DI ProdCast

Production Forecast Report | March 2018

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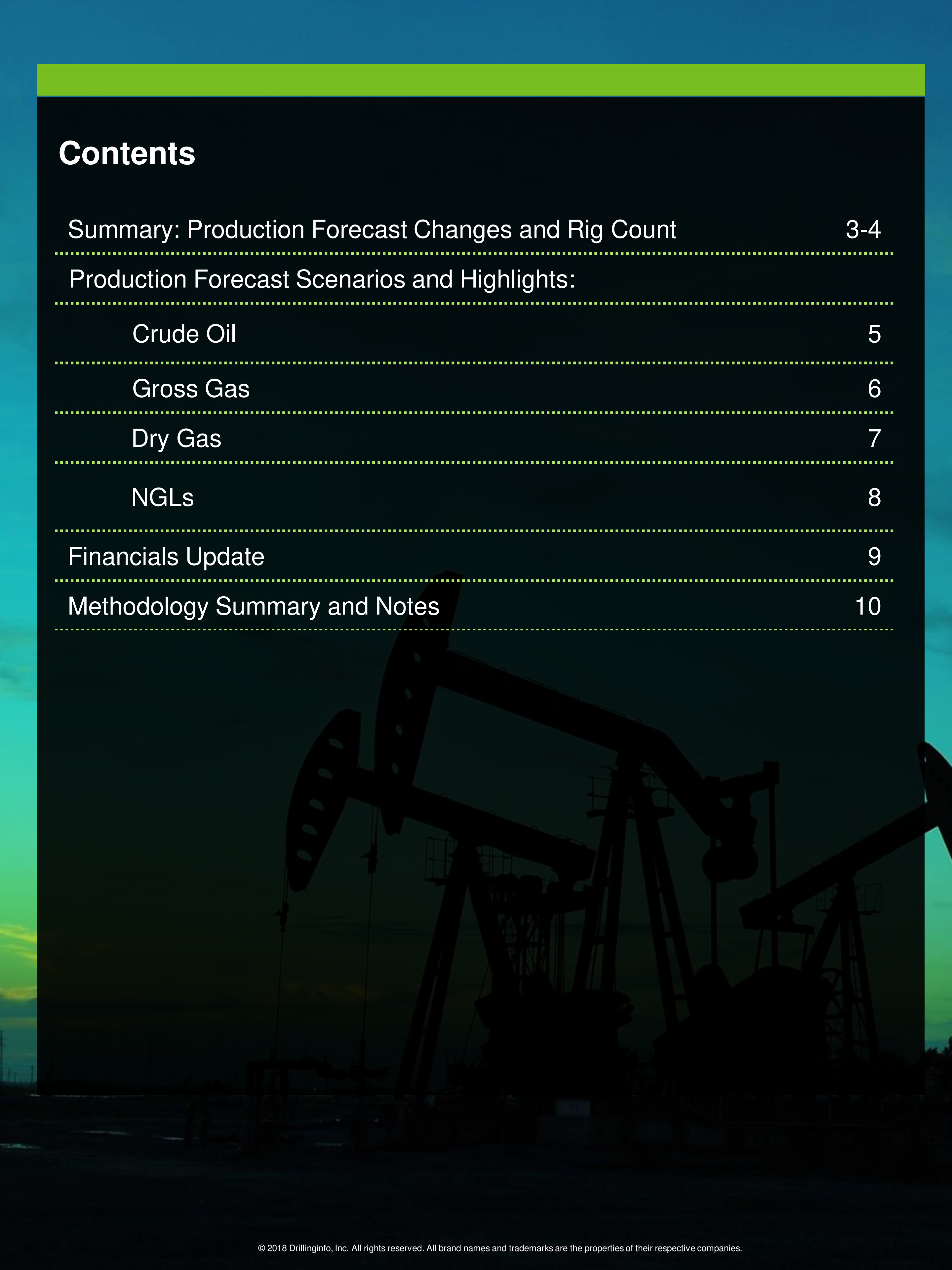

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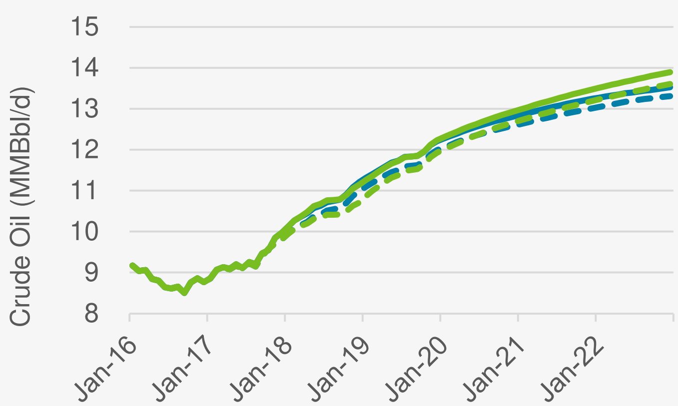
SUMMARY - PRODUCTION

DI FORECAST: *Crude oil and dry gas production growth expectations have changed from last month's forecast. These changes are driven by DI's Short Term Guidance Forecast updated with 4Q2017 corporate earnings announcements, updated state well-level data, and the revision down of the STEO GOM forecast.*

