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dcp Midstream



First Quarter 2018 Update

May 8, 2018 Earnings Call

Forward-Looking Statements

Under the Private Securities Litigation Act of 1995

This document may contain or incorporate by reference forward-looking statements regarding DCP Midstream, LP (the "Partnership" or "DCP") and its affiliates, including projections, estimates, forecasts, plans and objectives. Although management believes that expectations reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations will prove to be correct. In addition, these statements are subject to certain risks, uncertainties and other assumptions that are difficult to predict and may be beyond our control. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from what management anticipated, estimated, projected or expected.

The key risk factors that may have a direct bearing on the Partnership's results of operations and financial condition are highlighted in the earnings release to which this presentation relates and are described in detail in the Partnership's periodic reports most recently filed with the Securities and Exchange Commission, including its most recent Forms 10-Q and 10-K. Investors are encouraged to consider closely the disclosures and risk factors contained in the Partnership's annual and quarterly reports filed from time to time with the Securities and Exchange Commission. The Partnership undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise except as required by applicable securities laws. Information contained in this document speaks only as of the date hereof, is unaudited, and is subject to change.

Regulation G

This document includes certain non-GAAP financial measures as defined under SEC Regulation G, such as distributable cash flow (DCF), adjusted EBITDA, adjusted segment EBITDA, gross margin, segment gross margin, forecasted distributable cash flow and forecasted adjusted EBITDA. A reconciliation of these measures to the most directly comparable GAAP measures is included in the Appendix to this presentation.

Q1 2018 Highlights and Execution

Q1 2018 Highlights

Q1 2018 Results

Strong Q1 results	• Generated $171 million of DCF
Strong coverage and leverage	• Distribution coverage 1.1x • Bank facility leverage 3.8x
Record volumes in key areas	• Record DJ Basin wellhead volumes • Record Sand Hills throughput volumes ramping quickly with expansions

Expanding Value Chain in Two of the Most Prolific Regions in the Country

Delivering G&P capacity and NGL/gas takeaway to the DJ Basin well into the next decade

- Adding up to 1.5 Bcf/d of capacity with Mewbourn 3, O'Connor 2 and Plant 12
  - Accelerating Mewbourn 3 and O'Connor 2 in service dates
- Adding up to 220 MBpd NGL takeaway through Southern Hills extension via White Cliffs and the Front Range and Texas Express expansions
- Cheyenne Connector adding 600 MMcf/d of gas takeaway

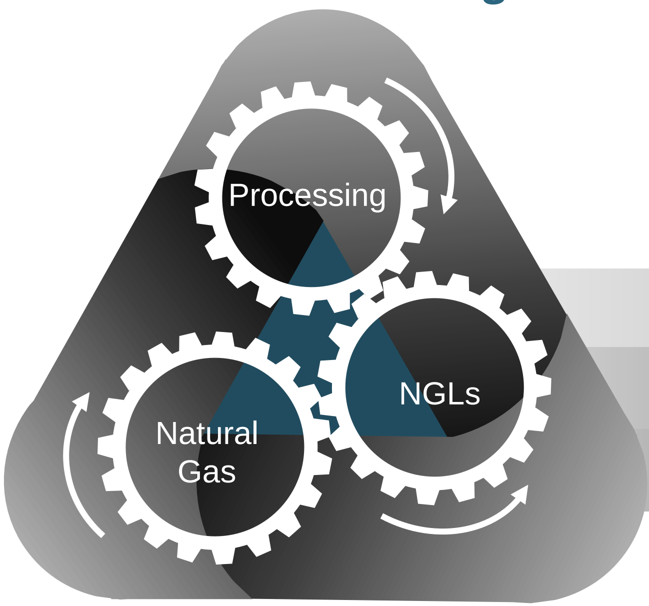
Permian Logistics infrastructure growing fast

- Completed Sand Hills expansion to 365 MBpd… capacity now 400 MBpd via operational optimization
- Next Sand Hills expansion has now increased from 450 to 485 MBpd by end of 2018
- Gulf Coast Express gas takeaway pipeline close to fully subscribed

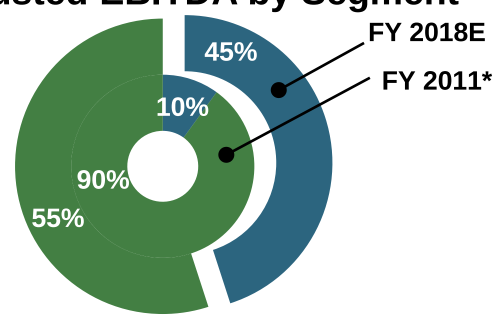
Diversified portfolio expanding and delivering strong Q1 results

Extending the Value Chain

Disciplined capital allocation strategy focused on strong returns



Adjusted EBITDA by Segment



■ Logistics and Marketing ■ Gathering and Processing

* Consolidated enterprise

Processing

5-7x multiple

- 2018 Mewbourn 3
- 2019 O'Connor 2
- 2020 DJ Plant 12

NGL Takeaway

2-7x multiple

- 2018 Sand Hills expansion
- 2019 Front Range expansion
- 2019 Texas Express expansion
- 2019 Southern Hills extension into the DJ via White Cliffs pipeline

Gas Takeaway

5-7x multiple

- 2019 Gulf Coast Express in the Permian
- 2019 Cheyenne Connector in the DJ

Leveraging and expanding our G&P footprint to grow higher return, fee-based Logistics business

Extending Integrated DJ Basin Infrastructure

dcp Midstream

Expanding leading position in the DJ Basin… well into the next decade

Adding up to
1.5 Bcf/d
of capacity

G&P Expansion

- **Adding** 0.5 Bcf/d in the next twelve months
  - Mewbourn 3 – 200 MMcf/d plant **accelerated** to Aug 2018
  - O'Connor 2 – **expanded** to 300 MMcf/d capacity and **accelerated** to Q2 2019 (200 MMcf/d plant + up to 100 MMcf/d bypass)
- Plant 12 **adding** up to 1 Bcf/d including bypass; 2020 and beyond

Adding up to
220 MBpd
of NGL takeaway

NGL Takeaway

- Southern Hills extension into the DJ via White Cliffs pipeline **adding** 90 MBpd* out of the DJ Q4 2019; expandable to 120 MBpd
- Front Range 100 MBpd **expansion** to 250 MBpd** Q2 2019
- Texas Express 90 MBpd** **expansion** Q2 2019

* DCP has a 50 MBpd long-term capacity lease on White Cliffs
** Represents 100% capacity. DCP owns 33% of Front Range and 10% of Texas Express

