years, and 6.0x at ~12 years

Modern Delaware Basin Well



Source: *DrillingInfo, Raymond James Research*

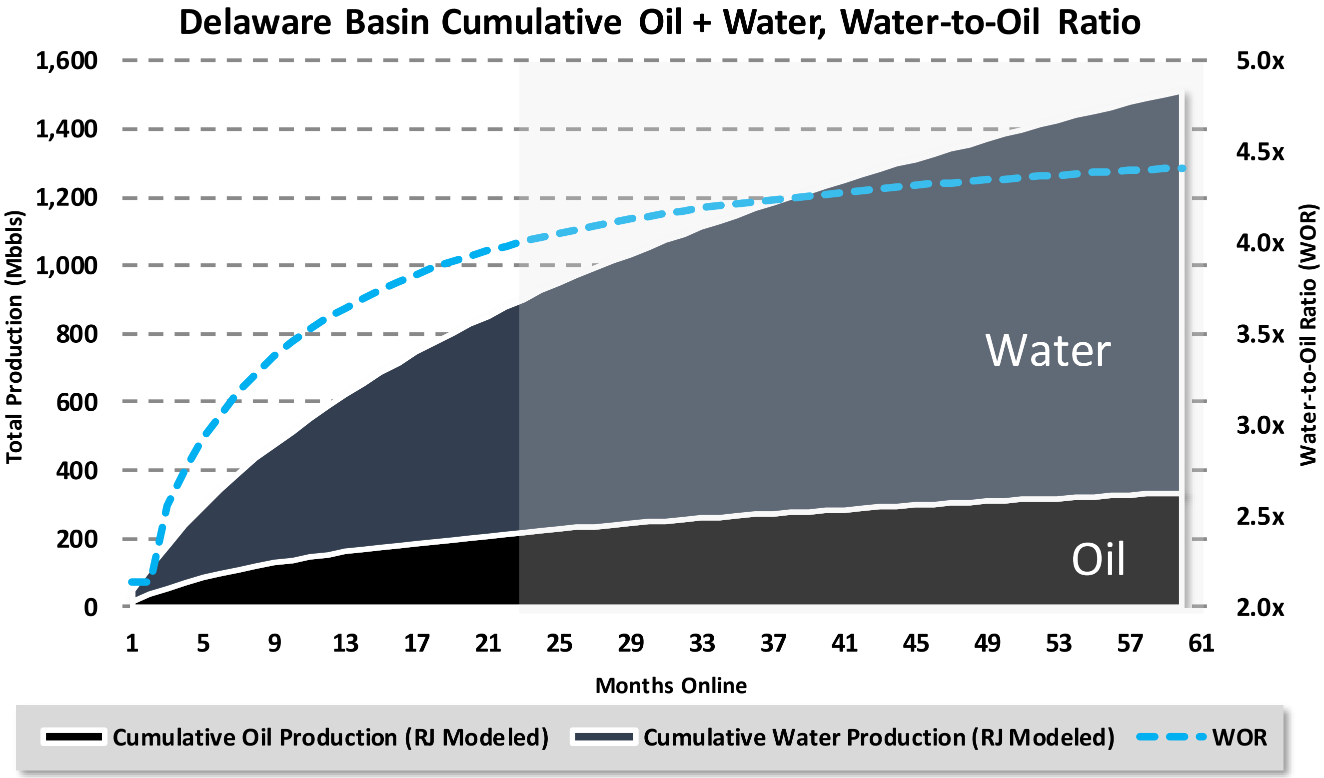
Well Parameters:

- Delaware Basin
- 2016-2019
- Horizontal
- Wolfcamp, Bone Spring Formations
- Avg. Lateral: 8,219fts

Oil IP30: 775 bbl/d
Oil IP360: 240 bbl/d
Water IP30: 1775 bbl/d
Water IP360: 800 bbl/d

Water-to-Oil Ratio of modern Delaware wells starts close to 3.0x, reaching 4.0x after 34 months, 5.0x at ~12 years, and 5.3x at 20 years

Projected Modern Delaware Well



Source: *DrillingInfo, Raymond James Research*

Well Parameters:

- Delaware Basin
- 2016-2019
- Horizontal
- Wolfcamp, Bone Spring Formations
- Avg. Lateral: 8,219fts

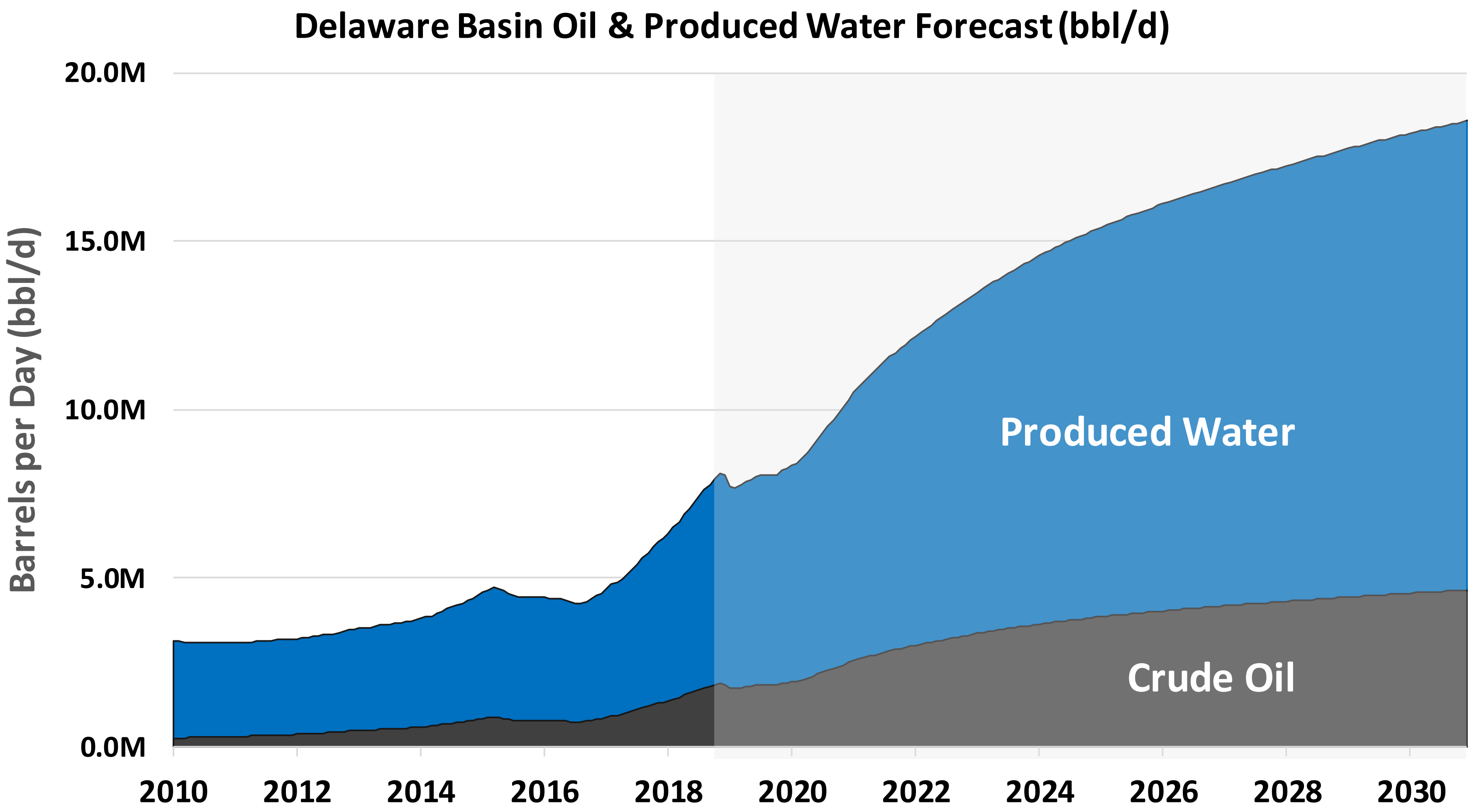
Oil IP30: 775 bbl/d
Oil IP360: 240 bbl/d
Water IP30: 1775 bbl/d
Water IP360: 800 bbl/d