- *Crude oil is expected to grow ~1,090 MBbl/d from March 2018 to March 2019. The expected increase in production is mainly attributed to producers taking advantage of the higher price environment with hedges and projecting double-digit growth rates, tax benefits, and increasing activity in prolific areas such as the Permian and Anadarko basins. Other unconventional basins such as DJ, Eagle Ford, & Bakken are also realizing improved economics and expected to increase production.*
- *Dry gas production is expected to grow by ~6.0 Bcf/d from December 2017 to December 2018 and an additional ~2.6 Bcf/d in 2019. The increased growth expectations is driven by improved 4Q2017 corporate guidance as well as faster than expected results in January 2018. Expected pipeline expansions in 2Q & 4Q of 2018 as well as activity from prolific basins like Permian, Anadarko, and Haynesville should support this growth.*

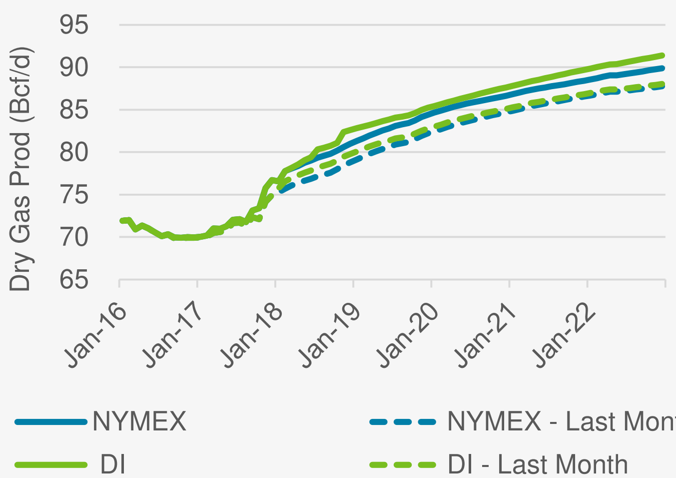
NYMEX FORECAST*: Crude oil forward prices are currently in a backwardation environment driven by stronger spot market trading and near term bullish indicators over the past several months. Crude oil prices retracted from their highs earlier in the year as historically high US production levels were reached and Trump's steel tariffs proposal ignited a trade war between US & China which could potentially negatively effect the demand growth. Prices are supported by OPEC supply cuts, declining Venezuelan production, as well as geopolitical unrest in the Middle East.*

Crude Oil Production Forecast



WTI Forward Curve	NYMEX 3/5/2018	NYMEX 4/8/2018	DI
2018	$ 59.39	$ 61.40	$ 60.00
2019	$ 58.48	$ 57.82	$ 60.00
2020	$ 57.05	$ 54.54	$ 60.00
2021	$ 56.16	$ 52.26	$ 60.00
2022	$ 55.80	$ 50.86	$ 60.00

Dry Gas Production Forecast



Henry Hub Forward Curve	NYMEX 3/5/2018	NYMEX 4/8/2018	DI
2018	$ 2.84	$ 2.85	$ 2.75
2019	$ 2.77	$ 2.79	$ 2.75
2020	$ 2.76	$ 2.76	$ 2.75
2021	$ 2.74	$ 2.80	$ 2.65
2022	$ 2.76	$ 2.85	$ 2.65

** Current year DI forecast is based on drilling and CAPEX guidance for 70+ operators.*

SUMMARY – RIGS AND DUCS

The overall rig count is 18 higher than the prior month. The Appalachian, and Piceance saw the largest declines in rig count, down 4 and 3 rigs, respectively. The Delaware and Midcontinent saw the most sizeable increases in their rig count, adding 11 and 10 rigs, respectively.

The rig count has remained fairly flat over the last 11 months, as crude prices has hovered in the $50-60 range while gas prices stayed in the $2.50-3.25 range. Currently rigs are the highest (~1,100 rigs) since their low seen in May 2016 at 433 rigs. The additions of rigs since that low have primarily come from the Permian.

