Investor Presentation

Q1 Fiscal 2017 Update

February 2, 2017

Safe Harbor For Forward Looking Statements

This presentation may contain "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995, including statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," and similar expressions. Forward-looking statements involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished.

In addition to other factors, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements: Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators; governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal; changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing; impairments under the SEC's full cost ceiling test for natural gas and oil reserves; changes in the price of natural gas or oil; financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions; factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; changes in price differentials between similar quantities of natural gas or oil at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations; other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date; the cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company; uncertainty of oil and gas reserve estimates; significant differences between the Company's projected and actual production levels for natural gas or oil; changes in demographic patterns and weather conditions; changes in the availability, price or accounting treatment of derivative financial instruments; changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services; the creditworthiness or performance of the Company's key suppliers, customers and counterparties; economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation; significant differences between the Company's projected and actual capital expenditures and operating expenses; changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities; or increasing costs of insurance, changes in coverage and the ability to obtain insurance.

Forward-looking statements include estimates of oil and gas quantities. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. Other estimates of oil and gas quantities, including estimates of probable reserves, possible reserves, and resource potential, are by their nature more speculative than estimates of proved reserves. Accordingly, estimates other than proved reserves are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosure in our Form 10-K available at www.nationalfuelgas.com. You can also obtain this form on the SEC's website at www.sec.gov.

For a discussion of the risks set forth above and other factors that could cause actual results to differ materially from results referred to in the forward-looking statements, see "Risk Factors" in the Company's Form 10-K for the fiscal year ended September 30, 2016 and the Forms 10-Q for the quarter ended December 31, 2016. The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date thereof or to reflect the occurrence of unanticipated events.

Quality Assets - Exceptional Location - Unique Integration

National Fuel®

Upstream

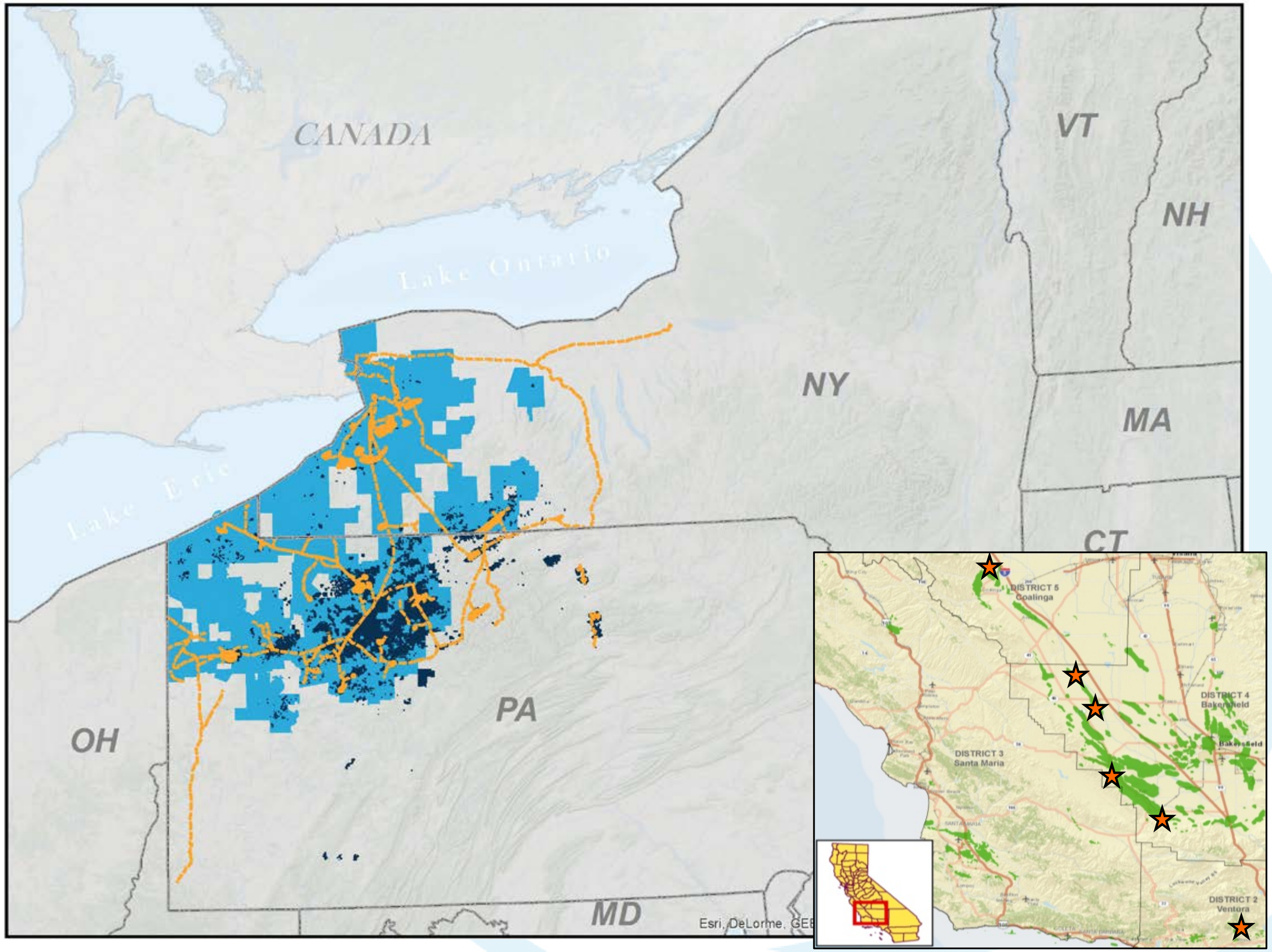
- 1.8 Tcfe Proved Reserves (1)
- 785,000 net acres in Appalachia - mostly held in fee with no royalty
- 3 million Bbls per year of crude oil production in California

Midstream

- $284 million annual adjusted EBITDA (2)
- $1.3+ billion midstream investments since 2010
- Coordinated gathering and transmission infrastructure build-out with NFG Upstream

Downstream

- 740,000 Utility customer accounts
- Stable, regulated earnings & cash flows
- Generates operational and financial synergies with other segments



(1) Total proved reserves are as of September 30, 2016. See slide 36 for further discussion .
(2) For the trailing twelve months ended December 31, 2016. A reconciliation of Adjusted EBITDA to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.

The National Fuel Value Proposition

National Fuel®

Considerable Upstream and Midstream Growth Opportunities in Appalachia

- ✓ Fee ownership on ~715,000 net acres in WDA = limited royalties or drilling commitments
- ✓ Seneca has >900,000 Dth/day of firm transportation & sales contracts by end of fiscal 2018
- ✓ Stacked pay potential in Utica and Geneseo shales across Marcellus acreage
- ✓ Coordinated gathering & interstate pipeline infrastructure build-out with NFG midstream
- ✓ Opportunity for further pipeline expansion to accommodate Appalachian supply growth

Unique Asset Mix and Integrated Model Provide Balance and Stability

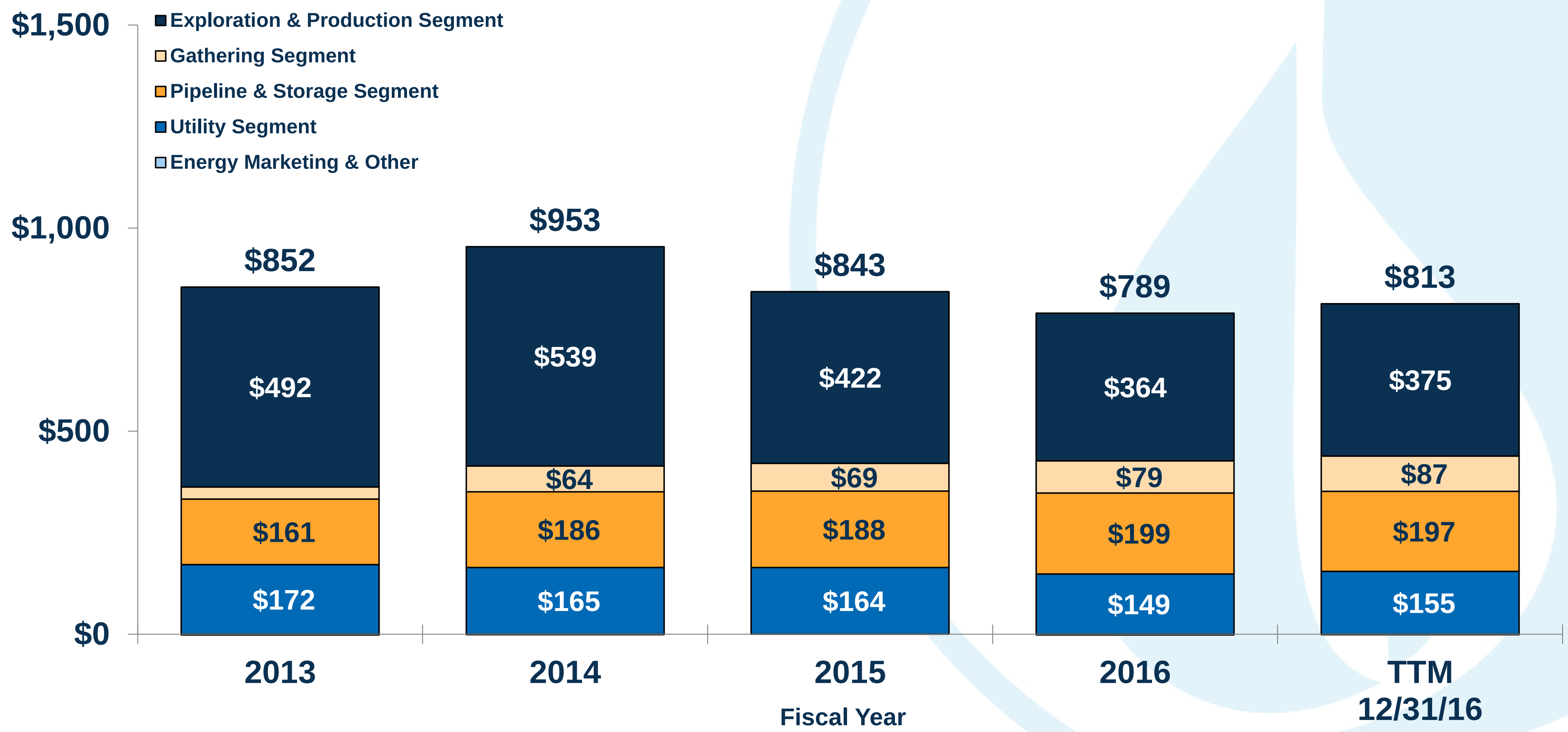
- ✓ Geographical and operational integration drives capital flexibility and reduces costs
- ✓ Investment grade credit rating and liquidity to support long-term Appalachian growth strategy
- ✓ Cash flow from rate-regulated businesses supports interest costs and funds the dividend

Disciplined Approach To Capital Allocation and Returns on Investment

- ✓ Capital allocation that is focused on earning economic returns
- ✓ Strong hedge book helps insulate near-term earnings and cash flows from commodity volatility
- ✓ **Creating long-term, sustainable value remains our #1 shareholder priority**

Balanced Earnings and Cash Flows

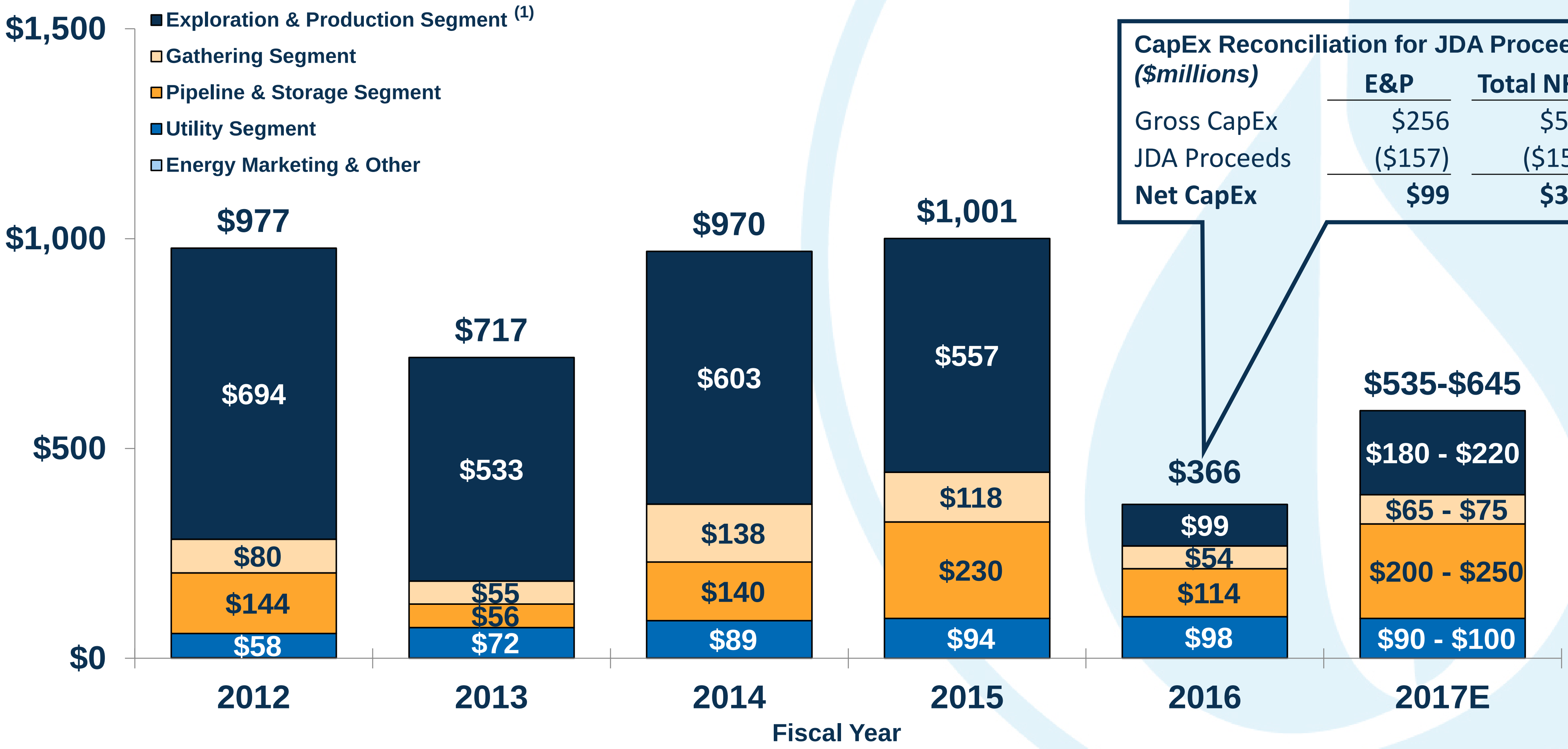
Adjusted EBITDA by Segment ($ millions)



Note: A reconciliation of Adjusted EBITDA to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.

Flexibility to Responsibly Deploy Capital

Capital Expenditures by Segment ($ millions)



CapEx Reconciliation for JDA Proceeds *($millions)*

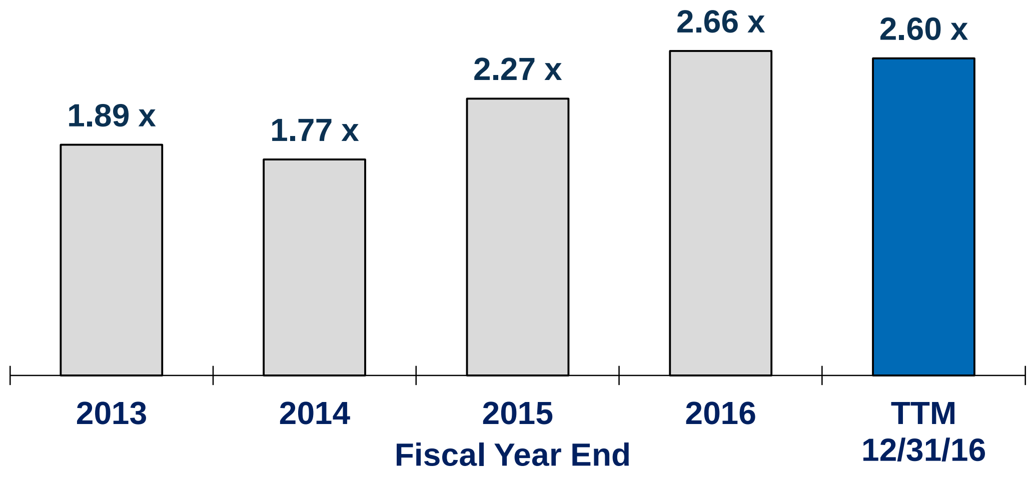
	E&P	Total NFG
Gross CapEx	$256	$523
JDA Proceeds	($157)	($157)
Net CapEx	**$99**	**$366**

(1) FY 2016 actual capital expenditures reflects the netting of $157 million of up-front proceeds received from joint development partner for working interest in joint development wells. FY 2017 guidance also reflects the netting of anticipated proceeds received from the joint development partner.

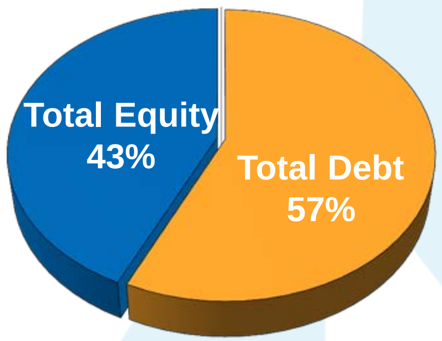
Note: A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

Strong Balance Sheet & Liquidity

Debt/Adjusted EBITDA

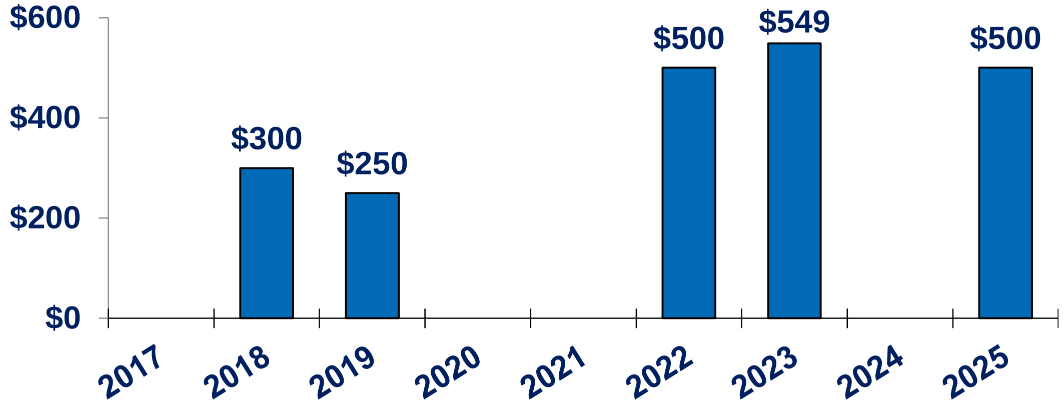


Capitalization



$3.7 Billion Total Capitalization as of December 31, 2016

Debt Maturity Profile ($MM)



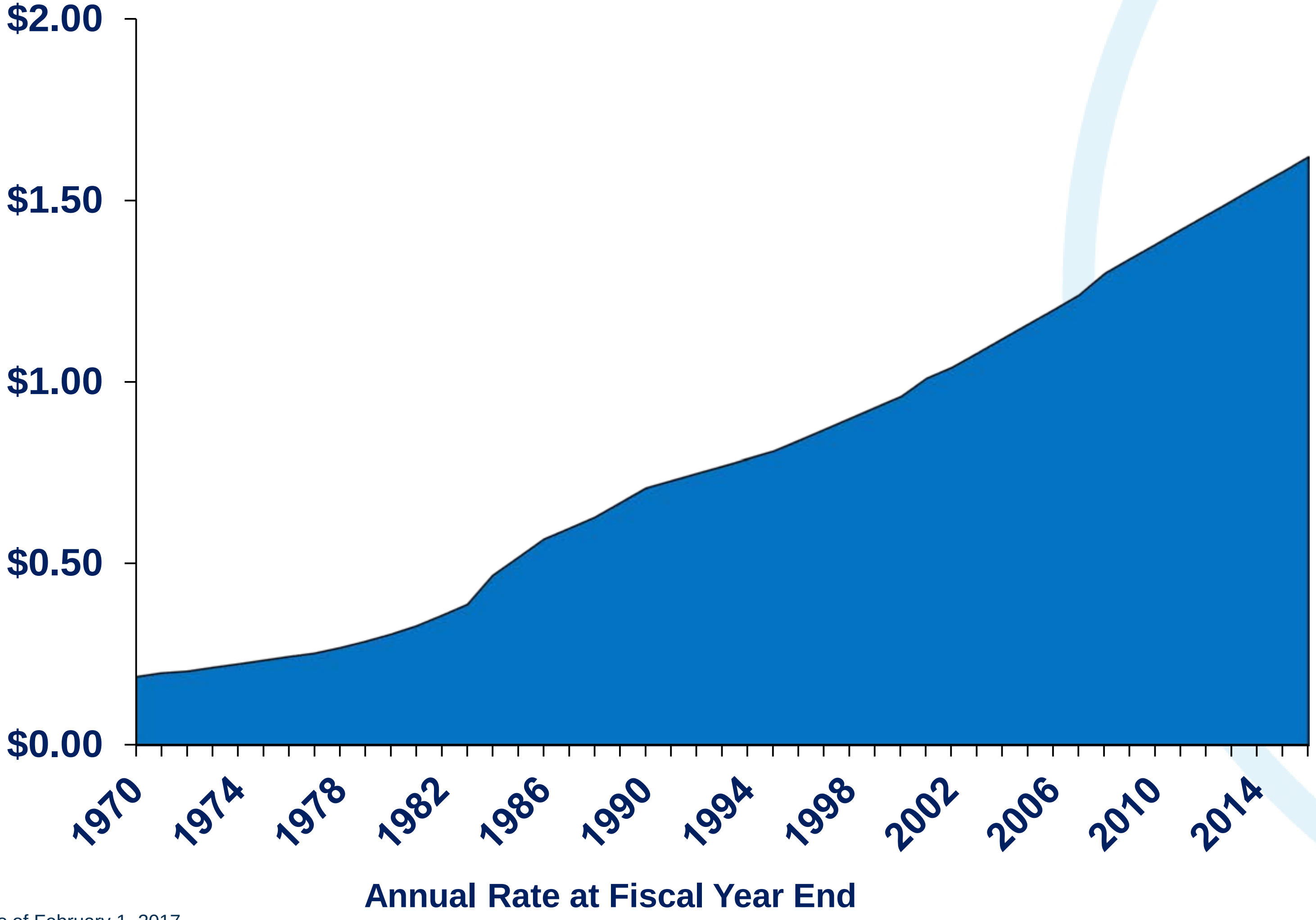
Liquidity

Committed Credit Facilities	$ 1,250 MM
Short-term Debt Outstanding	$ 0 MM
Available Short-term Credit Facilities	$ 1,250 MM
Cash Balance at 12/31/16	$ 136 MM
Total Liquidity at 12/31/16	**$ 1,386 MM**

Note: A reconciliation of Adjusted EBITDA to Net Income is included at the end of this presentation.

Dividend Track Record

Annual Dividend Rate ($ /share)



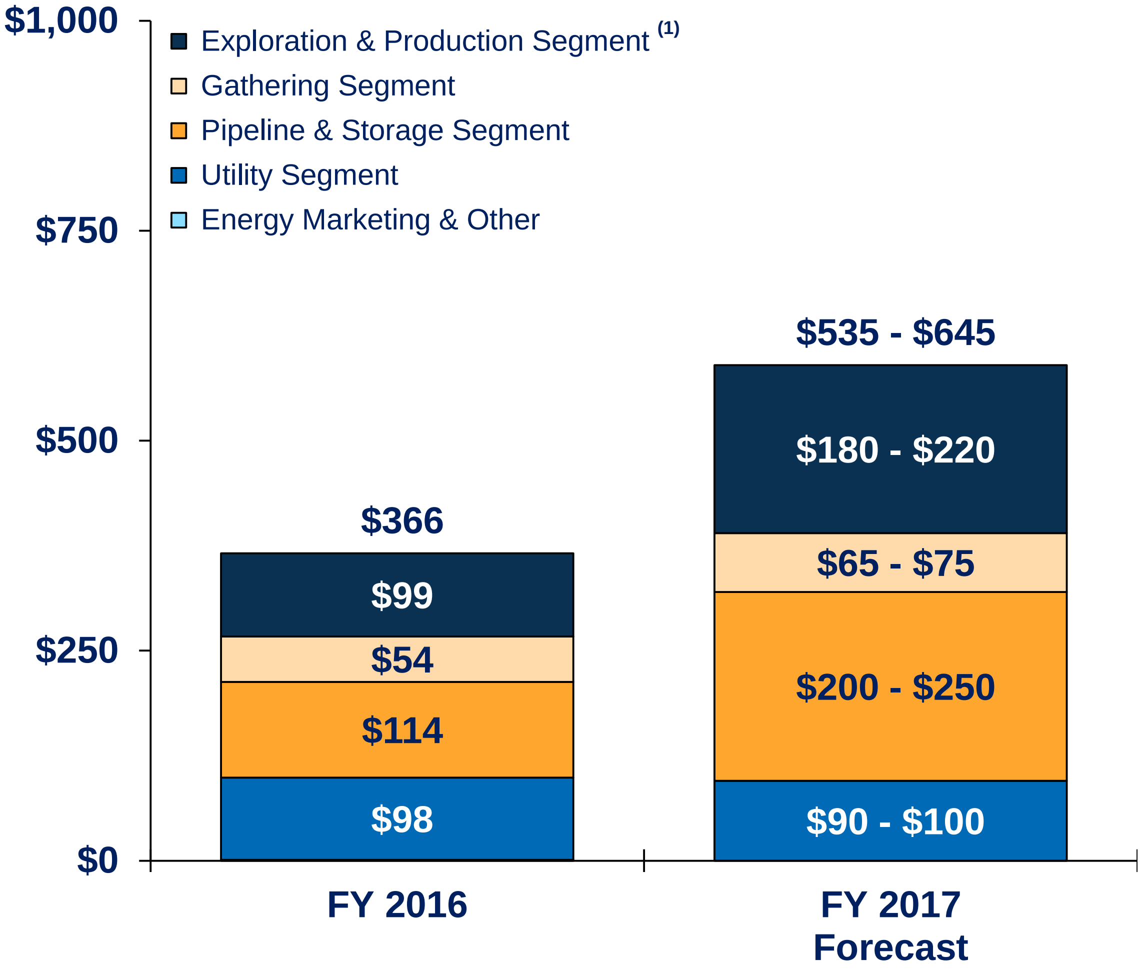
NFG's Dividend Consistency

Consecutive Payments	114 Years
Consecutive Increases	46 Years
Current Dividend Rate	$1.62 per Share
Current Dividend Yield (1)	2.9%

(1) As of February 1, 2017.

