USA Compression Partners, LP

UBS Midstream, MLP & Utilities Conference

January 15-16, 2019

Disclaimer

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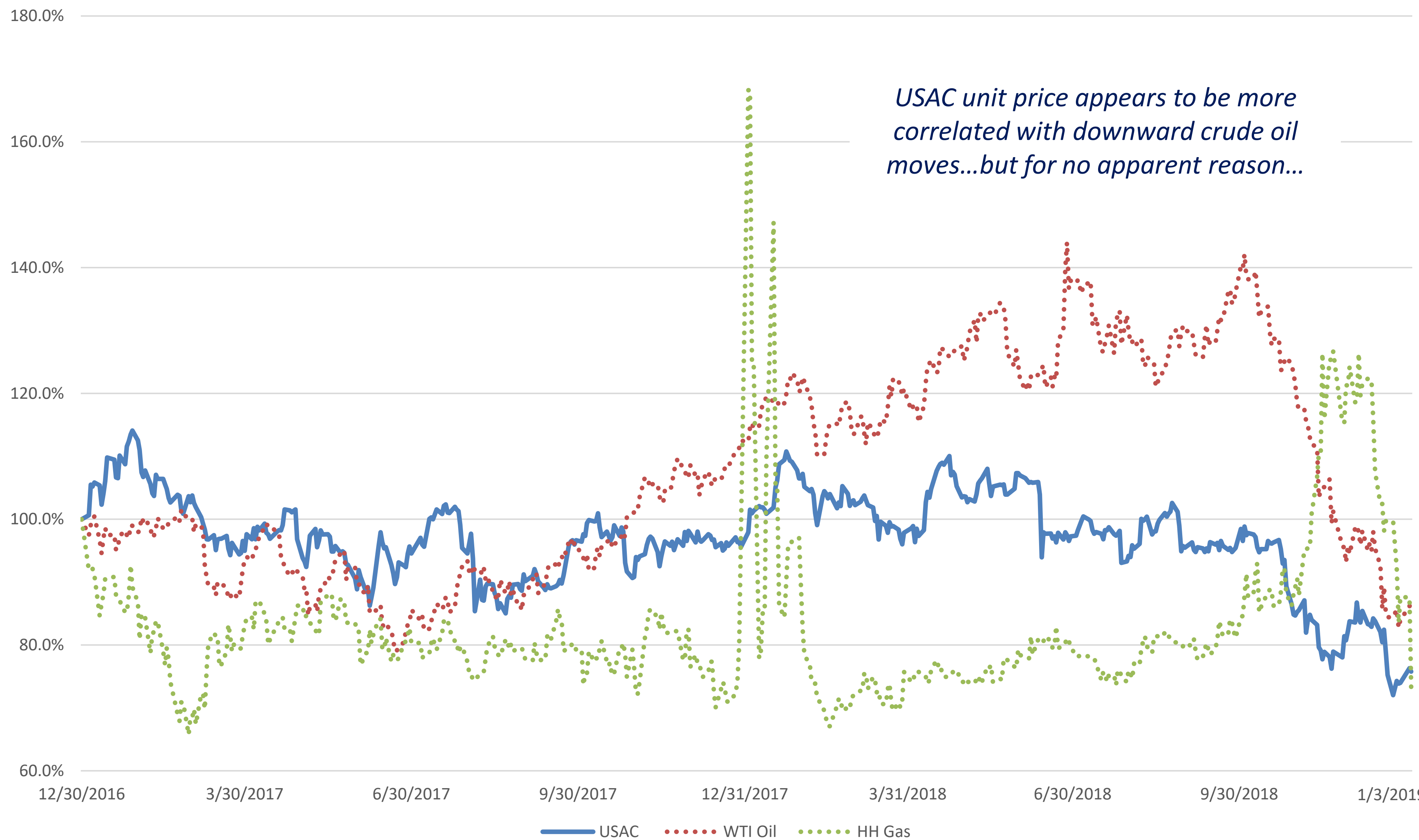
Current Market Perspectives

USAC Unit Price

No Meaningful Correlation with Commodity Prices…or Is There?



Large HP Compression is NOT an Oil Field Service

Large HP Strategy Has Proven Itself More Stable Over Cycles

	Large HP	Small HP
Nature of Application	Gathering Systems, Central Delivery Points, Processing Facilities	Well-head service
Asset Churn	Large infrastructure applications require asset deployment for extended periods	Commodity sensitivity can be meaningful
Customer Base	Typically larger operators with significant development projects demanding large HP	Generally broader customer base, given breadth of operators at the well-head
Entry / Exit Barriers	Capital-intensive; select group of operators with technical know-how; expensive to install & demobilize	Tends to be more of a commodity service offering; smaller size & reduced capabilities make barriers to entry/exit minor

Meaningful differences in the nature of the large horsepower business strategy

USAC View of Current Marketplace

Expect Present Cycle to be Shorter than Previous Cycles

Supply / Demand

- Global crude inventories remain tight; demand stronger than reported?; waiver impact softening; IMO 2020 impact
- OPEC supply cut expected to be meaningful – in hopes of balancing the market; lingering questions over longer-term shale productivity could further benefit price
- US will continue to produce natural gas to meet growing demand – other regions (NE, Rockies, Louisiana) stand ready
  - Macro factors positive: PetChem feedstock, LNG exports, Mexico demand & PowerGen

Compression Demand

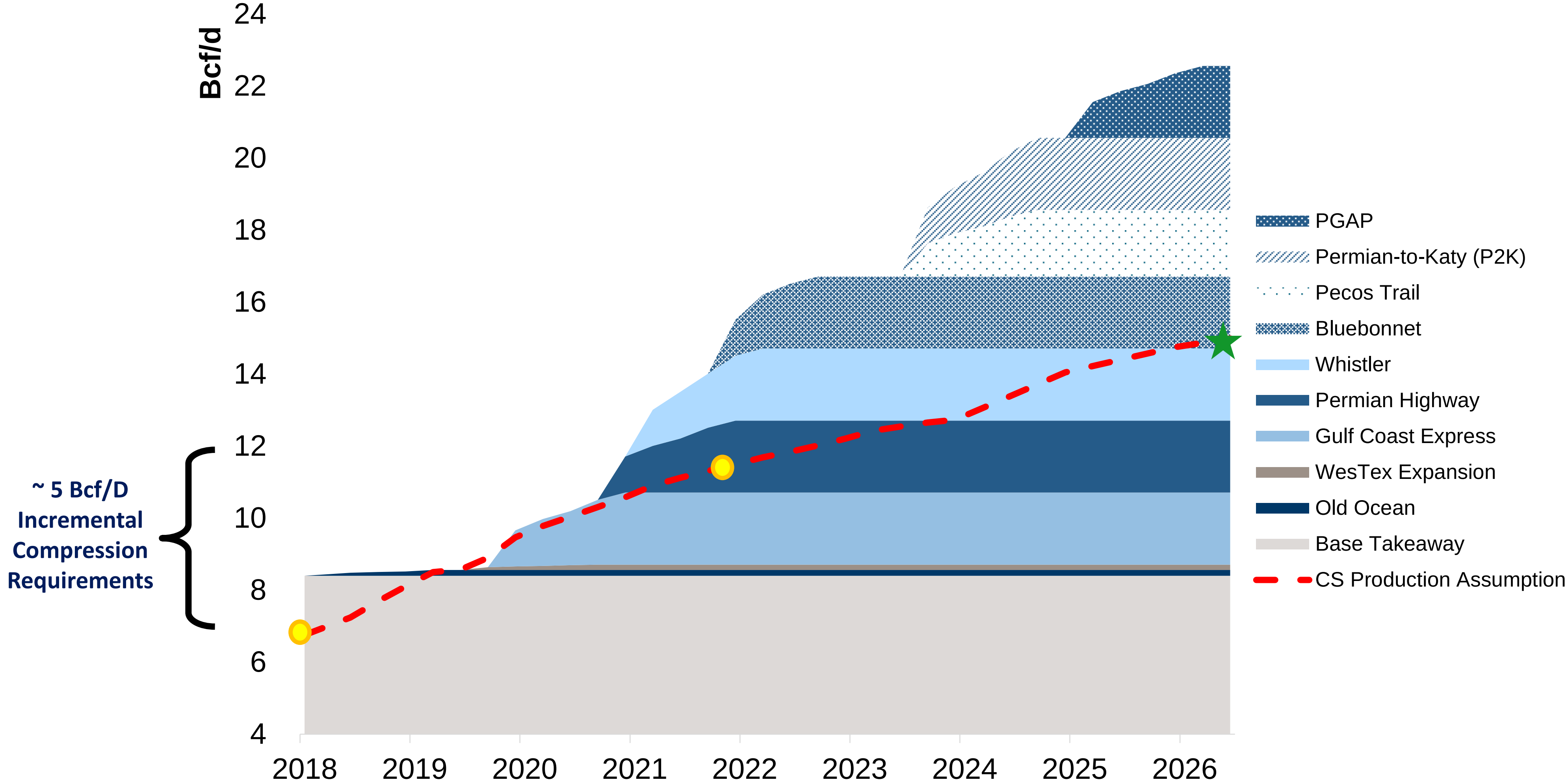
- More gas production will require more compression
- Permian & NE gas production projected to increase ~20 Bcf/d in next 4 years (~25%) – requiring incremental large HP infrastructure compression
- Believe large HP to be in short supply while demand continues

Demonstrated Stability

- Assets stay put once installed: slowing rig activity doesn't affect current production
- Utilization of large HP throughout sector is high
- Unit flexibility and ability to re-locate assets if necessary provides value