Water-to-Oil Ratio approaches 4.5x after 5 years online, hits 5.0x by ~12 years, and 6.0x after in +25 years with current type curves. WOR creep is slower than the 2010-2016 vintage, though absolute water produced is much higher.

Delaware Basin Assumptions

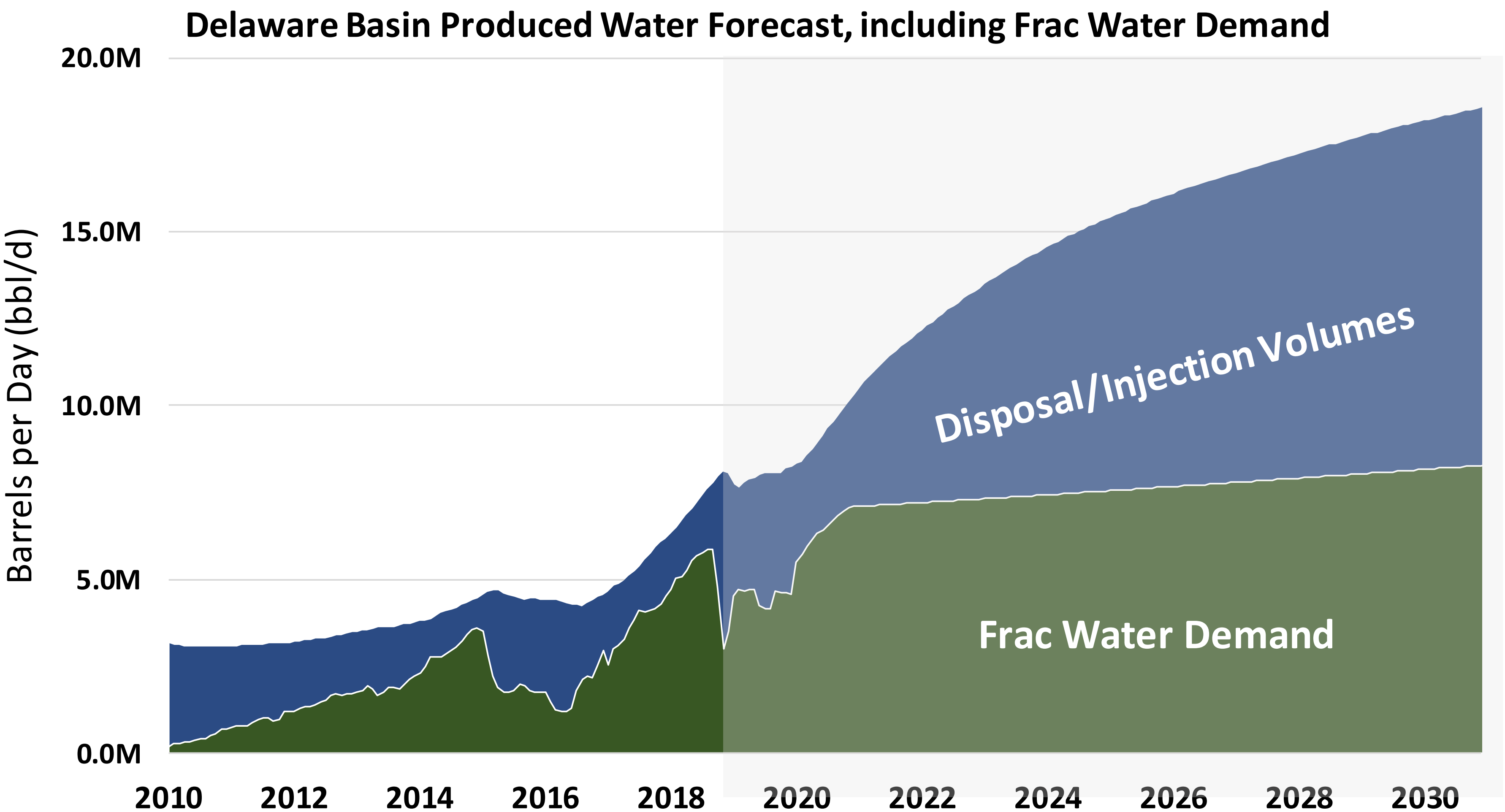
- **No DUC Builds after 2020**
- **Annual Oil-Directed Rig Count: ~300 from 2021-’30**
- **Flat well productivities per foot after 2025**
- **Type curves displayed in previous slides**
- **Requires 55,000 Delaware locations from 2020-’30**
- **WTI prices assumed supportive for U.S. oil supply growth. Long-term price deck of WTI $75.**