Adding
600 MMcf/d
of gas takeaway

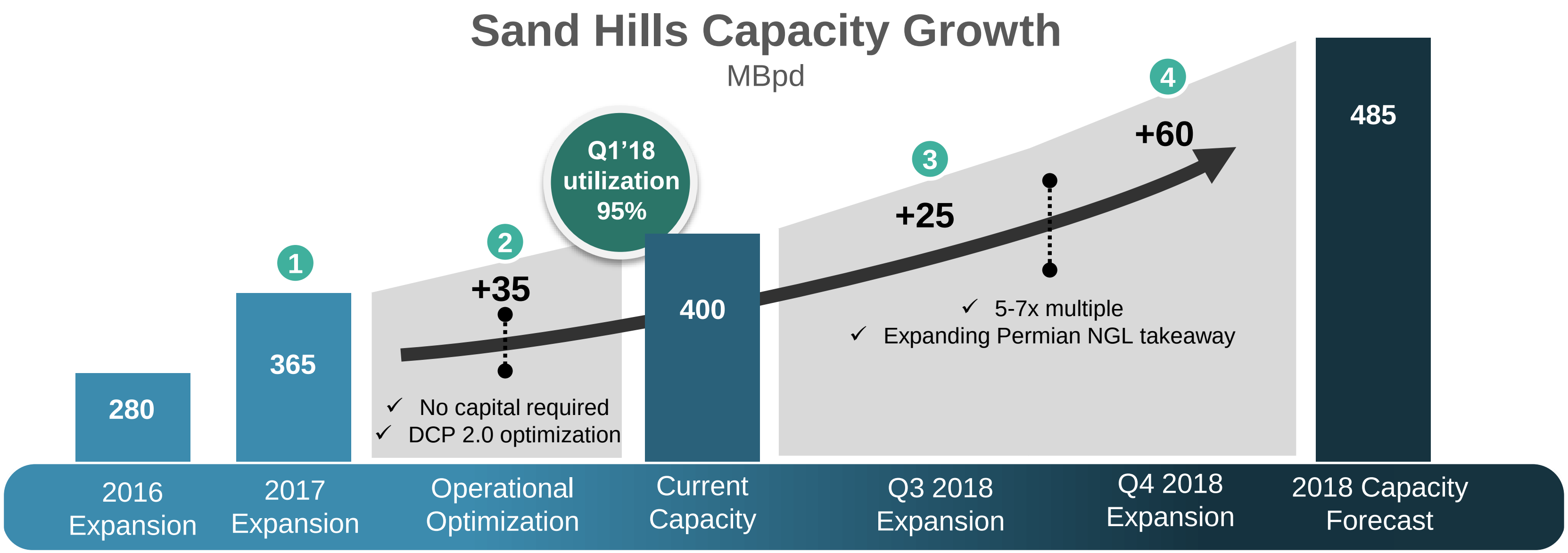
Gas Takeaway

- Cheyenne Connector
  - DCP secured 300 MMcf/d of transport
  - Option to acquire 33% equity ownership stake

Meeting the growing needs of our producers well into the next decade

Sand Hills Expanding Fast

Sand Hills bringing on more capacity at a faster pace, without incremental capital



Sand Hills capacity and volumes trending up…

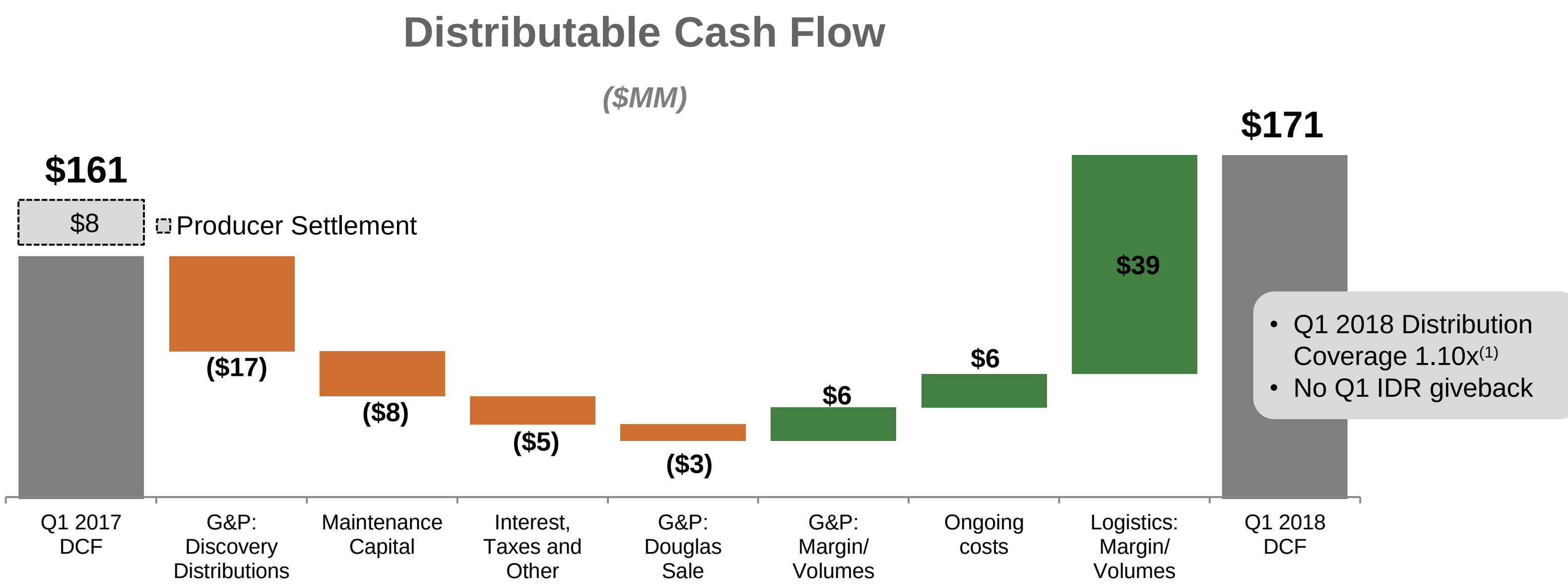
1. Sand Hills expansion to 365 MBpd placed into service in February 2018
2. **Capacity increased from 365 MBpd to 400 MBbd** by end of Q1 2018 through innovation and operational optimization, without incurring incremental capital

- **Next expansion to increase capacity 85 MBpd** is expected to be complete by end of 2018
  3. Capacity expected to be ~425 MBpd by Q3 2018
  4. **Ramping up to 485 MBpd by the end of 2018** to meet growing NGL takeaway demand in the Permian

Sand Hills volumes ramping quickly… driving increasing fee-based earnings

Consolidated Q1 2018 Financial Results

Strong Logistics & Marketing results and lower costs more than offsetting lower Discovery and higher maintenance capital



Key drivers

- Higher Logistics and Marketing from Sand Hills growth, gas storage and Guadalupe
- Lower costs
- Stronger G&P margins and Eagle Ford volumes
- Portfolio performance more than offsetting
  - G&P declines from Discovery and 2017 Douglas sale
  - Higher maintenance capital and interest

First half 2018

- Maintenance capital and operating costs higher in Q2 due to planned reliability spend

Second half 2018

- Mewbourn 3 and Sand Hills expansions setting the stage for fast volume increase
- Volume growth in the Permian, Eagle Ford and SCOOP
- Ethane recovery ramping up

(1) On declared basis without IDR giveback

Diversified portfolio with strong Logistics results and continued focus on cost optimization