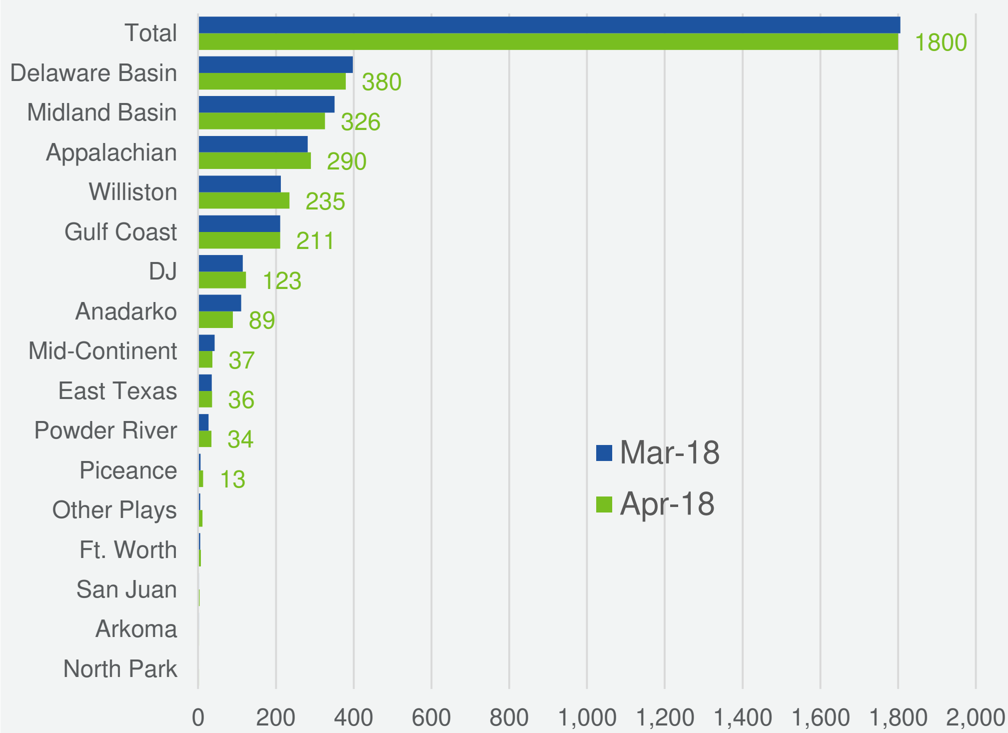
With the increased rig count in the Permian, completion crews have has a difficult time keeping up with the pace of drilling. The Permian currently has ~700 DUC wells, making up a good portion of DUCs in the US. These wells are economic and the infrastructure is in place to support these volumes. However, the completion crews are currently unable to keep up with the pace of drilling, allowing for an increasing number of DUCs in the area.

More completions crews are necessary and this is the reason why most operators are expecting 10%-20% increase in D&C costs moving forward.

Average Daily Rig Count

	March-18	MoM Change	YoY Change	Change From Peak
Delaware Basin	255	11	86	59
Midland Basin	191	(2)	23	(121)
Gulf Coast	123	1	7	(218)
Anadarko	110	(2)	15	(72)
Appalachian	66	(4)	5	(79)
East Texas	58	(1)	11	8
Williston	58	0	15	(140)
Mid-Continent	52	10	12	(110)
Offshore	49	6	1	(102)
Other Play	48	6	5	(43)
Piceance	28	(3)	4	(30)
DJ	28	(1)	(1)	(46)
Powder River	17	(1)	8	(21)
Fort Worth	5	(2)	3	(22)
San Juan	2	(1)	2	(6)
Arkoma	2	1	1	(1)
North Park	1	-	1	(14)
TOTAL	1,094	18	199	(957)

DUC Count*



*Only shows wells that have been drilled but not completed for more than six months.