FY 2017 Capital Budget and Operating Plan

Capital Expenditures by Segment ($MM)



FY2017 Operating Plan Highlights

Upstream

- **Appalachia:**
  - Current activity: 1-rig program / daylight-only frac crew
  - Plans to add 2nd rig by end of fiscal 2017
  - Marcellus development pace designed to utilize new FT capacity in FY18
  - 10-well Utica appraisal program concurrent with Marcellus drilling
- **California:** $35- $45 million capex to keep production flat

Midstream

- **Gathering:** Just-in-time installation of gathering pipelines and compression facilities to accommodate Seneca production growth
- **Pipeline & Storage:** Construction of Northern Access (2Q FY18 in-service)
  - ~$125 million to be spent in FY17 ($455 million total project)
  - Federal and state regulatory approvals pending

Downstream

- **Utility:** Considering acceleration of pipeline replacement in NY from 90 miles to 110 miles per year

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Appalachia Overview

Exploration & Production ~ Gathering ~ Pipeline & Storage

Integrated Vision for Long-term Growth in Appalachia

Exploration & Production

1

Gathering

2

Pipeline & Storage

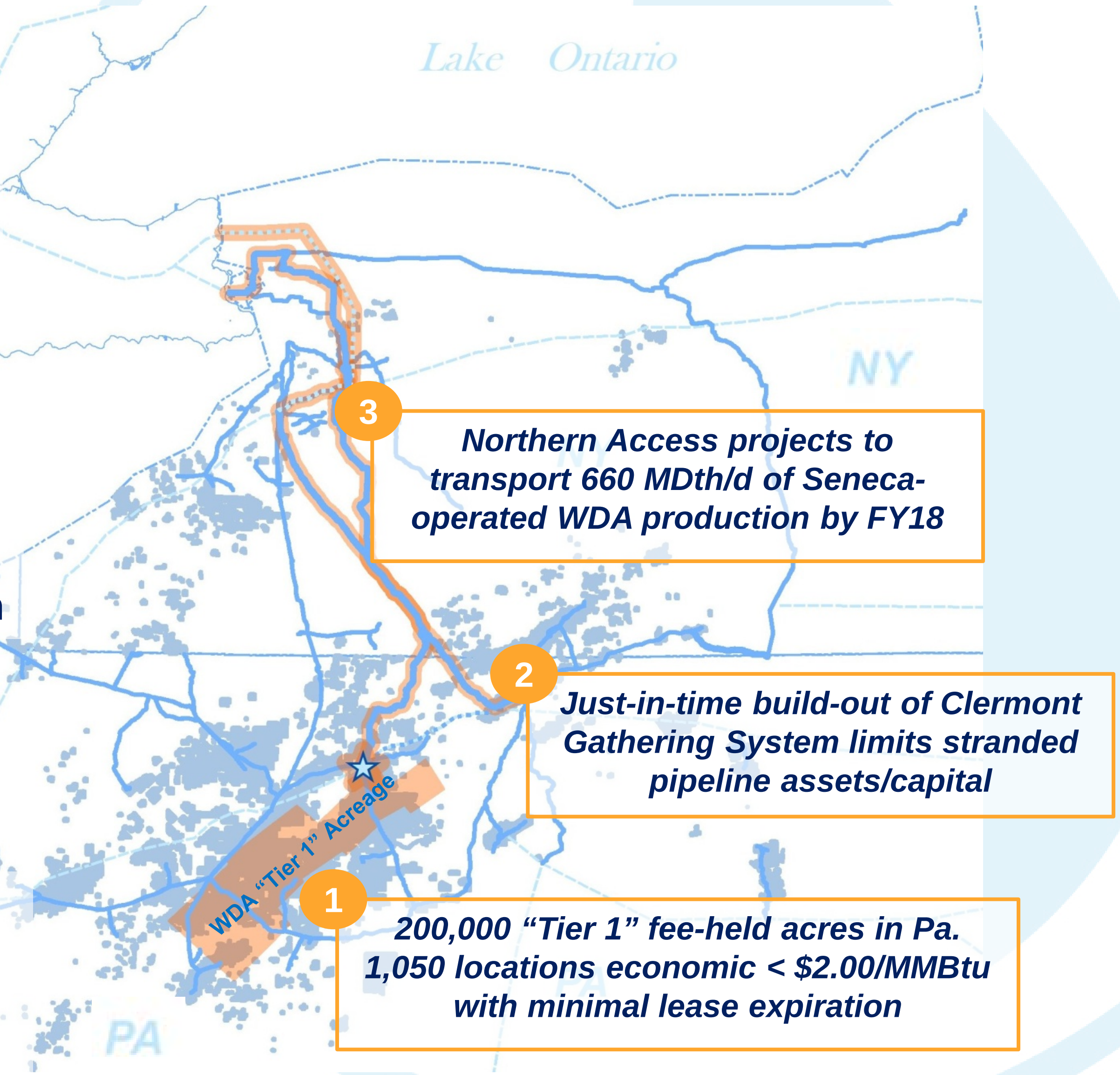
3

CANADA

Long-term, return-driven approach to developing vast Marcellus & Utica acreage position

Connecting Our Production to Our Interstate Pipeline System

Expanding Our Interstate Pipeline System to Reach Premium Markets



Significant Appalachian Acreage Position

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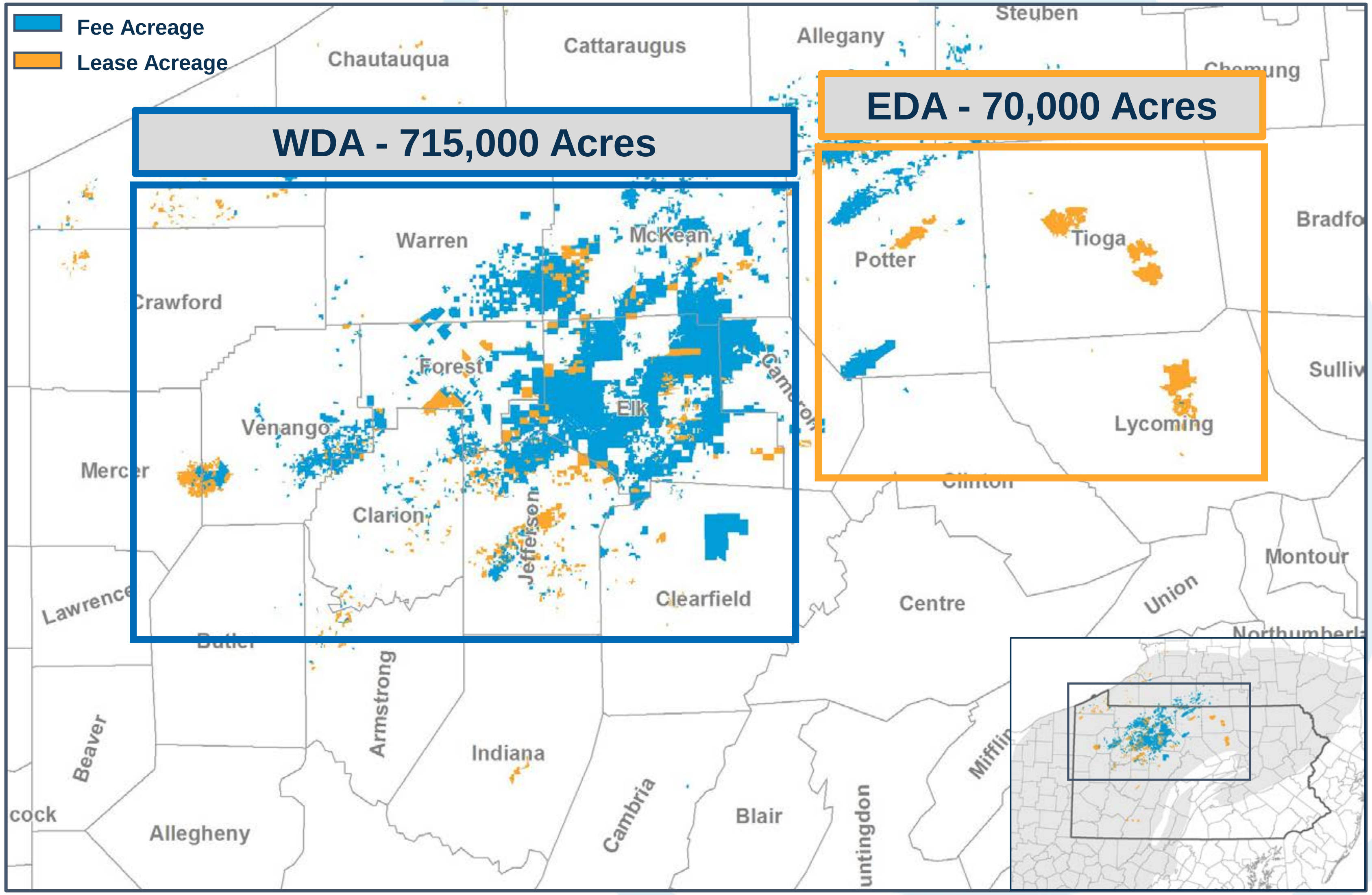
Western Development Area (WDA)

- 147 wells able to produce 310 MMcf/d
- Large inventory of high quality Marcellus acreage economic under $2.00/Mcf
- Fee ownership – lack of royalty enhances economics
- Highly contiguous nature drives cost and operational efficiencies
- 660 MDth/d firm transportation by FY18

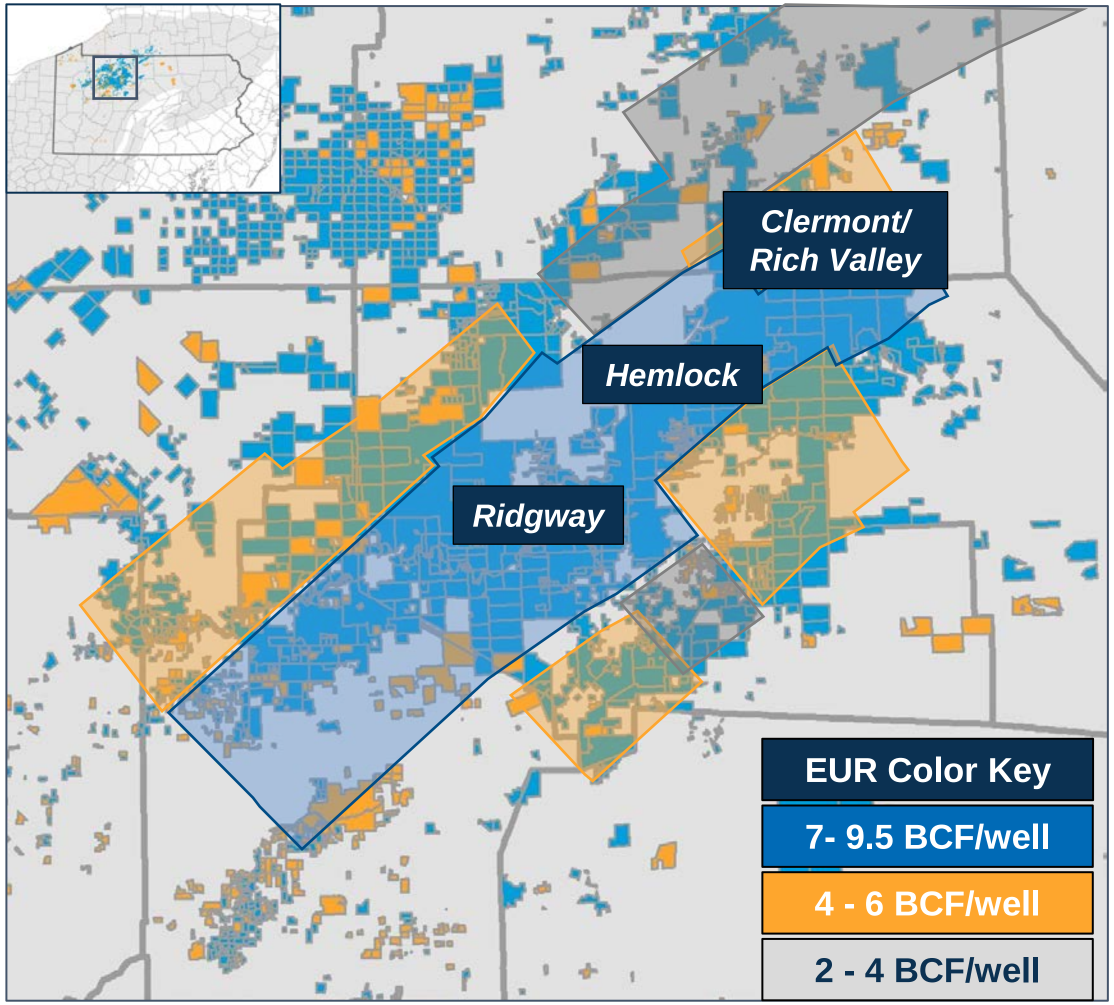
Eastern Development Area (EDA)

- 155 wells able to produce 294 MMcf/d
- Mostly leased (16-18% royalty) with no significant near-term lease expirations
- > 100 remaining Marcellus and Utica locations economic under $1.80/Mcf
- Additional Utica & Geneseo potential
- Limited development drilling until firm transportation on Atlantic Sunrise is available in mid-2018



Marcellus Shale: Western Development Area

WDA Tier 1 Acreage – 200,000 Acres



WDA Highlights

- ✓ **Large drilling inventory of quality Marcellus dry gas**
  - ~1,100 locations economic < $2.00/MMBtu realized
- ✓ **Fee acreage provides flexibility / enhances economics**
  - No royalty on most acreage
  - No lease expirations or requirements to drill acreage
- ✓ **Highly contiguous position drives best in class Marcellus well costs**
  - Multi-well pad drilling averaging 10 wells with 8,000 ft. laterals
  - Water management operations lowering water costs to under $1 /Bbl
- ✓ **NFG midstream infrastructure supporting growth**
  - NFG Clermont gathering system
  - NFG Northern Access projects 660 MDth/d firm transport to Dawn (Canada) and Midwest and northeast US markets
- ✓ **Early Utica test results in CRV on trend with other Utica wells in NE Pa.**
  - Will have 10 Utica test wells on-line by end of FY 2018

WDA Tier 1 Marcellus Economics(1)

	Locations Remaining	Avg Lateral Length (ft)	Avg EUR (Bcf)	$3.00 NYMEX/Dawn IRR%	15% IRR Realized Price
CRV	50	8,000	8.5-9.5	29%	$1.77
Hemlock/Ridgway	631	8,800	8-9	32%	$1.76
Other Tier 1	406	8,500	7-8	27%	$1.89

(1) Internal rate of return (IRR) is pre-tax and includes estimated well costs under the current well design and cost structure and projected firm transportation, gathering, LOE and other operating costs.

WDA Clermont/Rich Valley Development

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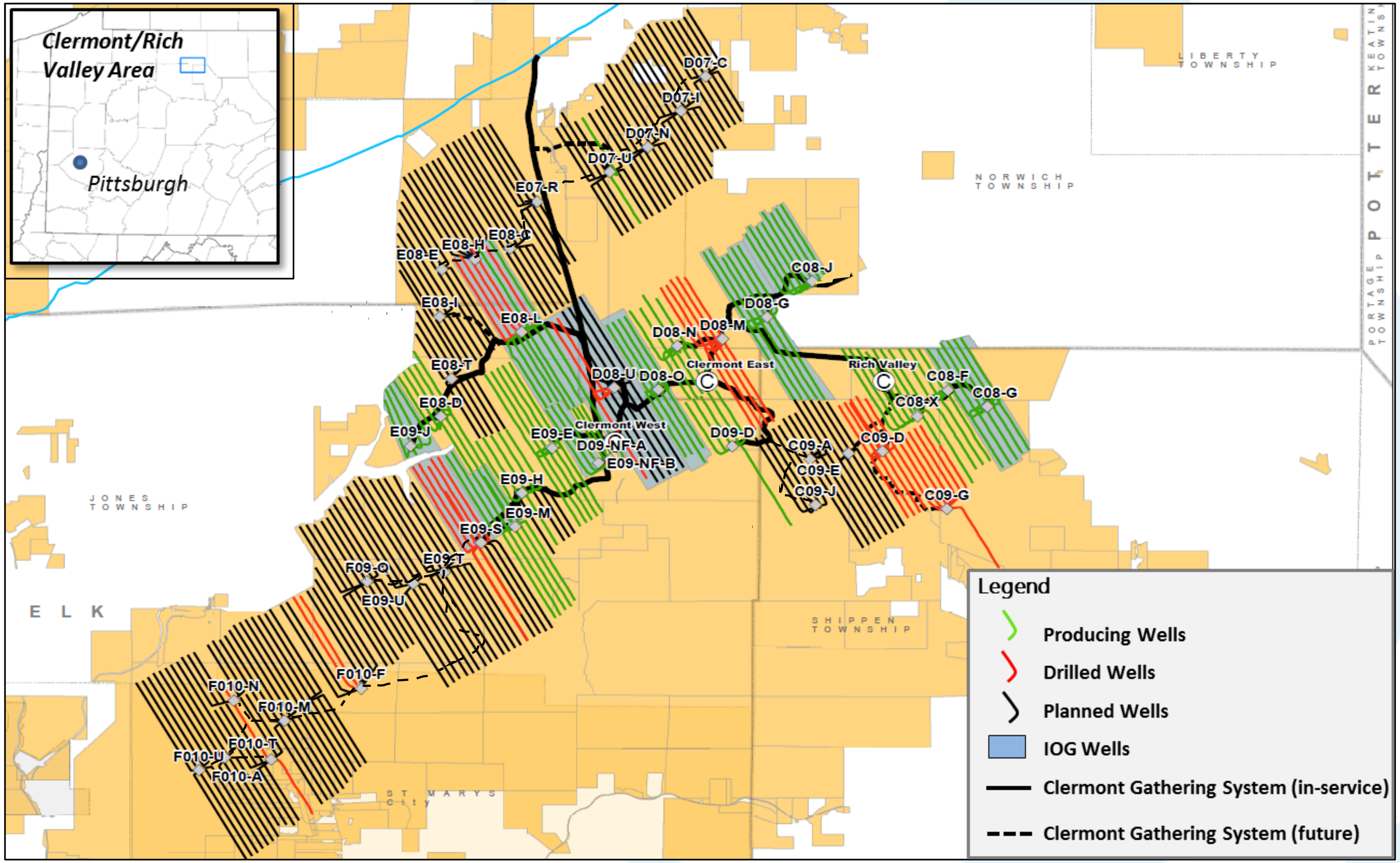
CRV Development Summary

- 125 wells able to produce 300 MMcf/d
- Dropped to 1 rig in March 2016 (down from 3 rigs at start of fiscal 2016)
- Rig additions planned at the end of FY17 and in FY18 to ramp-up production inventory to grow into Northern Access 2016 capacity
- Developing 75 wells with joint development partner (IOG)
  - 66 wells drilled
  - 58 wells online/producing
- Just-in-time gathering infrastructure build-out provides significant capital flexibility to adjust scheduling and pace of Seneca's development program
- Regional focus of development minimizes capital outlay and improves returns



Marcellus Shale: Eastern Development Area

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EDA Highlights

1 Covington & DCNR Tract 595 (Tioga Co., Pa.)

- Marcellus locations fully developed
- 92 wells(1) with 92 MMcf/d productive capacity
- 75-100 MDth/d firm sales (gross) in FY17
- Production flows into NFG Covington Gathering System
- Opportunity for future Geneseo & Utica development

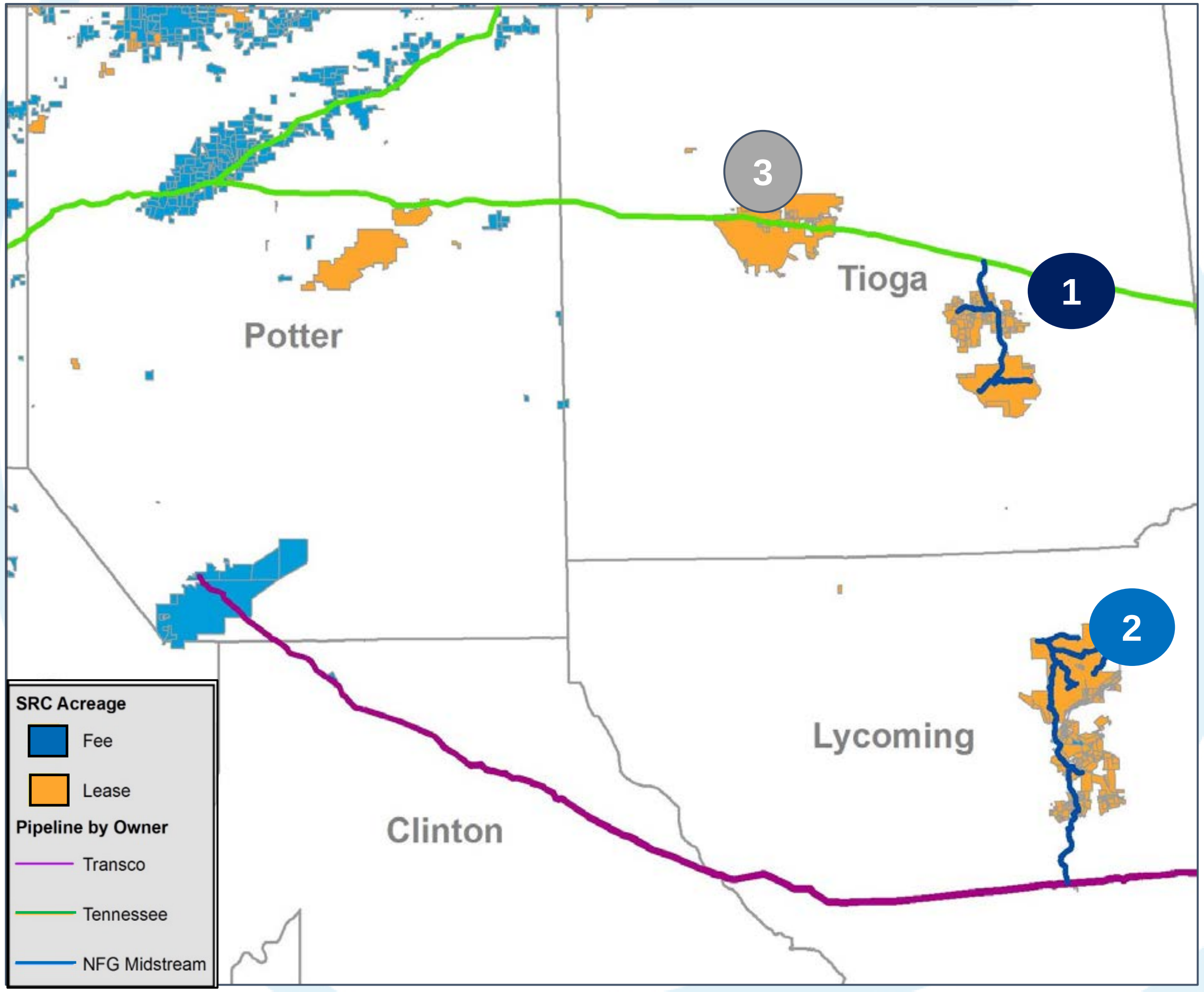
2 DCNR Tract 100 & Gamble (Lycoming Co., Pa.)

- 61 wells(1) with 202 MMcf/d productive capacity
- 130-190 MDth/d firm sales (gross) in FY17
- Atlantic Sunrise capacity (190 MDth/d) in mid-2018
- 55 remaining Marcellus locations economic < $1.60 /Mcf
- Production flows into NFG Trout Run Gathering System
- Geneseo well 24 IP test: 14.1MMcf/d on 4,920' lateral
- Geneseo to provide 100-120 additional locations

3 DCNR Tract 007 (Tioga Co., Pa)

- 1 Utica and 2 Marcellus exploration wells
- Utica 24hr IP = 22.7 MMcf/d; Marcellus 24hr IP = 11.7 MMcf/d
- Resource potential >1.1 Tcf over 75+ well locations
- New gathering system placed in-service Nov. 2016

EDA Acreage – 70,000 Acres



(1) One well included in the total for both Tract 595 and Tract 100 is drilled into and producing from the Geneseo Shale.