Infrastructure Development Will Require Compression

Permian Gas Pipeline Supply & Demand



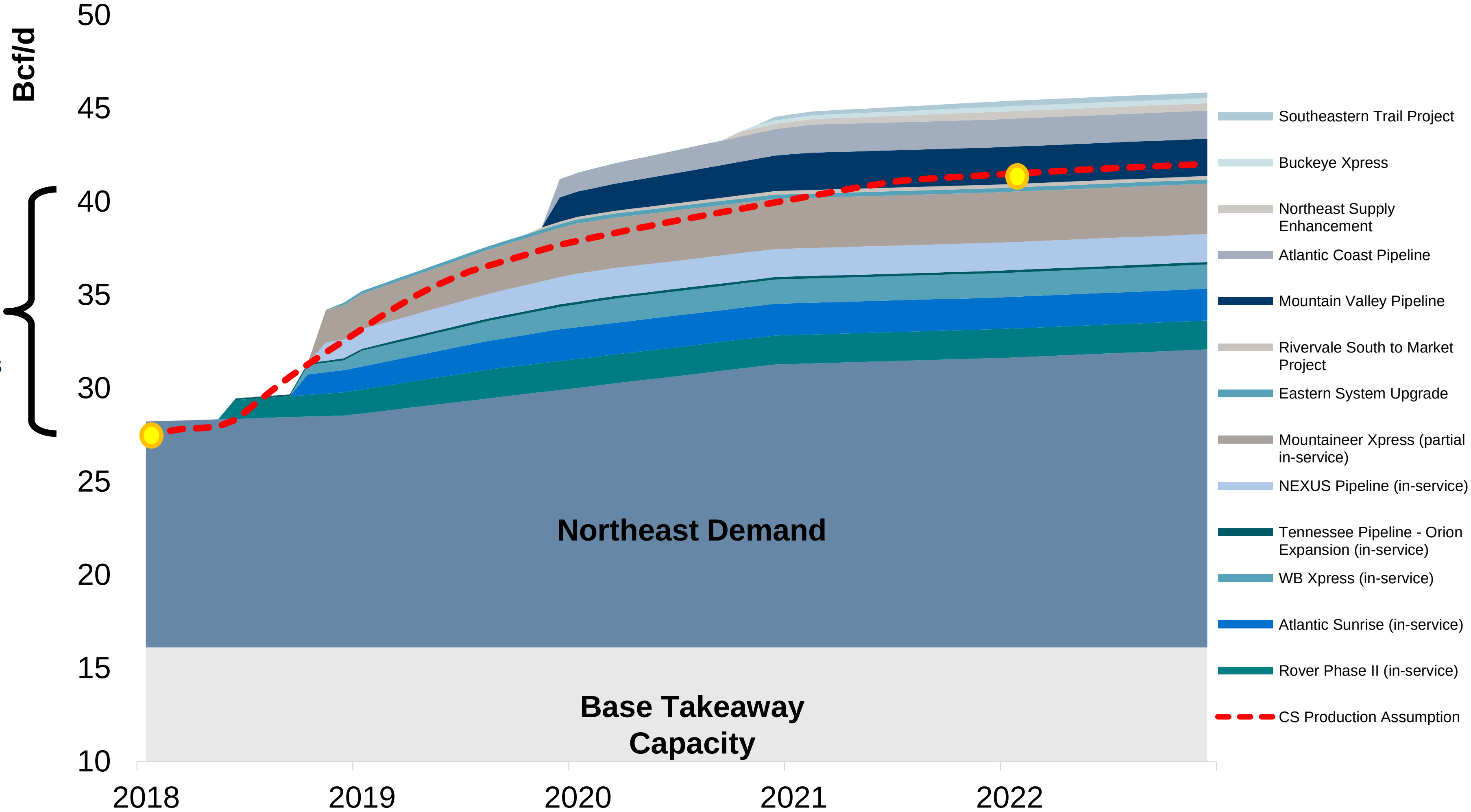
Permian Gas Supplies Projected to Increase ~70% in 4 Years – Requiring Incremental Field Compression

Source: Credit Suisse Research, Bentek, Company Filings.

Infrastructure Development Will Require Compression

Marcellus / Utica Gas Pipeline Supply & Demand: Constraints Removed

~ 15 Bcf/D Incremental Compression Requirements



NE Gas Supplies Projected to Increase >55% in 4 years – Requiring Incremental Field Compression

Source: Credit Suisse Research, Bentek, Company Filings.

Compression Sector in 2019 vs 2014

Cyclical Pullbacks are Not New, but Sector is Better Positioned in 2019

		Current - 2019	Previous - 2014
Customer Balance Sheets		Stronger; living within cash flow	More constrained
E&P Efficiencies		Strong: 4+ years of innovations	Evolving, but limited
Compression Utilization		High throughout large HP sector – mid 90%	Relatively high, but asset duplicity resulted in returns
Key Basin Maturity		**Permian/Delaware:** Transitioning to "mining" operation **Utica/Marcellus:** Takeaway debottlenecking providing options	**Permian/Delaware:** Land grab among broad group of operators **Utica/Marcellus:** Active, but takeaway constraints hindered growth

Better Positioned to Manage a Shorter Cycle – Positive for Compression Prospects

Macro Drivers Still Attractive

The "Big Four" Natural Gas Demand Drivers Not Slowing Down

LNG Exports

- ~50mtpa (~30 Bcf/d) of projects in US currently under construction; estimated ~35mtpa (~4.6 Bcf/d) to be sanctioned over next 2+ years [1]

PetChem/Industrial Demand

- Readily available natgas feedstock driving petchem investment
- Meaningful gas supply @ attractive prices have spurred major projects (Shell – PA, ExxonMobil/SABIC – TX, Lyondell – TX, others)

Exports to Mexico

- Mexico continuing its conversion to gas-fired electricity and renewable energy development
- Currently primarily burning expensive fuel oil and imported LNG, both significantly more expensive than natgas
- US-Mexico pipeline connections have been the bottleneck

Power Gen Conversion from Coal

- ~17 GW of coal-fired plants were retired in 2018
  - ~50% above 2017 retirement levels
  - Replacing half of generation capacity with natgas would require ~1.5 Bcf/d [2]
- US coal power capacity down by ~1/3 since 2010
- Additional 37 GW set for retirement by 2025 [2]

More domestic natural gas flowing in pipelines means more demand for compression

1. *Source: UBS Research dated October 12, 2018.*
2. *Source: Bloomberg New Energy Finance dated November 9, 2018.*

2019 Priorities & Opportunities

Conservative Approach Coming into Year; Positioned to Benefit from Market Strength

Capex

- Currently have ~120,000 of large HP on order for 2019 delivery
- Limited opportunities for idle unit redeployment (utilization is high)

Balance Sheet

- Leverage remains a focus; expect manageable levels as CDM acquisition is fully integrated during 2019
- Self-funding: currently no plans to issue equity to fund capital growth
- Expected increasing coverage will provide funds for debt repayment

Commercial

- New deliveries committed to large, existing customers
- Expect primary focus to be on Permian/Delaware, Northeast and Mid-Continent (SCOOP/STACK)
- Continued optimization of existing customer base – both assets and pricing

Corporate Governance

- Simplified corporate structure at time of CDM Acquisition
  - Extinguished IDRs
  - Converted GP Interest to non-economic interest (control only)

Macro Overview & Demand Drivers

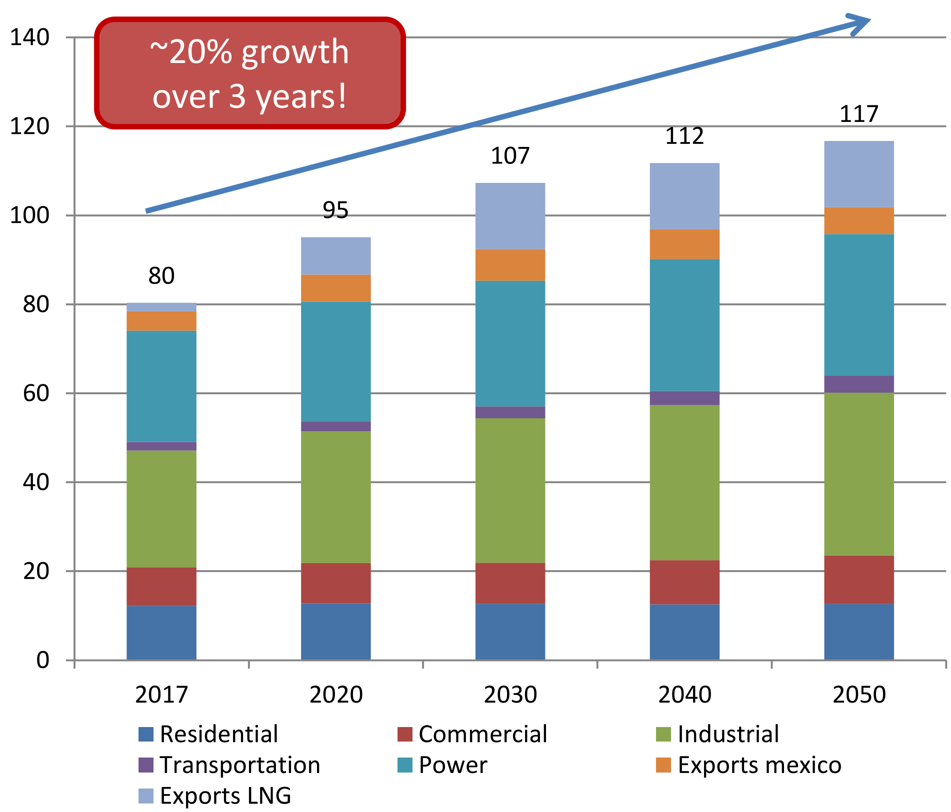
Domestic Natural Gas Supply & Demand Growth