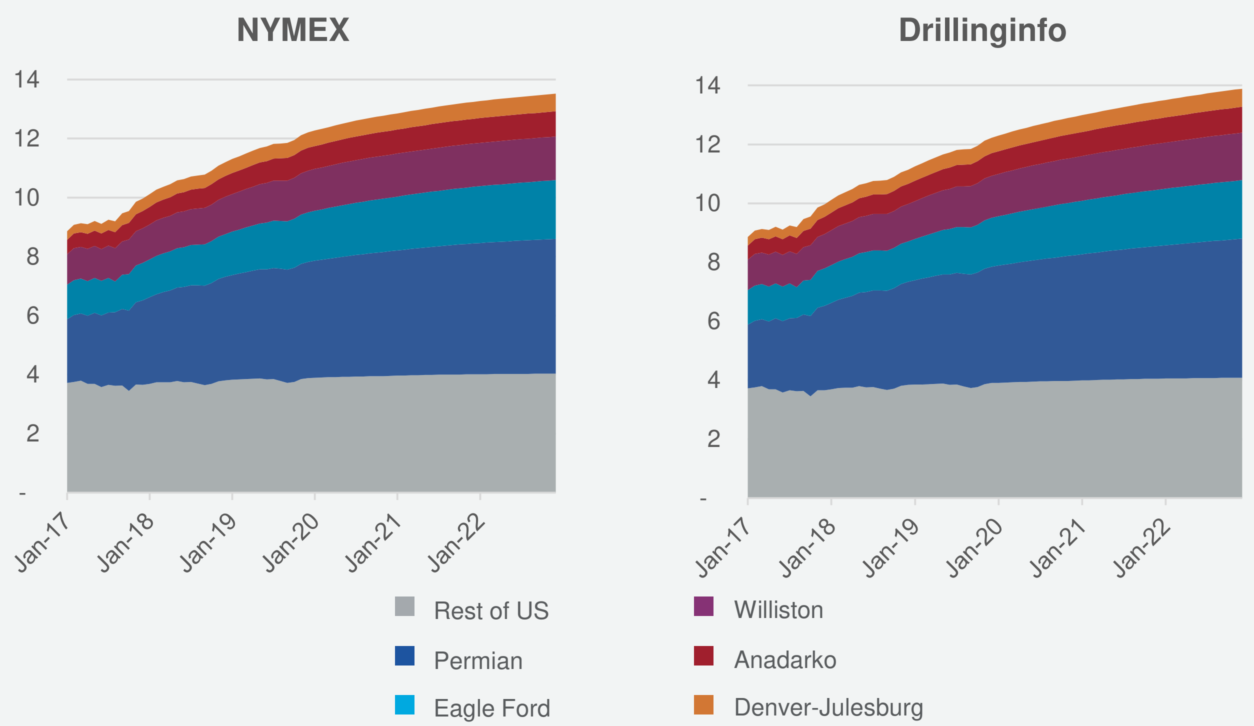
CRUDE OIL PRODUCTION

- *The Permian, Anadarko, and Eagle Ford basins will post the largest production growth, adding 630 MBbl/d, 100 MBbl/d, and 103 MBbl/d respectively, exit-to-exit. The growth from these basins is due to efficiency gains and more productive wells coming online.*
- *The higher price environment coupled with tax reform benefits is leading producers to ramp up activity. US production has reached historical highs. The US has surpassed Saudi Arabia to become the #2 oil producer globally and is hot on the heels of Russia for top spot. Producers hit their Q4'17 guidance levels while turning-in-line fewer wells than originally anticipated thanks to significant efficiencies realized throughout all major basins. Although production guidance was reached with fewer wells, CAPEX levels were maintained, as some cost inflation materialized during Q4'17. An additional 10-20% cost inflation is expected in 2018.*

Crude Oil Production Forecast by Major Basins (MMBbl/d)

	Mar-18		Apr-18		May-18		Jun-18		Jul-18		Aug-18		AVG-2018	
Basin	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI
Permian	3.1	3.0	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.2	3.2
Eagle Ford	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.3
Williston	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Anadarko	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.7	0.7	0.7	0.7	0.7	0.6
Denver-Julesburg	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.5	0.4	0.5	0.4	0.5	0.4	0.5
Rest Of US	3.7	3.7	3.7	3.7	3.8	3.8	3.7	3.8	3.8	3.8	3.7	3.7	3.7	3.7
TOTAL	**10.4**	**10.4**	**10.5**	**10.5**	**10.6**	**10.6**	**10.6**	**10.7**	**10.7**	**10.8**	**10.7**	**10.8**	**10.7**	**10.7**

Crude Oil Production by Major Basins (MMBbl/d)



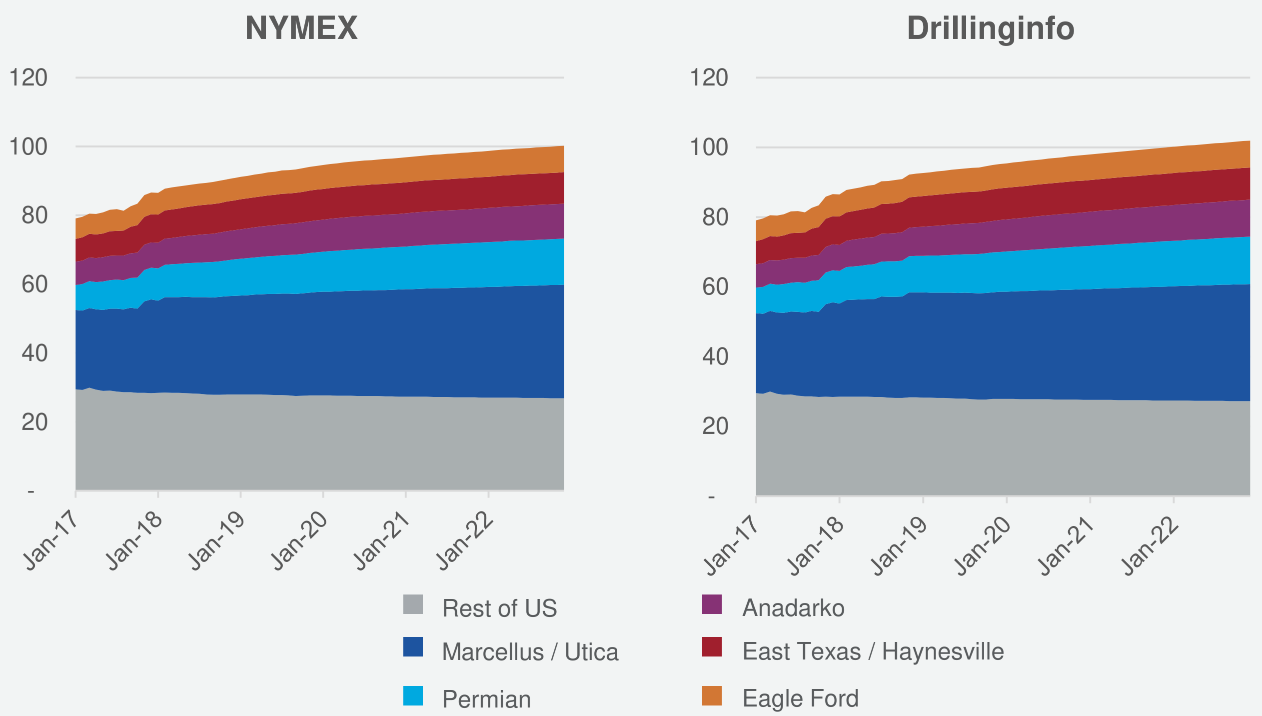
GROSS GAS PRODUCTION

- *According to the DI forecast, gross gas production is expected to increase by 5.8 Bcf/d exit-to-exit in December 2018, compared with December 2017. This growth is significantly higher than the previous forecast as DI updated its Short Term forecast with producers' 4Q2017 earnings calls.*
- *The Marcellus and Utica led the growth contributing to 2.98 Bcf/d followed by the Permian (1.2 Bcf/d), Anadarko (0.9 Bcf/d) and Haynesville (0.6 Bcf/d).*
- *Based on the forward curve (NYMEX prices), gross gas production is expected to grow 4.2 Bcf/d exit-to-exit.*