Delaware Basin Forecast



Source: EIA, Drilling Info, Baker Hughes, Raymond James Research

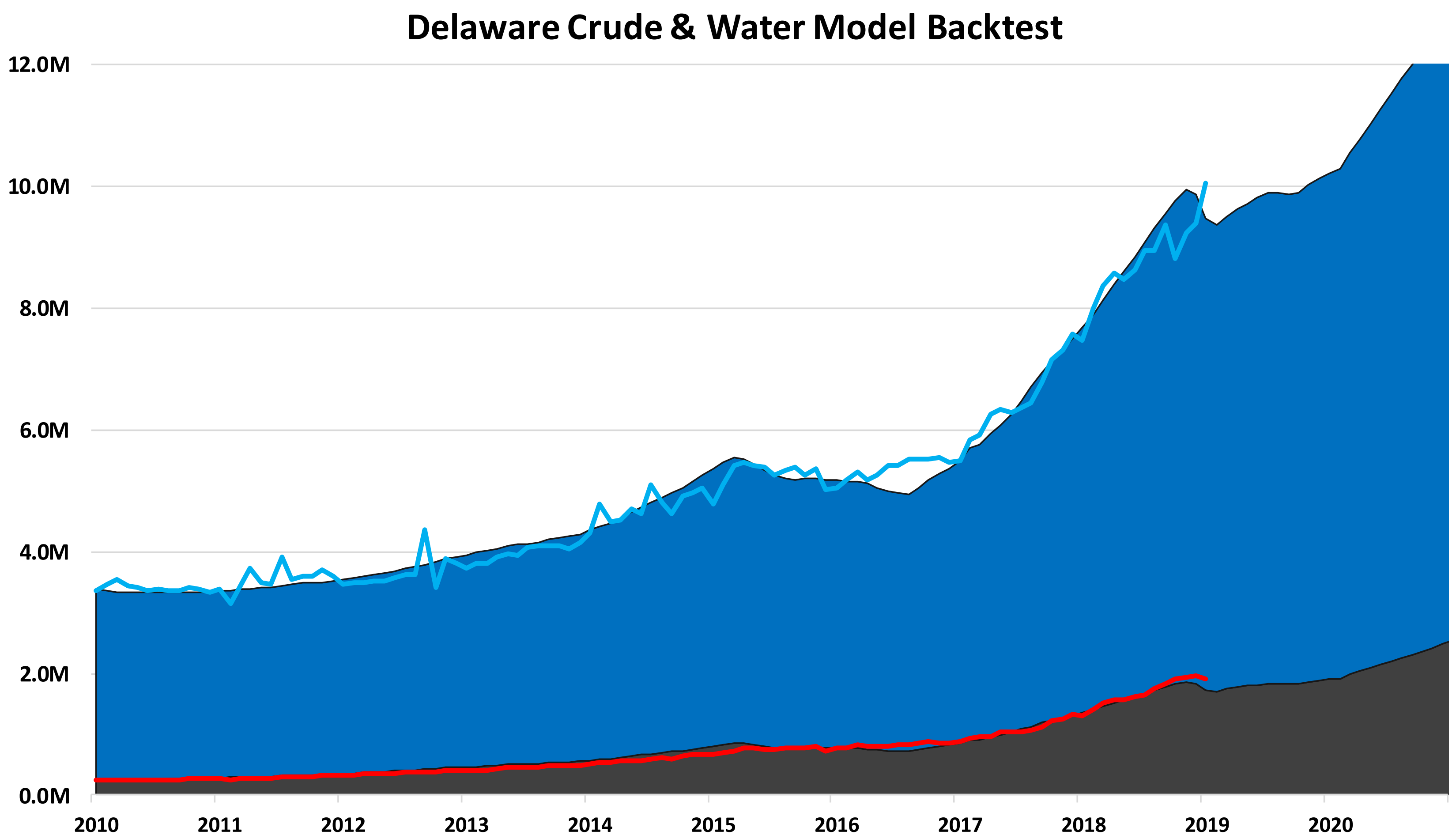
But What About Recycling?



Source: EIA, Drilling Info, Baker Hughes, Raymond James Research

Key assumptions: 525,000 bbl completions in 2020, Growing ~2% a year in perp., assumed ~75/bbl/lat.ft.

Back-tested Delaware Model



Source: EIA, Drilling Info, Baker Hughes, Raymond James Research

Our forecast begins on 1/1/2010, and was backtested against DrillingInfo production data for the Delaware counties and Baker Hughes Rig Count for these counties. For EIA DPR regions, EIA data was used.

Water Production By Basin

Water Production - By Basin										
	Permian	Delaware	Bakken	Anadarko	Eagle Ford	Niobrara	Midland	Total Modeled	All Other Basins	Total Onshore
2010	10,462,402	3,082,727	442,368	486,492	290,245	1,836,085	3,588,803	**13,517,592**	27,462,979	**40,980,571**
2011	10,677,923	3,122,473	540,437	577,677	434,673	1,732,544	3,717,724	**13,963,254**	28,370,680	**42,333,935**
2012	11,195,522	3,316,804	771,011	669,901	722,294	1,666,411	3,929,684	**15,025,139**	28,603,080	**43,628,219**
2013	11,749,727	3,613,483	968,260	690,990	941,421	1,628,926	4,168,909	**15,979,323**	28,448,645	**44,427,968**
2014	12,387,631	4,102,816	1,156,720	798,574	1,186,801	1,626,190	4,588,605	**17,155,915**	29,006,561	**46,162,476**
2015	13,056,306	4,526,561	1,320,297	820,897	1,225,348	1,609,351	4,886,238	**18,032,198**	27,675,393	**45,707,591**
2016	13,180,559	4,363,256	1,110,123	698,795	970,196	1,521,635	4,952,283	**17,481,308**	25,478,061	**42,959,369**
2017	14,032,116	5,371,198	1,217,753	736,871	922,223	1,499,629	5,494,908	**18,408,592**	25,623,638	**44,032,230**
2018	16,574,795	7,294,199	1,524,198	845,688	1,055,877	1,537,203	5,907,967	**21,537,762**	23,376,440	**44,914,202**
2019	18,677,535	7,967,680	1,773,941	909,950	1,163,796	1,546,221	6,317,483	**24,071,443**	21,904,773	**45,976,217**
2020	20,357,754	9,244,186	1,696,540	921,384	1,095,080	1,509,797	7,216,262	**25,580,554**	20,739,160	**46,319,714**
2021	23,220,254	11,323,329	1,876,725	1,013,952	1,170,416	1,542,166	8,382,148	**28,823,513**	19,741,918	**48,565,431**
2022	25,501,333	12,789,567	2,032,965	1,055,652	1,274,059	1,568,654	9,215,108	**31,432,663**	18,876,038	**50,308,701**
2023	27,573,916	13,997,664	2,179,896	1,081,569	1,373,513	1,589,744	9,871,292	**33,798,638**	18,114,987	**51,913,626**
2024	29,463,659	14,969,899	2,314,123	1,101,412	1,442,894	1,603,926	10,380,725	**35,926,015**	17,439,180	**53,365,194**
2025	31,016,015	15,736,347	2,419,826	1,117,741	1,484,955	1,618,257	10,769,918	**37,656,794**	16,833,799	**54,490,592**
2026	32,352,680	16,385,870	2,510,354	1,131,676	1,516,810	1,633,918	11,099,835	**39,145,439**	16,287,401	**55,432,840**
2027	33,491,573	16,956,732	2,590,456	1,143,826	1,543,067	1,651,360	11,392,080	**40,420,282**	15,790,988	**56,211,271**
2028	34,540,450	17,475,295	2,662,463	1,154,591	1,565,560	1,670,816	11,647,546	**41,593,880**	15,337,375	**56,931,255**
2029	35,464,910	17,957,899	2,727,813	1,164,240	1,585,287	1,692,428	11,893,709	**42,634,677**	14,920,743	**57,555,421**
2030	36,300,033	18,386,517	2,787,374	1,172,939	1,602,835	1,716,285	12,112,572	**43,579,466**	14,536,325	**58,115,791**