Natural Gas Supply & Demand Continues to Grow…

as does the need for midstream infrastructure to move it through the pipeline system

EIA projects significant increase in natural gas demand by 2050

Projected Natural Gas Demand (Bcf/d)(1)



Source: U.S. Energy Information Administration, Annual Energy Outlook 2018, February 2018

(1) Converted from TCF, on a 360 day/year basis

Exports to Mexico:
- Growing power needs to be met by US shale gas
- ~3 Bcf/d to Mexico by 2020

LNG Exports:
- ~8 Bcf/d by 2020; 15 Bcf/d by 2040

Power:
- ~30 Bcf/d by 2040
- Coal plant retirements expected to continue

Industrial Demand:
- ~35 Bcf/d by 2040
- Petrochemical plants (Gulf Coast, NE) driving demand

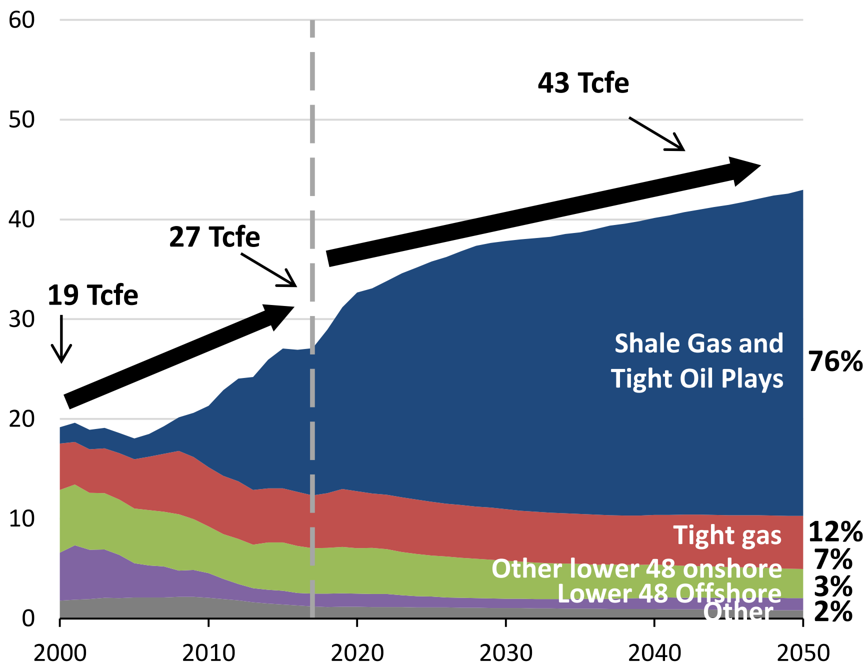
USA COMPRESSION

Macro Thesis: The “Shift to Shale”

Shale Gas Expected to be the Primary Source in Future

- **Shale Ramp**: Production from shale has now pulled **even** with all other sources
  - 2017 est. ~ 15 Tcfe of shale production – 55% of total
- **Pie Getting Bigger**: EIA projecting ~117 Bcf/d of total production by 2050 – with shale ~76% of total

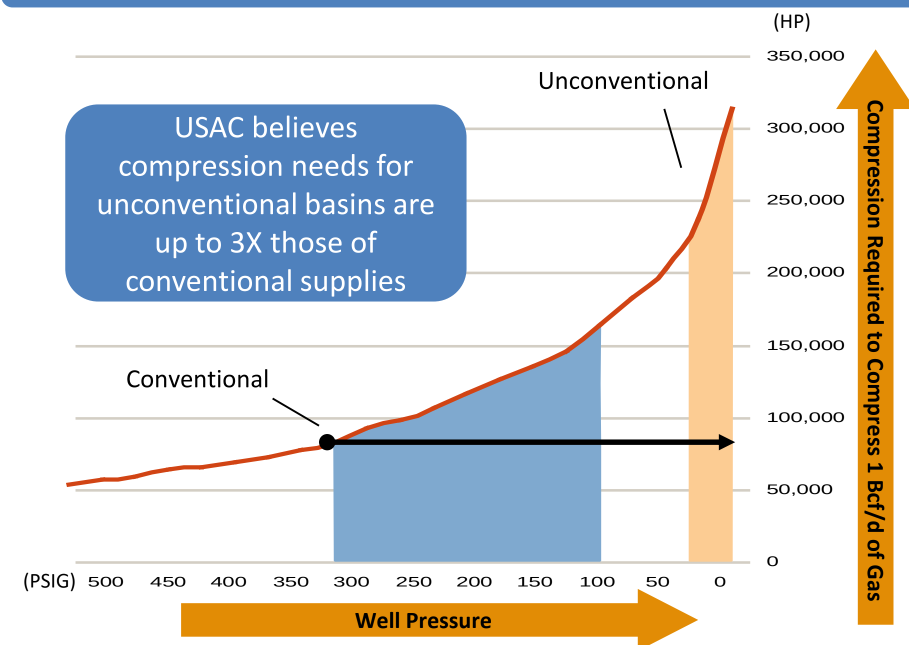
Natural gas production by type
trillion cubic feet



Source: U.S. Energy Information Administration, Annual Energy Outlook 2018, February 2018

- Shale gas is typically produced at lower wellhead pressures (0-50 PSIG) in contrast to conventional gas wells (100-300 PSIG)
- Pipeline specifications remain constant – requiring gas pressure to be increased significantly to move gas into and through pipelines
- As a result, to move the same amount of gas requires significantly more compression

Shale Production Drives Increasing Compression Requirements (1)



Source: Ariel Corporation: compressor sizing protocol.
(1) Assumes Discharge Pressure = 1,200 PSIG.

Key Industry Drivers for Compression Services

Compression is Critical Midstream Infrastructure for Producing & Transporting Hydrocarbons

Overall Gas Demand & Production

- ~85% of USAC's business (by HP) is installed in natural gas-based infrastructure applications ("Midstream")
- Projected increasing natural gas demand for the foreseeable future
- LNG and Mexico exports add to the increasing demand macro picture
- Largely gas price agnostic; activity driven by production volumes and the need to move gas

Shale Activity

- Expect majority of gas production growth to be satisfied by shale production
- Typically lower pressures (vs. conventional) require significantly more compression to move gas (~3x HP)
- Changing operating conditions over time require flexible assets
- Infrastructure build out is still in the early stages; compression follows
- Associated gas production as a byproduct of crude oil production

Customer Preference to Outsource

- Decision to outsource compression can be due to higher runtimes, lack of internal expertise, alternative capital investment opportunities and other factors
- Many of the largest, most sophisticated energy companies rely on outsourcing
- Mission-critical assets must run
- Guaranteed run time backed up by service and adherence to maintenance intervals
- As capital allocation moves to the forefront, shifting preference to use 3rd party providers

Customer Activity

E&P Activity Benefitting from Efficiencies; Compression Demand Follows

- Growth in drilling activity has moderated
- Producers continue to be active in attractive areas, but takeaway bottlenecks have had an impact
- Recent crude oil volatility causing some pause; gas demand/supply increase continues
- More gas moving through pipeline system leads to more demand for compression

DJ Basin

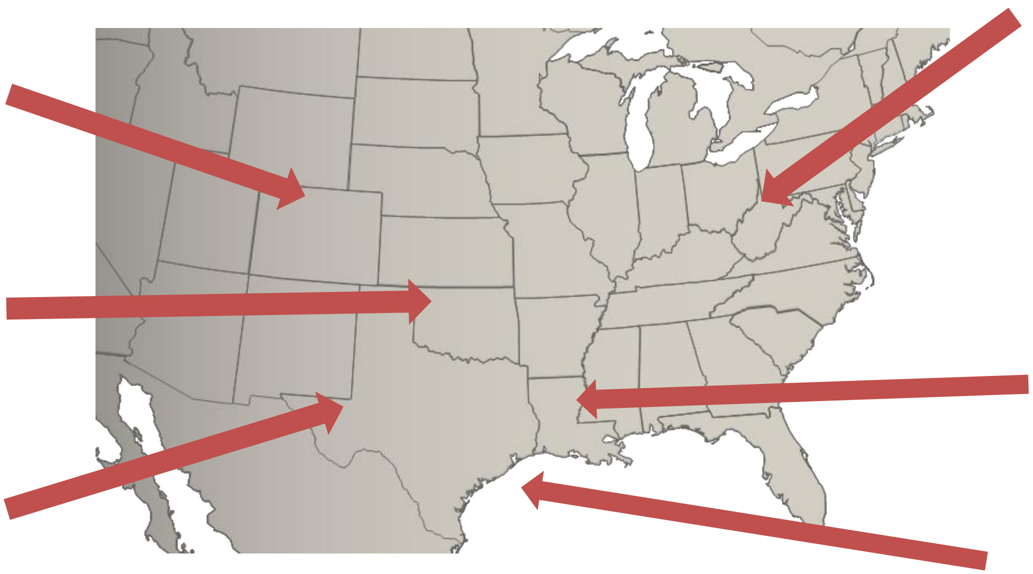
Rig	% Chg	
Total	Trough	Peak
27	125%	(54%)

SCOOP/Stack/Mid-Con

Rig	% Chg	
Total	Trough	Peak
122	149%	(10%)

Permian

Rig	% Chg	
Total	Trough	Peak
487	255%	(13%)



Marcellus

Rig	% Chg	
Total	Trough	Peak
57	119%	(31%)

Utica

Rig	% Chg	
Total	Trough	Peak
17	55%	(61%)

Haynesville

Rig	% Chg	
Total	Trough	Peak
55	206%	17%

Eagle Ford

Rig	% Chg	
Total	Trough	Peak
93	210%	(61%)

Source: Baker Hughes, Bloomberg, and B. Riley FBR Research dated January 7, 2019.