Gross Gas Production Forecast by Major Basins (Bcf/d)

	Mar-18		Apr-18		May-18		Jun-18		Jul-18		Aug-18		AVG-2018	
Basin	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI
Marcellus/Utica	27.7	27.8	27.8	27.9	27.9	28.0	28.0	28.1	28.1	28.9	28.2	28.9	28.0	28.5
Permian	9.6	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.0	9.9
East Texas / Haynesville	8.3	8.2	8.3	8.3	8.4	8.4	8.5	8.4	8.5	8.5	8.5	8.6	8.4	8.4
Anadarko	7.7	7.7	7.8	7.7	7.9	7.8	8.0	7.9	8.1	8.0	8.2	8.0	8.0	7.9
Eagle Ford	6.4	6.4	6.3	6.4	6.4	6.5	6.4	6.5	6.4	6.5	6.4	6.5	6.4	6.5
Rest Of US	28.5	28.5	28.4	28.4	28.4	28.5	28.2	28.4	28.2	28.4	28.0	28.2	28.2	28.4
TOTAL	**88.1**	**88.1**	**88.3**	**88.5**	**88.7**	**88.9**	**88.9**	**89.2**	**89.2**	**90.2**	**89.4**	**90.4**	**89.0**	**89.6**

Gross Gas Production by Major Basins (Bcf/d)



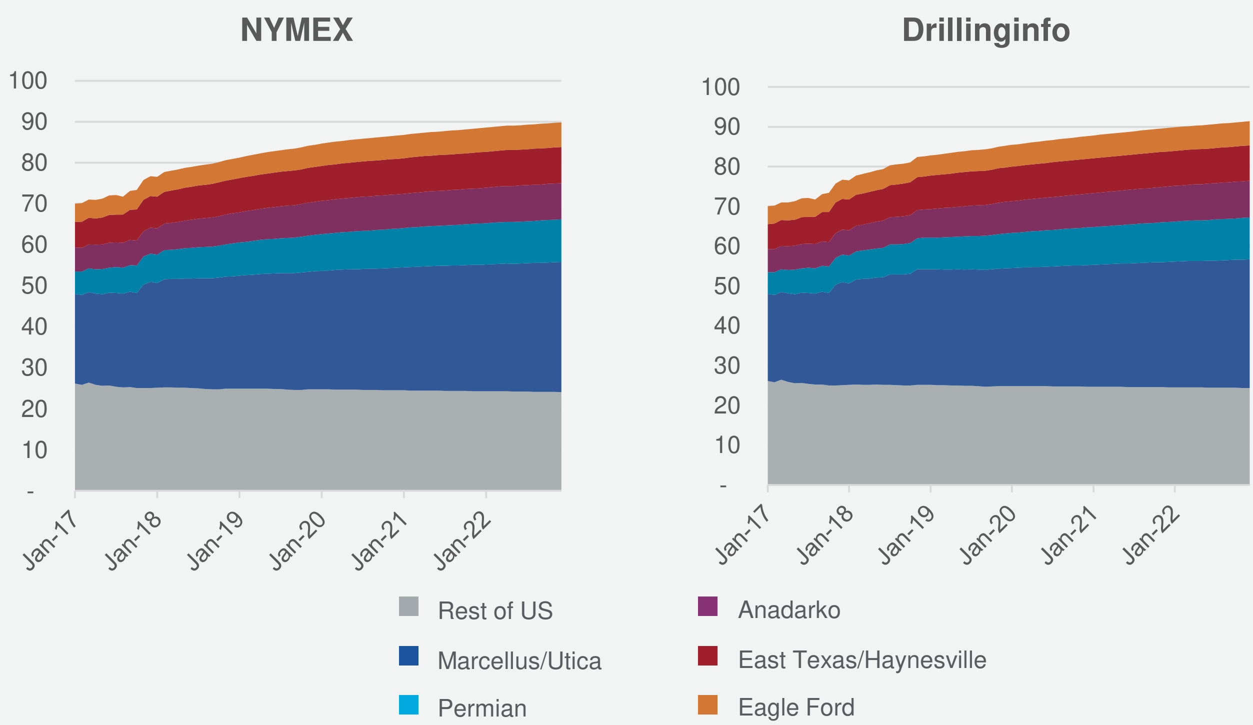
DRY GAS PRODUCTION

- *According to the DI forecast, dry gas production is expected to increase by 5.9 Bcf/d exit-to-exit in December 2018, compared with December 2017. This growth is lead by the Marcellus and Utica regions, which is expected to contribute with 3 Bcf/d, followed by 1.0 Bcf/d from the Permian, 0.8 Bcf/d from the Anadarko and 0.6 Bcf//d from the Haynesville.*
- *Longer term, Drillinginfo expects production to continue growing, but at a lower pace due to gas prices ranging between $2.75/MMBtu and $2.65 MMcf/d in the next five years. Dry gas production is expected to reach almost 91.4 Bcf/d by the end of 2022.*