Source: DrillingInfo, EIA, Baker Hughes, Raymond James Research

Water-to-Oil Ratio By Basin

Water-to-Oil Ratio By Basin										
	Permian	Delaware	Bakken	Anadarko	Eagle Ford	Niobrara	Midland	Total Modeled	All Other Basins	Total Onshore
2010	11.5x	11.8x	1.2x	3.2x	2.7x	14.3x	9.1x	**8.2x**	15.1x	**11.8x**
2011	10.5x	10.0x	1.0x	2.7x	1.4x	13.6x	8.5x	**6.4x**	17.6x	**11.1x**
2012	9.0x	8.3x	1.0x	2.4x	1.1x	10.4x	7.7x	**4.8x**	19.4x	**9.5x**
2013	7.9x	7.1x	1.0x	2.2x	1.0x	7.1x	7.0x	**4.0x**	18.8x	**8.1x**
2014	7.1x	6.1x	1.0x	2.0x	0.9x	4.7x	6.2x	**3.5x**	18.5x	**7.1x**
2015	6.5x	5.7x	1.0x	1.9x	0.9x	3.5x	5.8x	**3.2x**	21.6x	**6.6x**
2016	6.4x	5.8x	1.0x	1.7x	0.8x	3.4x	5.7x	**3.3x**	23.6x	**6.8x**
2017	5.9x	5.0x	1.1x	1.7x	0.8x	3.1x	5.2x	**3.3x**	22.9x	**6.6x**
2018	4.9x	4.5x	1.2x	1.7x	0.8x	2.5x	4.5x	**3.0x**	29.6x	**5.7x**
2019	4.5x	4.4x	1.2x	1.7x	0.8x	2.1x	4.0x	**2.9x**	32.1x	**5.1x**
2020	4.3x	4.3x	1.2x	1.6x	0.8x	1.9x	3.6x	**2.9x**	32.7x	**4.8x**
2021	4.0x	4.1x	1.3x	1.6x	0.8x	1.7x	3.3x	**2.8x**	33.2x	**4.4x**
2022	3.9x	4.1x	1.3x	1.6x	0.8x	1.5x	3.1x	**2.7x**	33.7x	**4.1x**
2023	3.8x	4.0x	1.3x	1.5x	0.8x	1.3x	3.0x	**2.7x**	34.1x	**3.9x**
2024	3.7x	4.0x	1.3x	1.5x	0.7x	1.2x	3.0x	**2.6x**	34.6x	**3.8x**
2025	3.7x	4.0x	1.3x	1.5x	0.7x	1.1x	2.9x	**2.6x**	35.0x	**3.6x**
2026	3.6x	4.0x	1.3x	1.5x	0.7x	1.0x	2.9x	**2.6x**	35.3x	**3.5x**
2027	3.6x	4.0x	1.3x	1.4x	0.7x	1.0x	2.9x	**2.6x**	35.7x	**3.5x**
2028	3.6x	4.0x	1.3x	1.4x	0.7x	0.9x	2.8x	**2.5x**	36.0x	**3.4x**
2029	3.6x	4.0x	1.4x	1.4x	0.7x	0.9x	2.8x	**2.5x**	36.4x	**3.3x**
2030	3.6x	4.0x	1.4x	1.4x	0.7x	0.8x	2.8x	**2.5x**	36.7x	**3.3x**

Source: DrillingInfo, EIA, Baker Hughes, Raymond James Research

Water Annual Growth % By Basin

Water Growth Rate (Annual Y/Y%)										
	Permian	Delaware	Bakken	Anadarko	Eagle Ford	Niobrara	Midland	Total Modeled	All Other Basins	Total Onshore
2010										
2011	2.06%	1.29%	22.17%	18.74%	49.76%	-5.64%	3.59%	**3.30%**	3.31%	**3.30%**
2012	4.85%	6.22%	42.66%	15.96%	66.17%	-3.82%	5.70%	**7.60%**	0.82%	**3.06%**
2013	4.95%	8.94%	25.58%	3.15%	30.34%	-2.25%	6.09%	**6.35%**	-0.54%	**1.83%**
2014	5.43%	13.54%	19.46%	15.57%	26.06%	-0.17%	10.07%	**7.36%**	1.96%	**3.90%**
2015	5.40%	10.33%	14.14%	2.80%	3.25%	-1.04%	6.49%	**5.11%**	-4.59%	**-0.99%**
2016	0.95%	-3.61%	-15.92%	-14.87%	-20.82%	-5.45%	1.35%	**-3.06%**	-7.94%	**-6.01%**
2017	6.46%	23.10%	9.70%	5.45%	-4.94%	-1.45%	10.96%	**5.30%**	0.57%	**2.50%**
2018	18.12%	35.80%	25.16%	14.77%	14.49%	2.51%	7.52%	**17.00%**	-8.77%	**2.00%**
2019	12.69%	9.23%	16.39%	7.60%	10.22%	0.59%	6.93%	**11.76%**	-6.30%	**2.36%**
2020	9.00%	16.02%	-4.36%	1.26%	-5.90%	-2.36%	14.23%	**6.27%**	-5.32%	**0.75%**
2021	14.06%	22.49%	10.62%	10.05%	6.88%	2.14%	16.16%	**12.68%**	-4.81%	**4.85%**
2022	9.82%	12.95%	8.33%	4.11%	8.86%	1.72%	9.94%	**9.05%**	-4.39%	**3.59%**
2023	8.13%	9.45%	7.23%	2.46%	7.81%	1.34%	7.12%	**7.53%**	-4.03%	**3.19%**
2024	6.85%	6.95%	6.16%	1.83%	5.05%	0.89%	5.16%	**6.29%**	-3.73%	**2.80%**
2025	5.27%	5.12%	4.57%	1.48%	2.92%	0.89%	3.75%	**4.82%**	-3.47%	**2.11%**
2026	4.31%	4.13%	3.74%	1.25%	2.15%	0.97%	3.06%	**3.95%**	-3.25%	**1.73%**
2027	3.52%	3.48%	3.19%	1.07%	1.73%	1.07%	2.63%	**3.26%**	-3.05%	**1.40%**
2028	3.13%	3.06%	2.78%	0.94%	1.46%	1.18%	2.24%	**2.90%**	-2.87%	**1.28%**
2029	2.68%	2.76%	2.45%	0.84%	1.26%	1.29%	2.11%	**2.50%**	-2.72%	**1.10%**
2030	2.35%	2.39%	2.18%	0.75%	1.11%	1.41%	1.84%	**2.22%**	-2.58%	**0.97%**

Source: DrillingInfo, EIA, Baker Hughes, Raymond James Research

Company Citations

Company Name	Ticker	Exchange	Closing Price	RJ Rating	RJ Entity
National Oilwell Varco, Inc.	NOV	NYSE	$21.72	MO2	Raymond James & Associates
NGL Energy Partners LP	NGL	NYSE	$15.18	MO2	Raymond James & Associates
Rattler Midstream LP	RTLR	NASDAQ	$18.90	MO2	Raymond James & Associates
TETRA Technologies, Inc.	TTI	NYSE	$1.48	MP3	Raymond James & Associates

Prices are as of the most recent close on the indicated exchange. See Disclosure section for rating definitions. Stocks that do not trade on a U.S. national exchange may not be registered for sale in all U.S. states. NC=not covered.