Q1 2018 Financial Position

Financial Priorities & 2018 Guidance	Q1 2018 Actual
1 Bank leverage(1) ~4.0x	3.8x
2 Distribution coverage ≥1.0x	1.1x
3 Stable distribution driving towards growth	Q1 distribution $0.78/unit

Ample liquidity and financial flexibility

- 3.8x bank facility leverage ratio(1)(2)
- Ample liquidity with ~$1.3 billion available on bank facility(2)
- Multiple financing alternatives to fund growth
  - Bank facility
  - Debt capital markets
  - Preferred equity
  - ATM
  - Portfolio optimization

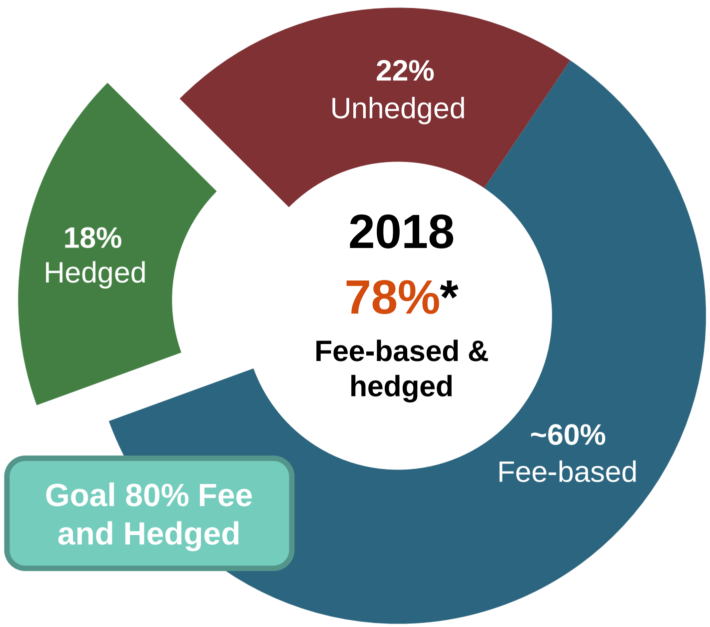
(1) Bank leverage ratio calculation = Adjusted EBITDA, plus certain project EBITDA credits from projects under construction, divided by bank debt (excludes $550 million 2043 junior subordinated debt) less cash
(2) As of March 31, 2018

Delivering on leverage targets… ample liquidity and financial flexibility

2018 Gross Margin, Sensitivities and Hedges

Investments in fee-based growth coupled with multi-year hedging program provides downside protection on commodity exposed margin

2018 Gross Margin

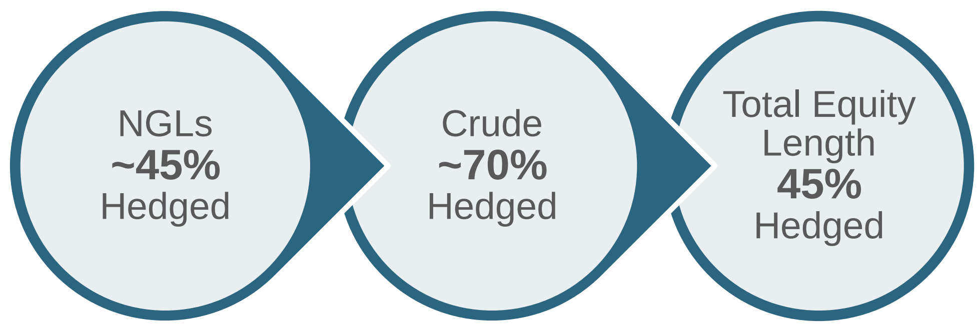


* 60% fee plus 40% Commodity margin x 45% hedged = 78% fee and hedged as of 5/3/18

2018 Annual Commodity Sensitivities

Commodity	Price Range	Per unit ∆	After Hedges ($MM)
NGL ($/gallon)	$0.60-0.70	$0.01	$4
Natural Gas ($/MMBtu)	$2.90-3.20	$0.10	$8
Crude Oil ($/Barrel)	$50-58	$1.00	$2

2018 Hedge Position as of 5/3/18[1]



Recently added crude, propane and butane hedges… including Q1 2019 crude and propane hedges

Note: Fee includes NGL, propane and gas marketing which depend on price spreads rather than nominal price level

(1) Direct commodity hedges for ethane, propane, normal butane and natural gasoline equity length at Mt Belvieu prices. Total equity length hedged based on crude equivalent.

Close to achieving 80% fee and hedged target

DCP 2.0 Driving the Operations of the Future

INTEGRATED COLLABORATION CENTER (ICC) LINKING NUMEROUS DATA SOURCES

Integrated Collaboration Center

- Integrated Collaboration Center continues to gain momentum with functionality and more plants being added
- Focus expanding to the field including DCP's large infrastructure of pipelines and compressors
- Moving towards 24/7 monitoring by the end of Q3 2018 for major field assets

Q1 2018 DCP 2.0 Benefits

- Collaborative and real-time decision making for asset optimization translating to better reliability, margin and cost benefits
- Digital solutions, process optimization and predictive analytics driving cost savings through workforce efficiencies
- Sand Hills optimization resulting in 35 MBpd incremental capacity
- Robotics process automation utilized to automate and streamline processes in corporate functions

Real-time decisions → Better reliability and safety → Asset optimization → Higher margins → Cost savings

Transforming through process optimization and digitization

Key Takeaways

Transforming our business… extending integrated value chain and driving increasing cash flows

- Strong Q1 results, coverage and leverage
- Multi-year DJ Basin infrastructure expansion plans providing G&P and NGL/gas takeaway well into the next decade
  - Accelerating Mewbourn 3 and O'Connor 2
  - Adding up to 1.5 Bcf/d of processing capacity
  - Adding up to 220 MBpd of NGL takeaway
  - Adding 600 MMcf/d of gas takeaway
- Growing Permian Logistics via accelerated Sand Hills growth and Gulf Coast Express
  - Sand Hills capacity increased to 400 MBpd through operational optimization
  - Next expansion to 485 MBpd by end of 2018
  - Gulf Coast Express close to fully subscribed
- DCP 2.0 delivering value by driving innovation throughout the organization

DCP Midstream – Appendix:
Financial and Other Supporting Slides

2018 Guidance

($ in Millions)

2018 Guidance

Adjusted EBITDA(1)	$1,045-1,135
Distributable Cash Flow (DCF) (1)(2)	$600-670
Total GP/ Common LP Distributions	$618
Series A Preferred Unit Distributions(2)	$37
Distribution Coverage Ratio (TTM)(3)	≥1.0x
Bank Leverage(4)	~4.0x
Maintenance Capital	$100-120
Growth Capital	$650-750

(1) *Adjusted EBITDA and distributable cash flow are Non GAAP measures. See Non GAAP reconciliation in the appendix section*
(2) *Distributable cash flow is reduced by cumulative cash distributions earned by the Series A Preferred Units*
(3) *Includes IDR giveback, if needed, to target a 1.0x distribution coverage ratio*
(4) *Bank leverage ratio calculation = Adjusted EBITDA, plus certain project EBITDA credits from projects under construction, divided by bank debt (excludes $550 million Jr. Subordinated notes which are treated as equity) less cash*