Dry Gas Production Forecast by Major Basins (Bcf/d)

	Mar-18		Apr-18		May-18		Jun-18		Jul-18		Aug-18		AVG-2018	
Basin	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI
Marcellus/Utica	26.5	26.6	26.5	26.7	26.6	26.8	26.7	27.0	26.9	27.7	27.0	27.8	26.8	27.4
Permian	7.2	7.2	7.3	7.3	7.4	7.4	7.5	7.5	7.6	7.5	7.7	7.6	7.5	7.5
East Texas / Haynesville	7.8	7.8	7.9	7.9	8.0	7.9	8.0	8.0	8.1	8.1	8.1	8.1	8.0	8.0
Anadarko	6.6	6.6	6.7	6.6	6.8	6.7	6.9	6.8	6.9	6.8	7.0	6.9	6.9	6.8
Eagle Ford	4.8	4.9	4.9	4.9	4.9	5.0	4.9	5.0	4.9	5.0	4.9	5.0	4.9	5.0
Rest Of US	25.2	25.2	25.1	25.2	25.2	25.3	25.1	25.2	25.0	25.2	24.9	25.1	25.0	25.2
TOTAL	**78.1**	**78.1**	**78.4**	**78.6**	**78.8**	**79.0**	**79.0**	**79.4**	**79.3**	**80.3**	**79.6**	**80.5**	**79.1**	**79.8**

Dry Gas Production by Major Basins (Bcf/d)



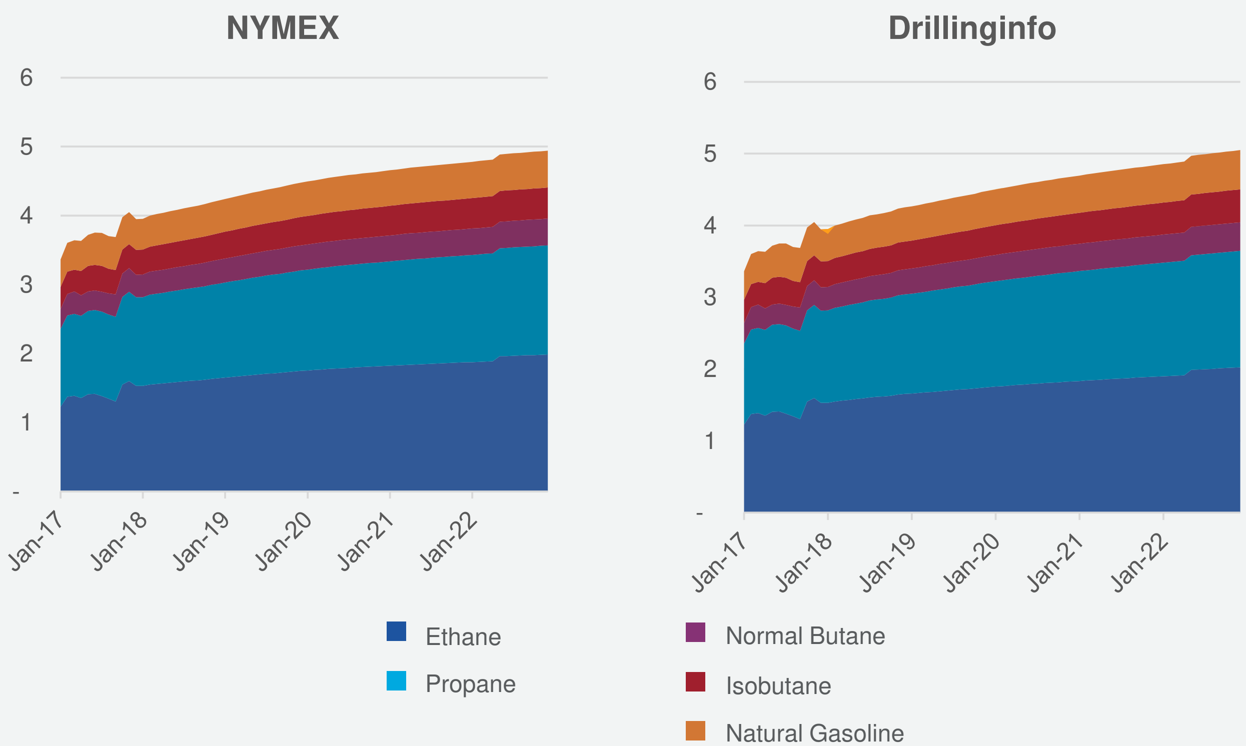
NGL PRODUCTION

- *According to the DI forecast, NGL production is expected to grow 278 MBbl/d from March 2018 to March 2019, where 131 MBbl/d is coming from the Permian basin.*
- *The NYMEX forecast is consistent with the DI forecast, showing an increase of 265 MBbl/d from March 2018 to March 2019, the main driver being the Permian with 148 MBbl/d.*
- *According to the most recent EIA data (January 2018), NGL production dropped 229 MBbl/d from the high in November 2017. Ethane production is 104 MBbl/d lower than its November 2017 high.*
- *Mariner East remains down, preventing exports from Marcus Hook and maxing out ATEX's 165 Mb/d of Northeast to Mont Belvieu capacity. This combined with a new cracker at Cedar Bayou, helps explain the 10% increase in ethane prices at Mont Belvieu over the past few weeks.*