USAC Overview

USAC Overview

Large Horsepower Strategy at Core of USAC Business

Business Overview

- Geographically diversified provider of compression services
  - Focused primarily on large horsepower (1,000 HP+) applications
  - Over 4,500 compressor units in 19 states
  - Areas of Activity: Permian/Delaware; Marcellus/Utica; Mid-Continent/SCOOP/STACK; S. Texas; E. Texas; Louisiana; Rockies
- Active / Total HP: 3.2mm / 3.6mm
  - >70% is greater than 1,000 HP
- Average Utilization ~93%
- ~900 employees
- $1.7 bn CDM acquisition closed in April 2018

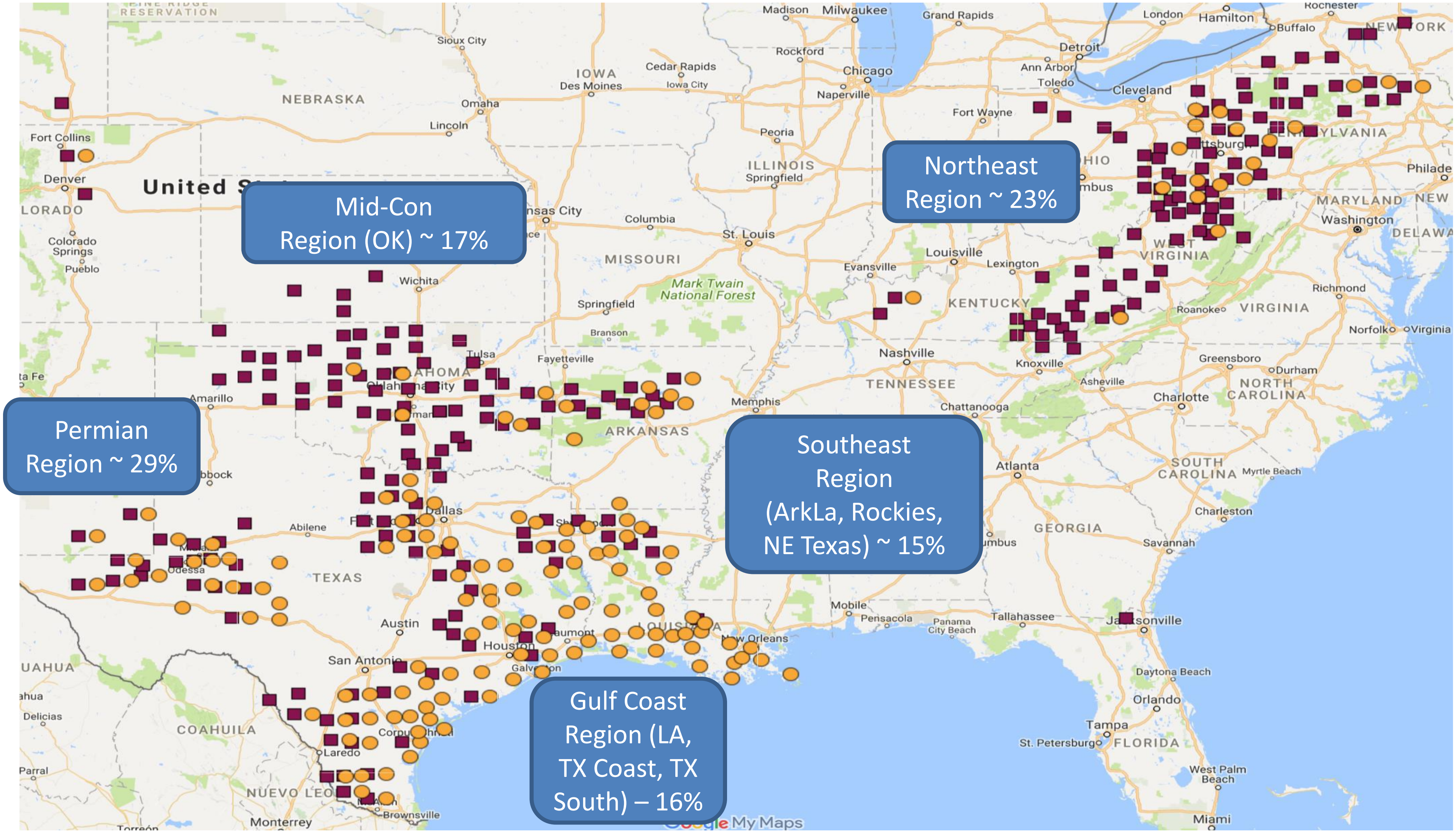
USAC Market Statistics

($ in billions)	
LP Equity Value	$1.4 billion
Preferred Equity	0.5 billion
ABL	1.0 billion
Sr. Notes	0.7 billon
Total Long-Term Debt	1.7 billion
Enterprise Value	**$3.6 billion**

Note: Market data as of January 9, 2019. Financial and operational data as of September 30, 2018.

Geographic Presence

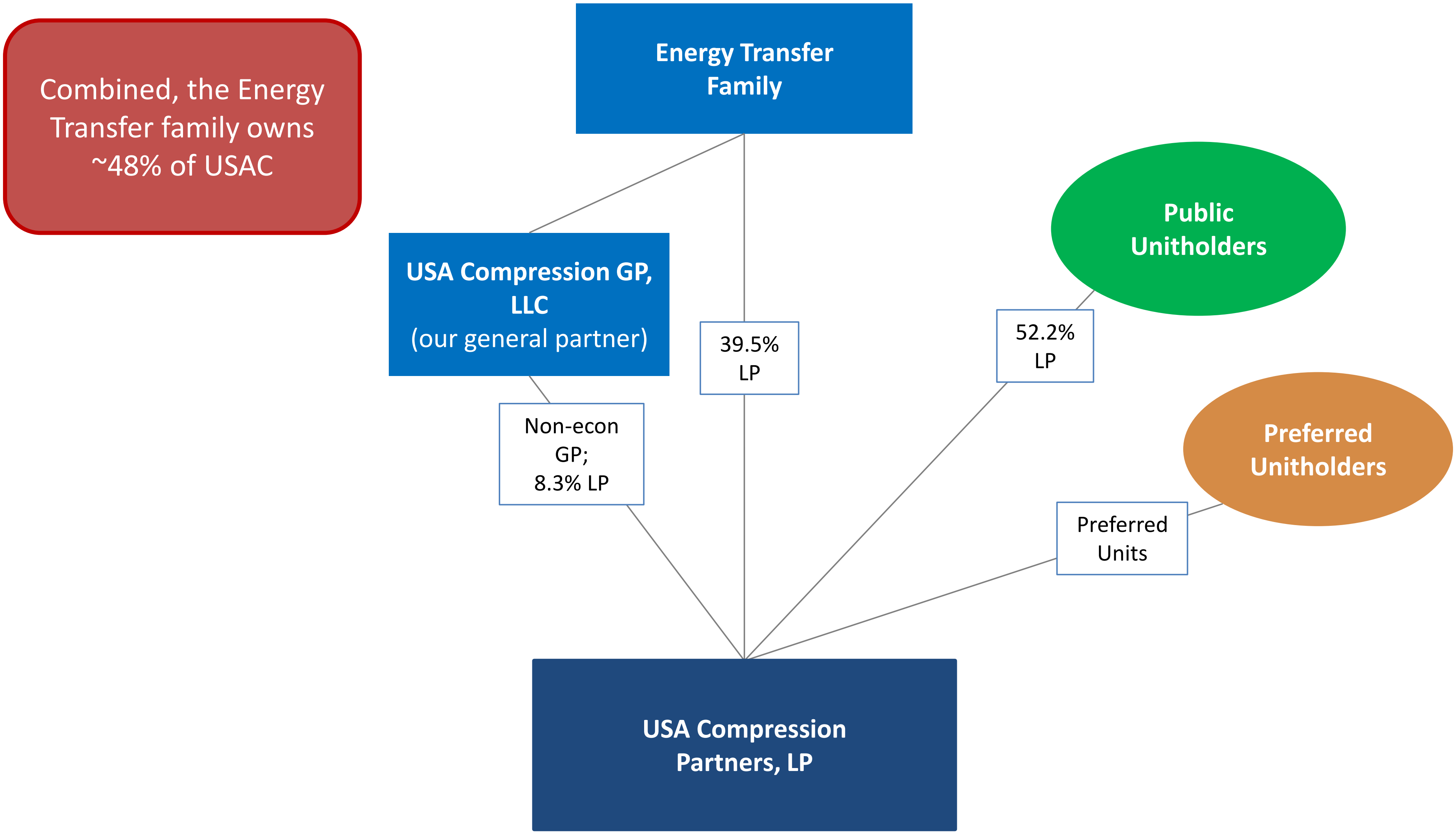
CDM Acquisition Expanded Geographic Footprint



CDM USAC

Note: Regional % breakdowns represent active fleet horsepower; excludes non-compression equipment.

Organizational Chart



Note: Percentages reflect USAC unit count as of December 31, 2018. ETP interest includes ~6.4mm Class B units.