Best in Class Marcellus Well Costs

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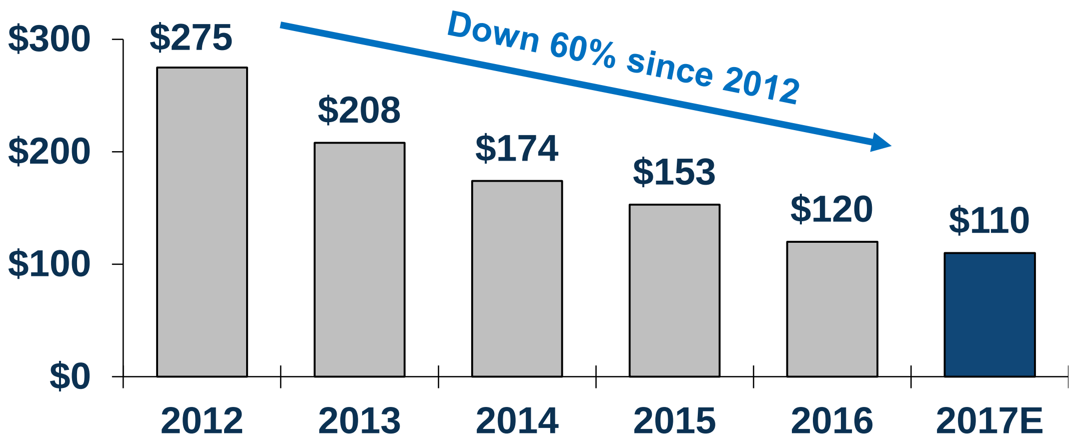
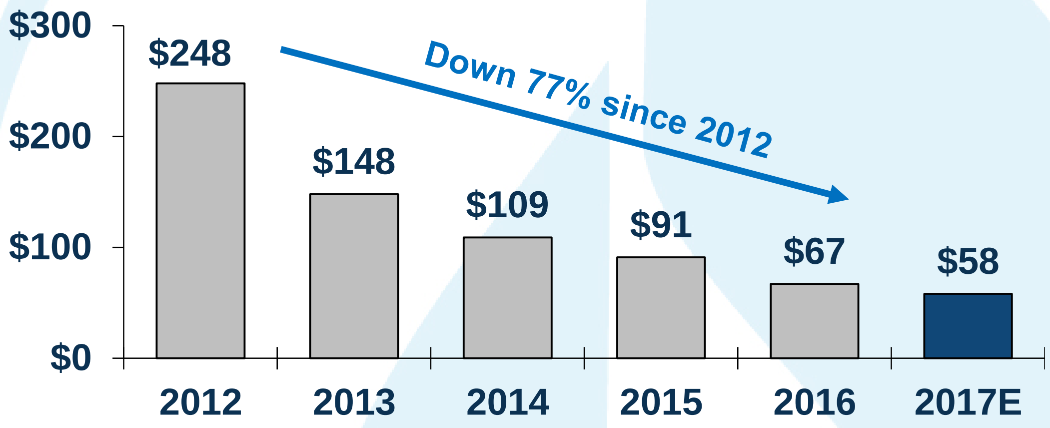
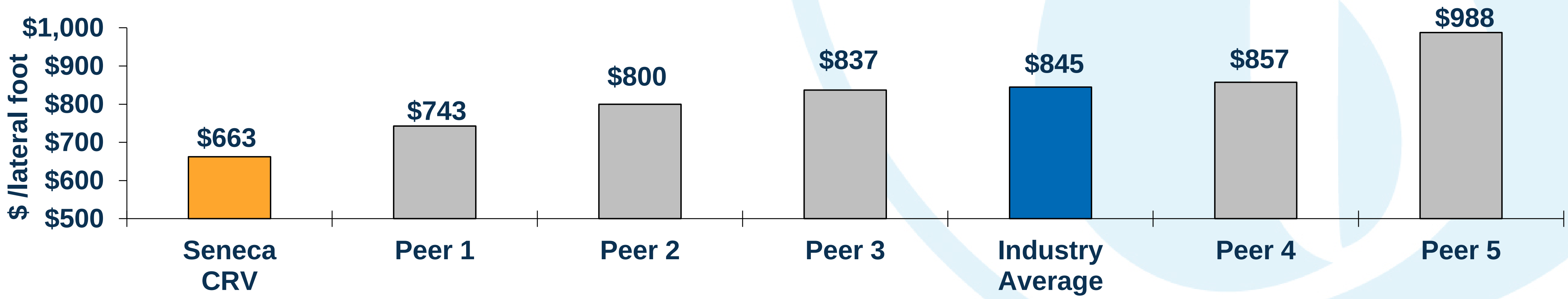
Marcellus Drilling Cost per Foot



Marcellus Completion Cost per Stage ($000s)



Seneca Average Marcellus Well Cost(1) vs. Appalachian Peers (2)



(1) Seneca CRV reflects a $5.3 million "all-in" total well cost for a 8,000 ft. lateral. Total well costs include drilling, completions, allocated pad level and production equipment.
(2) Appalachian peers include AR, COG, EQT, RICE, & RRC. Data obtained or recalculated from most recent peer company presentations.

Utica Shale Opportunities

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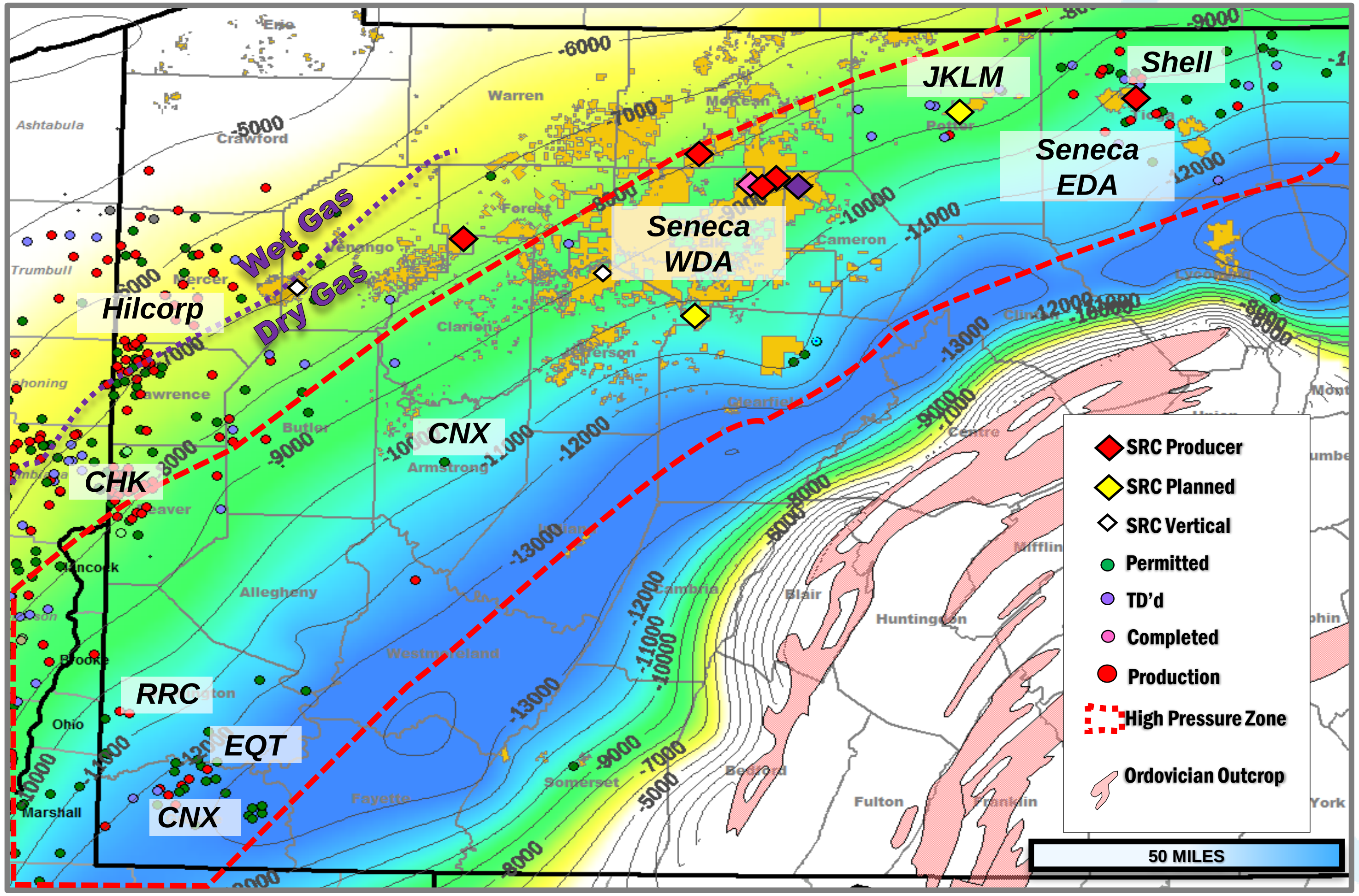
Pennsylvania Utica Activity



Seneca's Utica Opportunities

Seneca's Utica Activity on Trend with Strong Results in Northern Pa.

Western Development Area

- ✓ First 2 Utica test wells in Clermont / Rich Valley area are exceeding Marcellus performance
- ✓ Executing 10 well appraisal program over next 18 months
- ✓ Economics enhanced by 100% net revenue interest (no royalty) and ability to use existing infrastructure

Eastern Development Area

- ✓ 1st test well producing on DCNR 007 in Tioga County among the best in Northeastern Pa.
- ✓ Industry activity in Tioga and Potter Counties suggest strong Utica potential on other EDA prospects

WDA Utica Update

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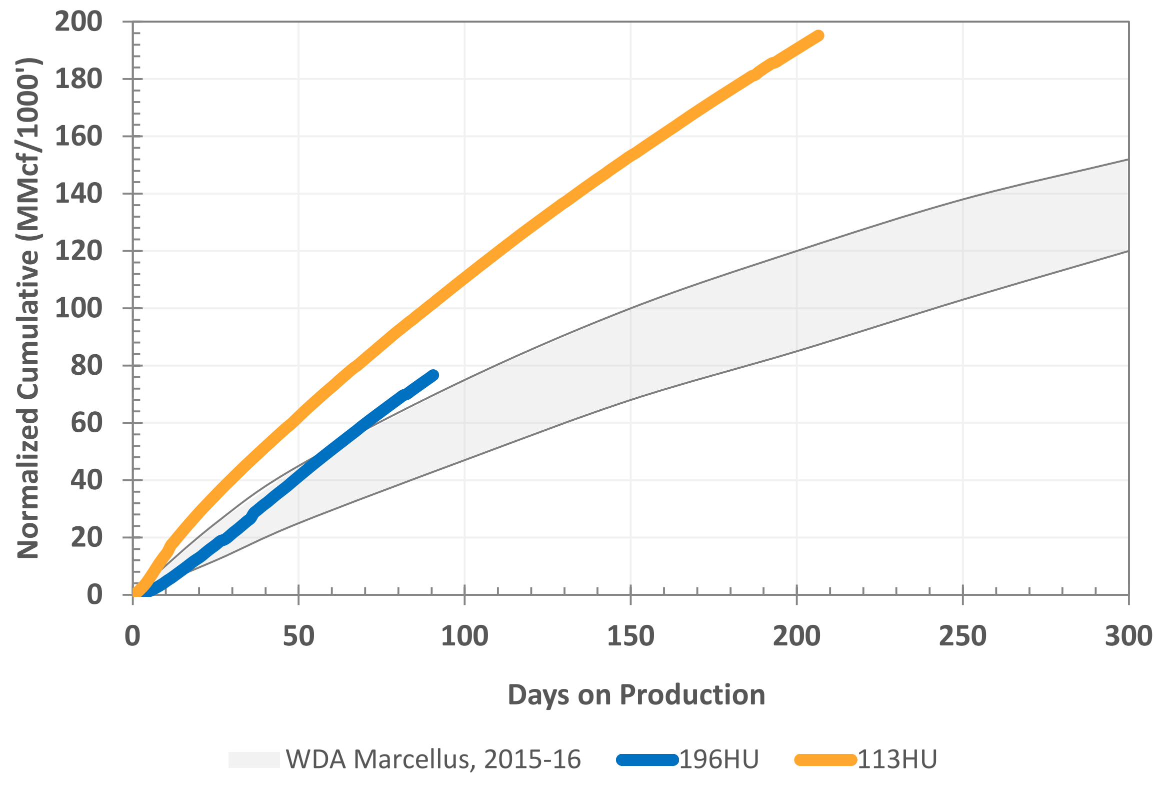
Initial Utica Test Wells in WDA CRV area Exceeds Marcellus Performance

Results: WDA Utica Results (1) vs Avg WDA Marcellus



	WDA-CRV Utica Test Wells		WDA-CRV Marcellus Wells (Average)
	Well 113HU	Well 196HU(1)	113 wells
Initial Test	June 2016	Nov 2016	
Lateral Length	4,630 ft	6,288 ft	7,115 ft
Choke Avg (/64th)	35/64th	28/64th	64/64th
30 Day IP /1,000 ft	1.4 MMcf/d	1.0 MMcf/d	0.8 MMcf/d
Est. EUR /1,000 ft	1.8 Bcf	1.65 - 1.8 Bcf	1.1 Bcf

- ✓ Early economic indicators:
  - 50 - 60% higher production / EUR
  - 25 - 35% increase in Upstream capital per well
- ✓ Will use existing Upstream pad and water facilities and Gathering infrastructure from current Marcellus development to drive efficiencies
- ✓ Can utilize existing and future contracted firm transport capacity (Niagara Expansion and Northern Access)

(1) Managed pressure drawdown of 196HU resulted in depressed early-time metrics.

WDA Utica Appraisal Program

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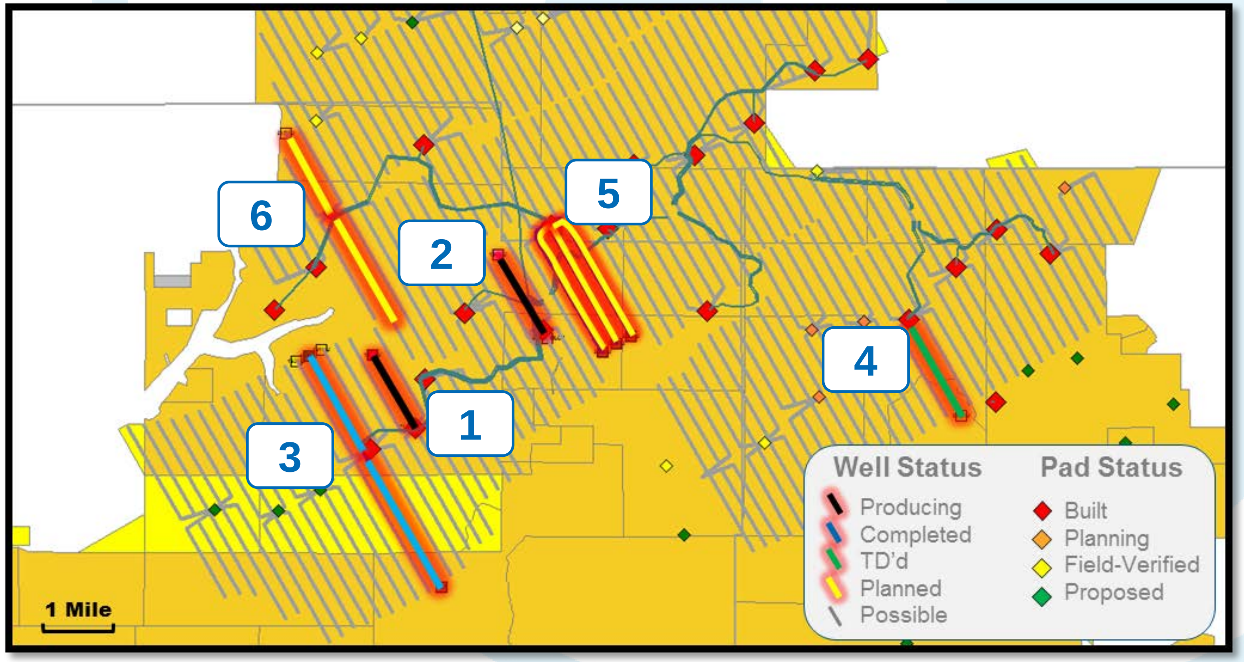
Short Term Plan Forward

- ✓ Plan to drill 10 total Utica appraisal wells off Marcellus development pads
- ✓ 2 wells producing, 2 completed, 1 drilled
- ✓ Optimize target zone and D&C design
- ✓ Can leverage existing upstream and midstream infrastructure to drive capital, operation and transportation cost efficiencies
- ✓ Expect Utica CRV WDA development costs to range from $5.0 to $6.0 million per well

WDA UTICA TESTING TIMELINE

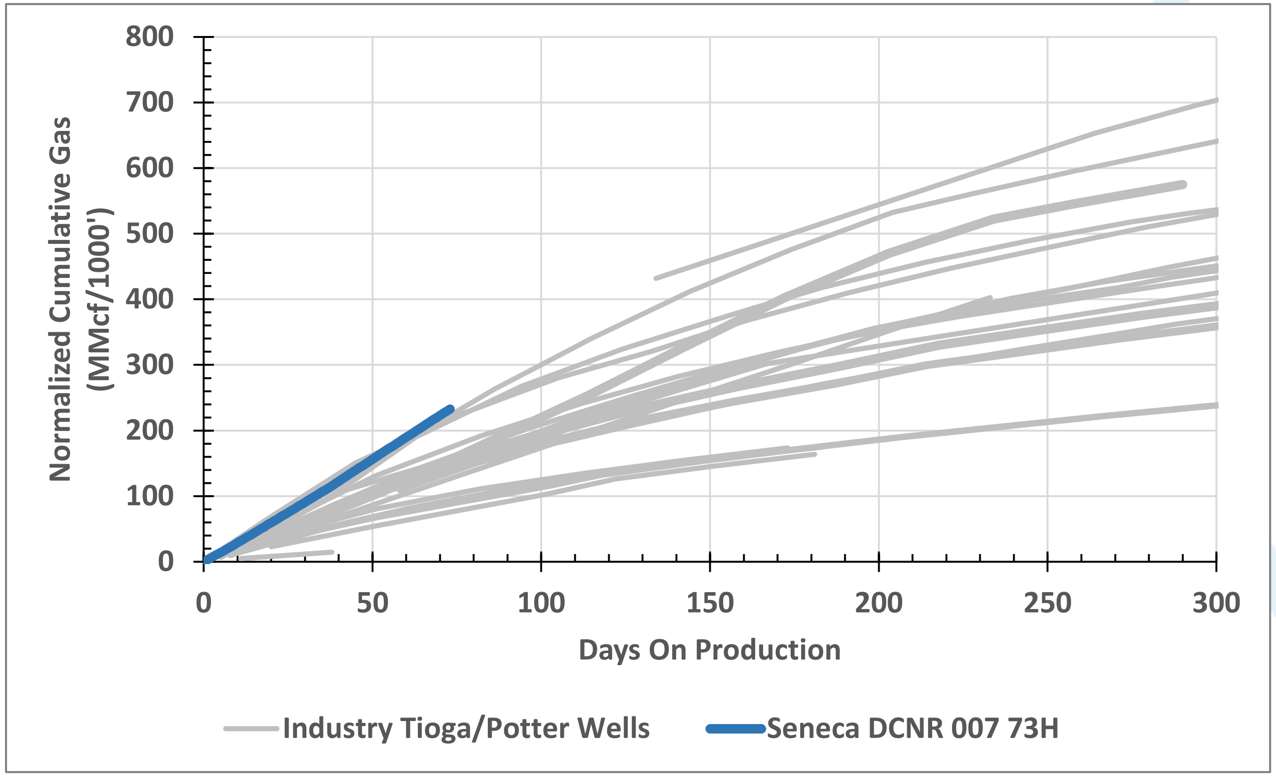
	Pad	# Wells	Status	Test	Timing (FY)
1	E09-M	1	Producing	Initial	On-line
2	NF-A	1	Producing	Sand	On-line
3	E09-S	2	Completed	Target	Q3 '17
4	C09-D	1	TD'd	Step-out	Q3 '17
5	D08-U	3	Planned	Target	Q2 '18
6	E08-T	2	Planned	Step-out	Q4 '18



EDA Utica Update

Seneca DCNR 007 Utica Well Among the Best in Northeastern PA

Northeast PA Utica Well Performance – Tioga and Potter County



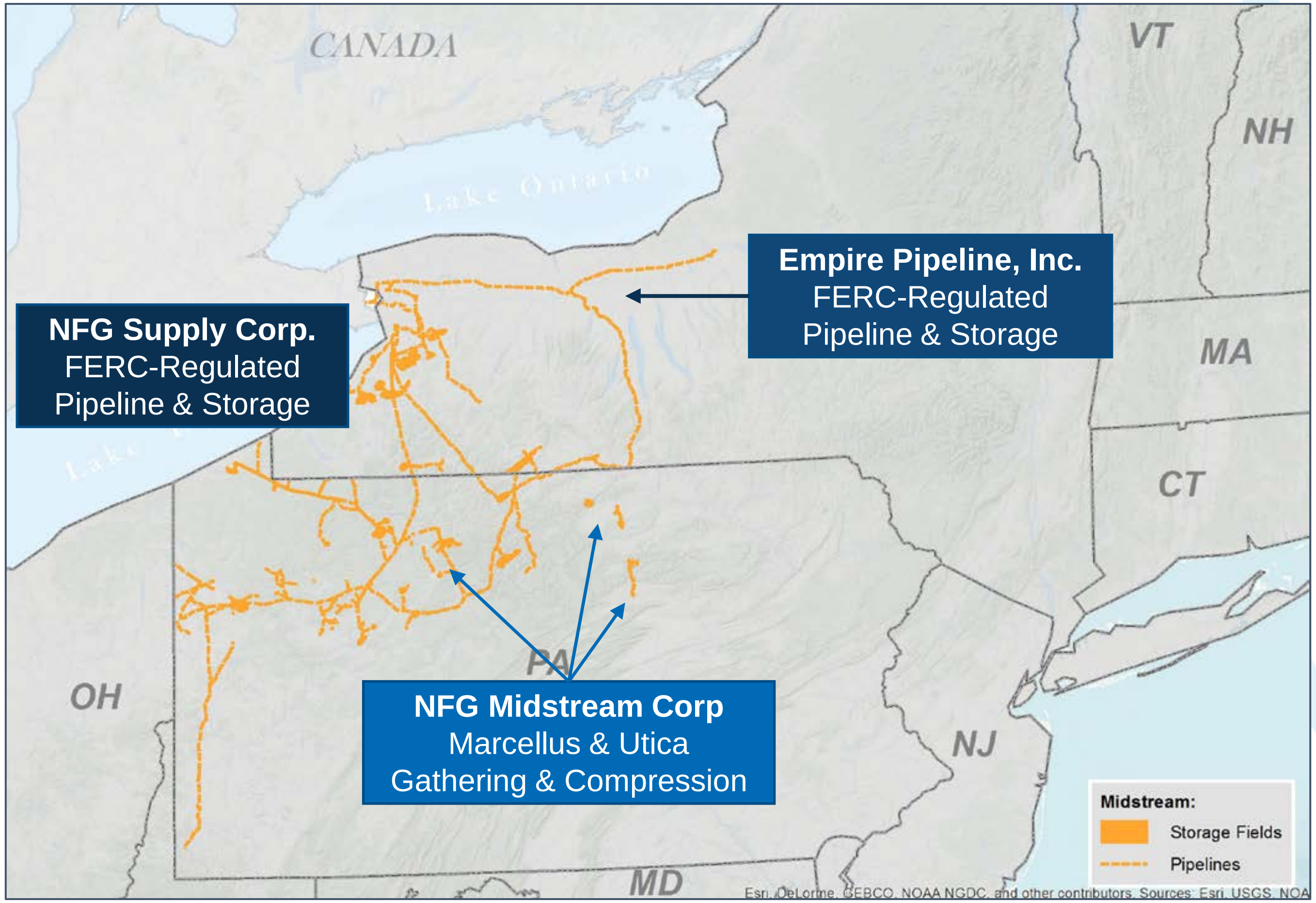
Source: PA DEP. Includes production from 19 Potter and Tioga County wells

	SRC EDA – Tract 007 Utica Test Well
Gathering Line In-Service	November 2016
Lateral Length	4,640 ft
30 Day IP /1,000 ft	3.4 MMcf/d
Est. EUR /1,000 ft	2.4 Bcf

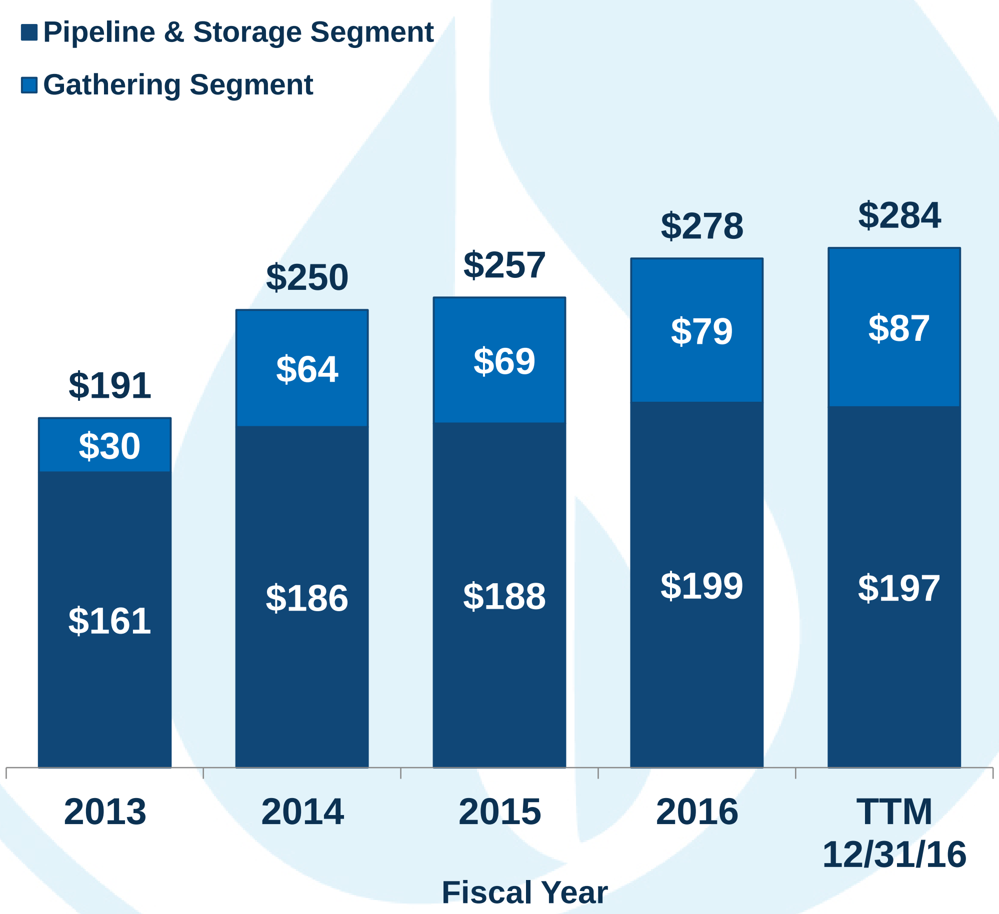
- ✓ Utica DCNR 007 development expected in 2018
- ✓ Up to 75 development locations delivering 1 Tcf recoverable resource
- ✓ Expect development costs to range from $5.5 to $6.5 million per well
- ✓ Midstream infrastructure:
  - NFG Midstream Wellsboro Gathering System
  - Interconnect with Tennessee Gas Pipeline 300
  - Evaluating long-term takeaway options

Midstream Businesses

Midstream Businesses System Map



Midstream Businesses Adjusted EBITDA ($MM)