2018 Assumptions

- Higher Sand Hills volumes, earnings and distributions associated with expansions placed in service
- Higher G&P volumes and margins across key regions
- Continuing multi-year trend of lower costs… more than offsetting inflation and growth
- Stronger asset performance enhanced by DCP 2.0 digital transformation investment
- No planned common equity offerings
- Potential upside from ethane recovery… ethane rejection consistent with 2017 (60,000-70,000 bbls/d)
- Lower Discovery earnings and distributions

Volume Outlook

Slight G&P volume growth in 2018

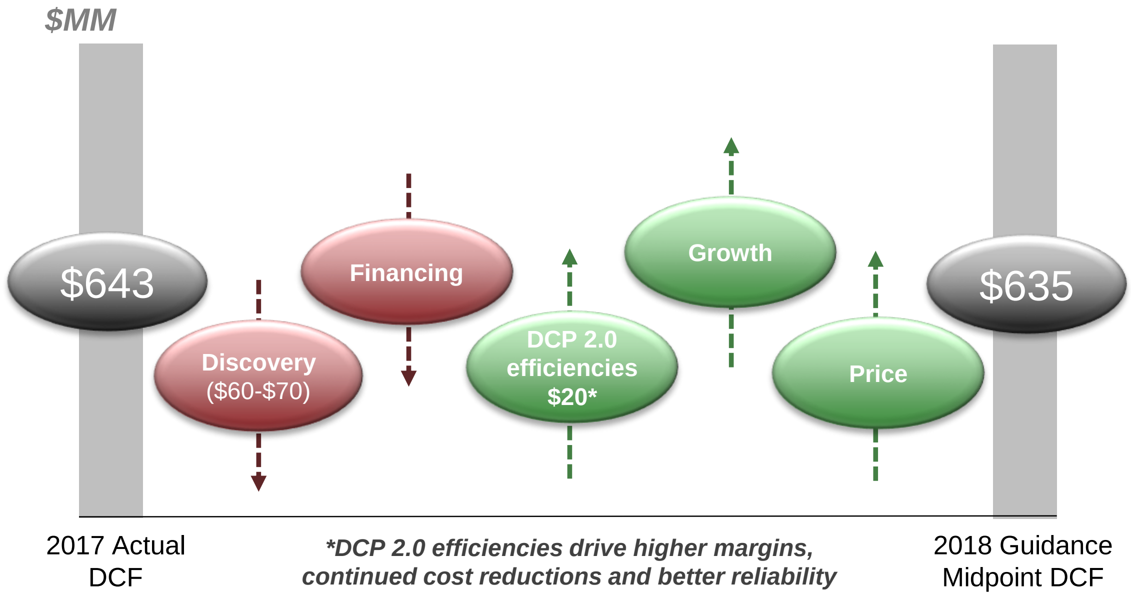
- North: increasing with Mewbourn 3 completion
- Permian: slight growth driven by the Delaware
- Midcontinent: flat, with SCOOP growth being offset by Western Midcontinent declines
- South: slight decrease, with Eagle Ford growth largely offsetting Discovery and other declines

Logistics volume growth driven by Sand Hills

- Sand Hills: continued ramp from Permian NGL production growth and capacity expansions

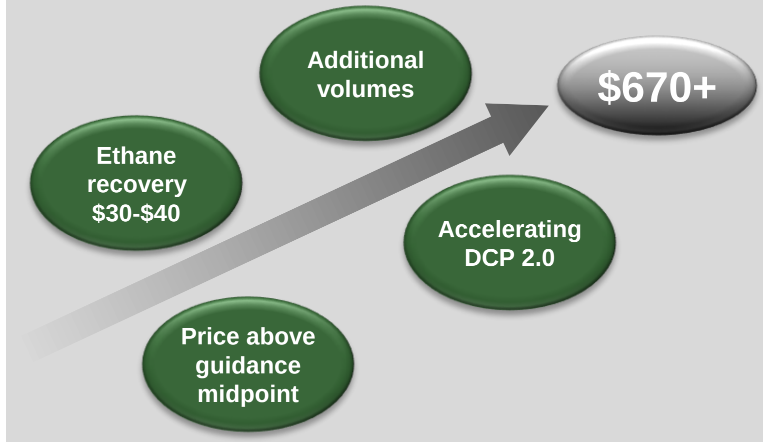
2017 to 2018 DCF Guidance Drivers

Growth, price and efficiencies offsetting Discovery and increased financing costs



**DCP 2.0 efficiencies drive higher margins, continued cost reductions and better reliability*

UPSIDE POTENTIAL TO FORECAST



Growth, efficiencies and price offsetting Discovery

Discovery 2018 earnings and distributions $60-70 million lower:

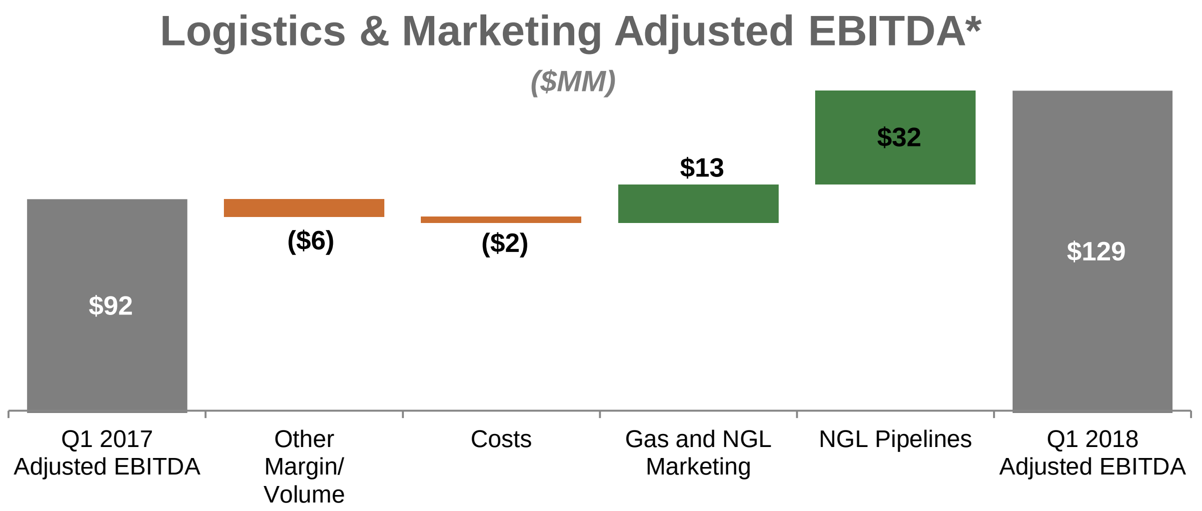
- ~$30-40 million due to significant volume declines from two offshore wells
- ~$30 million due to a contractual dispute with producers regarding demand charges… being challenged by Discovery