Key Strategic Priorities

Successful CDM Integration

- Continued focus on integrating all aspects of CDM into USAC
- Back office migration substantially complete
- Alignment of strategy / policies / procedures is critical; build a single culture
- Synergies on target, expect full run-rate during 2019

Consistent Business Model

- Further strengthen the USAC "Southwest Airlines" standardized business model
- Continue focus on large HP class units
- Implement best practices across the combined business

Prudent Capital Spending

- With capital scarcity, emphasizing highest-return opportunities
- Stringent capital allocation across the business
- 2019 order: 120,000 horsepower; lead times still elevated

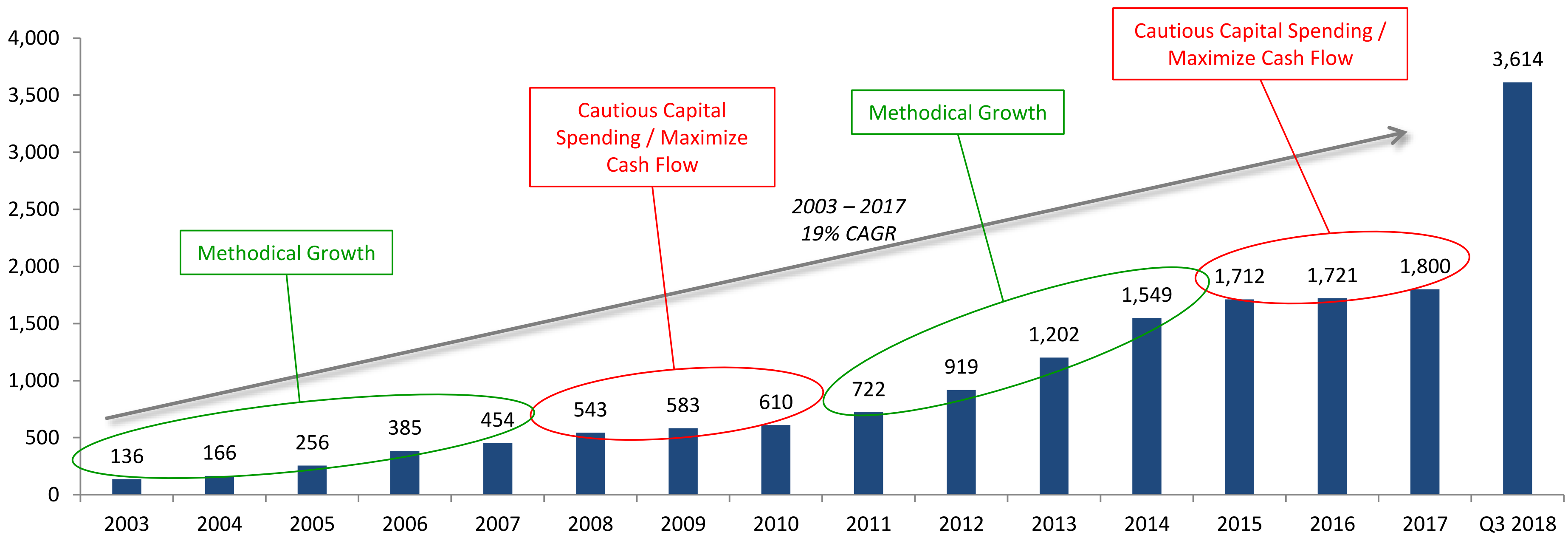
Sound Financial Management

- Optimize fleet pricing and contracts
- Continue to improve leverage & coverage metrics
- Facilitate Energy Transfer monetization when appropriate

Business Model Allows for Prudent Capital Spending…..

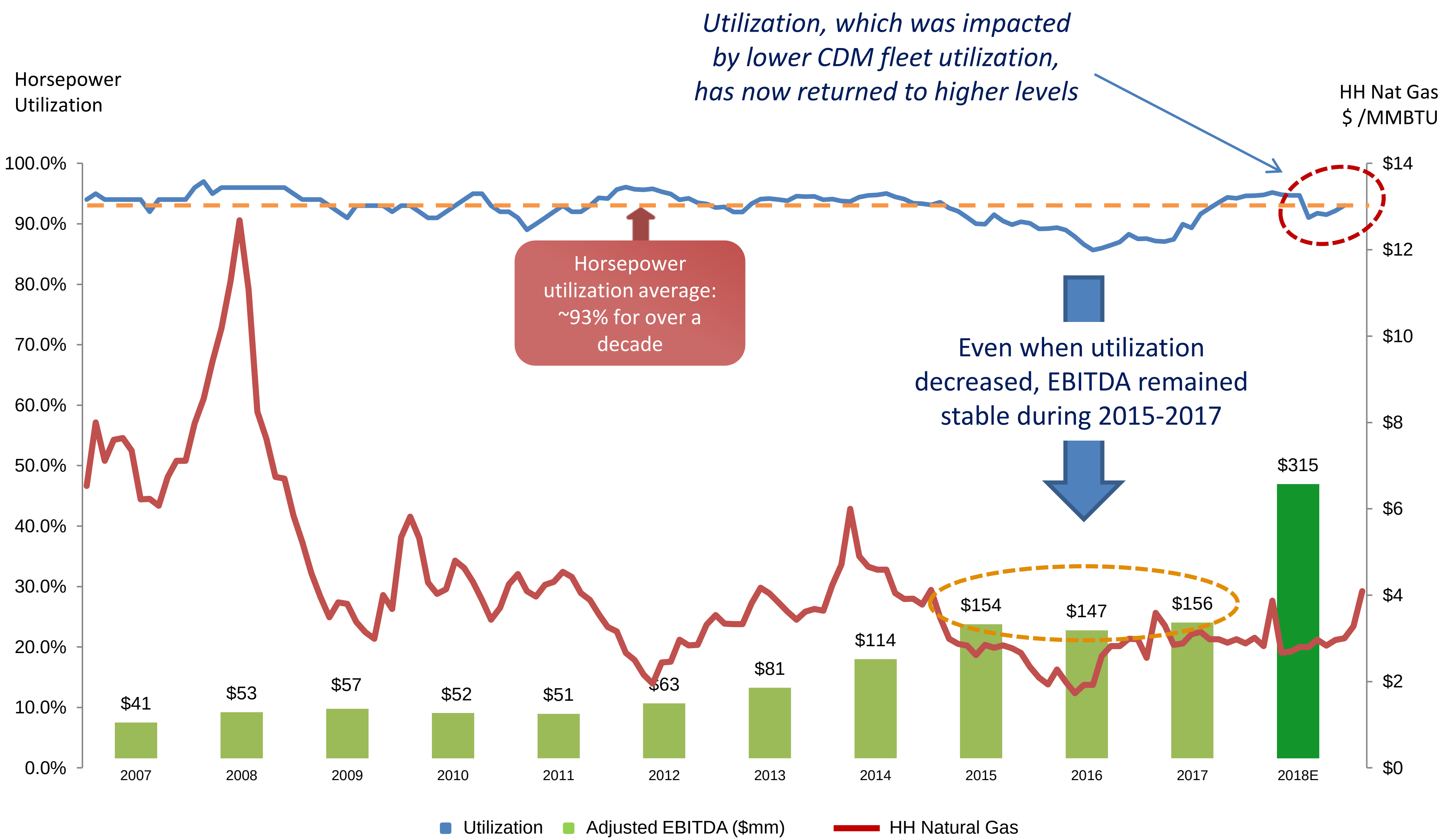
- Large HP focus ideally suited for <u>growth and stability</u>
- Shale production has changed the industry: demand for larger, more flexible assets
- Assets provide growth when marketplace demands (and willing to pay)
- Ability to rein in spending and operate for cash flow when market softens
- Largely agnostic to commodity prices; tied more to the overall domestic production of (and demand for) natural gas

Total Fleet Horsepower (000s)



Note: Represents historical USAC standalone fleet for periods prior to 2018.

…..Leading to Cash Flow and Asset Stability Through Cycles



Source: EIA.

Note: 2018E reflects midpoint of USAC guidance provided on November 6, 2018. Periods prior to 2018 reflect USAC standalone results.

USAC Customer Overview

Top 20 Customers: Diverse Counterparties & Long-Term Relationships

Customer	% of Rev[1]	Length of relationship	Total HP		Customer	% of Rev[1]	Length of relationship	Total HP
Independent Public E&P	8%	17 Years	283K		Major O&G	2%	4 Years	69K
Large Private E&P	4%	20 Years	115K		Private Midstream	2%	6 Years	79K
Public Utility	3%	5 Years	133K		Midstream C-corp	2%	11 Years	65K
Independent Public E&P	3%	13 Years	109K		Private Midstream	2%	5 Years	57K
Large MLP	3%	4 Years	108K		Independent Public E&P	2%	5 Years	52K
Independent Public E&P	3%	6 Years	98K		Independent Public E&P	2%	5 Years	72K
Large MLP	3%	11 Years	85K		Independent Public E&P	2%	6 Years	50K
Independent Public E&P	3%	10 Years	68K		Independent Public E&P	1%	1 Year	39K
Independent Public E&P	2%	4 Years	52K		Independent Public E&P	1%	7 Years	41K
Private E&P	2%	4 Years	52K		Midstream Sub of Large Public E&P	1%	12 Years	70K
USAC #1-10	**34%**		**1,103K**		**USAC #11-20**	**16%**		**594K**

- USAC standalone has historically had very little bad debt write-offs; in fact, over the last 13+ years, USAC has written off only ~$1.5 million in bad debts
  - Equates to 0.07% of total billings (>$2.2 billion) over same period [2]

1. *Represents recurring revenues for the 6 months ended September 30, 2018.*
2. *Write-off data refers to USAC standalone historical performance & combined performance in Q2 & Q3 2018.*