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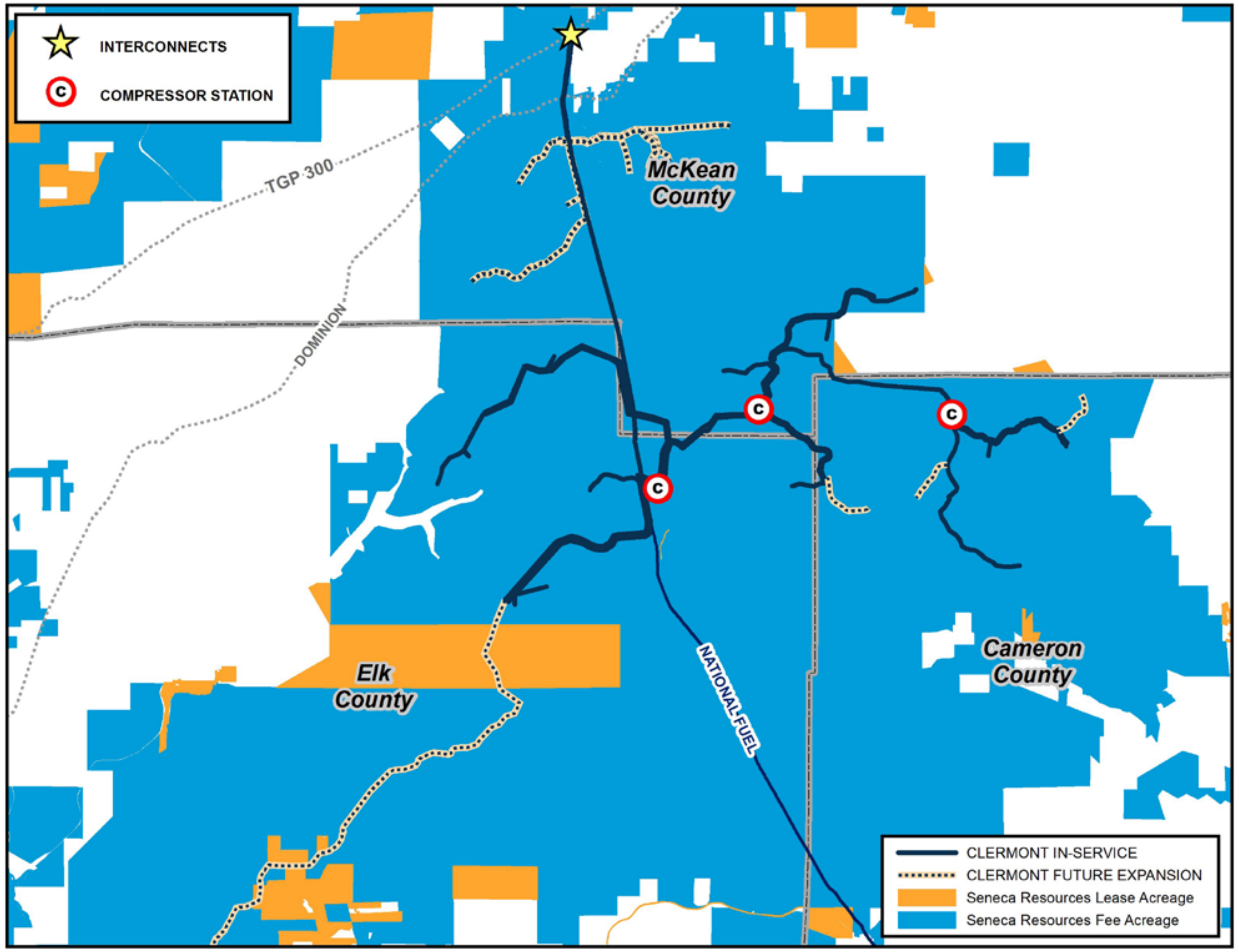
Integrated Development – WDA Gathering System

National Fuel

Gathering System Build-Out Tailored to Accommodate Seneca's WDA Development

Clermont Gathering System Map



Current System In-Service

- ~70 miles of pipe/26,220 HP of compression
- Current Capacity: 470 MMcf per day
- Interconnects with TGP 300
- Total CapEx To Date: $270 million

Fiscal 2017 Capital Plans

- FY17 CapEx: $30 to $40 million
- Adjusted timing of gathering & compression investment to match Seneca's modified development schedule/Northern Access

Future Build-Out

- Ultimate capacity can exceed 1 Bcf/d
- Over 300 miles of pipelines and five compressor stations (+60,000 HP installed)
- Deliverability into TGP 300 and NFG Supply

Integrated Development – EDA Gathering Systems

Gathering Segment Supporting Seneca's EDA Production & Future Development

Covington Gathering System

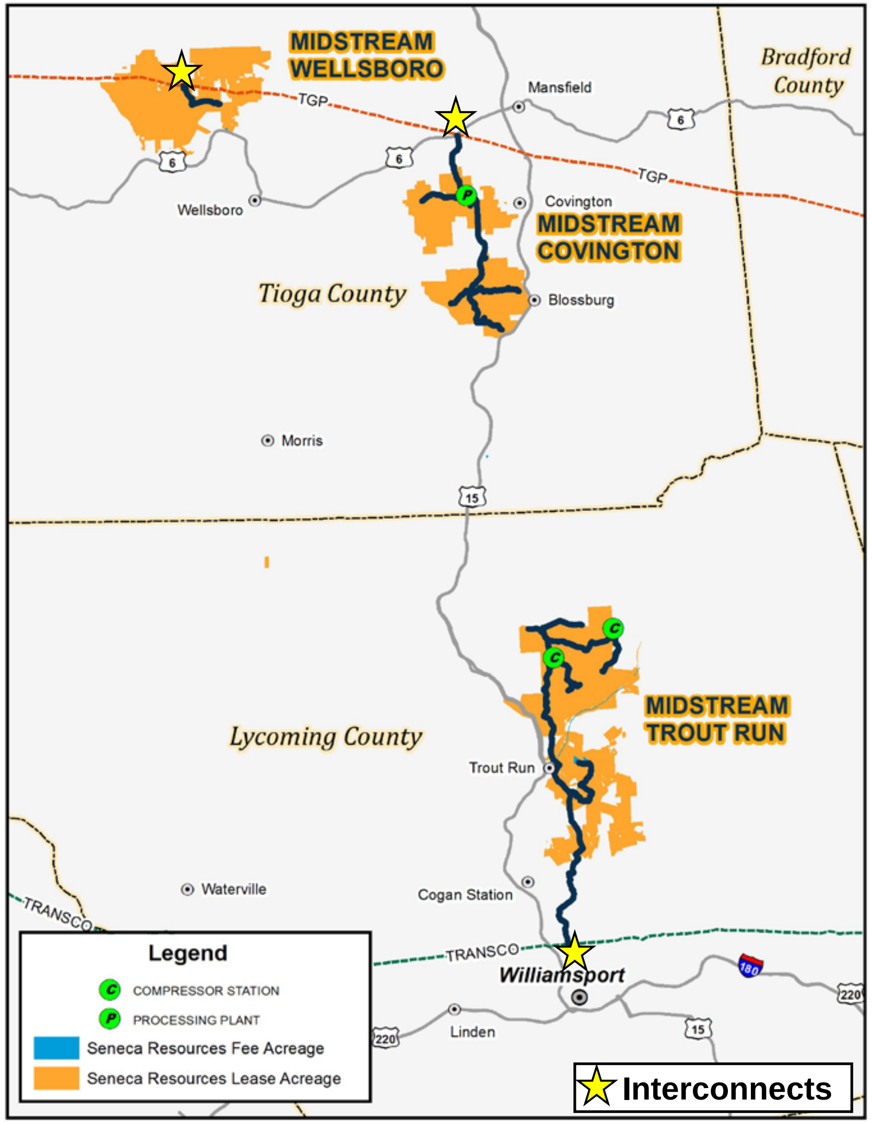
- **Capital Expenditures (to date):** $33 Million
- **Capacity:** 220,000 Dth per day
- **Production Source**: Seneca Resources – Tioga Co. (Covington and DCNR Tract 595 acreage)
- **Facilities:** Pipelines and dehydration

Trout Run Gathering System

- **Capital Expenditures (to date):** $168 Million
- **Capacity:** 466,000 to 585,000 Dth per day
- **Production Source:** Seneca Resources – Lycoming Co. (DCNR Tract 100 and Gamble acreage)
- **Facilities:** Pipelines, compression, and dehydration
- Future third-party volume opportunities

Wellsboro Gathering System

- **Capacity:** 200,000 Dth per day
- **Production Source:** Seneca Resources – DCNR Tract 007



Northern Access Expansions for Seneca Resources

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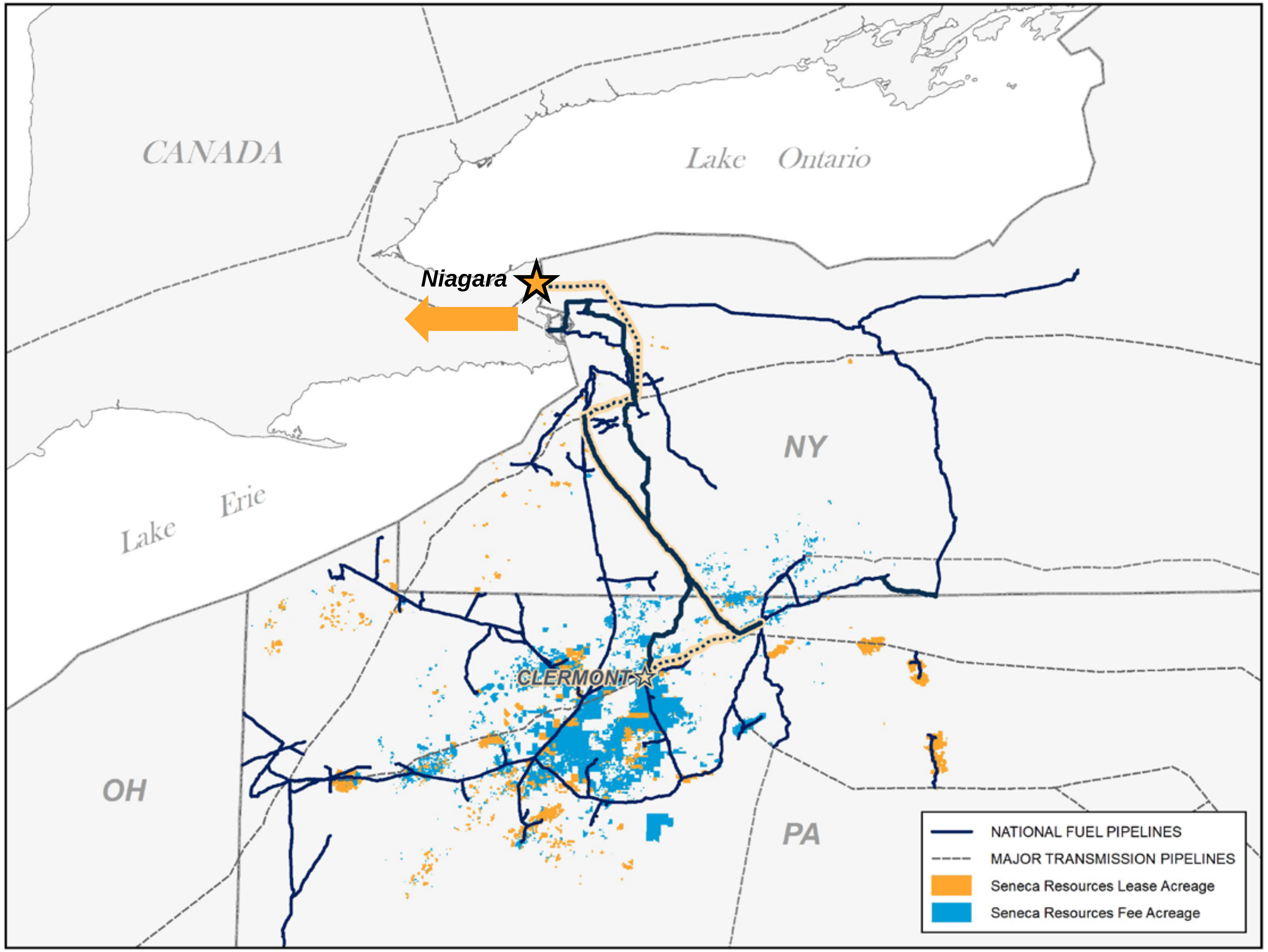
Expanding Our Pipelines to Integrate Seneca's WDA Production Into Broader Interstate System

Northern Access 2015

- Customer: Seneca Resources (NFG)
- In-Service: November 2015[(1)]
- System: NFG Supply Corp.
- Capacity: 140,000 Dth per day
  - Leased to TGP as part of TGP's Niagara Expansion project
- Delivery Interconnect:
  - Niagara (TransCanada)
- Major Facilities:
  - 23,000 hp Compression
- Total Cost: $67.1 million
- Annual Revenues: $13.3 million



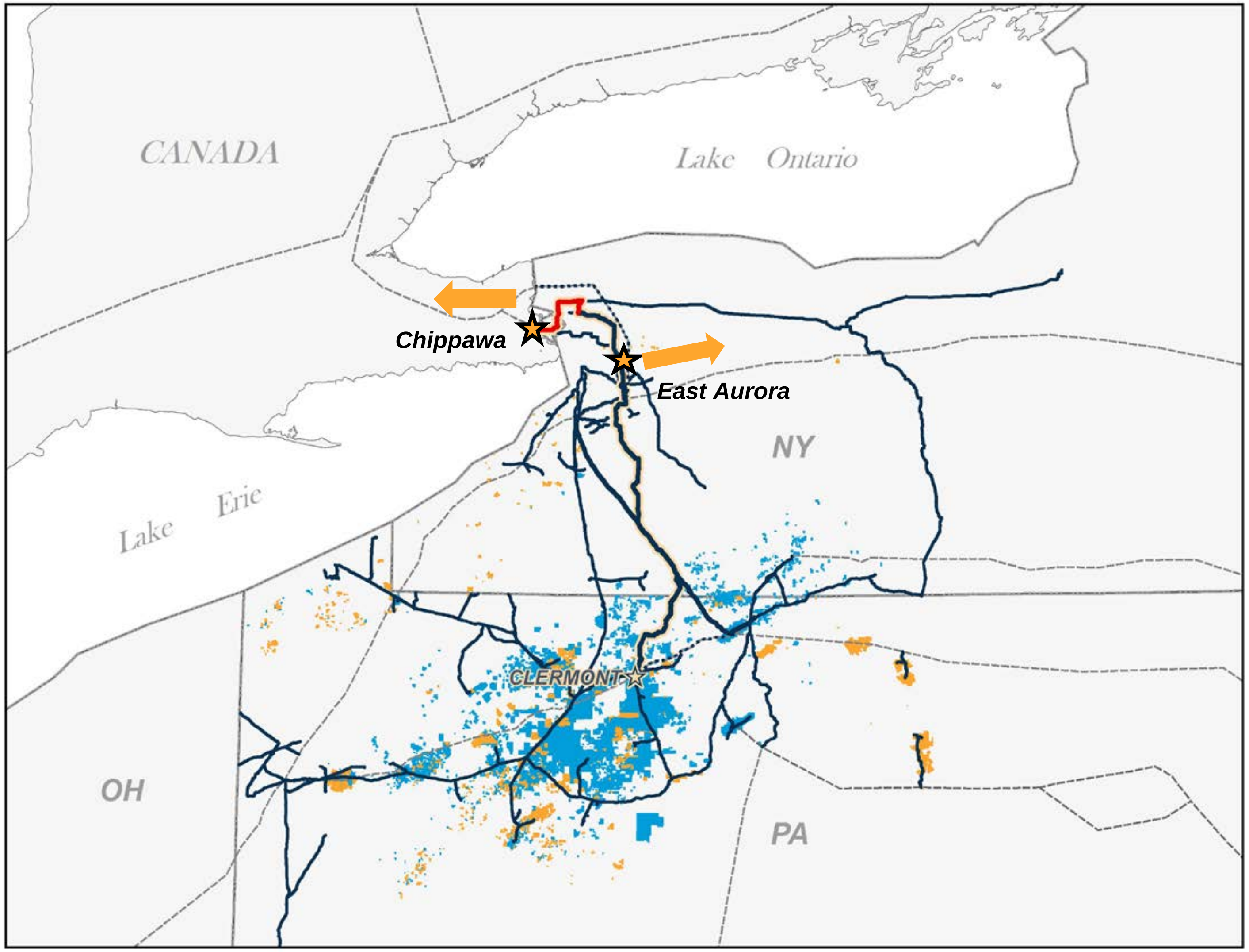
(1) 40,000 Dth per day went in-service on November 1, 2015. The remaining 100,000 Dth per day was placed in-service on December 1, 2015.

Northern Access Expansions for Seneca Resources

Northern Access 2016 to Increase Transport Capacity Out of WDA by 490,000 Dth/d

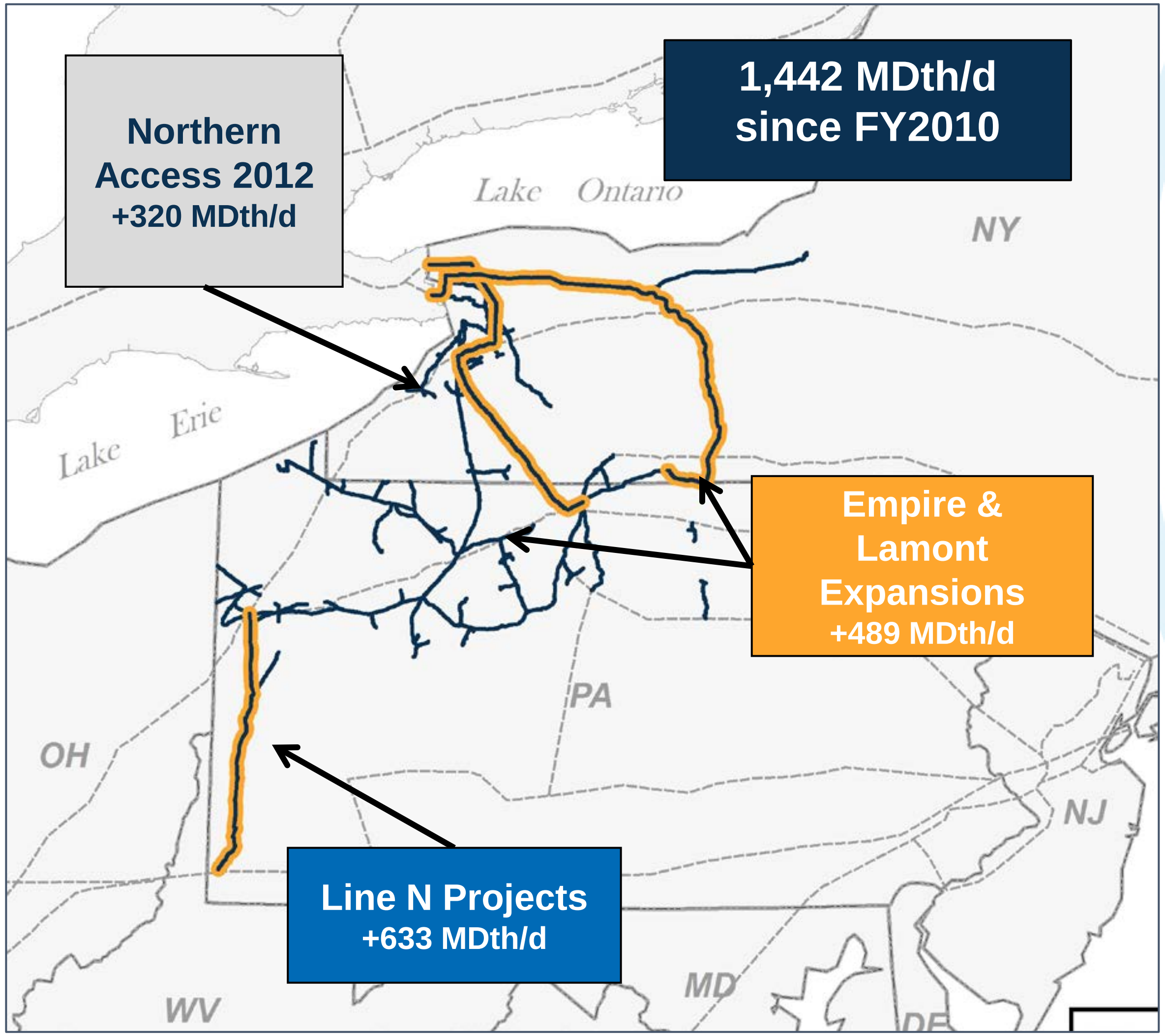
Northern Access 2016

- Customer: Seneca Resources (NFG)
- In-Service: Now expected Q2 fiscal 2018
- Capacity: 490,000 Dth/d
- Receipt Interconnect:
  - Clermont Gathering System (McKean Pa.)
- Delivery Interconnects:
  - TransCanada – Chippawa (350 MDth/d)
  - TGP 200 – East Aurora (140 MDth/d)
- Total Expected Cost: ~$455 Million
- Major Facilities:
  - 98.5 miles – 16” & 24” Pipeline
  - 22,214 hp & 5,350 hp Compression
- FERC/Regulatory Status:
  - FERC Environmental Assessment received 7/27/16
  - FERC Certificate and certifications pending
  - NY DEC 401 Water Quality permit expected 4/7/17

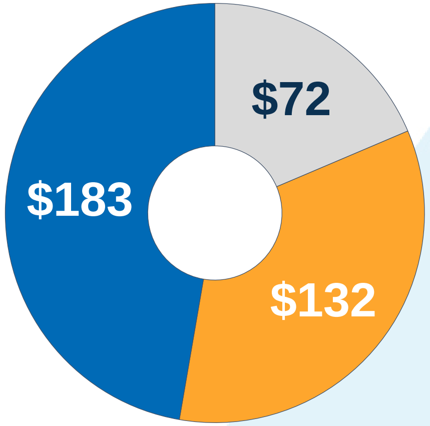


Recent 3rd Party Expansions Highly Successful

Expansions for 3rd Parties since 2010

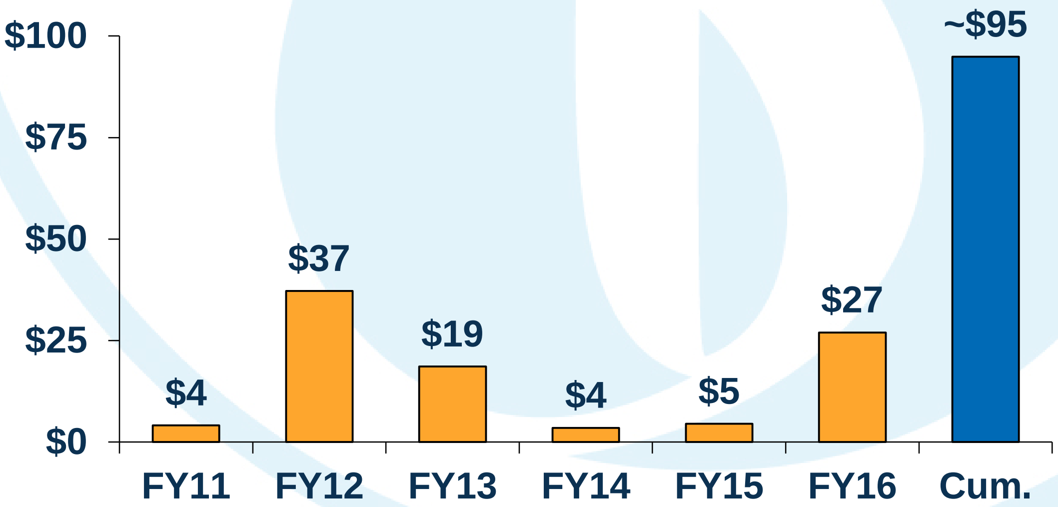


3rd Party Expansion Capital Cost ($MM)



$387 million since FY 2010

Annual Expansion Revenues Added ($MM)

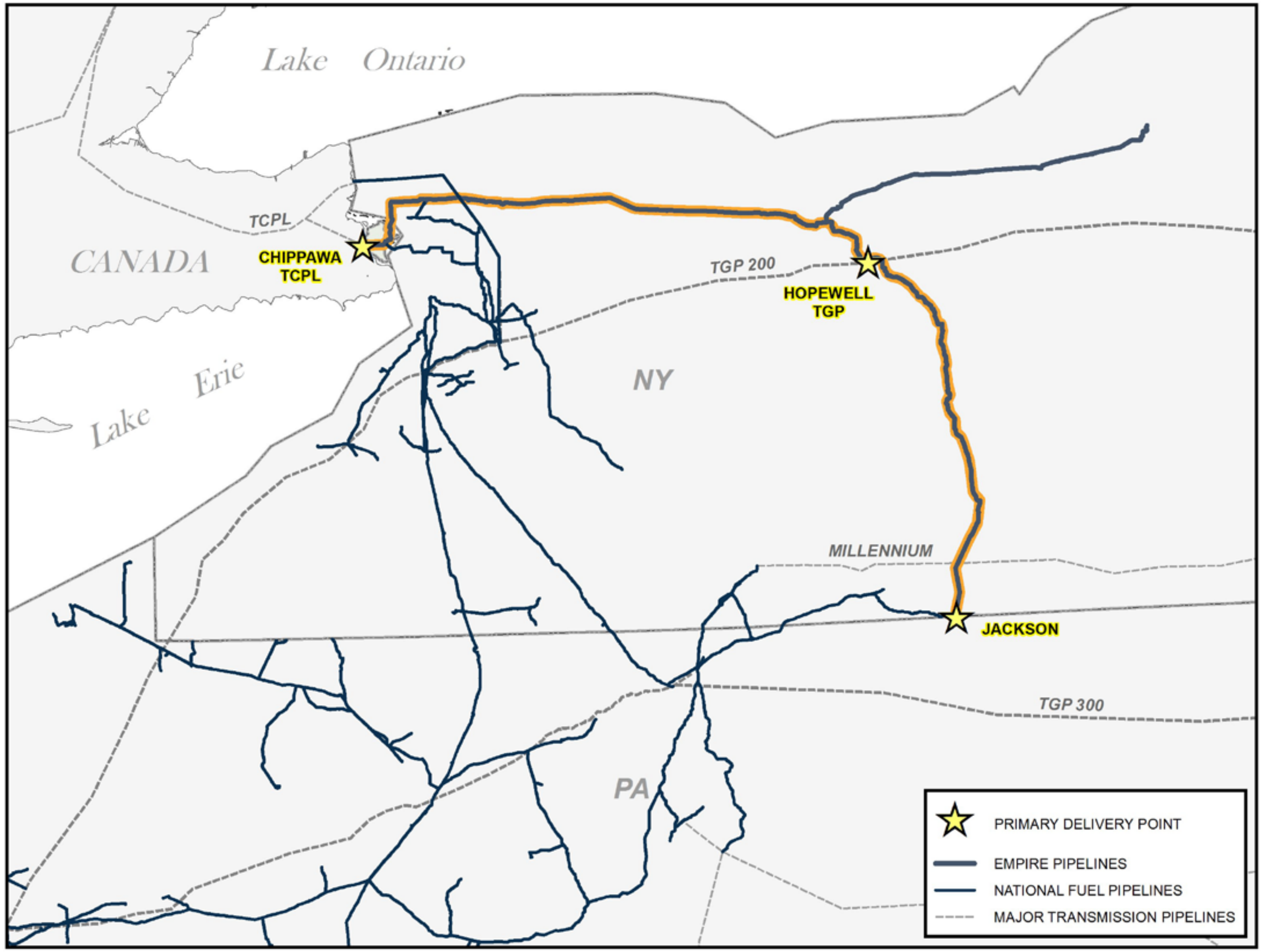


Empire System Expansion

Planned Empire Expansion Will Provide Optionality for Northeast Pennsylvania Producers