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The covering analyst and/or research associate owns shares of National Oilwell Varco, Inc..
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	RJA	RJL	RJA	RJL
Strong Buy and Outperform (Buy)	55%	63%	21%	27%
Market Perform (Hold)	41%	34%	12%	15%
Underperform (Sell)	4%	3%	6%	0%

** Columns may not add to 100% due to rounding.*

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Medium Risk/Income (M/INC) Lower to average risk equities of companies with sound financials, consistent earnings, and dividend yields above that of the S&P 500. Many securities in this category are structured with a focus on providing a consistent dividend or return of capital.

Medium Risk/Growth (M/GRW) Lower to average risk equities of companies with sound financials, consistent earnings growth, the potential for long-term price appreciation, a potential dividend yield, and/or share repurchase program.

High Risk/Income (H/INC) Medium to higher risk equities of companies that are structured with a focus on providing a meaningful dividend but may face less predictable earnings (or losses), more leveraged balance sheets, rapidly changing market dynamics, financial and competitive issues, higher price volatility (beta), and potential risk of principal. Securities of companies in this category may have a less predictable income stream from dividends or distributions of capital.

High Risk/Growth (H/GRW) Medium to higher risk equities of companies in fast growing and competitive industries, with less predictable earnings (or losses), more leveraged balance sheets, rapidly changing market dynamics, financial or legal issues, higher price volatility (beta), and potential risk of principal.