NGL Forecast by Product (MMBbl/d)

	Mar-18		Apr-18		May-18		Jun-18		Jul-18		Aug-18		AVG-2018	
	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI	NYMEX	DI
Ethane	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Propane	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.3	1.3
Normal Butane	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Isobutane	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Natural Gasoline	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TOTAL	**4.0**	**4.0**	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.1**	**4.1**

NGL Production by Product (MMBbl/d)

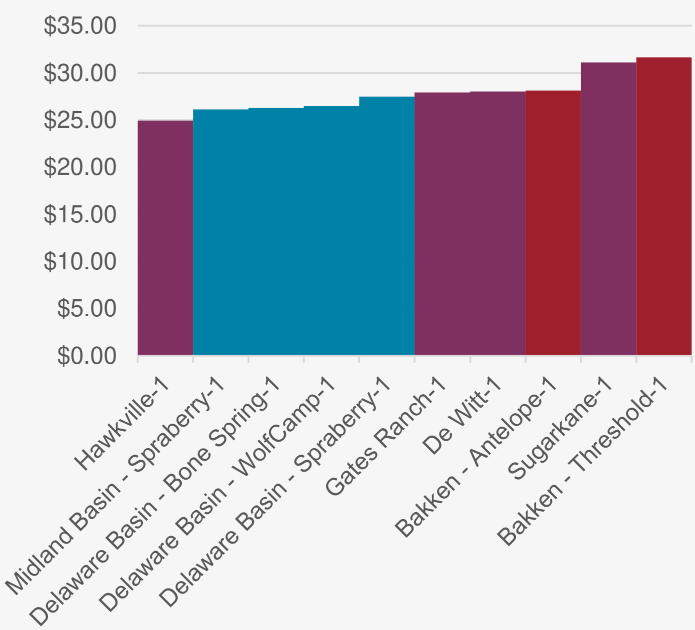


FINANCIALS UPDATE

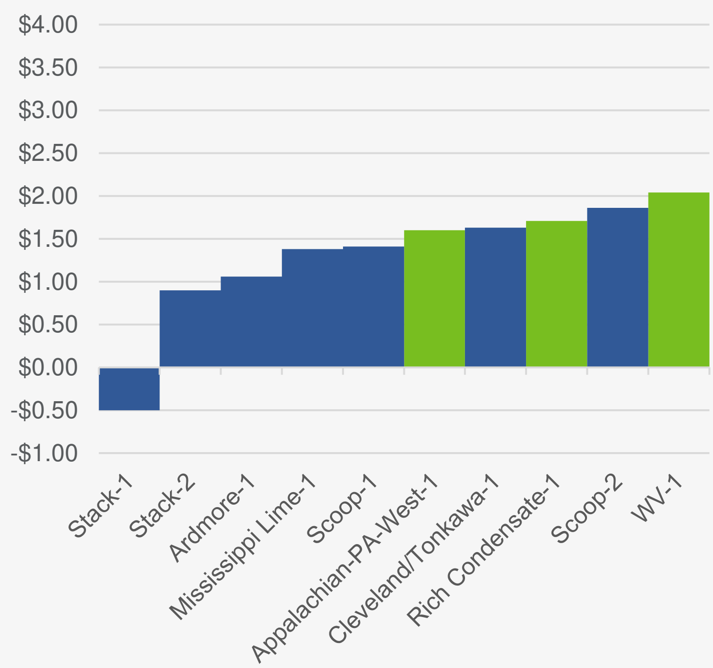
Recent Transaction Highlights

Date	Target	Deal Type	Description	Status	Value ($MM)
2/15/2018	Noble Energy, Inc.	Acquisition / Merger	Noble Energy, Inc to acquire deepwater Gulf of Mexico oil and gas business from Noble Energy, Inc.	Pending	$ 810.00
2/21/2018	Paragon Offshore Ltd.	Majority Stake	Borr Drilling Ltd acquired a 99.38% majority stake in Paragon Offshore Ltd for cash via tender offer	Complete	$ 218.88
2/22/2018	Tucker Energy Services Holdings, Inc.	Acquisition / Merger	STEP Energy Services Ltd acquired Tucker Energy Services Holdings Inc for cash. Tucker provides fracturing and completions solutions.	Complete	$ 275.00
3/8/2018	Chesapeake Energy Corp.	Acquisition / Merger	Tellurian is rumored to be interested in Chesapeake's assets in Haynesville for a reported valuation of $2B. Chesapeake reportedly not interested in partial equity deal	Rumor	$ 2,000.00
3/21/2018	Longfellow Nemaha LLC	Acquisition / Merger	SK E&P America Inc, a subsidiary of SK Innovation Co Ltd, agreed to acquire Longfellow Nemaha LLC. Includes 2 shale oil assets in the Midcontinent region.	Pending	$ 280.73
3/27/2018	Reliance Eagleford	Acquisition / Merger	Sundance Energy Inc signed a purchase and sale agreement to acquire Eagle Ford assets from Reliance Eagle Ford Upstream Holding LP	Pending	$ 100.00
3/28/2018	RSP Permian, Inc.	Acquisition / Merger	Concho Resources Inc agreed to aquire RSP Permian Inc for $8B in stock. Concho issuing 0.32 shares for every share of RSP. The price of $50.24 is a 29% premium to the stock price on March 27th.	Pending	$ 9,481.30