Empire North Expansion Project

- Target In-Service: Fiscal 2019
- System: Empire Pipeline
- Target Market:
  - Marcellus & Utica producers in Tioga & Potter County, Pa., and on-system markets in N.Y.
- Open Season Capacity: 300,000 Dth/d
- Receipt Point: Jackson (Tioga Co., Pa.)
- Delivery Points:
  - 180,000 Dth/d to Chippawa (TCPL)
  - Up to 158,000 Dth/d to Hopewell (TGP)
- Estimated Cost: $205 million
- Major Facilities:
  - 3 new compressor stations
- Project Status:
  - Open Season concluded Nov. 2015 fully subscribed
  - Precedent agreements from shippers due March 2017



National Fuel

2015 Pipeline Expansion Projects In-Service

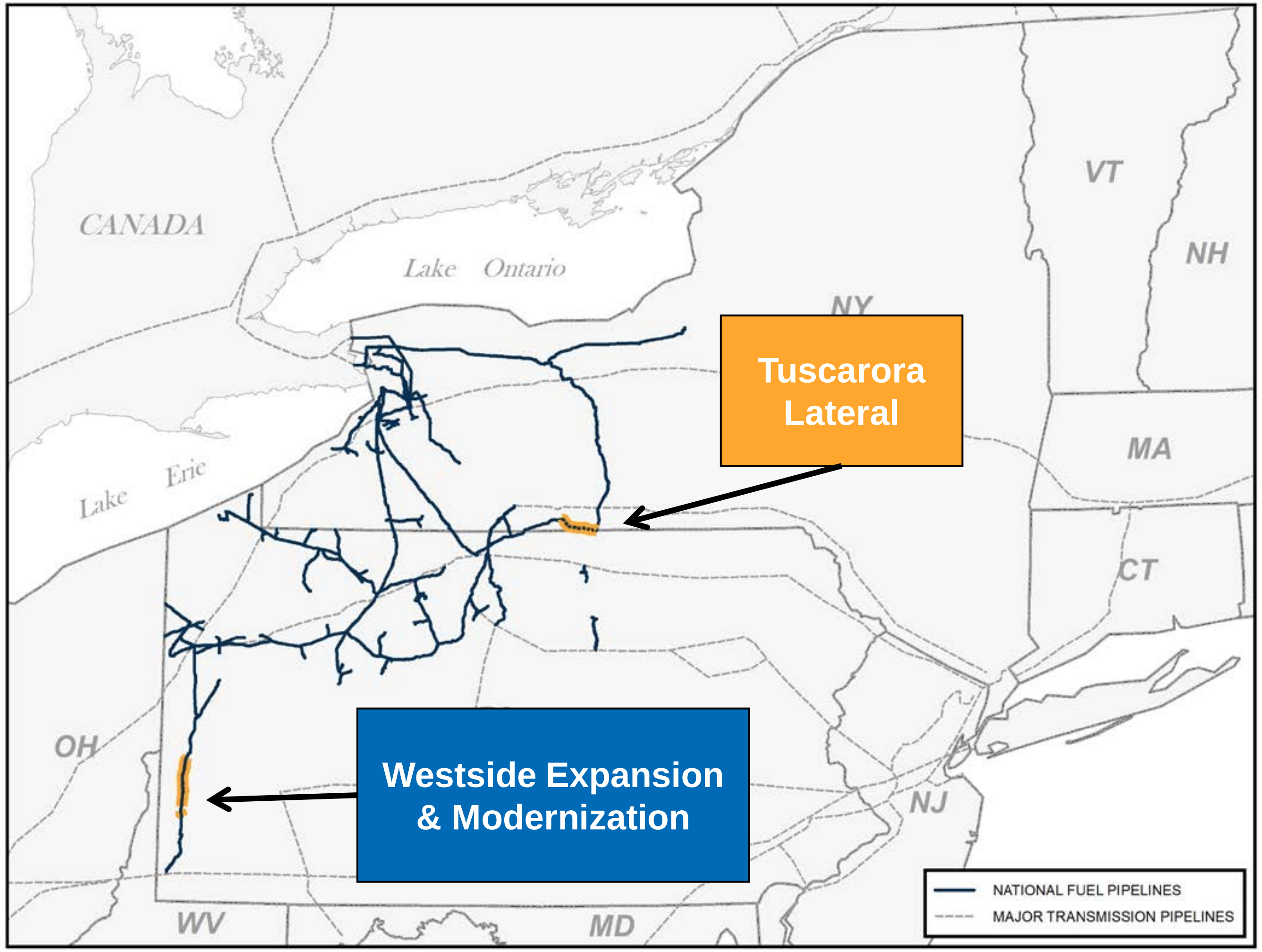
Westside Expansion & Modernization
In-Service (October 2015)

- Total Cost: $82.3 million
  - Expansion: $43.3 million
  - Modernization: $39 million
- Incremental Annual Revenues: $8.8 million
- Capacity: 175,000 Dth per day
  - Range Resources (145,000 Dth/d)
  - Seneca Resources (30,000 Dth/d)

Tuscarora Lateral
In-Service (November 2015)

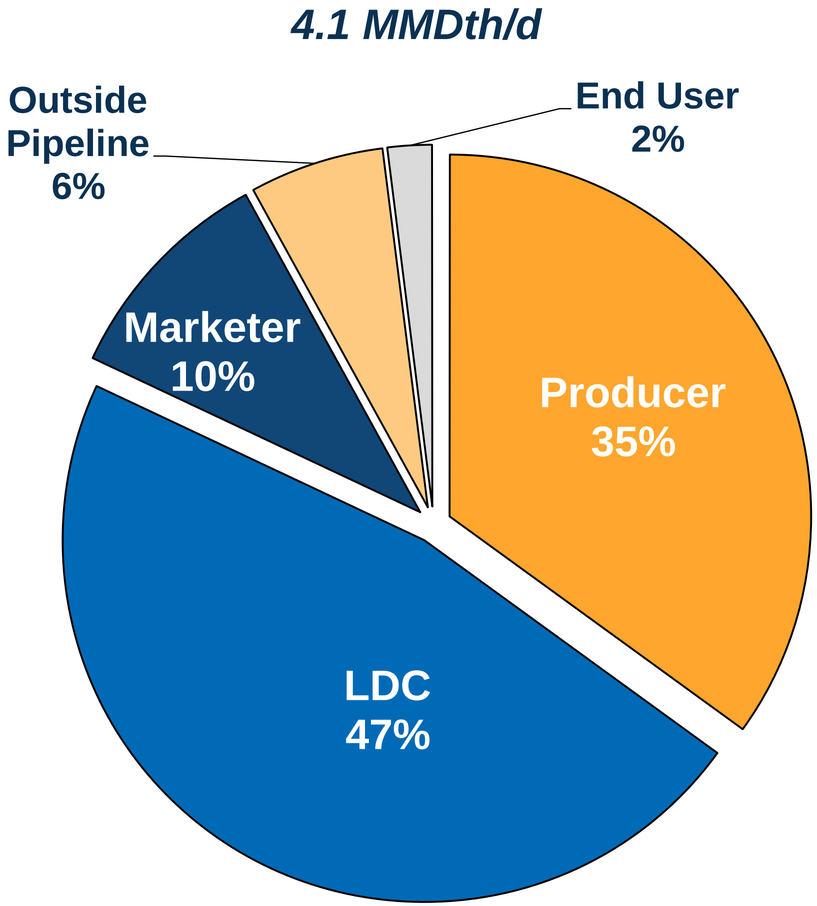
- Total Cost: $64.8 million
- Incremental annual revenues of $10.9 million on 49,000 Dth per day capacity
- Preserves $16.1 million in annual revenues on existing FT (192,500 Dth/d) and retained storage (3.3 Bcf) services

2015 Completed Pipeline Expansion Projects

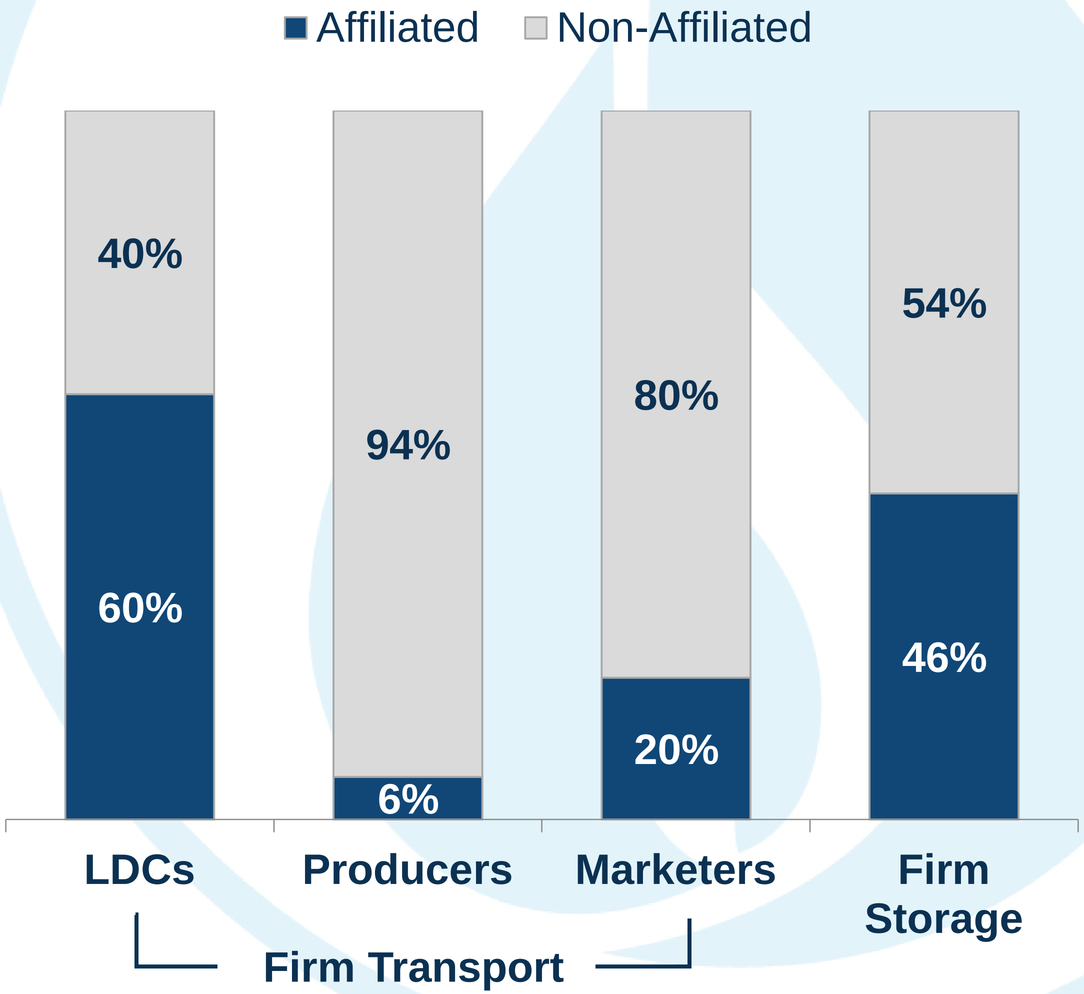


Pipeline & Storage Customer Mix

Customer Transportation by Shipper Type[(1)]



Affiliated Customer Mix (Contracted Capacity)



(1) Contracted as of 10/20/2016.

California Overview

Exploration & Production

California

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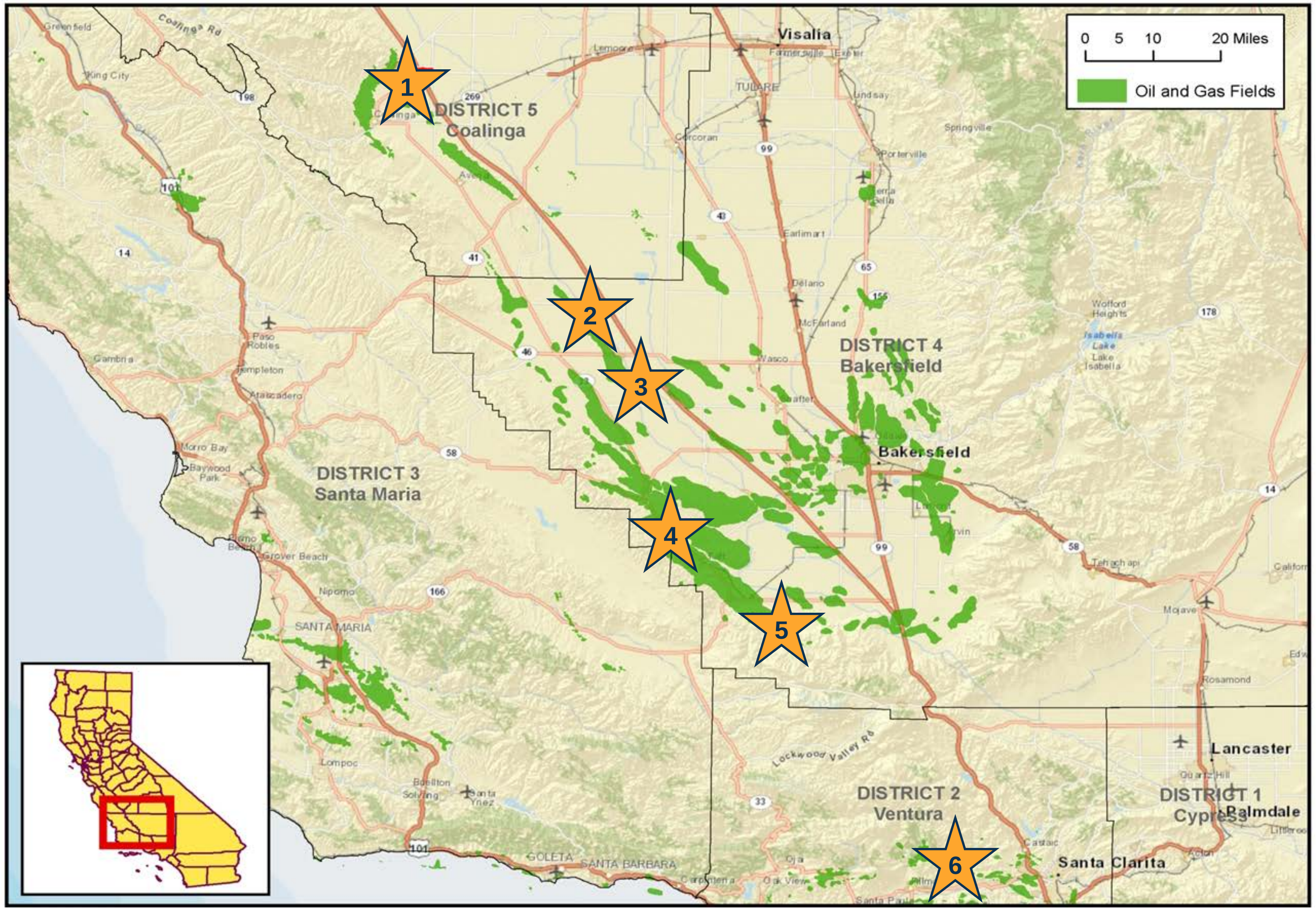
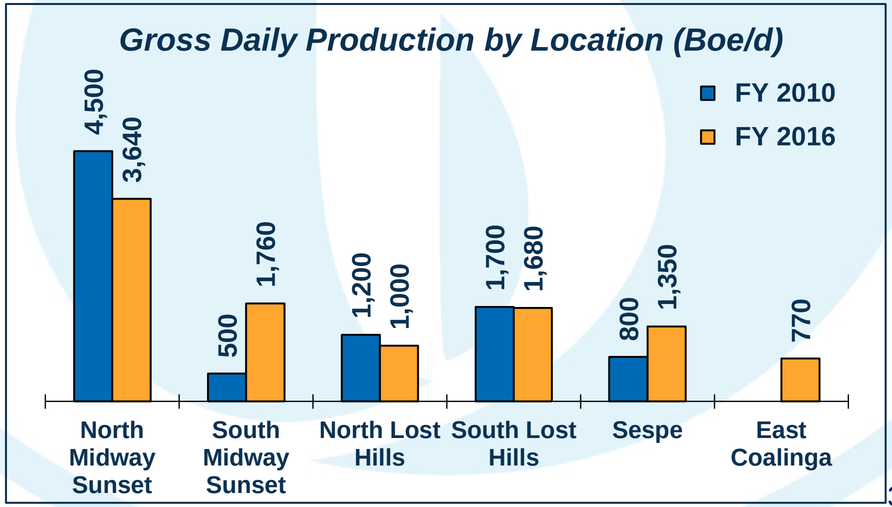
Stable Oil Production | Minimal Capital Investment | Free Cash Flow Positive



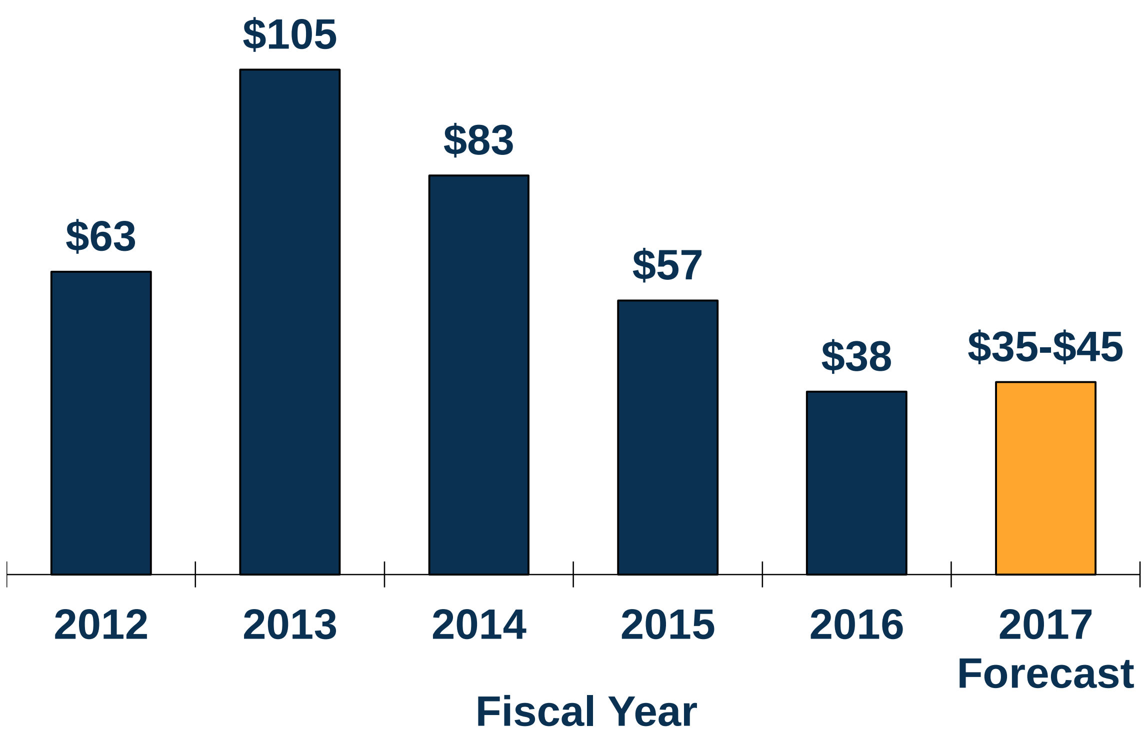
	Location	Formation	Production Method
1	East Coalinga	Temblor	Primary
2	North Lost Hills	Tulare & Etchegoin	Primary/ Steamflood
3	South Lost Hills	Monterey Shale	Primary
4	North Midway Sunset	Tulare & Potter	Steamflood
5	South Midway Sunset	Antelope	Steamflood
6	Sespe	Sespe	Primary



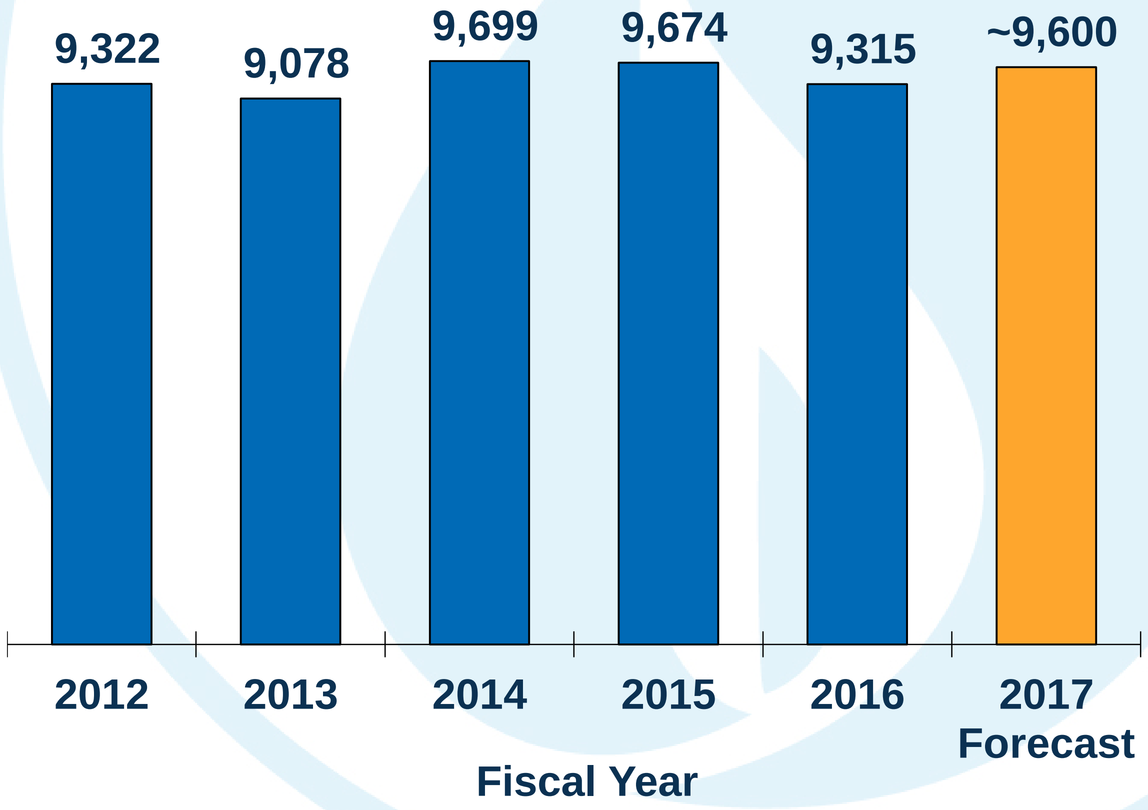
California Average Daily Net Production

Less than $40 Million Annual Capital Spending Needed to Keep CA Production Flat

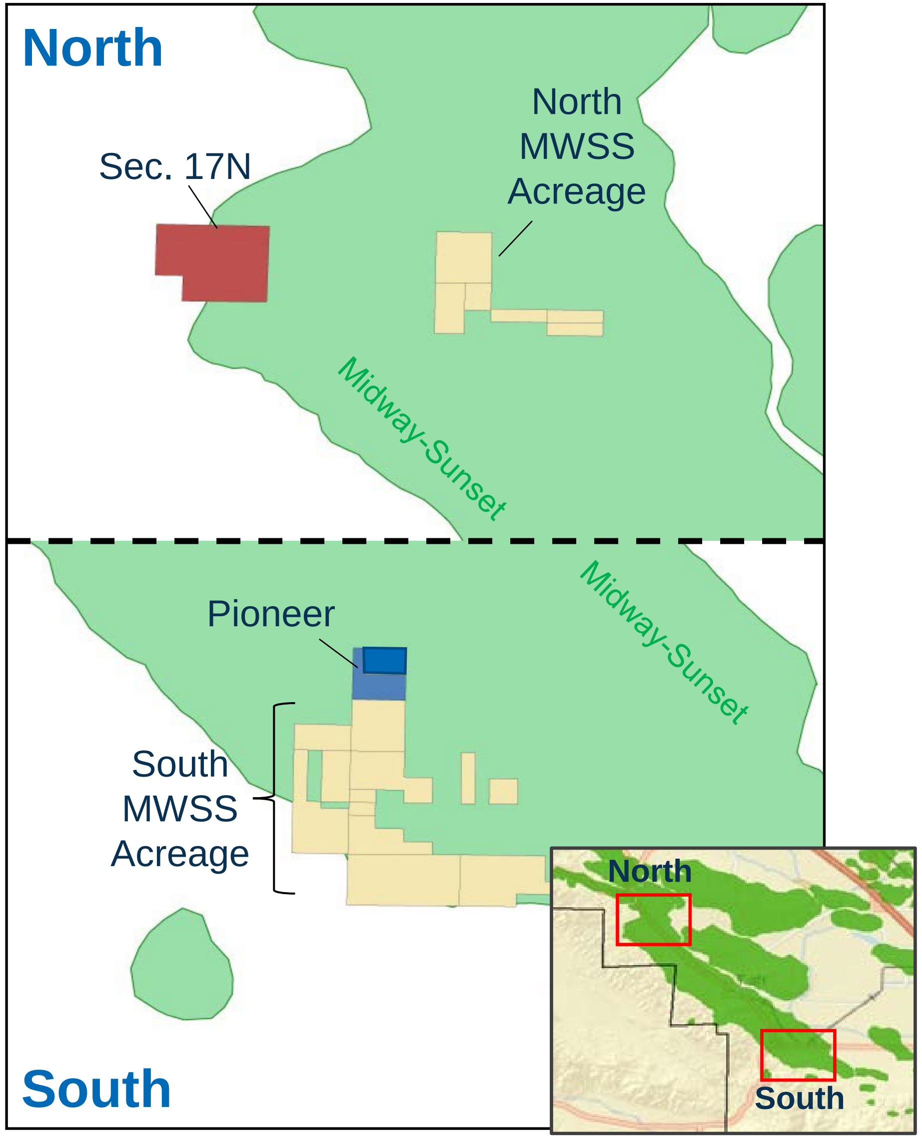
California Annual Capital Expenditures ($MM)