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NGL Energy Partners LP	Raymond James & Associates has received compensation for investment banking services provided to NGL Energy Partners LP within the past 12 months.
NGL Energy Partners LP, National Oilwell Varco, Inc., Rattler Midstream LP and TETRA Technologies, Inc.	Raymond James & Associates, Inc. makes a market in the shares of NGL Energy Partners LP, National Oilwell Varco, Inc., Rattler Midstream LP and TETRA Technologies, Inc..
NGL Energy Partners LP and Rattler Midstream LP	Raymond James & Associates has managed or co-managed an offering of securities for NGL Energy Partners LP and Rattler Midstream LP within the past 12 months.
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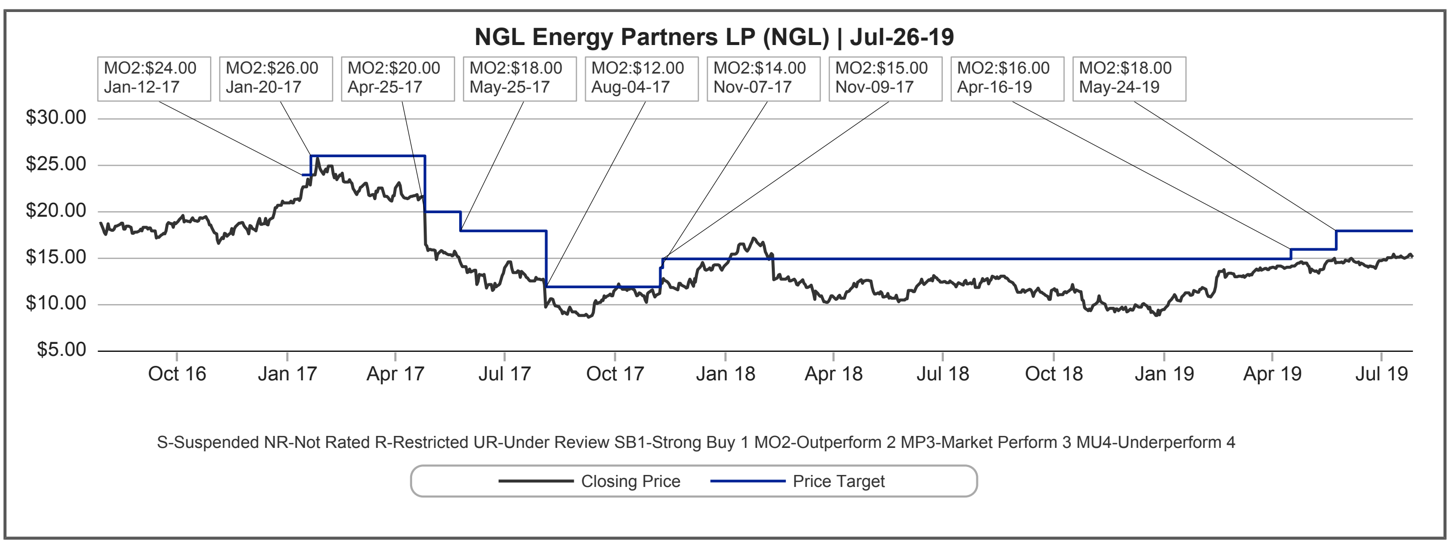
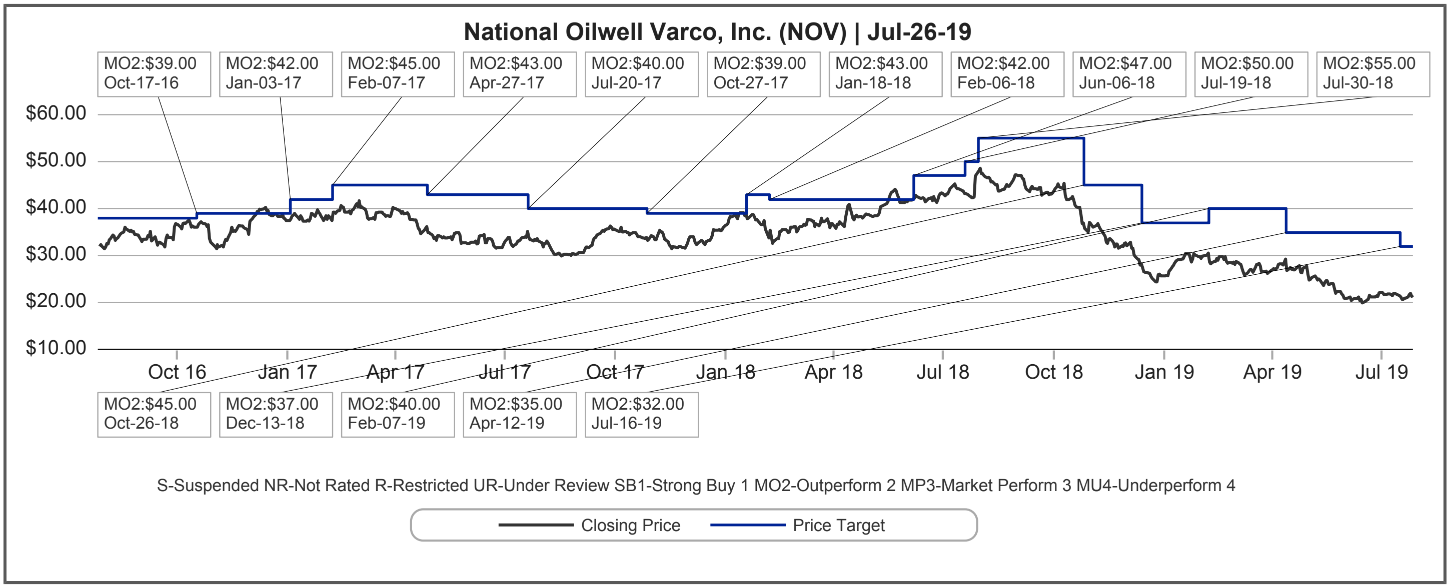
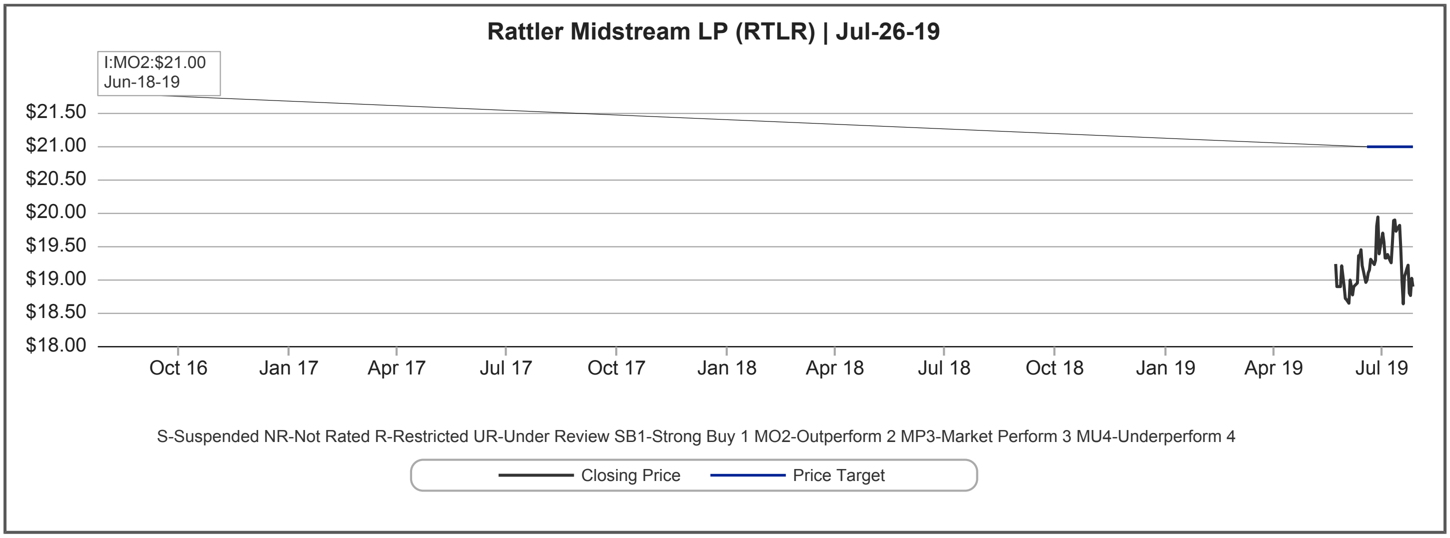
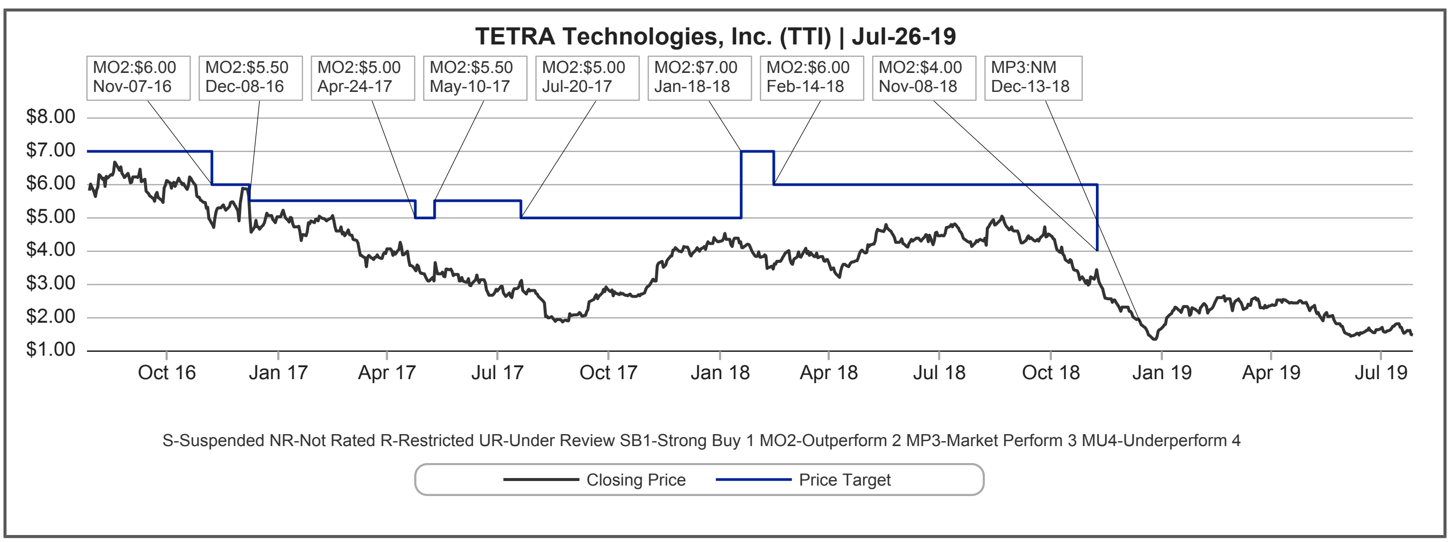
Target Prices: The information below indicates our target price and rating changes for the subject companies over the past three years.