Upside Potential

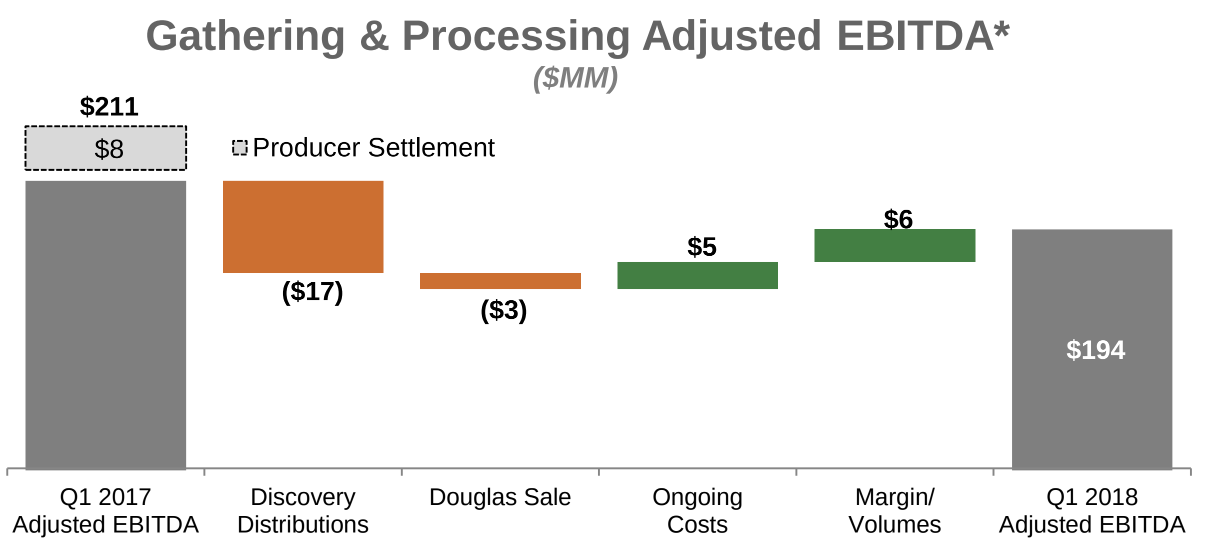
- Commodity prices above guidance range significantly increase DCF
- Accelerating DCP 2.0 increases the incremental $20 million benefit through further improvements in asset performance
- Additional gas processing volumes and throughput on NGL pipelines increase earnings
- Ethane recovery associated with increased demand and favorable processing economics add $30-40 million… without incremental capital investment

Significant upside potential to achieve high end or above forecast range

Adjusted Segment EBITDA*



Strong Q1 2018 Sand Hills NGL volume growth and marketing results



Logistics & Marketing more than offsetting lower G&P Discovery and Douglas sale

* Adjusted Segment EBITDA is viewed as a non-Generally Accepted Accounting Principles (GAAP) measure under the rules of the SEC and is reconciled to its most directly comparable GAAP financial measure under “Reconciliation of Non-GAAP Financial Measures” in schedules at the end of this presentation

Volumes

Logistics NGL Pipeline Volume Trends and Utilization

Pipeline	Approx System Length (Miles)	Average Gross Capacity (MBbls/d)	% Owned	Net Capacity (MBbls/d)	Q1'17 Average NGL Throughput (MBbls/d)[1]	Q4'17 Average NGL Throughput (MBbls/d)[1]	Q1'18 Average NGL Throughput (MBbls/d)[1]	Q1'18 Pipeline Utilization
Sand Hills	1,300	378[2]	66.70%	252	169	226	239	95%
Southern Hills	950	175	66.70%	117	67	75	75	64%
Front Range	450	150	33.30%	50	34	38	38	76%
Texas Express	600	280	10.00%	28	14	15	15	54%
Other[3]	1,200	326	Various	241	143	149	152	63%
Total	**4,500**	**1,309**			**427**	**503**	**519**	

(1) Represents total throughput allocated to our proportionate ownership share
(2) Represents the average capacity in Q1'18. Sand Hills' gross capacity increased to 400 MBpd by the end of Q1'18.
(3) Other includes the Black Lake, Panola, Seabreeze, Wilbreeze and other NGL pipelines

Sand Hills is bringing on more capacity at a faster pace than originally anticipated, without spending incremental capital

G&P Volume Trends and Utilization

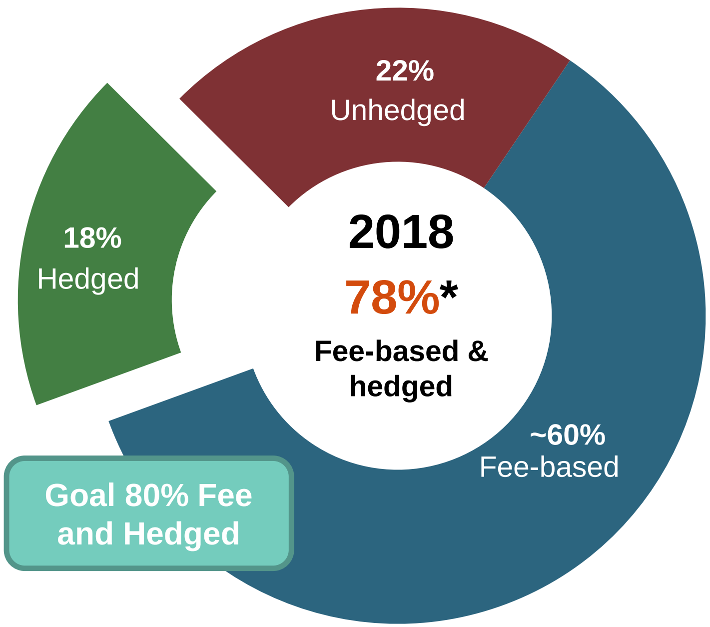
System	Q1'18 Net Plant/ Treater Capacity (MMcf/d)	Q1'17 Average Wellhead Volumes (MMcf/d)	Q4'17 Average Wellhead Volumes (MMcf/d)	Q1'18 Average Wellhead Volumes (MMcf/d)	Q1'18 Average NGL Production (MBbls/d)	Q1'18 Plant Utilization[4]
North[5][6]	1,190	1,106	1,137	1,206	85	101%
Permian	1,260	961	913	872	102	69%
Midcontinent	1,765	1,199	1,317	1,194	102	68%
South	2,315	1,279	1,236	1,195	95	52%
Total	**6,530**	**4,545**	**4,603**	**4,467**	**384**	**68%**

(4) Plant utilization: Average wellhead volumes divided by active plant capacity, excludes idled plant capacity
(5) Q1'17 wellhead volumes exclude 35MMcf/d, associated with the sale of Douglas, Wyoming in June 2017
(6) Q1'17, Q4'17 and Q1'18 include 794 MMcf/d, 877 MMcf/d and 886 MMcf/d, respectively, of DJ Basin wellhead volumes. Remaining volumes are Michigan and Collbran,WY treating

2018 Gross Margin, Sensitivities and Hedges

Investments in fee-based growth coupled with multi-year hedging program provides downside protection on commodity exposed margin

2018 Gross Margin



* 60% fee plus 40% commodity margin x 45% hedged = 78% fee and hedged as of 5/3/18