California Average Net Daily Production (BOE/D)

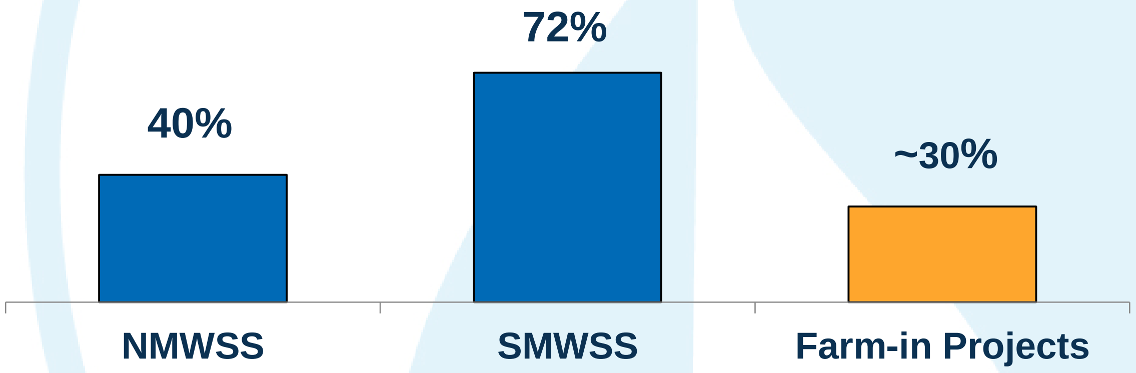


Economic Development Focused on Midway Sunset



Midway Sunset Economics

MWSS Project IRRs at $55/Bbl(1)

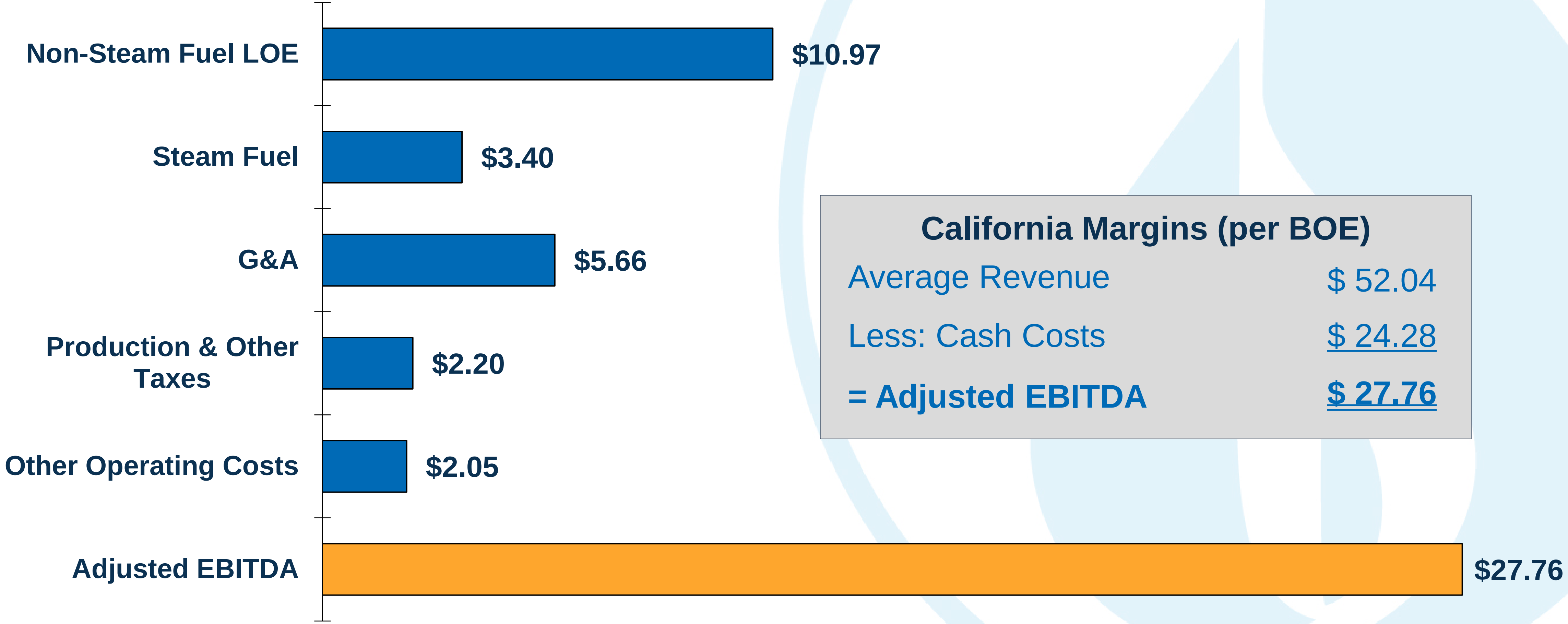


- ✓ Modest near-term capital program focused on locations that earn attractive returns in current oil price environment
- ✓ A&D will focus on low cost, bolt-on opportunities
- ✓ Sec. 17 and Pioneer farm-ins to provide future growth
  - F&D (est.) = $6.50/Boe

(1) Reflects pre-tax IRRs at a $55/Bbl WTI.

Strong Margins Support Significant Free Cash Flow

West Division Adjusted EBITDA per BOE[1]
Trailing 12-months Ended 12/31/16



California Margins (per BOE)

Average Revenue	$ 52.04
Less: Cash Costs	$ 24.28
= Adjusted EBITDA	**$ 27.76**

(1) Average revenue per BOE includes impact of hedging and other revenues.

Note: A reconciliation of Adjusted EBITDA margin to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation. EBITDA per BOE includes Seneca corporate results and eliminations.

Production and Marketing

Exploration & Production

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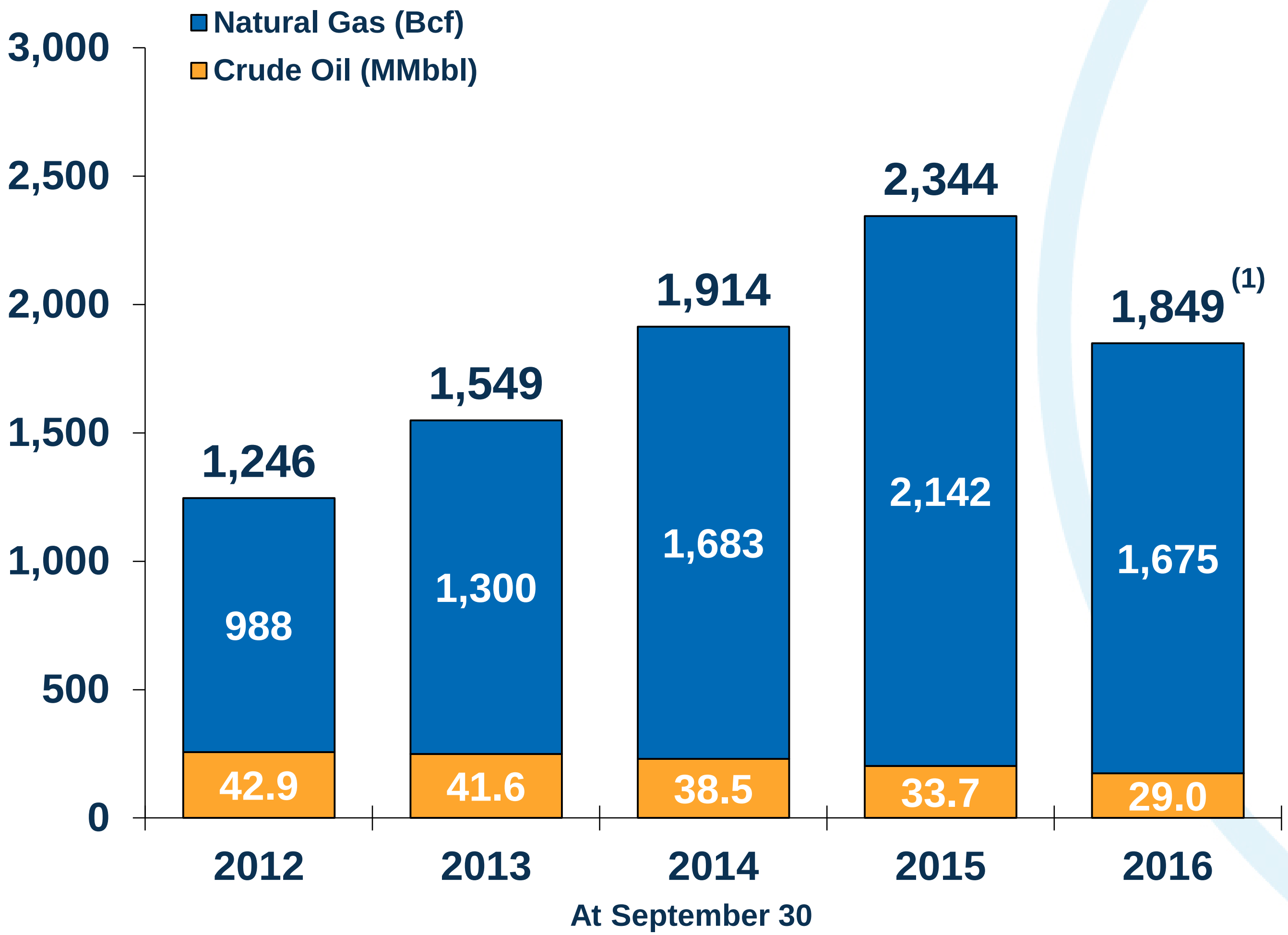
Proved Reserves & Development Costs

Total Proved Reserves (Bcfe)



Fiscal 2016 Proved Reserves Reconciliation (Bcfe)

Proved Reserves - FYE '15	**2,344**
FY '16 Production	(161)
Mineral Sales[(2)]	(262)
Net Negative Revisions[(3)]	(262)
Extensions & Discoveries	190
Proved Reserves - FYE '16	**1,849**

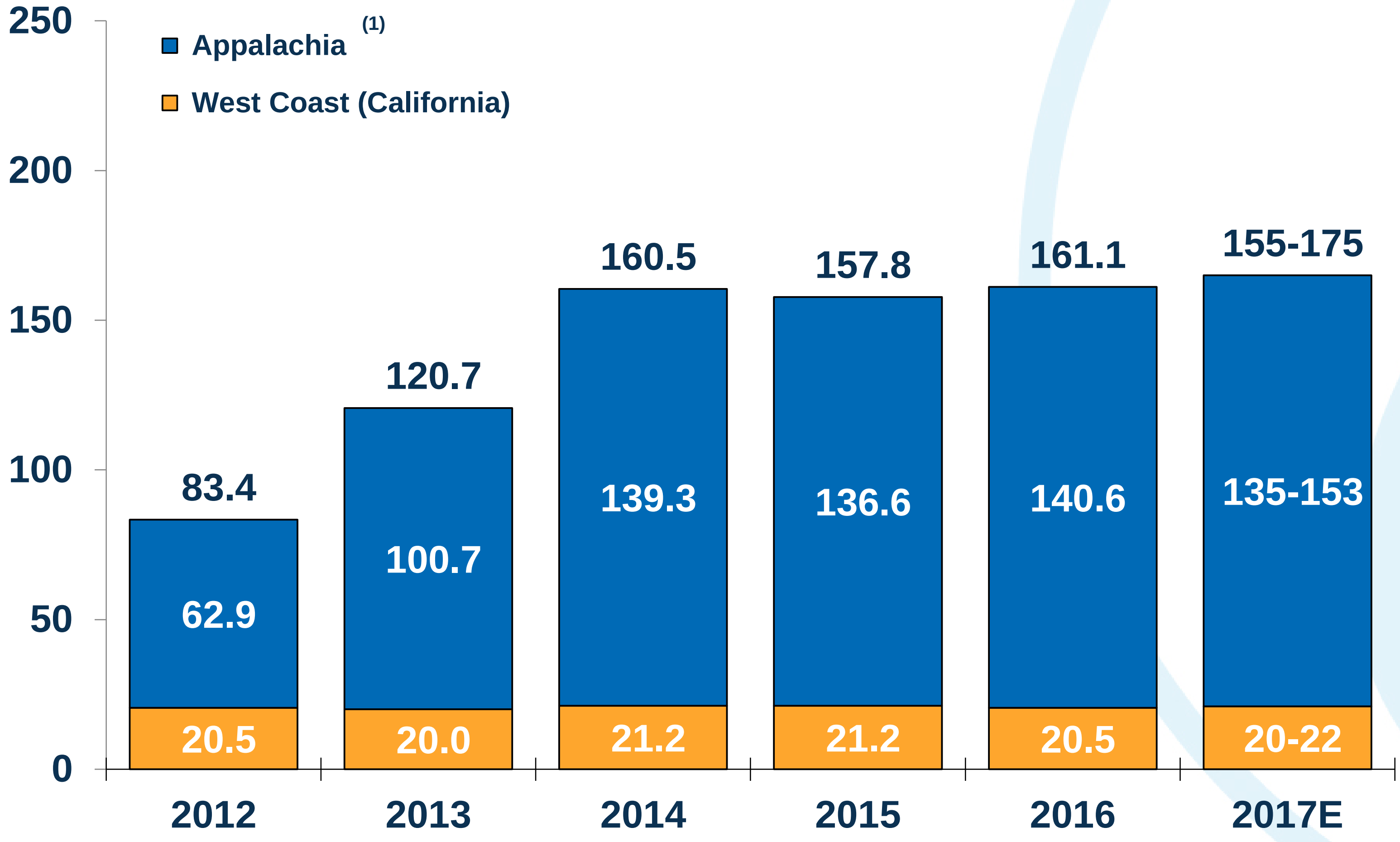
Fiscal 2016 Proved Reserves Stats

- **117% Reserve Replacement Rate (adjusted for revisions and sales)**
- **65% Proved Developed**
- **35% Proved Undeveloped**

(1) Includes approximately 69 Bcf of natural gas proved reserves in Appalachia that will be transferred in fiscal 2017 as interests in the joint development wells are conveyed to the partner.
(2) Reflects 246 Bcfe of natural gas reserves that were conveyed and sold to joint development partner and 16 Bcfe of Upper Devonian sales.
(3) FY 2016 net negative revisions include 227 Bcfe of proved reserves that were revised due to lower oil and gas pricing.

Seneca Production

Seneca Resources Net Production (Bcfe)



Joint Development Agreement tempers net production growth in FY17

- Gross production expected to grow >10%
- Growth is largely being generated from joint development wells where Seneca has 26% NRI, resulting in flat net production YOY
- Increasing gross production will benefit NFG Midstream businesses:
  - Gathering segment throughput and revenues
  - Utilization of firm transport capacity on NFG pipelines (Northern Access)

(1) Refer to slides 40 and 42 for additional details on fiscal 2017 firm sales and local Appalachian spot market exposure.

Long-Term Contracts Supporting Appalachian Growth

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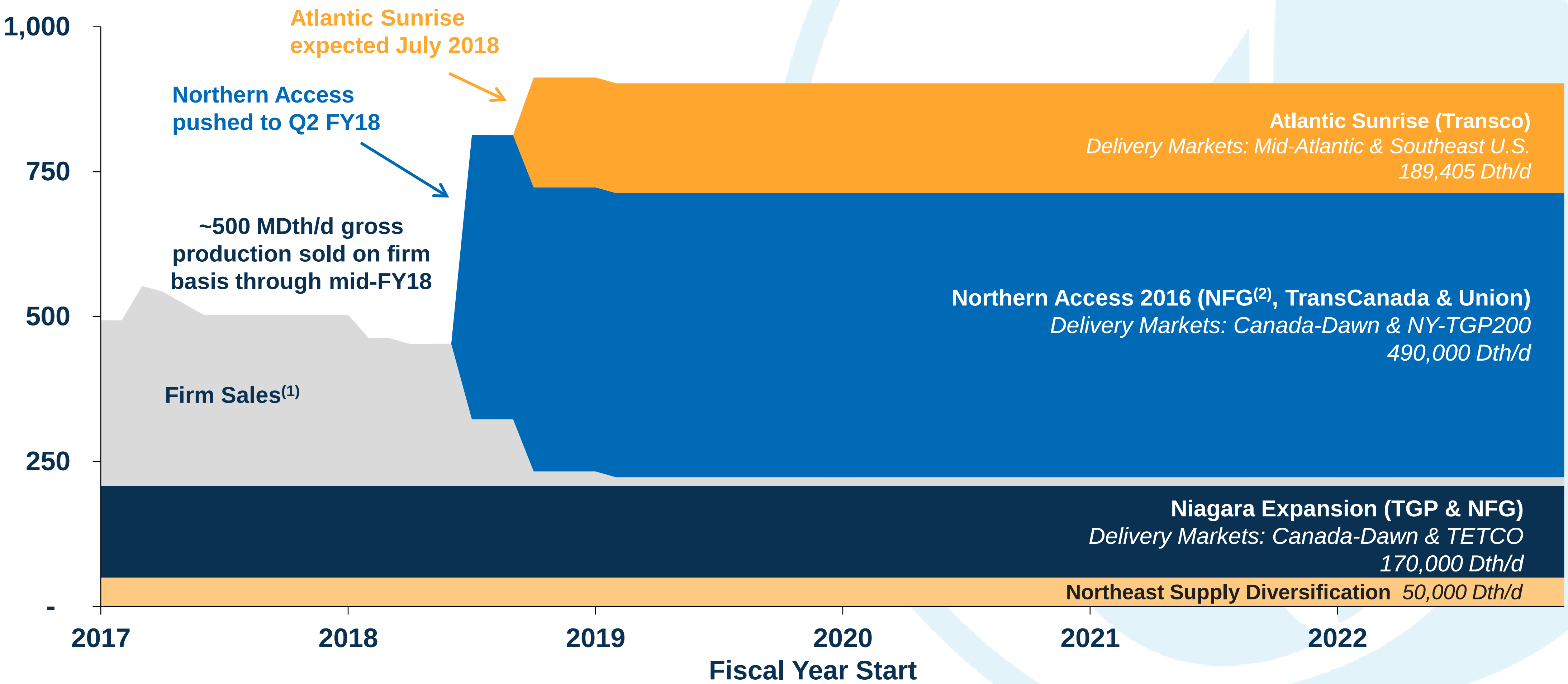
Gross Firm Sales and Firm Transport Volumes Under Contract *(Thousands Dth per Day)*



(1) Includes base firm sales contracts not tied to firm transportation capacity. Base firm sales are either fixed priced or priced at an index (e.g., NYMEX) +/- a fixed basis and do not carry any transportation costs. See slide 40 for details on firm sales portfolio for the remainder of fiscal 2017.

(2) Includes capacity on both National Fuel Gas Supply Corp. and Empire Pipeline, Inc., both wholly owned subsidiaries of National Fuel Gas Company.

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Firm Transportation Commitments

		Production Source	Volume (Dth/d)	Delivery Market	Demand Charges ($/Dth)	Gas Marketing Strategy
Currently In-Service	**Northeast Supply Diversification Project** *Tennessee Gas Pipeline*	EDA -Tioga County Covington & Tract 595	50,000	Canada (Dawn)	$0.50 (3rd party)	Firm Sales Contracts 50,000 Dth/d Dawn/NYMEX+ 10 years
	Niagara Expansion *TGP & NFG*	WDA – Clermont/ Rich Valley	158,000	Canada (Dawn)	NFG pipelines = $0.24 3rd party = $0.43	Firm Sales Contracts 158,000 Dth/d Dawn/NYMEX+ 8 to 15 years
			12,000	TETCO (SE Pa.)	NFG pipelines = $0.12	
Future Capacity	**Northern Access** *NFG – Supply & Empire* *In-Service: 2Q FY18*	WDA – Clermont /Rich Valley	350,000	Canada (Dawn)	NFG pipelines = $0.50 3rd party = $0.21	Firm Sales Contracts 145,000 Dth/d Dawn / Fixed Price First 3 years
			140,000	TGP 200 (NY)	NFG pipelines = $0.38	
	Atlantic Sunrise *WMB - Transco* *In-service: Mid-2018(1)*	EDA - Lycoming County Tract 100 & Gamble	189,405	Mid-Atlantic/ Southeast	$0.73 (3rd party)	Firm Sales Contracts 189,405 Dth/d NYMEX+ First 5 years

(1) WMB is now targeting the middle of calendar 2018 following the change in the timing of the environmental review from FERC.

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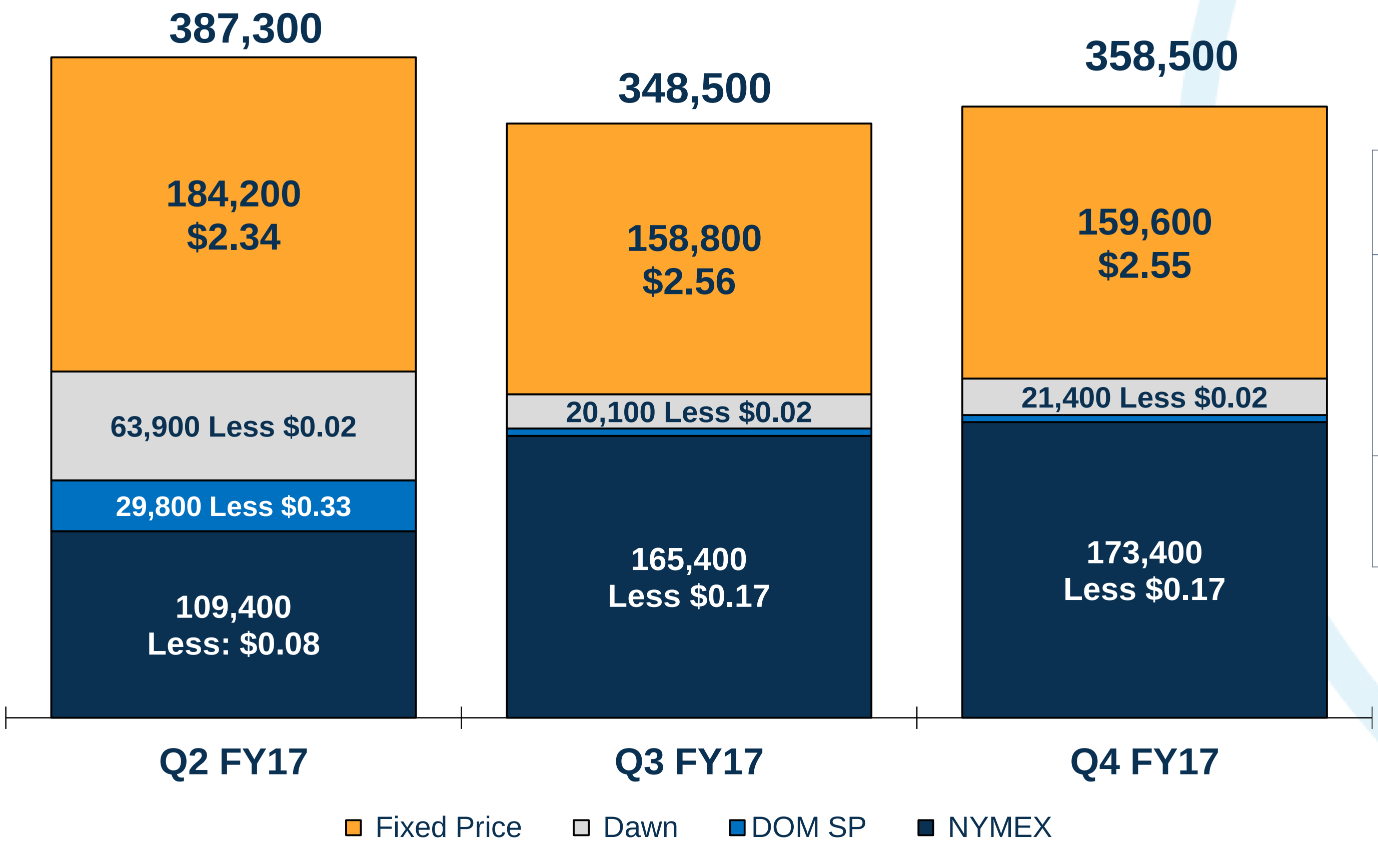
Firm Sales Provide Market for Appalachian Production

FY 17 Net Contracted Volumes (Dth per day)
Contracted Index Price Differentials ($ per Dth)(1)



Gross vs. Net Firm Sales Volumes (Dth per Day)

	Q2 FY17	Q3 FY17	Q4 FY17
Gross	523,000/d	503,000/d	503,000/d
NRI Owners(2)	135,700/d	154,500/d	144,500/d
Net	387,300/d	348,500/d	358,500/d

(1) Values shown represent the price or differential to a reference price (netback price) at the point of sale.
(2) Reflects adjustment to gross sales volumes to reflect impact of lease royalties in EDA and net revenue interests assigned to joint development partner on certain contracts in WDA.