Large Horsepower Gas Applications Drives Stability

Compression Unit Size Matters

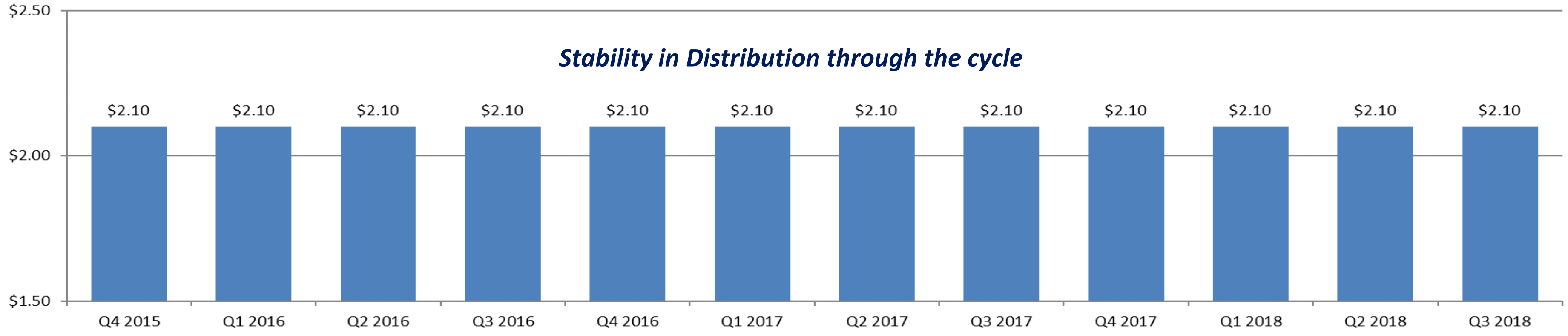
USAC Focus:

Gas Compression Industry: Key Characteristics by Size						
	Small	Medium	Large	Ex. Large	XX Large	Commentary
Compression Unit HP Range	0 – 400 HP	400 – 1,000 HP	1,000 – 1,500 HP	1,500 – 2,300 HP	2,300 – 2,600 HP	**More horsepower needed to move larger gas volumes**
Gas Vol (MMcf/d)	0.90	3.20	5.0	8.0	13.0	
Size (L x W x H, ft.)	21 x 12 x 11	33 x 19 x 16	38 x 27 x 20	43 x 34 x 20	80 x 17x 28	**Increasing size, transportation & demobilization costs create significant 'barriers to exit'**
Weight (lbs.)	~40,000	~85,000	~185,000	~250,000+	~400,000+	
Transportation Requirements	1 F350	2 x 18-wheelers	3 x 18-wheelers	5 x 18-wheelers	8 x 18-wheelers	
De-mobilization Costs (cust pays)	< $10K	~$25K	~$60K	$100K+	$200K+	
Typical Contract Length	1 – 12 mos	6 months – 2 years	2 – 5 years	2 – 5 years	2 – 5 years +	**Larger units = longer deployment**

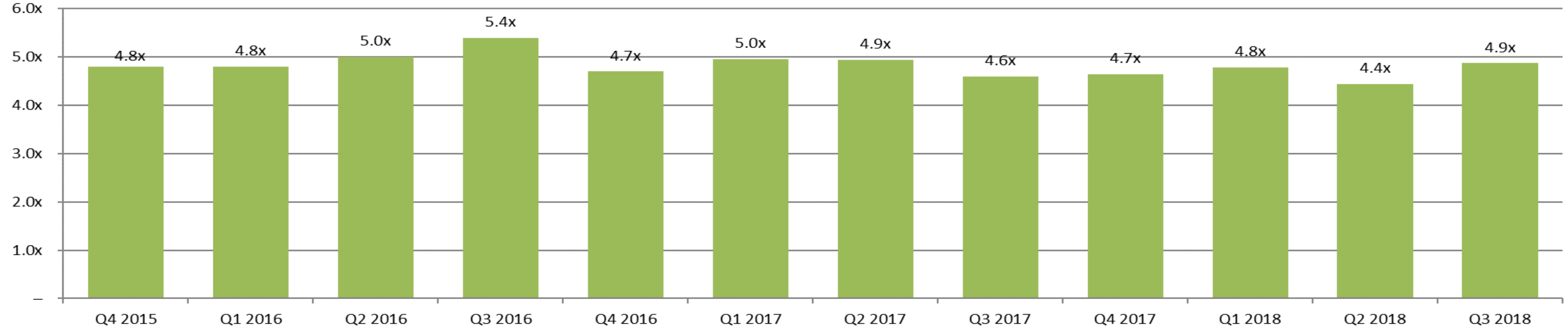
Note: Used CAT 3306TA ,CAT 3508TALE, CAT 3516BLE, CAT 3606TALE and CAT 3608TALE as representative units for small, medium, large, extra large and XX large horsepower categories, respectively. Gas volumes based on 50 psi suction pressure and 1,200 psi discharge pressure.

Balancing Distribution Stability and Leverage

Annualized Distributions per Common Unit



USAC Historical Leverage[1]

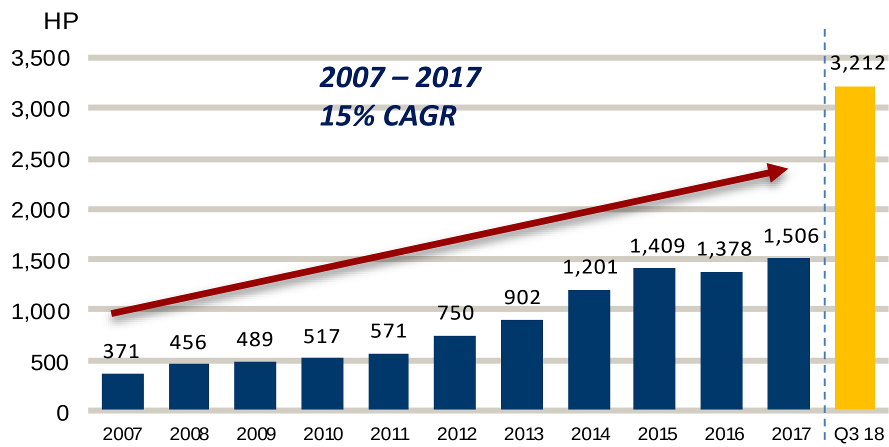


Note: Reflects USAC standalone for all periods prior to April 1, 2018. Q2 2018 and Q3 2018 reflect USAC and CDM combined.

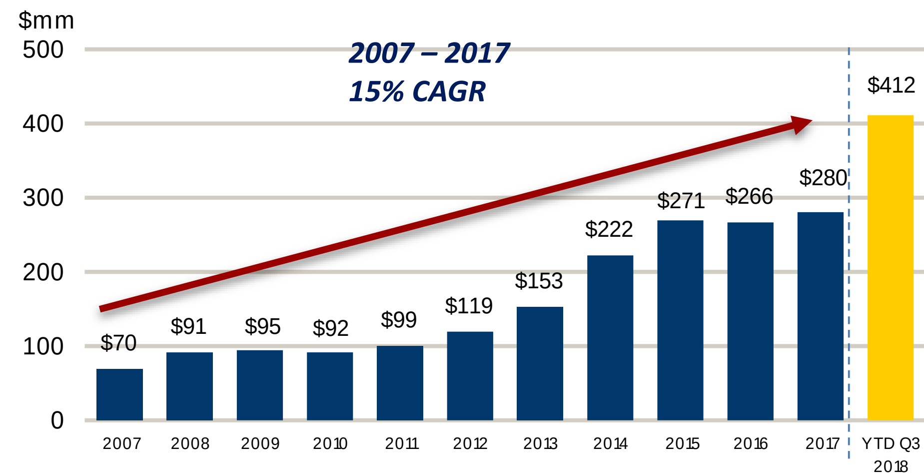
1. *Historical leverage calculated as total debt divided by annualized quarterly Adjusted EBITDA for the applicable quarter, in accordance with our current Credit Agreement. Actual historical leverage may differ based on certain adjustments.*

USAC Standalone Operational and Financial Performance

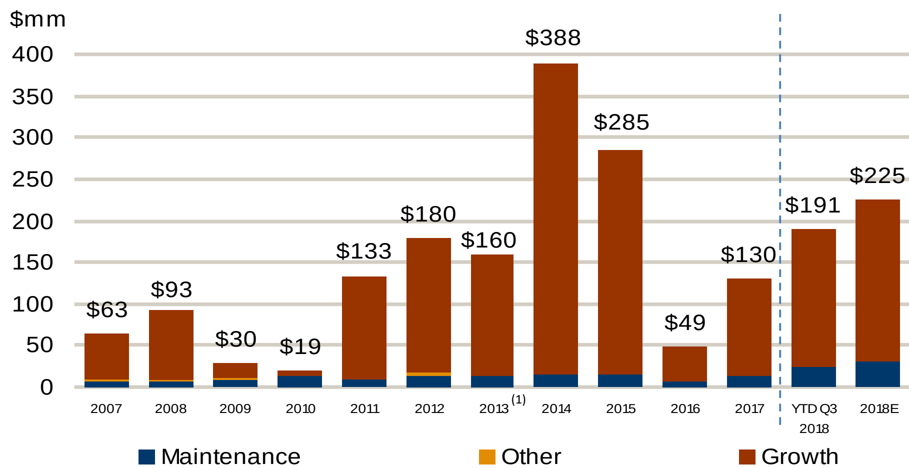
Avg. Revenue Generating HP (000s)



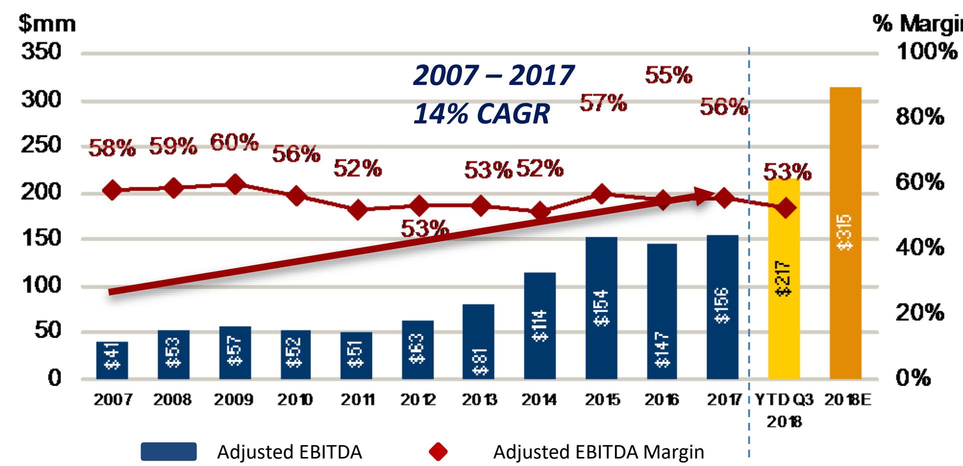
Revenue ($MM)



Total Capex ($MM)(2)



Adjusted EBITDA ($MM) & Margin Percentage(2)(3)



Note: Historical periods prior to 2018 do not reflect the reverse merger treatment in connection with CDM acquisition. YTD Q3 2018 data reflects Q1 historical data for CDM standalone.