Top 10 Oil Directed Fields by WTI BE @ $2.75/MMBtu HH



Top 10 Gas Directed Fields by HH BE @ $60/Bbl WTI



Williston | Gulf Coast | Powder River | Denver-Julesburg
Anadarko | Eagle Ford | Ft. Worth | Permian
East Texas / Haynesville | Marcellus/Utica | Fayetteville/Woodford

METHODOLOGY SUMMARY & NOTES

***ProdCast Now* forecasts are a simplified, easy-to-use roll-up of the full DI ProdCast offering. This aggregated data is based on 500+ breakouts of production across the country at the basin/operator/tier and basin/field/tier level. DI tracks type curves, breakeven economics, current & historical drilling activity levels, infrastructure bottlenecks & expansions, pipeline flow data, and other market dynamics to accurately predict future production trends. Two different forecasts are available in the data and report:**

1. **Drillinginfo Forecast** – Volumes for the balance of the current year are based on DI's tracking of CAPEX and drilling plans of 70+ operators across the country that represent ~80% of active rigs in the major basins. Volumes beginning next year are driven by economics. DI assumes economic wells get drilled and uneconomic wells do not get drilled, based on the DI price forecast. If an area is out-of-the-money, any existing drilling activity ramps down from current levels linearly over six months. If an area is in-the-money or comes into-the-money at a later date, drilling activity ramps up to previously observed peak spud rates based on the ramp-up schedule detailed below.

2. **Forward Curve Forecast** – Production volume is immediately driven by economics. DI assumes economic wells get drilled and uneconomic wells do not get drilled, based on NYMEX forward curve prices. If an area is out-of-the-money, any existing activity ramps down from current levels linearly over six months. If an area is in-the-money or comes into-the-money at a later date, drilling activity ramps up to previously observed peak spud rates based on the ramp-up schedule detailed below.

Economics Driven by Half-Cycle Breakevens

Drillinginfo uses a discounted cash flow (DCF) model to calculate the breakeven WTI Crude Oil and Henry Hub Natural Gas prices for all 500+ breakouts of production across the country. The DCF model uses the decline curves in conjunction with drilling & completion costs, operating costs, basis & crude oil differentials, royalty rates, prevailing severance & ad valorem taxes in the state of interest, and income tax rates. Drillinginfo uses a DCF model to calculate a breakeven price for the commodity of interest given the price of the other commodity and a minimum acceptable rate of return (MARR) of 12.5%.

Decline Curves Directly Impact Economics and Volume

Drillinginfo builds representative decline curves for the operator/tier or field/tier of interest by grouping well-level production data by wellbore trajectory and/or target commodity, normalizing by months on production, and fitting a hyperbolic decline curve to the average. Two decline curves are calculated for each representative well in the forecast: one for crude oil and one for gross gas. For PDP calculations, all producing wells are assigned a decline curve based on the vintage year when it first produced. The appropriate vintage type curve parameters are used to forecast the production from the well given its current production volumes and months on production.

NGL/Dry Gas Production

Historical NGL production and barrel composition matches the EIA's Natural Gas Field Production data at the sub-PADD level. Using field-level gas-to-oil ratios, gallons/Mcf (GPMs) are calculated at the field-level. The field level GPMs and barrel compositions at the sub-PADD level are applied to the gross gas forecast in order to forecast NGLs by component. In order to calculate dry gas production, NGLs and other shrink are subtracted from the gross gas volumes.

Ramp-up Schedule

a. Tier 1 – Ramps up to peak seen in history over a 12-month period with 0-month starting lag.
b. Tier 2 – Ramps up to peak seen in history over a 18-month period with 3-month starting lag.
c. Tier 3 – Ramps up to peak seen in history over a 24-month period with 6-month starting lag.

Assumptions

1. Current drilling and completion costs – Economics are calculated using the most recent drilling and completion cost data disclosed by operators in the relevant field. Adjustments to these costs up or down in the future are not considered.
2. Current type curves – Both forecasts use go-forward type curves based on the wells that began producing in the past 24 months. DI does not build in additional efficiency gains.

These two key assumptions make our forecasts generally conservative, and we encourage you to use the sensitivity file delivered through SpotFire with your *ProdCast Now* subscription alongside the written report to analyze the impact of changing costs, type curves, and various other inputs on future production.

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