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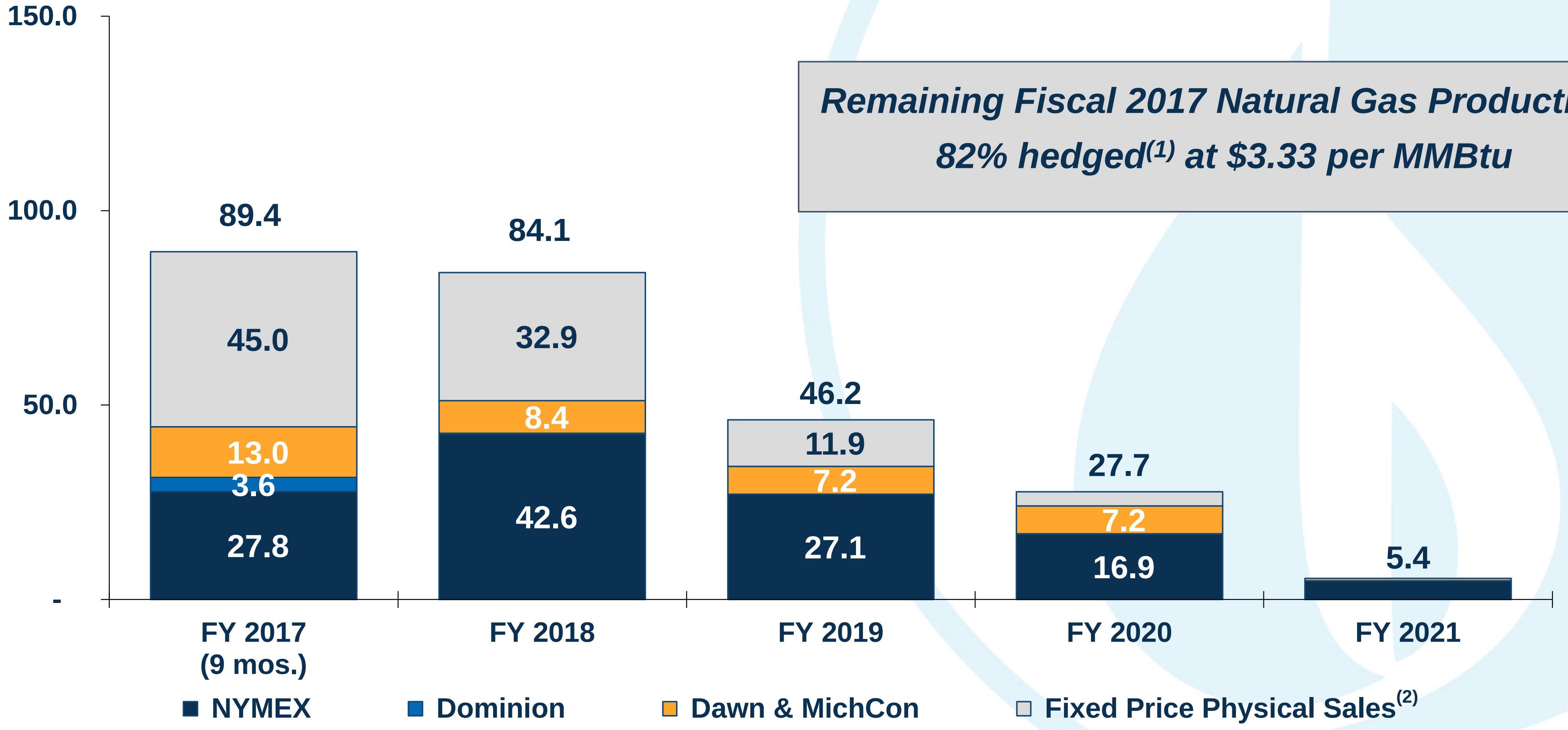
Strong Hedge Book in Fiscal 2017

Natural Gas Swap & Fixed Physical Sales Contracts (Millions MMBtu)

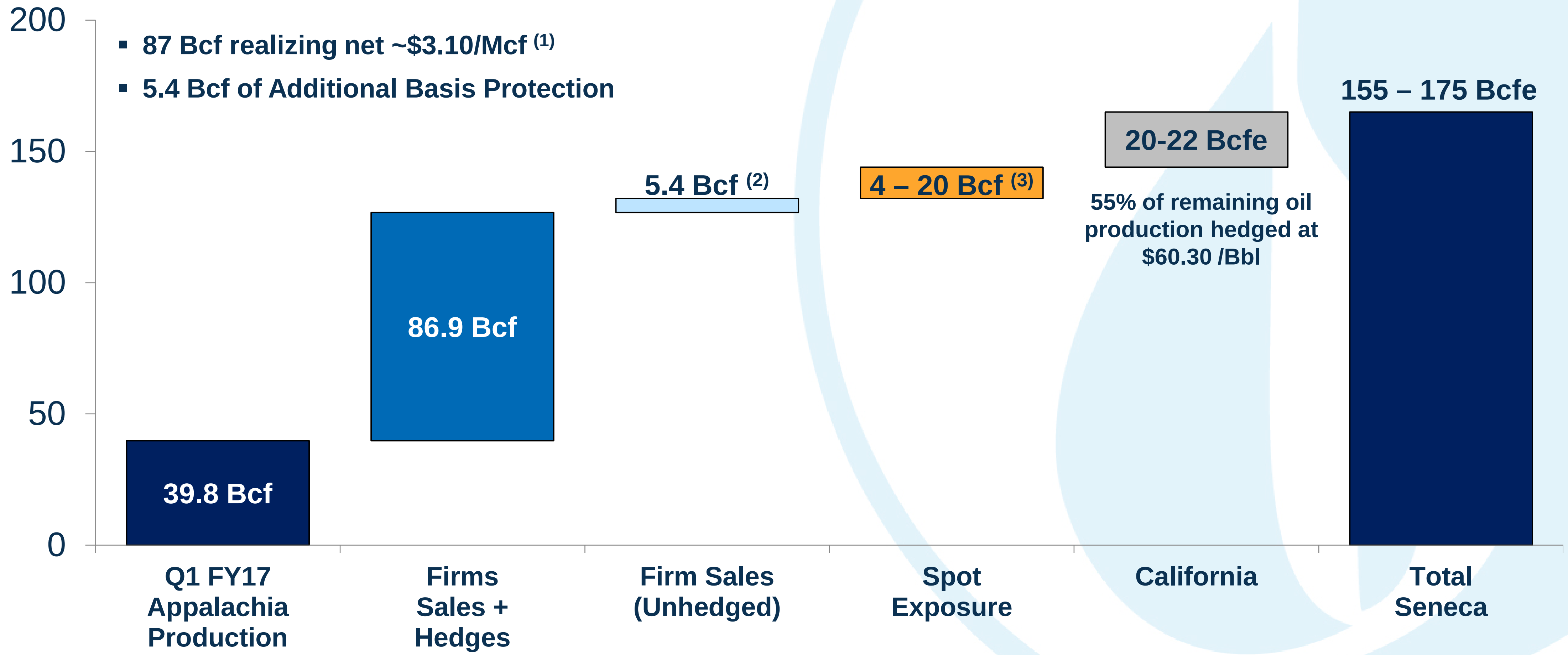
Remaining Fiscal 2017 Natural Gas Production
82% hedged[(1)] at $3.33 per MMBtu



(1) Assumes midpoint of natural gas production guidance, adjusted for year-to-date actual results.
(2) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement.

Fiscal 2017 Production and Price Certainty

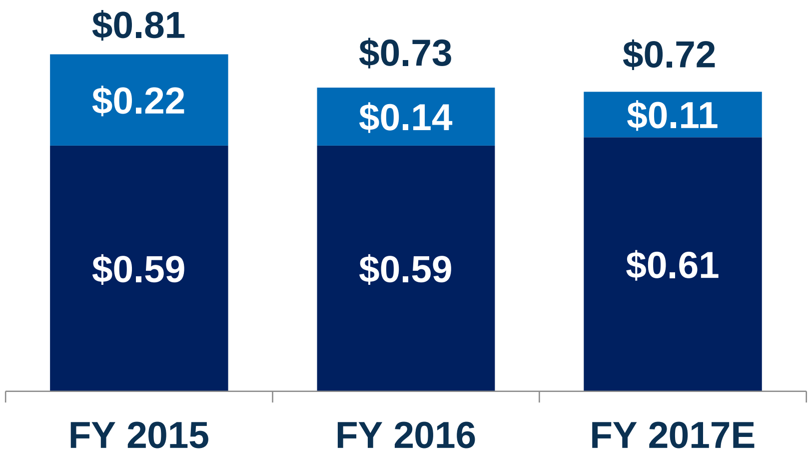
FINANCIAL HEDGE + FIRM SALE = PRICE CERTAINTY



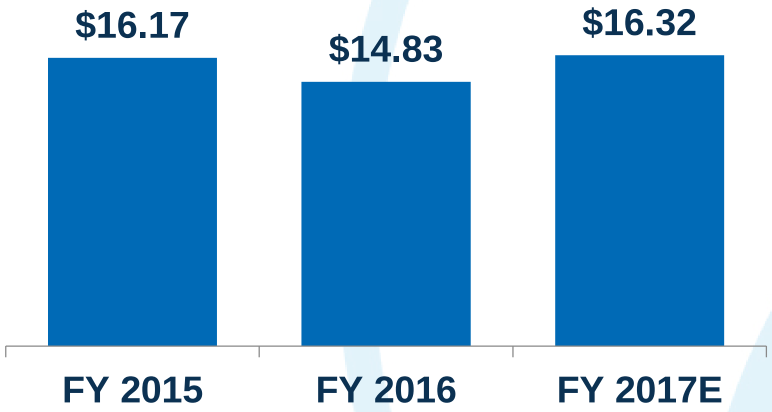
(1) Average realized price reflects uplift from financial hedges less fixed differentials under firm sales contracts and firm transportation costs.
(2) Indicates firm sales contracts with fixed index differentials but not backed by a matching NYMEX financial hedge.
(3) Includes non-operated production from Western Development Area (legacy EOG JV wells) of ~4 Bcf.

Operating Costs

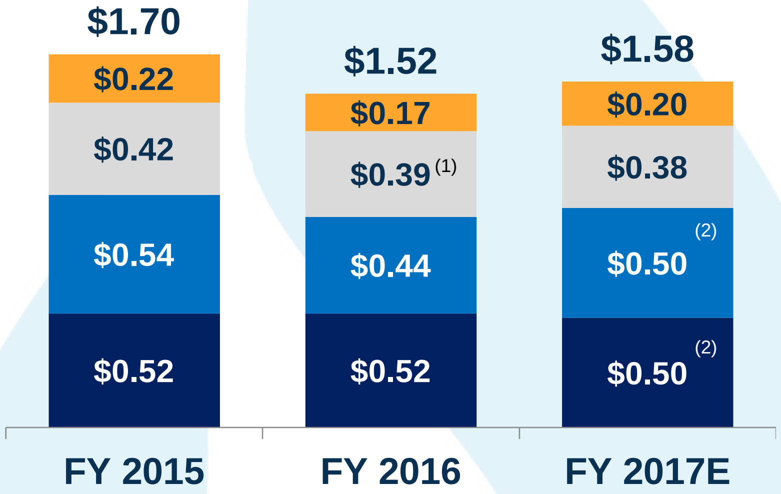
Appalachia LOE & Gathering
$/Mcfe



California LOE
$/Boe

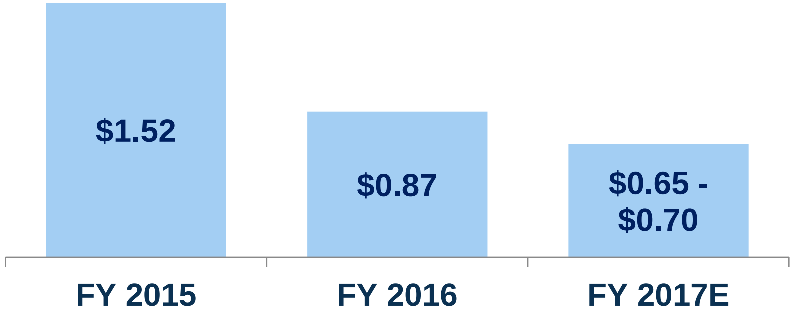


Seneca Resources Consolidated
$/Mcfe



■ Gathering & Transport ■ LOE (non-Gathering) ■ G&A ■ Taxes & Other

DD&A
$/Mcfe



- ✓ Competitive, low cost structure in Appalachia and California supports strong cash margins
- ✓ Gathering fee generates significant revenue stream for affiliated gathering company
- ✓ DD&A decrease due to improving Marcellus F&D costs and reduction in net plant resulting from ceiling test impairments

(1) Excludes $7.9 million , or $0.05 per Mcfe, of professional fees relating to the joint development agreement announced in December 2015.
(2) The total of the two LOE components represents the midpoint of the LOE guidance range of $0.95 to $1.05 per Mcfe for fiscal 2017.

Downstream Overview

Utility ~ Energy Marketing

New York & Pennsylvania Service Territories

New York

Total Customers[(1)]: 528,312

ROE: 9.1% (NY PSC Rate Case Settlement, May 2014)

Rate Mechanisms:
- Earnings Sharing
- Revenue Decoupling
- Weather Normalization
- Low Income Rates
- Merchant Function Charge (Uncollectibles Adj.)
- 90/10 Sharing (Large Customers)

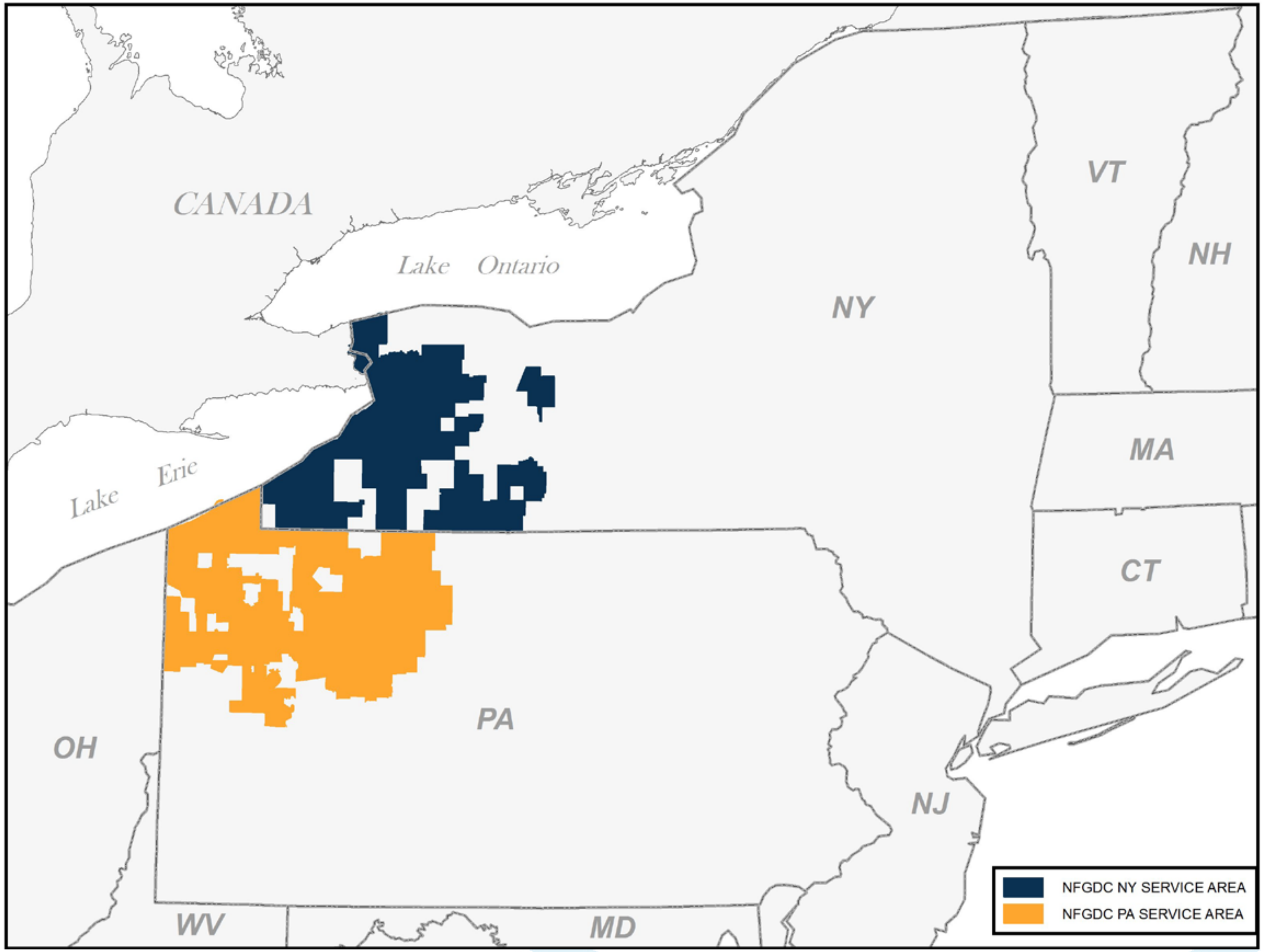
Filed Rate Case with NY PSC on 4/28/16

Pennsylvania

Total Customers[(1)]: 213,924

ROE: Black Box Settlement (2007)

Rate Mechanisms:
- Low Income Rates
- Merchant Function Charge



(1) As of September 30, 2016.

New York Rate Case

National Fuel

Background

On April 28, 2016, National Fuel Gas Distribution Corporation filed a request with the New York Public Service Commission (NY PSC) to amend its tariff and increase its base rates. National Fuel's base rates have not changed since the last base rate case was litigated in 2007.

Rate Case Timeline

April 28, 2016
Request filed with NY PSC for $41.7mm in rate relief

October 19, 2016
Filed Notice of Impending Confidential Settlement Negotiations and request for 1 month extension of suspension period with "make whole" provision

November 23, 2016
Filed Notice of Discontinued Settlement Discussions

January 23, 2017
ALJ issued Recommended Decision (RD)

April 27, 2017
Approximate date that revised rates may become effective (subject to "make whole" request)

Rate Case Status

April 2016: Company requested rate relief that would increase annual revenues by $41.7 million

- ✓ 10.2% ROE / 48% equity capital structure (Company is currently allowed to earn a 9.1% ROE)
- ✓ $127.5 million increase in net plant since 2007 rate case due to:
  - Accelerated removal of vintage pipe
  - Replacement of aging information technology infrastructure completed in 2nd half of FY16

January 2017: Administrative Law Judge issued RD recommending revenue increase of $8.5 million

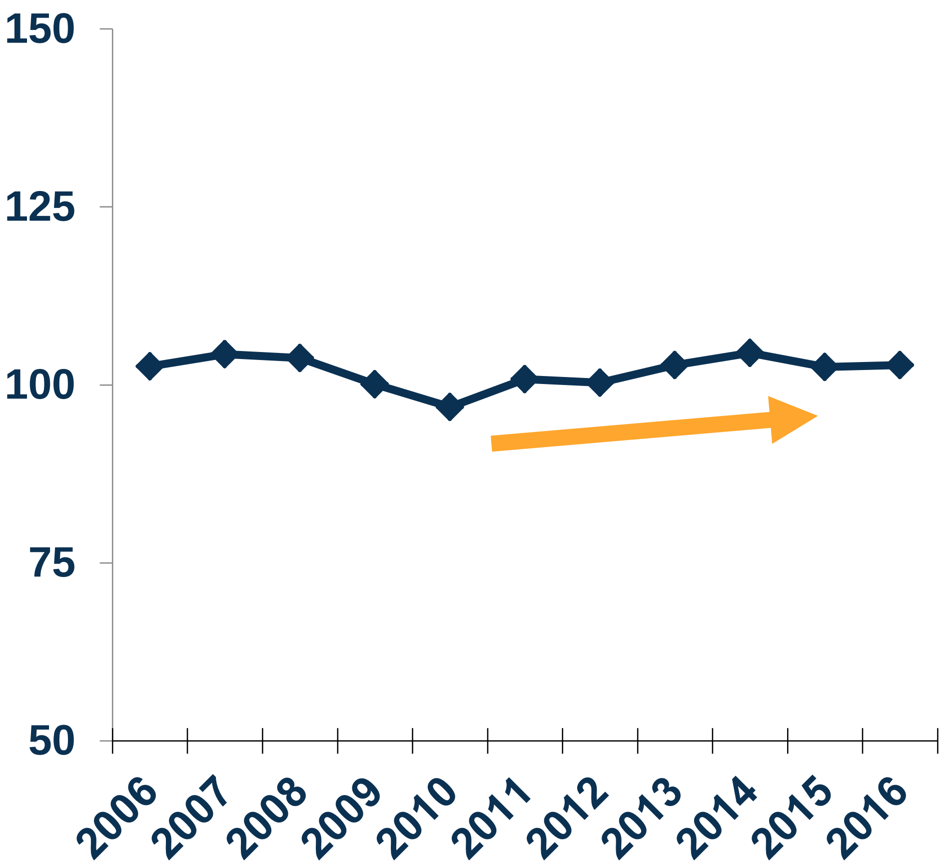
- ✓ Recommends 8.6% ROE / 42.3% equity capital structure (subject to updates)
- ✓ RD may be accepted, modified, or rejected by the NY PSC

National Fuel

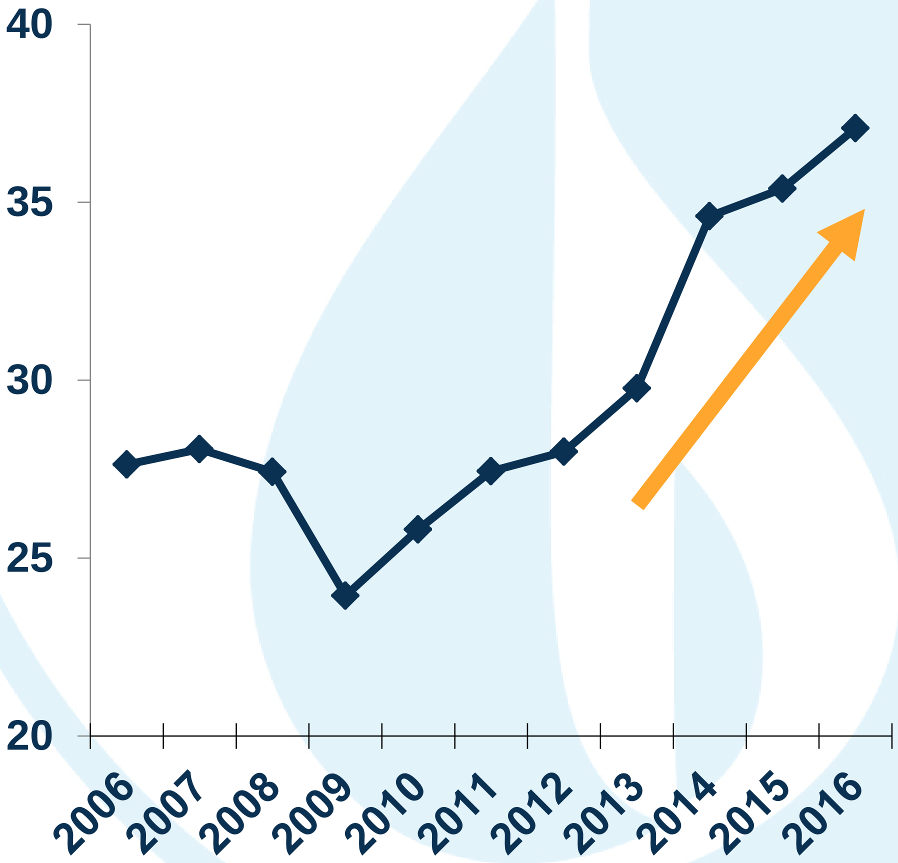
Utility: Shifting Trends in Customer Usage

Usage Per Account (1)

Residential (Mcf)



Industrial (MMcf)

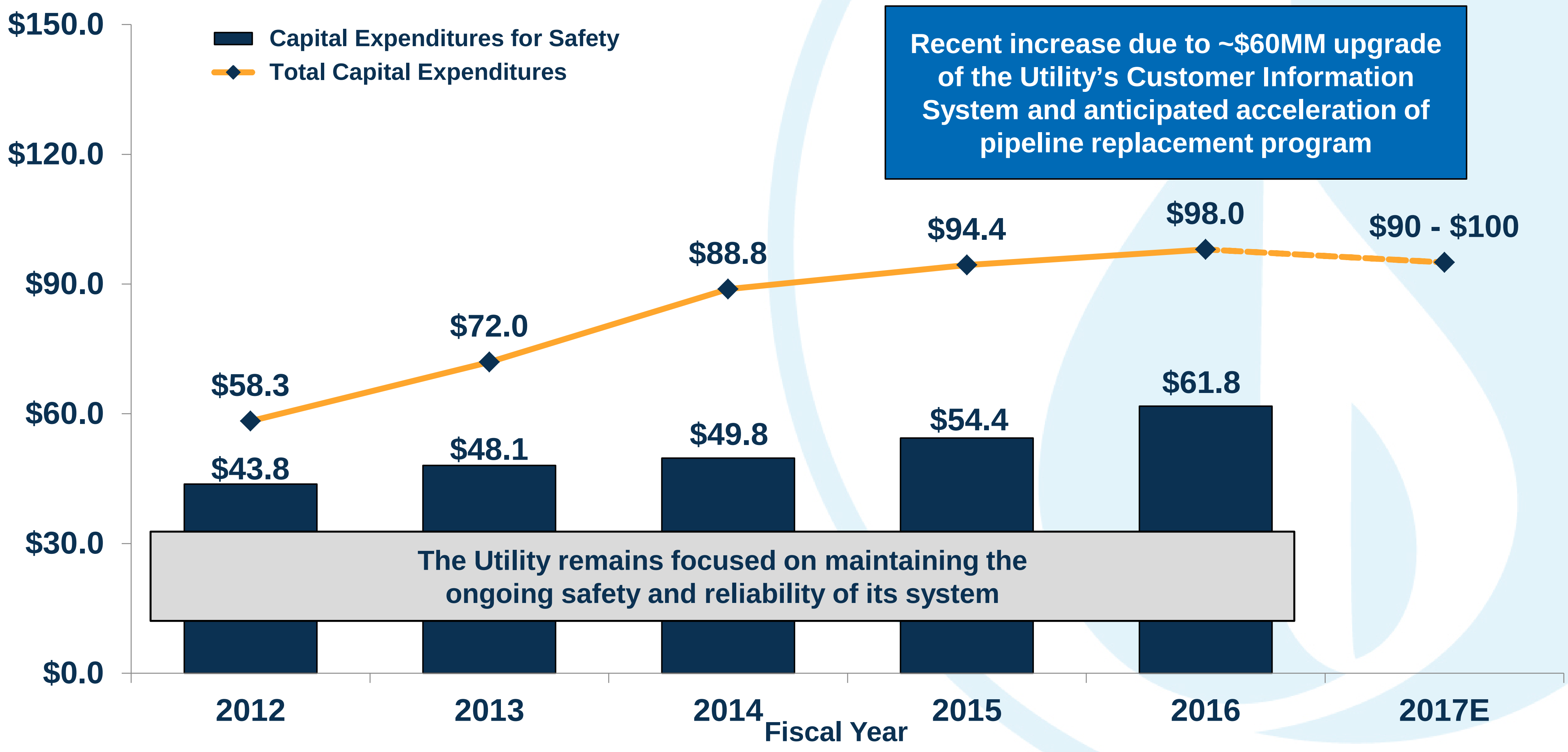


12-Months Ended December 31

(1) Weighted Average of New York and Pennsylvania service territories (assumes normal weather).