2018 Annual Commodity Sensitivities

Commodity	Price Range	Per unit ∆	Before Hedges ($MM)	Hedge Impact	After Hedges ($MM)
NGL ($/gallon)	$0.60-0.70	$0.01	$7	($3)	$4
Natural Gas ($/MMBtu)	$2.90-3.20	$0.10	$8	-	$8
Crude Oil ($/Barrel)	$50-58	$1.00	$5	($3)	$2

Hedge position as of 5/3/18	Q2'18	Q3'18	Q4'18	Q2-Q4 2018	Q1-Q4 2019
NGLs hedged[1] (Bbls/d)	20,934	23,315	21,848	22,029	2,102 [2]
Average hedge price[1] ($/gal)	$0.60	$0.60	$0.62	$0.61	
% NGL exposure hedged				~45%	
Crude hedged (Bbls/d)	10,220	10,109	10,109	10,146	2,264
Average hedge price ($/Bbl)	$56.97	$56.86	$56.58	$56.80	$60.32
% crude exposure hedged				~70%	
Total equity length hedged (based on crude equivalent)				***45%***	

Recently added crude, propane and butane hedges… including Q1 2019 crude and propane hedges

Note: Fee includes NGL, propane and gas marketing which depend on price spreads rather than nominal price level

(1) Direct commodity hedges for ethane, propane, normal butane and natural gasoline equity length at Mt Belvieu prices

(2) 2019 NGL hedges are for propane at an average price of $0.73/gal as of 5/3/18

Reducing commodity volatility via opportunistic hedges

Margin by Segment*

$MM, except per unit measures		Q1 2018		Q4 2017		Q3 2017		Q2 2017		Q1 2017
Gathering & Processing (G&P) Segment										
Natural gas wellhead - Bcf/d		4.47		4.60		4.46		4.48		4.58
Segment gross margin including equity earnings before hedging (1)	$	350	$	402	$	375	$	352	$	374
Net realized cash hedge settlements received (paid)	$	(11)	$	(25)	$	(6)	$	(2)	$	(9)
Non-cash unrealized gains (losses)	$	14	$	(20)	$	(51)	$	16	$	31
G&P Segment gross margin including equity earnings	**$**	**353**	**$**	**357**	**$**	**318**	**$**	**366**	**$**	**396**
G&P Margin including equity earnings before hedging/wellhead mcf	$	0.87	$	0.95	$	0.92	$	0.86	$	0.91
G&P Margin including equity earnings and realized hedges/wellhead mcf	$	0.84	$	0.89	$	0.90	$	0.86	$	0.89
G&P Segment Fee as % of G&P margin including equity earnings before hedging (2)		39%		41%		42%		46%		42%
Logistics & Marketing Segment gross margin including equity earnings (3)	**$**	**95**	**$**	**103**	**$**	**116**	**$**	**112**	**$**	**112**
Total gross margin including equity earnings	**$**	**448**	**$**	**460**	**$**	**434**	**$**	**478**	**$**	**508**
Direct Operating and G&A Expense	$	(221)	$	(236)	$	(237)	$	(249)	$	(229)
DD&A		(94)		(97)		(94)		(94)		(94)
Other Income (Loss) (4)		(2)		4		(48)		29		(10)
Interest Expense, net		(67)		(70)		(73)		(73)		(73)
Income Tax Expense		(1)		3		(2)		(2)		(1)
Noncontrolling interest		(1)		(4)		(0)		(1)		(0)
Net Income (Loss) - DCP Midstream, LP	**$**	**62**	**$**	**60**	**$**	**(20)**	**$**	**88**	**$**	**101**
Industry average NGL $/gallon	$	0.70	$	0.72	$	0.62	$	0.55	$	0.60
NYMEX Henry Hub $/mmbtu	$	3.00	$	2.93	$	3.00	$	3.18	$	3.32
NYMEX Crude $/bbl	$	62.87	$	55.40	$	48.23	$	48.28	$	51.91
Other data:										
NGL pipelines throughput (MBbl/d) (5)		519		503		462		451		427
NGL Production (MBbl/d)		384		406		376		366		352
Total Fee margin as % of Total gross margin including equity earnings before G&P hedging (6)		52%		53%		56%		59%		56%

FOOTNOTES:

(1) Represents Gathering and Processing (G&P) Segment gross margin plus Earnings from unconsolidated affiliates, excluding Trading and marketing (losses) gains, net

(2) G&P segment fee margin includes Transportation, processing and other revenue, adding the $40 million impact of Topic 606 change per Footnote 3 in the Notes to Condensed Consolidated Financial Statements, plus approximately 90% of Earnings from unconsolidated affiliates

(3) Represents Logistics and Marketing Segment gross margin plus Earnings from unconsolidated affiliates

(4) "Other Income" includes gain/(loss) on asset sales, asset write-offs and other miscellaneous items

(5) This volume represents equity and third party volumes transported on DCP's NGL pipeline assets

(6) Total Fee margin includes G&P segment fee margin (refer to (2) above), plus the Logistics and Marketing segment which includes fees for NGL transportation and fractionation, and NGL, propane and gas marketing which depend on price spreads rather than nominal price level

* *Segment gross margin is viewed as a non-Generally Accepted Accounting Principles ("GAAP") measure under the rules of the Securities and Exchange Commission ("SEC"), and is reconciled to its most directly comparable GAAP financial measures under "Reconciliation of Non-GAAP Financial Measures" in schedules at the end of this presentation.*

Disciplined and Strategic Growth

Executing strategic, lower risk growth projects at 5-7x multiples with line of sight to fast volume ramp… growing fee-based earnings

Projects in Progress *($MM net to DCP's interest)*	**Est. 100% Capacity**	**Status**	**Est. CapEx**	**Expected In-Service**
Gathering & Processing:				
DJ Mewbourn 3	200 MMcf/d	In Progress	$395	Aug 2018
DJ O'Connor 2 plant	200 MMcf/d	In Progress	$350-400	Q2 2019
DJ O'Connor 2 bypass	100 MMcf/d	Development		Q2 2019
DJ Plant 12 including bypass	Up to 1.0 Bcf/d	Development		2020+
Logistics:				
Permian Sand Hills 85 MBpd expansion (67%)	485 MBpd	In Progress	$300	Q4 2018
DJ Front Range 100 MBpd expansion (33%)	250 MBpd	Announced		Q2 2019
DJ Texas Express 90 MBpd expansion (10%)		Announced		Q2 2019
DJ Cheyenne Connector (option to acquire 33%)	600 MMcf/d	Development		Q3 2019
Permian Gulf Coast Express (25%)	~2.0 Bcf/d	In Progress	$440	Q4 2019
DJ NGL takeaway via White Cliffs NGL pipeline	90 MBpd	Development		Q4 2019