(1) Does not include $182mm acquisition of S&R Compression, financed with 7.4mm Common Units ($178mm net of cash acquired).

(2) 2018E data reflects midpoint of guidance provided on November 6, 2018 in earnings release and 10-Q.

(3) See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for information on calculations of Adjusted EBITDA and Adjusted EBITDA Margin Percentage.

USAC Investment Highlights

USAC's Business Prospects Driven By Positive Macro Drivers in the Midstream Industry

Critical Midstream Infrastructure

- Continued focus on infrastructure-oriented compression applications; compression is critical to transporting natural gas to end markets
- Shale gas continues to reward flexible compression providers
- Gas lift operations continue in our core areas; well economics (lifting vs. finding costs) still favorable

Exposure to Strategic Producing Regions

- USAC owns and operates assets in prolific oil and gas shale basins benefitting from ongoing midstream build-out
- CDM Acquisition further expands presence in areas where USAC was historically under-represented (S. Texas, Rockies, Louisiana)
- Continued organic development through presence in areas of natural gas processing

Stable Cash Flows with Visible Growth

- Infrastructure nature of assets results in compression units typically remaining in the field well beyond initial contract term
- Continued strong utilization history drives return on capital employed
- Tightness in market allows pricing upside

Strategic Customer Relationships

- Services provided to large, high-quality midstream and upstream customers
- Continued outsourcing of service providers creates strategic opportunities for USAC
- Long-standing customer relationships in all operating regions creates a significant barrier to entry
- CDM brings new customers / opportunities to USAC

Appendix

Compression Throughout the Value Chain

Midstream Compression Offers Cash Flow & Customer Stability

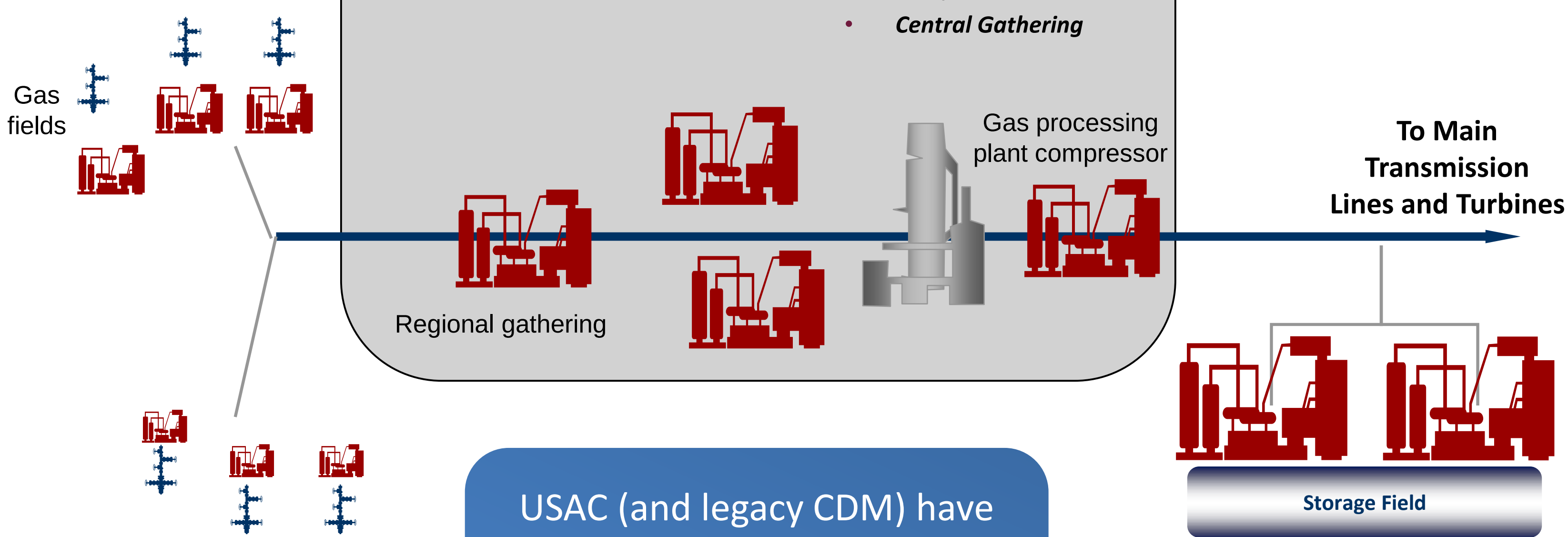
Lower (Sm. Volumes) **Pressure Regime** *Higher (Lg. Volumes)*

Crude Oil Wells
- ***Gas Lift***
- ***Gas Reinjection***

Limited exposure for both USAC & CDM

Midstream Applications
- ***Regional Gathering***
- ***Gas Processing Plant Compression***
- ***Central Gathering***

Rate-Base Applications
- ***Interstate Pipeline***
- ***Trunkline gathering***
- ***Underground Gas Storage***



Natural Gas Wells
- ***Wellhead Compression***
- ***Gas Lift / Gas Reinjection***

USAC (and legacy CDM) have made the strategic decision not to pursue more volatile gas wellhead equipment

Non-GAAP Reconciliations

	Three months ended		
	September 30, 2018	June 30, 2018	March 30, 2018
Net income (loss)	(563)	$ 3,197	$ (23,370)
Interest expense, net	25,443	25,682	-
Depreciation and amortization	59,403	52,868	44,672
Income tax expense (benefit)	(918)	(271)	(435)
EBITDA	$ 83,365	$ 81,476	$ 20,867
Impairment of compression equipment	2,292	-	-
Interest income on capital lease	225	273	-
Unit-based compensation expense	1,892	8,564	435
Transaction expenses for acquisitions	1,257	2,863	-
Severance Charges	(149)	1,531	-
Other	-	-	-
Loss (gain) on sale of assets and other	1,250	731	10,347
Adjusted EBITDA	**$ 90,132**	**$ 95,438**	**$ 31,649**
Interest expense, net	(25,443)	(25,682)	-
Income tax expense	918	271	435
Interest income on capital lease	(225)	(273)	-
Non-cash interest expense and other	1,516	2,039	-
Transaction expenses for acquisitions	(1,257)	(2,863)	-
Severance Charges	149	(1,531)	-
Other	(688)	85	(627)
Changes in operating assets and liabilities	(26,272)	8,019	(12,590)
Net cash provided by operating activities	**$ 38,830**	**$ 75,503**	**$ 18,867**

Note: Three months ended March 30, 2018 reflects CDM standalone historical data due to reverse merger accounting treatment.

Non-GAAP Reconciliations, cont'd.

	Years Ended December 31,										
($ in 000's)	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Net income (loss)	$ 11,440	$ 12,935	$ (154,273)	$ 24,946	$ 11,071	$ 4,503	$ 69	$ 10,479	$ 21,228	$ 20,911	$ 7,122
Interest expense, net	25,129	21,087	17,605	12,529	12,488	15,905	12,970	12,279	10,043	14,003	16,468
Depreciation and amortization	98,603	92,337	85,238	71,156	52,917	41,880	32,738	24,569	22,957	18,016	13,437
Income tax expense	538	421	1,085	103	280	196	155	155	190	119	155
EBITDA	$ 135,710	$ 126,780	$ (50,345)	$ 108,734	$ 76,756	$ 62,484	$ 45,932	$ 47,482	$ 54,418	$ 53,049	$ 37,182
Impairment of compression equipment	4,972	5,760	27,274	2,266	203	—	—	—	1,677	—	1,028
Impairment of goodwill	—	—	172,189	—	—	—	—	—	—	—	—
Interest income on capital lease	1,610	1,492	1,631	1,274	—	—	—	—	—	—	—
Unit-based compensation expense	11,708	10,373	3,863	3,034	1,343	—	—	382	269	225	2,352
Equipment operating lease expense	—	—	—	—	—	—	4,053	2,285	553	—	—
Riverstone management fee	—	—	—	—	49	1,000	1,000	—	—	—	—
Restructuring charges	—	—	—	—	—	—	300	—	—	—	—
Fees and expenses related to the Holdings Acquisition	—	—	—	—	—	—	—	1,838	—	—	—
Transaction expenses for acquisitions	1,406	894	—	1,299	2,142	—	—	—	—	—	—
Severance charges	314	577	—	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets and other	(17)	772	(1,040)	(2,198)	637	—	—	—	—	—	—
Adjusted EBITDA	$ 155,703	$ 146,648	$ 153,572	$ 114,409	$ 81,130	$ 63,484	$ 51,285	$ 51,987	$ 56,917	$ 53,274	$ 40,562
Interest expense, net	(25,129)	(21,087)	(17,605)	(12,529)	(12,488)	(15,905)	(12,970)	(12,279)	(10,043)	(14,003)	(16,468)
Income tax expense	(538)	(421)	(1,085)	(103)	(280)	(196)	(155)	(155)	(190)	(119)	(155)
Interest income on capital lease	(1,610)	(1,492)	(1,631)	(1,274)	—	—	—	—	—	—	—
Equipment operating lease expense	—	—	—	—	—	—	(4,053)	(2,285)	(553)	—	—
Riverstone management fee	—	—	—	—	(49)	(1,000)	(1,000)	—	—	—	—
Restructuring charges	—	—	—	—	—	—	(300)	—	—	—	—
Non-cash interest expense and other	2,186	2,108	1,702	1,189	1,839	(58)	(920)	3,362	288	201	1,666
Fees and expenses related to the Holdings Acquisition	—	—	—	—	—	—	—	(1,838)	—	—	—
Transaction expenses for acquisitions	(1,406)	(894)	—	(1,299)	(2,142)	—	—	—	—	—	—
Severance charges	(314)	(577)	—	—	—	—	—	—	—	—	—
Other	(490)	—	—	—	—	—	—	—	—	—	—
Changes in operating assets and liabilities	(3,758)	(20,588)	(17,552)	1,498	180	(4,351)	1,895	(220)	(3,474)	1,346	836
Net cash provided by operating activities	$ 124,644	$ 103,697	$ 117,401	$ 101,891	$ 68,190	$ 41,974	$ 33,782	$ 38,572	$ 42,945	$ 40,699	$ 26,441