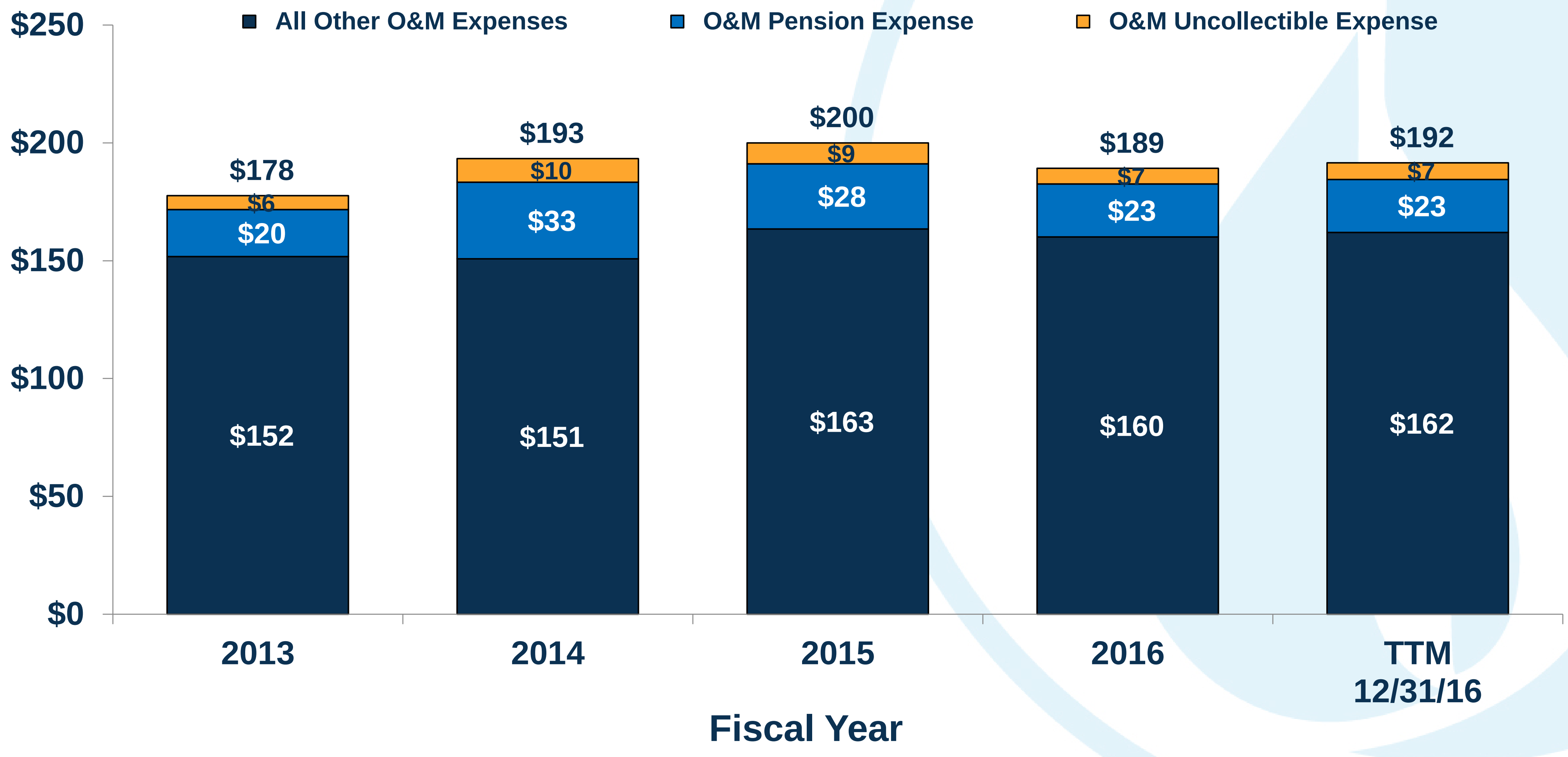
Utility: Strong Commitment to Safety

Capital Expenditures ($ millions)



A Proven History of Controlling Costs

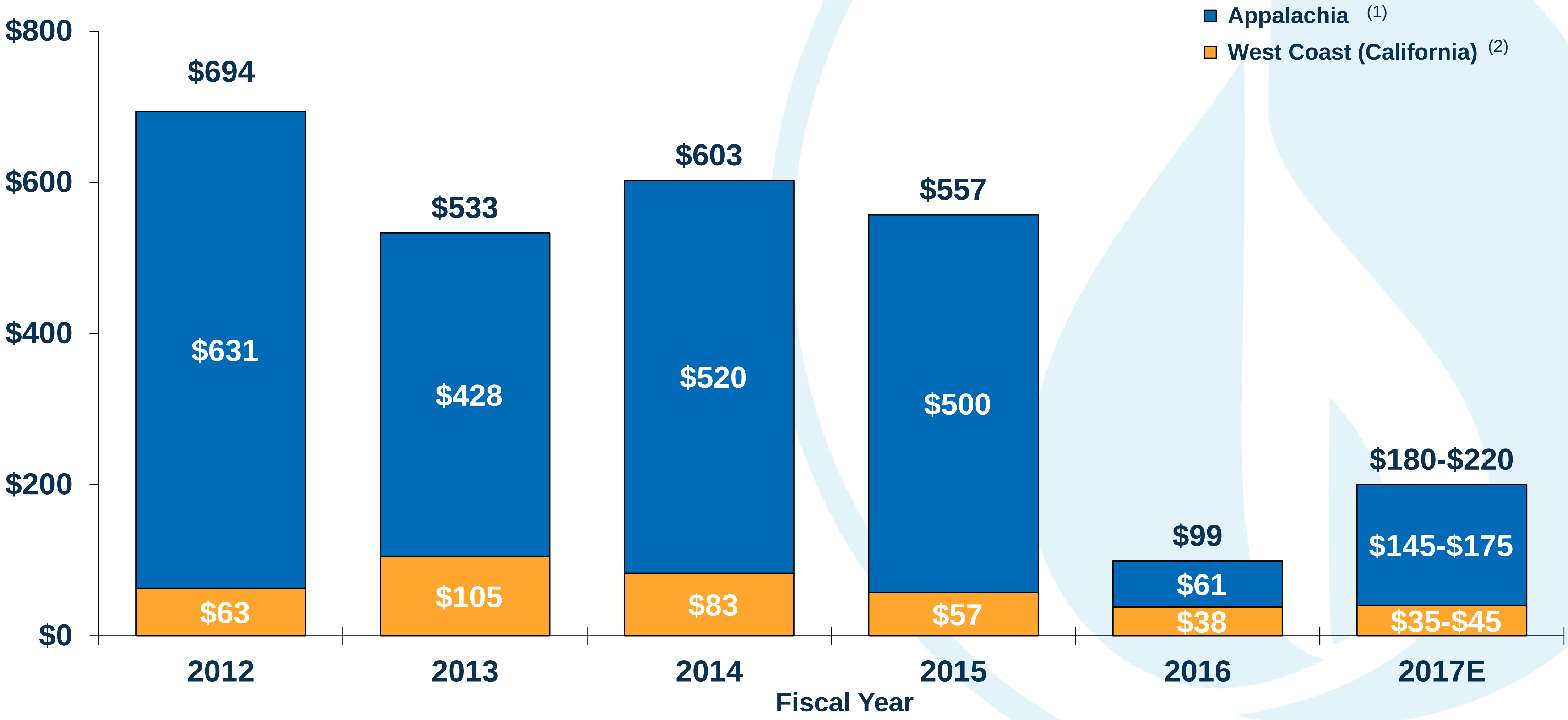
O&M Expense ($ millions)



Appendix

Seneca Resources

Capital Expenditures by Division ($ millions)



(1) FY2016 and FY 2017 capital expenditure guidance reflects the netting of up-front and recurring proceeds received from joint development partner for working interest in joint development wells.
(2) Seneca's West Coast division includes Seneca corporate and eliminations.

Seneca WDA Joint Development Agreement

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Transaction

On June 13, 2016, Seneca announced the extension of asset-level joint development agreement with IOG CRV – Marcellus Capital, LLC, an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group LLC, to jointly develop Marcellus Shale natural gas assets located in the Western Development Area.

Key Terms of the Agreement

- **Assets:** 75 current and future Marcellus development wells in the Clermont/Rich Valley region of Seneca's WDA.
- **Locations Developed Under Initial Obligation**: 39 wells
- **Remaining Locations to be Developed:** 36 wells
- **Partner Option:** IOG has one-time option to participate in a 7-well pad to be completed before December 31, 2017
- **Economics:** IOG participates as an 80% working interest owner until the IOG achieves a 15% IRR hurdle. Seneca retains a 7.5% royalty and remaining 20% working interest.

	Seneca	IOG
Working Interest	20%	80%
Net Revenue Interest	26%	74%

- **Natural Gas Marketing**: IOG to receive same realized price before hedging as Seneca on production from the joint development wells, including firm sales and the cost of firm transportation.

Strategic Rationale

- ✓ Significantly reduces near-term upstream capital spending
  - ***Initial 39 wells*** - $170 million(1)
  - ***Remaining 36 wells*** - $155 million(1)
- ✓ Validates quality of Seneca's Tier 1 Marcellus WDA acreage
- ✓ Seneca maintains activity levels to continue to drive Marcellus drilling and completion efficiencies
- ✓ Solidifies NFG's midstream growth strategy:
  - ***Gathering*** - All production from JV wells will flow through NFG Midstream's Clermont Gathering System
  - ***Pipeline & Storage*** - Provides production growth that will utilize the 660 MDth/d of firm transportation capacity on NFG's Northern Access pipeline expansion projects available starting Nov. 1, 2017
- ✓ Strengthened balance sheet and makes Seneca cash flow positive in near-term

(1) Estimated reduction in capital expenditures from joint development agreement assumes current wells costs.

Marcellus Operated Well Results

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WDA Development Wells:

Area	Producing Well Count	Average IP Rate (MMcfd)	Average 30-Day (MMcf/d)	Average Treatable Lateral Length (ft)
Clermont/Rich Valley (CRV) & Hemlock *Elk, Cameron & McKean counties*	113[1]	6.9	5.3	7,115'

EDA Development Wells:

Area	Producing Well Count	Average IP Rate (MMcfd)	Average 30-Day (MMcf/d)	Average Treatable Lateral Length (ft)
Covington Tioga County	47	5.2	4.1	4,023'
Tract 595 Tioga County	44[2]	7.4	4.9	4,754'
Tract 100 Lycoming County	60[2]	17.0	12.6	5,221'

(1) Excludes 2 wells now operated by Seneca that were drilled by another operator as part of a joint-venture. Excludes 2 wells producing from the Utica shale.
(2) Excludes 1 well each drilled into and producing from the Geneseo Shale in Tract 595 and Tract 100.

Marcellus Shale Program Economics

~1,150 Locations Economic Below $2.00/MMBtu

	Prospect	Product	Locations Remaining to Be Drilled	Completed Lateral Length (ft)	Average EUR (Bcf)	NYMEX / DAWN Pricing $3.00 IRR % (1)	NYMEX / DAWN Pricing $2.75 IRR % (1)	NYMEX / DAWN Pricing $2.50 IRR % (1)	Net Realized Price(2) Required for 15% IRR	Anticipated Delivery Market
EDA	DCNR 100	Dry Gas (1033 BTU)	12	5,700	13.5-14.5	84%	61%	42%	$1.44	Atlantic Sunrise Southeast US (NYMEX+)
EDA	Gamble	Dry Gas (1033 BTU)	42	4,250	10-11	57%	42%	25%	$1.60	
WDA	CRV	Dry Gas (1045 BTU)	50	8,000	8.5-9.5	29%	21%	14%	$1.77	Niagara Expansion Northern Access Canada (Dawn)/ TGP200
WDA	Hemlock/ Ridgway	Dry Gas (1045 BTU)	631	8,800	8-9	32%	23%	14%	$1.76	
WDA	Remaining Tier 1	Dry Gas (1045 BTU)	406	8,500	7-8	27%	18%	10%	$1.89	

(1) Internal Rate of Return (IRR) is pre-tax and includes estimated well costs under current cost structure, LOE, and Gathering tariffs anticipated for each prospect.
(2) Net realized price reflects either (a) price received at the well-head or (b) price received at delivery market net of firm transportation charges.

Hedge Positions

SENECA RESOURCES
A NATIONAL FUEL GAS COMPANY

Natural Gas Volumes in thousand MMBtu; Prices in $/MMBtu

	Fiscal 2017 (last 9 mos.)		Fiscal 2018		Fiscal 2019		Fiscal 2020		Fiscal 2021	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
NYMEX Swaps	27,780	$4.32	42,570	$3.34	27,060	$3.17	16,880	$3.07	4,840	$3.01
Dominion Swaps	3,630	$3.85	180	$3.82	-	-	-	-	-	-
Dawn Swaps	12,990	$3.63	8,400	$3.08	7,200	$3.00	7,200	$3.00	600	$3.00
Fixed Price Physical(1)	45,029	$2.60	32,928	$2.43	11,947	$3.09	3,567	$3.24	-	-
Total	**89,429**	**$3.33**	**84,078**	**$2.96**	**46,207**	**$3.13**	**27,647**	**$3.07**	**5,440**	**$3.01**

Crude Oil Volumes & Prices in Bbl

	Fiscal 2017 (last 9 mos.)		Fiscal 2018		Fiscal 2019	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Brent Swaps	72,000	$91.00	24,000	$91.00	-	-
NYMEX Swaps	1,163,000	$58.40	1,119,000	$55.38	756,000	$54.60
Total	**1,235,000**	**$60.30**	**1,143,000**	**$56.13**	**756,000**	**$54.60**

(1) Fixed price physical sales exclude joint development partner's share of fixed price contract WDA volumes as specified under the joint development agreement.

Comparable GAAP Financial Measure Slides & Reconciliations

This presentation contains certain non-GAAP financial measures. For pages that contain non-GAAP financial measures, pages containing the most directly comparable GAAP financial measures and reconciliations are provided in the slides that follow.

The Company believes that its non-GAAP financial measures are useful to investors because they provide an alternative method for assessing the Company's ongoing operating results and for comparing the Company's financial performance to other companies. The Company's management uses these non-GAAP financial measures for the same purpose, and for planning and forecasting purposes. The presentation of non-GAAP financial measures is not meant to be a substitute for financial measures prepared in accordance with GAAP.

The Company defines Adjusted EBITDA as reported GAAP earnings before the following items: interest expense, depreciation, depletion and amortization, interest and other income, impairments, items impacting comparability and income taxes.

Non-GAAP Reconciliations – Adjusted EBITDA

National Fuel®

Reconciliation of Adjusted EBITDA to Consolidated Net Income
($ Thousands)

	FY 2013	FY 2014	FY 2015	FY 2016	12-Months Ended 12/31/16
Total Adjusted EBITDA					
Exploration & Production Adjusted EBITDA	$ 492,383	$ 539,472	$ 422,289	$ 363,830	375,166
Pipeline & Storage Adjusted EBITDA	161,226	186,022	188,042	199,446	196,719
Gathering Adjusted EBITDA	29,777	64,060	68,881	78,685	87,328
Utility Adjusted EBITDA	171,669	164,643	164,037	148,683	155,096
Energy Marketing Adjusted EBITDA	6,963	10,335	12,237	6,655	7,655
Corporate & All Other Adjusted EBITDA	(9,920)	(11,078)	(11,900)	(8,238)	(9,328)
Total Adjusted EBITDA	**$ 852,098**	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 812,636**
Total Adjusted EBITDA	**$ 852,098**	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 812,636**
Minus: Interest Expense	(94,111)	(94,277)	(99,471)	(121,044)	(119,305)
Plus: Interest and Other Income	9,032	13,631	11,961	14,055	13,052
Minus: Income Tax Expense	(172,758)	(189,614)	319,136	232,549	31,767
Minus: Depreciation, Depletion & Amortization	(326,760)	(383,781)	(336,158)	(249,417)	(235,062)
Minus: Impairment of Oil and Gas Properties (E&P)	-	-	(1,126,257)	(948,307)	(512,856)
Plus: Reversal of Stock-Based Compensation	-	-	7,776	-	-
Plus: Elimination of Other Post-Retirement Regulatory Liability (P&S)	-	-	-	-	-
Minus: Pennsylvania Impact Fee Related to Prior Fiscal Years (E&P)	-	-	-	-	-
Minus: New York Regulatory Adjustment (Utility)	(7,500)	-	-	-	-
Minus: Joint Development Agreement Professional Fees	-	-	-	(7,855)	(3,173)
Rounding	-	-	-	-	-
Consolidated Net Income	**$ 260,001**	**$ 299,413**	**$ (379,427)**	**$ (290,958)**	**$ (12,941)**
Consolidated Debt to Total Adjusted EBITDA					
Long-Term Debt, Net of Current Portion (End of Period)	$ 1,649,000	$ 1,649,000	$ 2,099,000	$ 2,099,000	$ 2,099,000
Current Portion of Long-Term Debt (End of Period)	-	-	-	-	-
Notes Payable to Banks and Commercial Paper (End of Period)	-	85,600	-	-	-
Total Debt (End of Period)	$ 1,649,000	$ 1,734,600	$ 2,099,000	$ 2,099,000	$ 2,099,000
Long-Term Debt, Net of Current Portion (Start of Period)	1,149,000	1,649,000	1,649,000	2,099,000	2,099,000
Current Portion of Long-Term Debt (Start of Period)	250,000	-	-	-	-
Notes Payable to Banks and Commercial Paper (Start of Period)	171,000	-	85,600	-	31,400
Total Debt (Start of Period)	$ 1,570,000	$ 1,649,000	$ 1,734,600	$ 2,099,000	$ 2,130,400
Average Total Debt	**$ 1,609,500**	**$ 1,691,800**	**$ 1,916,800**	**$ 2,099,000**	**$ 2,114,700**
Average Total Debt to Total Adjusted EBITDA	**1.89 x**	**1.77 x**	**2.27 x**	**2.66 x**	**2.60 x**

Non-GAAP Reconciliations – Capital Expenditures

Reconciliation of Segment Capital Expenditures to Consolidated Capital Expenditures ($ Thousands)	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017 Forecast
Capital Expenditures from Continuing Operations					
Exploration & Production Capital Expenditures	$ 533,129	$ 602,705	$ 557,313	$ 256,104	$180,000 - $220,000
Pipeline & Storage Capital Expenditures	$ 56,144	$ 139,821	$ 230,192	$ 114,250	$200,000 - $250,000
Gathering Segment Capital Expenditures	$ 54,792	$ 137,799	$ 118,166	$ 54,293	$65,000 - $75,000
Utility Capital Expenditures	$ 71,970	$ 88,810	$ 94,371	$ 98,007	$90,000 - $100,000
Energy Marketing, Corporate & All Other Capital Expenditures	$ 1,062	$ 772	$ 467	$ 397	
Total Capital Expenditures from Continuing Operations	$ 717,097	$ 969,907	$ 1,000,509	$ 523,051	$535,000 - $645,000
Plus (Minus) Accrued Capital Expenditures					
Exploration & Production FY 2016 Accrued Capital Expenditures	$ -	$ -	$ -	$ (25,215)	
Exploration & Production FY 2015 Accrued Capital Expenditures	-	-	(46,173)	46,173	
Exploration & Production FY 2014 Accrued Capital Expenditures	-	(80,108)	80,108	-	
Exploration & Production FY 2013 Accrued Capital Expenditures	(58,478)	58,478	-	-	
Exploration & Production FY 2012 Accrued Capital Expenditures	38,861	-	-	-	
Exploration & Production FY 2011 Accrued Capital Expenditures	-	-	-	-	
Pipeline & Storage FY 2016 Accrued Capital Expenditures	-	-	-	(18,661)	
Pipeline & Storage FY 2015 Accrued Capital Expenditures	-	-	(33,925)	33,925	
Pipeline & Storage FY 2014 Accrued Capital Expenditures	-	(28,122)	28,122	-	
Pipeline & Storage FY 2013 Accrued Capital Expenditures	(5,633)	5,633	-	-	
Pipeline & Storage FY 2012 Accrued Capital Expenditures	12,699	-	-	-	
Pipeline & Storage FY 2011 Accrued Capital Expenditures	-	-	-	-	
Gathering FY 2016 Accrued Capital Expenditures	-	-	-	(5,355)	
Gathering FY 2015 Accrued Capital Expenditures	-	-	(22,416)	22,416	
Gathering FY 2014 Accrued Capital Expenditures	-	(20,084)	20,084	-	
Gathering FY 2013 Accrued Capital Expenditures	(6,700)	6,700	-	-	
Gathering FY 2012 Accrued Capital Expenditures	12,690	-	-	-	
Gathering FY 2011 Accrued Capital Expenditures	-	-	-	-	
Utility FY 2016 Accrued Capital Expenditures	-	-	-	(11,203)	
Utility FY 2015 Accrued Capital Expenditures	-	-	(16,445)	16,445	
Utility FY 2014 Accrued Capital Expenditures	-	(8,315)	8,315	-	
Utility FY 2013 Accrued Capital Expenditures	(10,328)	10,328	-	-	
Utility FY 2012 Accrued Capital Expenditures	3,253	-	-	-	
Utility FY 2011 Accrued Capital Expenditures	-	-	-	-	
Total Accrued Capital Expenditures	$ (13,636)	$ (55,490)	$ 17,670	$ 58,525	
Total Capital Expenditures per Statement of Cash Flows	**$ 703,461**	**$ 914,417**	**$ 1,018,179**	**$ 581,576**	**$535,000 - $645,000**

Non-GAAP Reconciliations – E&P Adjusted EBITDA

Reconciliation of Exploration & Production Adjusted EBITDA for Appalachia and West Coast divisions to Exploration & Production Segment Net Income ($ Thousands)

	Three Months Ended December 31, 2016			Twelve Months Ended December 31, 2016		
	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P
Reported GAAP Earnings	**$ 26,363**	**$ 8,717**	**$ 35,080**	**$ (183,770)**	**$ 3,094**	**$ (180,676)**
Depreciation, Depletion and Amortization	23,694	5,359	29,053	101,972	23,011	124,983
Interest and Other Income	(87)	1	(86)	(267)	(10)	(277)
Interest Expense	13,175	348	13,523	52,469	1,906	54,375
Income Taxes	18,182	6,724	24,906	(135,198)	(4,070)	(139,268)
Impairment of Oil and Gas Producing Properties	-	-	-	442,729	70,127	512,856
Joint Development Agreement Professional Fees	-	-	-	3,173	-	3,173
Adjusted EBITDA	**$ 81,327**	**$ 21,149**	**$ 102,476**	**$ 281,108**	**$ 94,058**	**$ 375,166**

	Appalachia	West Coast	Total E&P	Appalachia	West Coast	Total E&P
Production:						
Gas Production (MMcf)	39,807	776	40,583	147,476	3,083	150,559
Oil Production (MBbl)	-	721	721	22	2,874	2,896
Total Production (Mmcfe)	39,807	5,102	44,909	147,608	20,327	167,935
Adjusted EBITDA Margin per Mcfe	**$ 2.04**	**NM**	**$ 2.28**	**$ 1.90**	**$ 4.63**	**$ 2.23**
Total Production (Mboe)	NM	850	NM	NM	3,388	NM
Adjusted EBITDA Margin per Boe	**NM**	**$ 24.88**	**NM**	**NM**	**$ 27.76**	**NM**

Note: Seneca West Coast division includes Seneca corporate and eliminations.

Non-GAAP Reconciliations – E&P Operating Expenses

National Fuel®

Reconciliation of Exploration & Production Segment Operating Expenses by Division
($000s unless noted otherwise)

	Twelve Months Ended September 30, 2016						Twelve Months Ended September 30, 2015					
	Appalachia	West Coast[2]	Total E&P	Appalachia	West Coast[2]	Total E&P	Appalachia	West Coast[2]	Total E&P	Appalachia	West Coast[2]	Total E&P
				$/ Mcfe	*$ / Boe*	*$ / Mcfe*				*$/ Mcfe*	*$ / Boe*	*$ / Mcfe*
Operating Expenses:												
Gathering & Transportation Expense [1]	$82,949	$309	$83,258	$0.59	$0.09	$0.52	$81,212	$435	$81,647	$0.59	$0.12	$0.52
Lease Operating Expense	$20,402	$50,254	$70,656	$0.14	$14.74	$0.44	$29,510	$56,643	$86,153	$0.22	$16.04	$0.54
Lease Operating and Transportation Expense	$103,351	$50,563	$153,914	$0.73	$14.83	$0.96	$110,722	$57,078	$167,800	$0.81	$16.17	$1.06
General & Administrative Expense	$55,293	$15,305	$70,598	$0.39	$4.49	$0.44	$47,445	$18,669	$66,114	$0.35	$5.29	$0.42
All Other Operating and Maintenance Expense	$6,228	$6,604	$12,832	$0.04	$1.94	$0.08	$5,296	$9,008	$14,304	$0.04	$2.55	$0.09
Property, Franchise and Other Taxes	$5,403	$8,391	$13,794	$0.04	$2.46	$0.09	$9,046	$11,121	$20,167	$0.07	$3.15	$0.13
Total Taxes & Other	$11,631	$14,995	$26,626	$0.08	$4.40	$0.17	$14,342	$20,129	$34,471	$0.11	$5.70	$0.22
Depreciation, Depletaion & Amortization			$139,963			$0.87			$239,818			$1.52
Production:												
Gas Production (MMcf)				140,457	3,090	143,547				136,404	3,159	139,563
Oil Production (MBbl)				28	2,895	2,923				30	3,004	3,034
Total Production (Mmcfe)				140,625	20,460	161,085				136,584	21,183	157,767
Total Production (Mboe)				23,438	3,410	26,848				22,764	3,531	26,295

(1) Gathering and Transportation expense is net of any payments received from JDA partner for the partner's share of gathering cost
(2) Seneca West Coast division includes Seneca corporate and eliminations.