Deliberately choosing projects in key regions across our integrated value chain

Expanding Integrated DJ Basin Footprint

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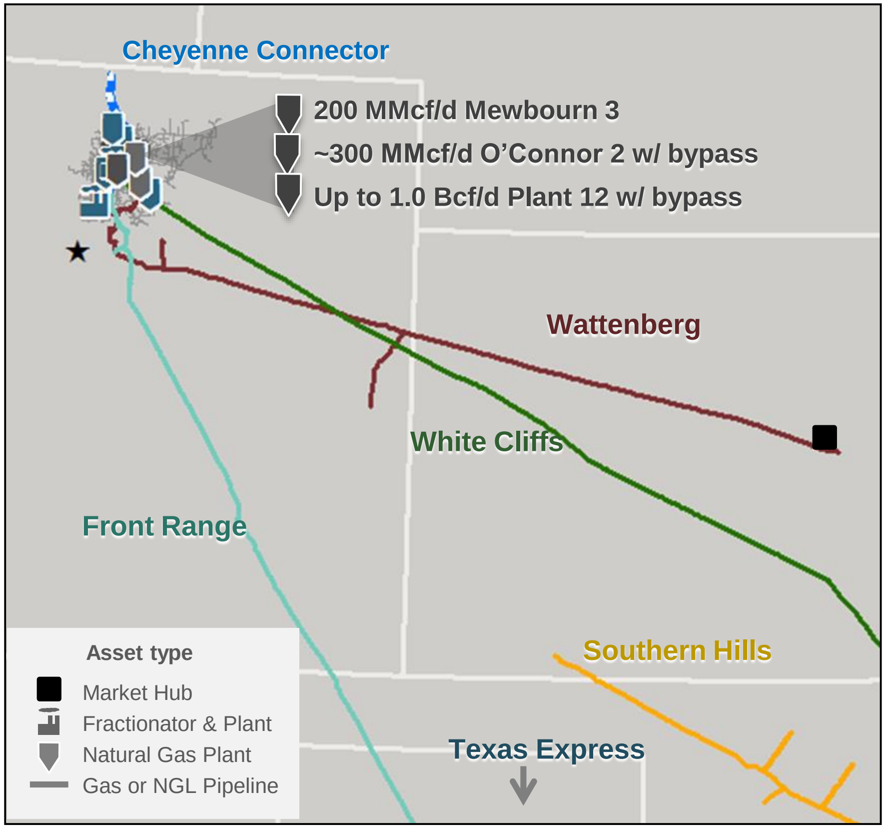
*Expanding integrated **DJ Basin** footprint… one of the top basins in the country*



Solving G&P, NGL and gas takeaway for the DJ Basin into the next decade

G&P Expansion… adding up to 1.5 Bcf/d of capacity

Adding 0.5 Bcf/d in the next twelve months

- Mewbourn 3 – 200 MMcf/d plant **accelerated** to Aug 2018
- O'Connor 2 – **expanded** to 300 MMcf/d capacity and **accelerated** to Q2 2019 (200 MMcf/d plant + up to100 MMcf/d bypass)

Plant 12 **adding** up to 1 Bcf/d including bypass; 2020 & beyond

NGL Takeaway… adding up to 220 MBpd

Southern Hills extension into the DJ via White Cliffs pipeline **adding** 90 MBpd* out of the DJ Q4 2019; expandable to 120 MBpd

- Diversifying NGL takeaway from the DJ to Mont Belvieu

Front Range 100 MBpd **expansion** to 250 MBpd** Q2 2019 with additional pump stations

Texas Express 90 MBpd** **expansion** Q2 2019

* DCP has a 50 MBpd long-term capacity lease on White Cliffs
* Represents 100% capacity. DCP owns 33% of Front Range and 10% of Texas Express

Gas Takeaway… adding 600 MMcf/d

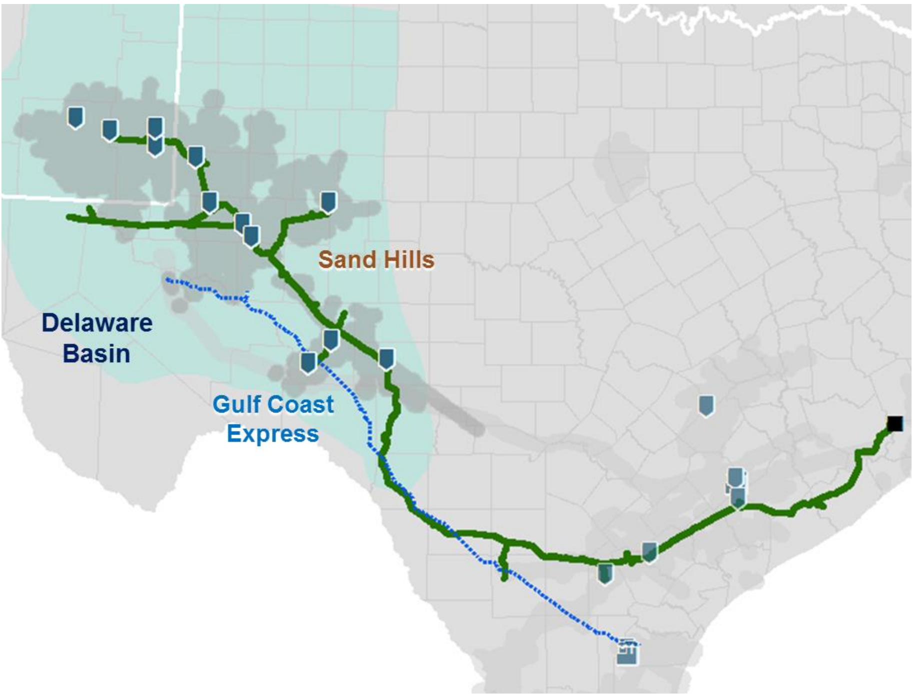
Cheyenne Connector

- DCP has secured 300 MMcf/d of transport
- Option to acquire 33% equity ownership stake

Continued strong capacity utilization driving expansions of up to 1.5 Bcf/d… expanding and diversifying integrated NGL and natural gas takeaway

Expanding Permian Logistics Footprint

*Extending Logistics value chain with fee-based projects in the **Permian***



Strategic focus on higher margin fee-based Logistics growth given risk of G&P overbuild and tighter margins

Sand Hills leverages the entire Permian with lower risk and higher returns

Sand Hills NGL Pipeline expansion

- Completed expansion to 365 MBpd in Q1 2018… capacity now 400 MBpd via operational optimization
- Next Sand Hills expansion to 485 MBpd by end of 2018
- Profitable, fee-based contract portfolio with 10-15 year commitments

Gulf Coast Express Natural Gas Pipeline

- Gulf Coast Express gas takeaway pipeline close to fully subscribed
- 500 mile primarily 42" intrastate pipeline connecting Permian to Gulf Coast; ~2 Bcf/d capacity; in service Q4 2019
- Supply push from Permian growth where DCP's G&P position provides significant connectivity

Executing strategic, lower risk growth projects at 5-7x multiples with line of sight to fast volume ramp… growing fee-based earnings