Valuation Methodology

NGL Energy Partners LP:

Our valuation methodology is based on a blended valuation comprising 1) a 10-year, three-stage distribution/dividend discount model (DDM), 2) forward price-to-distributable cash flow (P/DCF) multiples relative to comparable industry peers, and 3) forward enterprise value-to-EBITDA (EV/EBITDA) multiples relative to comparable industry peers. Our DDM assumes 1) cash distributions/dividends based on our forward-looking assumptions of the asset base, 2) a general cost of equity/discount rate/required rate of return for LP holders approximating either the capital asset pricing model (CAPM), the distribution/dividend discount model (forward yield plus growth), or the bond yield plus equity risk premium approach, and 3) a perpetual growth rate/terminal growth rate based on the growth profile of the partnership/company.

National Oilwell Varco, Inc.:
Valuation Methodology: For NOV, our valuation methodology utilizes a relative EV/EBITDA multiple and also takes into consideration the company's P/E ratio in comparison to comparable P/E ratios from a peer group and its own historical trading levels.

Rattler Midstream LP:
Our valuation methodology is based on a blended valuation comprising 1) a 10-year, three-stage distribution/dividend discount model (DDM), 2) forward price-to-distributable cash flow (P/DCF) multiples relative to comparable industry peers, and 3) forward enterprise value-to-EBITDA (EV/EBITDA) multiples relative to comparable industry peers. Our DDM assumes 1) cash distributions/dividends based on our forward-looking assumptions of the asset base, 2) a general cost of equity/discount rate/required rate of return for LP holders approximating either the capital asset pricing model (CAPM), the distribution/dividend discount model (forward yield plus growth), or the bond yield plus equity risk premium approach, and 3) a perpetual growth rate/terminal growth rate based on the growth profile of the partnership/company.

TETRA Technologies, Inc.:
We value shares of TETRA based on an EV/EBITDA analysis, which assigns EBITDA multiples for each of the company's subsegments, based on peers and relative differentiation.

Risk Factors

General Risk Factors: Following are some general risk factors that pertain to the business of the subject companies and the projected target prices and recommendations included on Raymond James research: (1) Industry fundamentals with respect to customer demand or product/service pricing could change and adversely impact expected revenues and earnings; (2) Issues relating to major competitors or market shares or new product expectations could change investor attitudes toward the sector or this stock; (3) Unforeseen developments with respect to the management, financial condition or accounting policies or practices could alter the prospective valuation; or (4) External factors that affect the U.S. economy, interest rates, the U.S. dollar or major segments of the economy could alter investor confidence and investment prospects. International investments involve additional risks such as currency fluctuations, differing financial accounting standards, and possible political and economic instability.

Company-Specific Risks

NGL Energy Partners LP:
NGL Energy Partners (NGL)
Inability to Remove the General Partner
Consistent with the MLP structure, Class A common unitholders are not entitled to elect the partnership's general partner or the general partner's directors. Even if unitholders are dissatisfied, they cannot remove the general partner except in rare circumstances. Given that a majority of holders vote to remove the general partner, they would also have the right to elect a successor general partner.
Counterparty Risk
NGL Energy Partners relies on third parties for services, product, and demand. As a result, the partnership could be impacted in a number of ways by counterparty risk. NGL Energy's business would be adversely affected if the operations of its refinery, producer, or other customers experienced significant interruption. In addition, the partnership relies on third parties for pipeline, truck, rail, and barge transportation services in its crude oil logistics segment. In its natural gas liquids logistics segment, the partnership relies on third-party operators for several of its NGL terminals. While NGL Energy mitigates its commodity exposure through its: 1) back-to-back purchase and sale structure of crude oil and NGLs in these two logistics businesses; and 2) fee-based contracts (some with acreage dedications or volume commitments) in the Water Services segment, commodity price volatility could have an adverse effect on profits and cash flow. In its Retail Propane segment, the volatility in commodity prices could have an adverse effect on propane margins. Given that price is a natural response to demand, materially lower prices could affect throughput volumes in all four of NGL Energy's segments. Despite structural measures that help create a "fixed" margin mechanism in its Crude and NGL Logistics segments, in some cases, price volatility may also impact margins. Separately, there is no guarantee concerning the future activities of the partnership. NGL Energy could purchase assets with greater commodity exposure to fluctuations in commodity prices.
Acquisition/Integration Risk
While acquisitions are a critical component of the partnership's growth strategy, NGL Energy Partners may be unable to make such acquisitions under accretive terms and/or obtain the necessary financing to fund these acquisitions. Even if such an acquisition is completed, the risk that it will

be unsuccessful still exists due to integration risk, overpayment risk, environmental liabilities, and the risk of asset underperformance following the acquisition. These risks could impair NGL Energy's ability to grow cash distributions.

Interest Rate Risk

Interest rate movements can impact yield-oriented investments such as MLPs. Increasing interest rates could have an adverse effect on NGL Energy's unit price if alternative yield-oriented investments become more attractive. Rising interest rates could also increase the partnership's financing costs, thereby reducing the amount of cash flow available for distribution to common unitholders. It is worth noting that NGL Energy has particular exposure to interest rate volatility given that interest on its credit facility is set by a variable rate.

Dependence on Capital Markets

MLPs pay out a significant portion of available cash in the form of distributions to unitholders. When growth projects/acquisitions become available, partnerships typically access the capital markets for the necessary funds to finance this growth. Market conditions may or may not be attractive for NGL Energy at the time it seeks external funding, which may result in higher capital costs, lower returns, and in some instances, the inability to fund growth.

Distributions Are Not Guaranteed

The actual amount of cash distributed to NGL Energy unitholders may fluctuate and will depend on NGL Energy's ability to capture consistent margins in its four business segments. The partnership's ability to maintain adequate and stable coverage can fluctuate from quarter to quarter depending on the volumes and prices at which the partnership buys and sells its products, demand for its services, its ability to maintain steady operating costs, working capital changes, and macroeconomic and sociopolitical factors.

Competition Risk

NGL Energy competes with other gatherers, transporters, marketers, brokers, and aggregators, including refiners, independents, and major integrated companies as well as their marketing affiliates, which may have greater capital resources and/or a larger supply of crude oil and NGLs. Its ability to compete could be harmed by a competitor's construction of new assets or redeployment of existing assets so as to capture market share, the perception that competitors offer better service, and the availability of alternative supply located closer to customers. Moreover, while the partnership intends to grow its business by identifying organic and inorganic opportunities, there is no guarantee that the partnership will be successful at securing such growth. Any of these factors could result in customers utilizing the assets and services of competitors or price degradation, either of which could impact operating results, financial position, cash flow, and coverage.

Terrorism

Pipelines and other midstream energy assets could be targets of terrorist activities. NGL Energy may be subject to an elevated risk of terrorism. There is no guarantee that insurance to protect against these events will be available at reasonable rates in the future. The partnership may also face rising compliance costs to adhere to new government-imposed security measures.

Regulatory Risk

The ownership, operation, and development of midstream energy assets involve numerous regulatory, environmental, political, and legal uncertainties that are outside of NGL Energy's control. Environmental laws and regulations have recently raised operating costs for the oil and refined products industry. Compliance with such laws and regulations may cause the partnership to incur higher integrity and maintenance costs in the future.