Note: Does not reflect the reverse merger accounting treatment in connection with CDM acquisition. Reflects USAC standalone only.

Non-GAAP Reconciliations, cont'd.

	Three months ended		
	September 30, 2018	June 30, 2018	March 30, 2018
Net income (loss)	$ (563)	$ *3,197*	$ *(23,370)*
Plus: Non-cash interest expense	1,516	*2,039*	-
Plus: Non-cash income tax expense (benefit)	(1,038)	(390)	(435)
Plus: Depreciation and amortization	59,403	*52,868*	*44,672*
Plus: Unit-based compensation expense	1,892	*8,564*	*435*
Plus: Impairment of compression equipment	2,292	-	-
Plus: Transaction expenses for acquisitions	1,257	*2,863*	-
Plus: Severance Charges	(149)	*1,531*	-
Plus: Other	-	-	-
Plus: Proceeds from insurance recovery	253	-	-
Less: Loss (gain) on sale of assets	*1,250*	*731*	*10,347*
Less: distribution to preferred units	*(12,188)*	*(12,054)*	-
Less: Maintenance capital expenditures	(6,447)	(7,927)	(9,213)
Distributable cash flow	**$ 47,478**	**$ 51,422**	**$ 22,436**
Plus: Maintenance capital expenditures	*6,447*	*7,927*	*9,213*
Plus: Change in operating assets and liabilities	*(26,272)*	*8,019*	*(12,590)*
Less: Transaction expenses for acquisitions	(1,257)	(2,863)	-
Less: Severance Charges	149	(1,531)	-
Less: distribution to preferred units	12,188	12,054	-
Less: Other	97	475	(192)
Net cash provided by operating activities	**$ 38,830**	**$ 75,503**	**$ 18,867**
Distributable Cash Flow	47,478	51,422	22,436
Distributions for coverage ratio	$ 47,233	$ 47,225	$ -
Distributions reinvested in the DRIP	$ 218	$ 218	$ -
Distributions for cash coverage ratio	$ 47,014	$ 47,007	$ -
Adjusted distributable cash flow coverage ratio	1.01	1.09	N/A
Cash coverage ratio	1.01	1.09	N/A

Note: Three months ended March 30, 2018 reflects CDM standalone historical data due to reverse merger accounting treatment.

Non-GAAP Reconciliations, cont'd.

	Guidance
Net loss	$(18.0) million to $(8.0) million
Plus: Interest expense, net	$78.3 million
Plus: Depreciation and amortization	$216.3 million
Plus: Income tax expense	$(1.6) million
EBITDA	$275.0 million to $285.0 million
Plus: Interest income on capital lease	$0.7 million
Plus: Unit-based compensation expense (1)	$14.0 million
Plus: Transaction expenses and severance charges	$5.7 million
Plus: Loss on disposition of assets	$12.3 million
Plus: Impairment of compression equipment	$2.3 million
Adjusted EBITDA	$310.0 million to $320.0 million
Less: Cash interest expense	$74.0 million
Plus: Insurance proceeds	$0.3 million
Less: Preferred unit distribution	$36.4 million
Less: Current income tax expense	$0.3 million
Less: Maintenance capital expenditures	$29.6 million
Distributable Cash Flow	$170.0 million to $180.0 million

(1) Based on the Partnership's common unit closing price as of September 30, 2018.

Basis of Presentation; Explanation of Non-GAAP Financial Measures

This presentation includes the non-GAAP financial measures of Adjusted EBITDA, Adjusted EBITDA Margin Percentage, Distributable Cash Flow, Distributable Cash Flow Coverage Ratio and Cash Coverage Ratio, as well as horsepower utilization.

EBITDA, a measure not defined under U.S. generally accepted counting principles ("GAAP"), is defined by USAC as net income (loss) before net interest expense, income taxes, and depreciation and amortization expense. Adjusted EBITDA, which also is a non-GAAP measure, is defined by USAC as EBITDA plus impairment of compression equipment, impairment of goodwill, interest income on capital lease, unit-based compensation expense, restructuring/severance charges, management fees, expenses under our operating lease with Caterpillar, certain transaction fees, (gain)/loss on sale of assets and other. The Partnership's management views Adjusted EBITDA as one of its primary tools, to assess: (1) the financial performance of the Partnership's assets without regard to the impact of financing methods, capital structure or historical cost basis of the Partnership's assets; (2) the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities; (3) the ability of the Partnership's assets to generate cash sufficient to make debt payments and to make distributions; and (4) the Partnership's operating performance as compared to those of other companies in its industry without regard to the impact of financing methods and capital structure. The Partnership believes that Adjusted EBITDA provides useful information to investors because, when viewed with GAAP results and the accompanying reconciliations, it provides a more complete understanding of the Partnership's performance than GAAP results alone. Adjusted EBITDA Margin Percentage is calculated by USAC as Adjusted EBITDA divided by Revenue for the period presented. LTM Adjusted EBITDA is calculated by USAC as the sum of Adjusted EBITDA for the most recently completed fiscal year and the Adjusted EBITDA for the most recent fiscal year-to-date period for which we have provided an income statement, minus the Adjusted EBITDA for the corresponding year-to-date period of the preceding fiscal year.

Distributable Cash Flow, a non-GAAP measure, is defined as net income (loss) plus non-cash interest expense, non-cash income tax expense, depreciation and amortization expense, unit-based compensation expense, severance charges, impairment of compression equipment, impairment of goodwill, certain transaction fees, and (gain)/loss on sale of assets and other, less maintenance capital expenditures. The definition of Distributable Cash Flow is identical to the definition of Adjusted Distributable Cash Flow previously presented. The Partnership's management believes Distributable Cash Flow is an important measure of operating performance because it allows management, investors and others to compare basic cash flows the Partnership generates (prior to the establishment of any retained cash reserves by the Partnership's general partner and the effect of the Partnership's Distribution Reinvestment Plan) to the cash distributions the Partnership expects to pay its unitholders. See previous slides for Adjusted EBITDA reconciled to net income (loss) and net cash provided by operating activities, and net income (loss) reconciled to Distributable Cash Flow.

This presentation contains a forward-looking estimate of Adjusted EBITDA and Distributable Cash Flow projected to be generated by the Partnership in its 2018 fiscal year. A reconciliation of the forward-looking estimates of Adjusted EBITDA and Distributable Cash Flow to net cash provided by operating activities is not provided because the items necessary to estimate net cash provided by operating activities, in particular the change in operating assets and liabilities amounts, are not accessible or estimable at this time. The Partnership does not anticipate the changes in operating assets and liabilities amounts to be material, but changes in accounts receivable, accounts payable, accrued liabilities and deferred revenue could be significant, such that the amount of net cash provided by operating activities would vary substantially from the amount of projected Adjusted EBITDA and Distributable Cash Flow.

Adjusted EBITDA and Distributable Cash Flow should not be considered an alternative to, or more meaningful than, net income (loss), operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance and liquidity. Moreover, Adjusted EBITDA and Distributable Cash Flow as presented may not be comparable to similarly titled measures of other companies because other entities may not calculate such measures in the same manner.

The Partnership believes that external users of its financial statements benefit from having access to the same financial measures that management uses in evaluating the results of the Partnership's business. Further, the Partnership believes that these measures are useful to investors because they are one of the bases for comparing the Partnership's operating performance with that of other companies with similar operations.

Horsepower utilization is calculated as (i)(a) revenue generating HP plus (b) HP in the Partnership's fleet that is under contract, but is not yet generating revenue plus (c) HP not yet in the Partnership's fleet that is under contract, not yet generating revenue and is subject to a purchase order, divided by (ii) total available HP less idle HP that is under repair. Average utilization calculated as the average utilization for the months in the period based on utilization at the end of each month in the period.

Distributable Cash Flow Coverage Ratio, a non-GAAP measure, is defined as Distributable Cash Flow divided by distributions declared to common unitholders for the period. We define Cash Coverage Ratio as Distributable Cash Flow divided by cash distributions expected to be to common in respect of such period, after consideration of the non-cash impact of the DRIP. We believe Distributable Cash Flow Coverage Ratio and Cash Coverage Ratio are important measures of operating performance because they allow management, investors and others to gauge our ability to pay cash distributions to common unitholders using the cash flows we generate. Our Distributable Cash Flow Coverage Ratio and Cash Coverage Ratio as presented may not be comparable to similarly titled measures of other companies.