Non GAAP Reconciliations

Non GAAP Reconciliation

($ in millions)	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017[(1)]
Gathering and Processing (G&P) Segment		
Segment net income attributable to partners	$ 113	$ 152
Operating and maintenance expense	148	153
Depreciation and amortization expense	84	85
General and administrative expense	4	6
Other expense, net	3	-
Earnings from unconsolidated affiliates	(1)	(20)
Net income attributable to noncontrolling interests	1	-
Segment gross margin	**$ 352**	**$ 376**
Earnings from unconsolidated affiliates	1	20
Segment gross margin including equity earnings	**$ 353**	**$ 396**
Logistics and Marketing Segment		
Segment net income attributable to partners	$ 79	$ 87
Operating and maintenance expense	11	9
Depreciation and amortization expense	3	4
Other (income) expense, net	(1)	9
General and administrative expense	3	3
Earnings from unconsolidated affiliates	(77)	(54)
Segment gross margin	**$ 18**	**$ 58**
Earnings from unconsolidated affiliates	77	54
Segment gross margin including equity earnings	**$ 95**	**$ 112**

*** We define gross margin as total operating revenues including trading and marketing gains and losses, less purchases and related costs, and we define segment gross margin for each segment as total operating revenues for that segment including trading and marketing gains and losses less purchases and related costs for that segment. Segment gross margin is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases and related costs. As an indicator of our operating performance, margin should not be considered an alternative to, or more meaningful than, net income or net cash provided by operating activities as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.*

(1) Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

Commodity Derivative Activity

($ in millions)	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017(1)
Gathering & Processing Segment: Non-cash unrealized gains	$ 14	$ 31
Logistics & Marketing Segment: Non-cash unrealized (losses) gains	(43)	5
Non-cash unrealized (losses) gains – commodity derivative	**(29)**	**36**
Gathering & Processing Segment: Net realized cash hedge settlements paid	(11)	(9)
Logistics & Marketing Segment: Net realized cash hedge settlements (paid) received	(1)	4
Net realized cash hedge settlements paid	**(12)**	**(5)**
Trading and marketing (losses) gains, net	**(41)**	**31**

(1) Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

Non GAAP Reconciliation

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(Millions)	
Reconciliation of Non-GAAP Financial Measures:		
Net income attributable to partners	$ 62	$ 101
Interest expense	67	73
Depreciation, amortization and income tax expense, net of noncontrolling interests	95	95
Distributions from unconsolidated affiliates, net of earnings	13	2
Other non-cash charges	2	10
Non-cash commodity derivative mark-to-market	29	(36)
Adjusted EBITDA	$ 268	$ 245
Interest expense	(67)	(73)
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(23)	(15)
Preferred unit distributions ***	(9)	—
Other, net	2	4
Distributable cash flow	$ 171	$ 161
Net cash provided by operating activities	$ 122	$ 144
Interest expense	67	73
Net changes in operating assets and liabilities	54	66
Non-cash commodity derivative mark-to-market	29	(36)
Other, net	(4)	(2)
Adjusted EBITDA	268	$ 245
Interest expense	(67)	(73)
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(23)	(15)
Preferred unit distributions ***	(9)	—
Other, net	2	4
Distributable cash flow	$ 171	$ 161

*** Represents cumulative cash distributions earned by the Series A Preferred Units, assuming distributions are declared by DCP's board of directors.

Non GAAP Reconciliation

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(Millions, except as indicated)	
Gathering and Processing Segment:		
Financial results:		
Segment net income attributable to partners	$ 113	$ 152
Non-cash commodity derivative mark-to-market	(14)	(31)
Depreciation and amortization expense, net of noncontrolling interest	84	85
Distributions from unconsolidated affiliates, net of earnings	8	5
Other charges	3	—
Adjusted segment EBITDA	$ 194	$ 211
Operating and financial data:		
Natural gas wellhead (MMcf/d)	4,467	4,580
NGL gross production (MBpd)	384	352
Operating and maintenance expense	$ 148	$ 153
Logistics and Marketing Segment:		
Financial results:		
Segment net income attributable to partners	$ 79	$ 87
Non-cash commodity derivative mark-to-market	43	(5)
Depreciation and amortization expense	3	4
Distributions from unconsolidated affiliates, net of earnings	5	(3)
Other charges	(1)	9
Adjusted segment EBITDA	$ 129	$ 92
Operating and financial data:		
NGL pipelines throughput (MBpd)	519	427
NGL fractionator throughput (MBbls/d)	62	50
Operating and maintenance expense	$ 11	$ 9

Non GAAP Reconciliation

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(Millions, except as indicated)	
Reconciliation of Non-GAAP Financial Measures:		
Distributable cash flow	$ 171	$ 161
Distributions declared **	$ 155	$ 135
Distribution coverage ratio - declared	1.10 x	1.19 x
Distributable cash flow	$ 171	$ 161
Distributions declared without IDR giveback	$ 155	$ 155
Distribution coverage ratio - declared without IDR giveback	1.10 x	1.04 x
Distributable cash flow	$ 171	$ 161
Distributions paid ***	$ 194	$ 121
Distribution coverage ratio - paid	0.88 x	1.33 x

	Quarter Ended June 30, 2017	Quarter Ended September 30, 2017	Quarter Ended December 31, 2017	Quarter Ended March 31, 2018	Twelve Months Ended March 31, 2018
	(Millions, except as indicated)				
Distributable cash flow	$ 119	$ 187	$ 176	$ 171	$ 653
Distributions declared **	$ 134	$ 155	$ 194	$ 155	$ 638
Distribution coverage ratio - declared	0.89x	1.21x	0.91x	1.10x	1.02x
Distributable cash flow	$ 119	$ 187	$ 176	$ 171	$ 653
Distributions declared without IDR giveback	$ 154	$ 155	$ 154	$ 155	$ 618
Distribution coverage ratio - declared without IDR giveback	0.77x	1.21x	1.14x	1.10x	1.06x
Distributable cash flow	$ 119	$ 187	$ 176	$ 171	$ 653
Distributions paid ***	$ 135	$ 134	$ 155	$ 194	$ 618
Distribution coverage ratio - paid	0.88x	1.40x	1.14x	0.88x	1.06x

** There were no IDR givebacks reflected in distributions declared for the year ended March 31, 2018. Distributions declared for the three months ended March 31, 2017 and June 30, 2017 reflect $20 million of IDR givebacks, respectively.

*** Distributions paid reflect the payment of $40 million of IDR givebacks previously withheld for the three months ended March 31, 2018.

Non GAAP Reconciliation

	Twelve Months Ended December 31, 2018	
	Low Forecast	High Forecast
	(Millions)	
Reconciliation of Non-GAAP Measures:		
Forecasted net income attributable to partners	$ 310	$ 390
Distributions from unconsolidated affiliates, net of earnings	60	70
Interest expense, net of interest income	300	300
Income taxes	5	5
Depreciation and amortization, net of noncontrolling interests	390	390
Non-cash commodity derivative mark-to-market	(20)	(20)
Forecasted adjusted EBITDA	1,045	1,135
Interest expense, net of interest income	(300)	(300)
Maintenance capital expenditures, net of reimbursable projects	(100)	(120)
Preferred unit distributions ***	(37)	(37)
Other, net	(8)	(8)
Forecasted distributable cash flow	$ 600	$ 670

*** Represents cumulative cash distributions earned by the Series A Preferred Units, assuming distributions are declared by DCP's board of directors.