National Oilwell Varco, Inc.:

International Exposure Poses Potential Risk National-Oilwell has been expanding its international presence to take advantage of opportunities that have arisen worldwide. National- Oilwell conducts business in the Middle East, Africa, Southeast Asia, South America, and other international markets. This expansion exposes National-Oilwell to a certain degree of risk associated with international operations. Such risks include potentially volatile political climates, exchange rate fluctuations, import-export quotas, and other forms of governmental regulation. While National-Oilwell has taken measures to ease this risk, it is a possibility that foreign government interruptions for oil and gas-related activity could occur, hindering operations in such areas. As international expansion continues to grow, the exposure to such risks will also increase.

Projected Cost Savings From Acquisitions Could Be Insufficient National Oilwell Varco has made several acquisitions over the past few years to increase market share and enhance product offerings. Factors could arise in the marketplace that would prevent National Oilwell from realizing anticipated synergies and hinder its ability to integrate acquisitions into the overall business model. Combining organizations could have a negative impact on operations by interrupting the activities or businesses of National Oilwell Varco.

Impact of Volatile Commodities National-Oilwell Varco's business primarily is dependent on the state of the oil and gas industry and capital expenditures for exploration, production, and transmission activities. The amount oil and gas operators allocate for capital expenditures generally depends on oil and gas prices. While we believe that the supply/demand fundamentals suggest a rebound in commodity prices, investors should be aware oil and natural gas prices tend to be volatile and the near-term outlook suggests continued lower oil prices. Furthermore, a sustained downturn in either U.S. natural gas prices or worldwide oil prices would undoubtedly lead to lower levels of oilfield activity continuingbeyond what we are currently experiencing

High-Risk Suitability Rating

We assign a High Risk suitability rating to NOV shares based on the highly cyclical nature of commodity prices, which can cause shares to meaningfully underperform the broader market during times of commodity market distress. Such cycles can be brought on by factors including, but not limited to, geopolitical issues, supply disruptions, economic slowdown, and/or periods of over-investment.

Rattler Midstream LP:
The amount of cash Rattler Midstream LP distributes to its unitholders depends principally upon the cash generated from operations. Since the cash generated from operations will fluctuate from quarter to quarter, Rattler Midstream LP may not be able to maintain future quarterly distributions at the current level. Rattler's ability to pay quarterly distributions depends primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. As a result, Rattler Midstream LP may pay cash distributions during periods when it records net losses and may be unable to pay cash distributions during periods when it records net income.

Rattler Midstream LP is subject to risks associated with nonpayment or nonperformance by customers to which Rattler Midstream LP provides services and sells commodities. With one predominant customer upon its IPO, Rattler operates at a substantial customer concentration risk. Further, some of Rattler's future customers may be highly leveraged or under-capitalized and subject to their own operating and regulatory risk; these customers could have increased risk that could result in default on their obligations to Rattler Midstream LP.

While acquisitions are not a primary component of the company’s growth strategy, Rattler Midstream LP may be unable to make such acquisitions under accretive terms and/or obtain the necessary financing to fund these acquisitions. Even if such an acquisition is completed, the risk that it will be unsuccessful still exists due to integration risk, overpayment risk, environmental liabilities, and the risk of asset underperformance following the acquisition. These risks could impair Rattler's ability to make cash distributions. Management attempts to minimize these risks by performing extensive due diligence.

Interest rate movements can affect yield-based investments, such as Rattler Midstream LP. Increasing interest rates could have an adverse effect on Rattler's share price as alternative yield investments, such as U.S. Treasuries, become more attractive. In addition, increased debt service cost and interest expense might negatively affect the partnership's distributable cash flow.

Midstream companies pay out a significant portion of available cash in the form of distributions to shareholders. When growth projects/ acquisitions become available, companies typically tap the capital markets for the necessary financing to fund such projects. Market conditions may or may not be attractive for Rattler Midstream LP at the time it needs external funding.

Although very limited, RTLR's operations or margins could eventually be exposed to volatility in commodity prices indirectly through its volume exposure to Diamondback (FANG). While a midstream company’s revenues are typically generated primarily by tolling fees, margin-based businesses can be directly and/or indirectly impacted by increases or decreases in commodity prices. This technically results in some indirect exposure at the Rattler level.

High Risk/Income Suitability rating: While RTLR is largely insulated from direct exposure to commodity prices, it does have indirect exposure to commodity prices given its dependence on volume growth in the Permian. Additionally, Rattler lacks customer diversity as the entirety of the partnership’s earnings relies on volumes from FANG. Although we regard Diamondback as a strong E&P and strong sponsor, we have to acknowledge that RTLR would benefit from a more varied customer base. Given the partnership’s indirect exposure to commodity pricing and dependence on FANG, we view a high risk/income suitability rating as appropriate.

TETRA Technologies, Inc.:
Drilling Activity At least two of Tetra's operating divisions are highly dependent upon drilling activity levels. Its fluids business depends largely on drilling activity in the Gulf of Mexico and abroad. Likewise, its well testing division is mainly driven by North American natural gas drilling activity. Natural gas drilling has fallen dramatically and the slowdown may not be as dramatic as it was earlier in the decade.

Weather Conditions As with any operation in the Gulf of Mexico, stormy weather or choppy sea conditions can severely impact Tetra Technologies' ability to perform operations and/or profitability. Also, poor weather conditions could cause damage to the company's vessels. While there can be no guarantees as to the impact on activity the weather can cause, Tetra does carry appropriate insurance coverage in the event of any vessel damage.

Exploration and Production Expenditures Tetra's business is dependent on the state of the oil and gas industry and capital expenditures for exploration and production in the U.S. The level of such expenditures is generally dependent on the price for oil and gas, and ultimately translates into drilling activity. As oil and natural gas are volatile commodities, a sustained downturn in either would lead to lower levels of oilfield activity and operating results for Tetra. We expect publicly traded E&P companies to continue increasing their capital spending which depends, of course, on commodity prices - which we expect to remain on track to support such growth.

International Expansion Poses Risks Tetra Technologies has been expanding its international presence to take advantage of opportunities that have arisen worldwide. This expansion exposes Tetra to a certain degree of risk associated with international operations. Such risks include potentiallyvolatile political climates, exchange rate fluctuations, import-export quotas, and other forms of governmental regulation. While Tetra has taken measures to ease this risk, it is a possibility that foreign government interruptions for oil- and gas-related activity could occur, hindering operations in such areas. As international expansion continues to grow, the exposure to such risks will also increase

High-Risk Suitability Rating

We assign a High Risk suitability rating to Tetra Technologies based on the highly cyclical nature of commodity prices, which can cause shares to meaningfully underperform the broader market during times of commodity market distress. Such cycles can be brought on by factors including, but not limited to, geopolitical issues, supply disruptions, economic slowdown, and/or periods of over-investment.

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