UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): August 3, 2017

NATIONAL FUEL GAS COMPANY
(Exact name of registrant as specified in its charter)

New Jersey	1-3880	13-1086010
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

6363 Main Street, Williamsville, New York	14221
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (716) 857-7000

Former name or former address, if changed since last report: Not Applicable

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 2.02 Results of Operations and Financial Condition.

On August 3, 2017, National Fuel Gas Company (the "Company") updated its Investor Presentation. A copy of the presentation is furnished as part of this Current Report as Exhibit 99.

Neither the furnishing of the presentation as an exhibit to this Current Report nor the inclusion in such presentation of any reference to the Company's internet address shall, under any circumstances, be deemed to incorporate the information available at such internet address into this Current Report. The information available at the Company's internet address is not part of this Current Report or any other report filed or furnished by the Company with the Securities and Exchange Commission.

In addition to financial measures calculated in accordance with generally accepted accounting principles ("GAAP"), the presentation furnished as part of this Current Report as Exhibit 99 contains certain non-GAAP financial measures. The Company believes that such non-GAAP financial measures are useful to investors because they provide an alternative method for assessing the Company's operating results in a manner that is focused on the performance of the Company's ongoing operations, for measuring the Company's cash flow and liquidity, 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.

Certain statements contained herein or in the materials furnished as part of this Current Report, including statements regarding estimated future earnings and statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will" and "may" and similar expressions, are "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. There can be no assurance that the Company's projections will in fact be achieved nor do these projections reflect any acquisitions or divestitures that may occur in the future. While the Company's expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis, actual results may differ materially from those projected in forward-looking statements. Furthermore, each forward-looking statement speaks only as of the date on which it is made. In addition to other factors, the following are important factors that 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 sold 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 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; 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; or increasing costs of insurance, changes in coverage and the ability to obtain insurance. The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit 99 Investor Presentation dated August 2017

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

NATIONAL FUEL GAS COMPANY

By: /s/ Sarah J. Mugel
Sarah J. Mugel
Assistant Secretary

Dated: August 3, 2017

EXHIBIT INDEX

Exhibit Number	Description
99	Investor Presentation dated August 2017

Exhibit 99

National Fuel®

Investor Presentation

Q3 Fiscal 2017 Update
August 3, 2017

Safe Harbor For Forward Looking Statements

National Fuel

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 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; 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; 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, March 31, 2017 and June 30, 2017. 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.

NFG: A Diversified, Integrated Natural Gas Company

Upstream
E&P

Developing our large, high quality acreage position in Marcellus & Utica shales with a focus on returns

785,000
Net acres in Appalachia

Midstream
Gathering
Pipeline & Storage

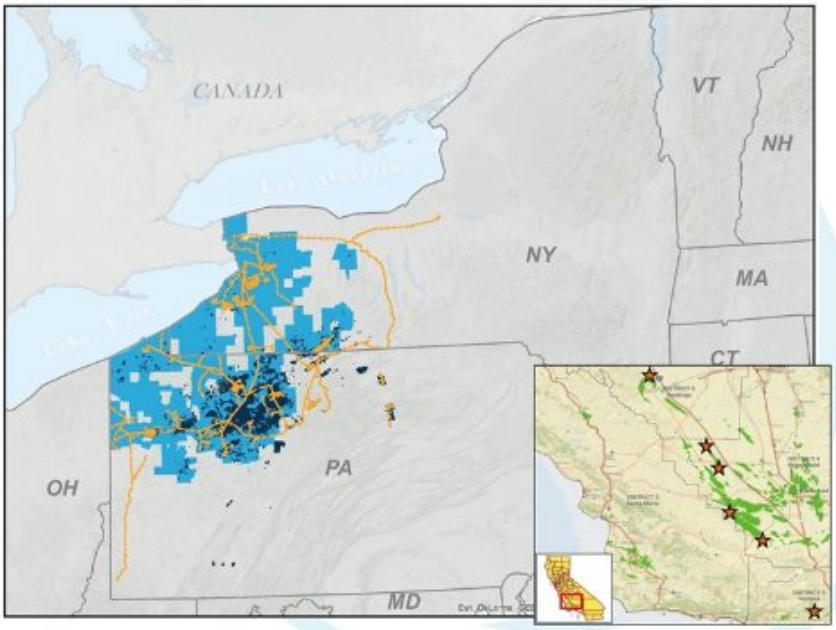
Expanding and modernizing pipeline infrastructure to provide access to Appalachian supplies

$282 million[1]
Annual Adjusted EBITDA

Downstream
Utility
Energy Marketing

Providing significant base of stable, regulated earnings & cash flows

740,000
Utility customer accounts in NY & PA

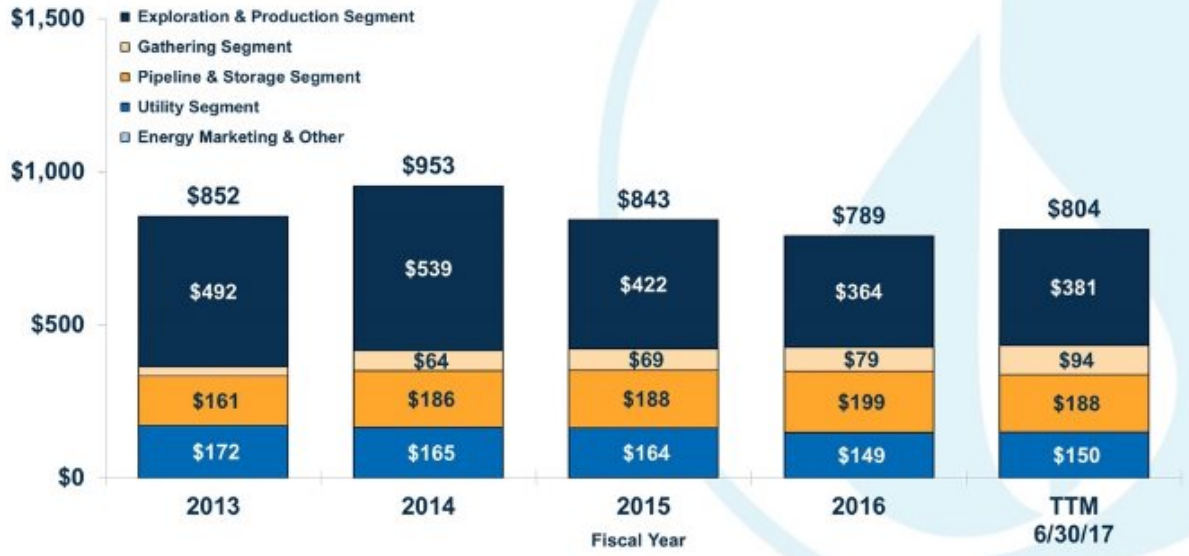


(1) For the trailing twelve months ended June 30, 2017. A reconciliation of Adjusted EBITDA to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.

Balanced Earnings and Cash Flows

National Fuel

Adjusted EBITDA by Segment ($ millions)[1]

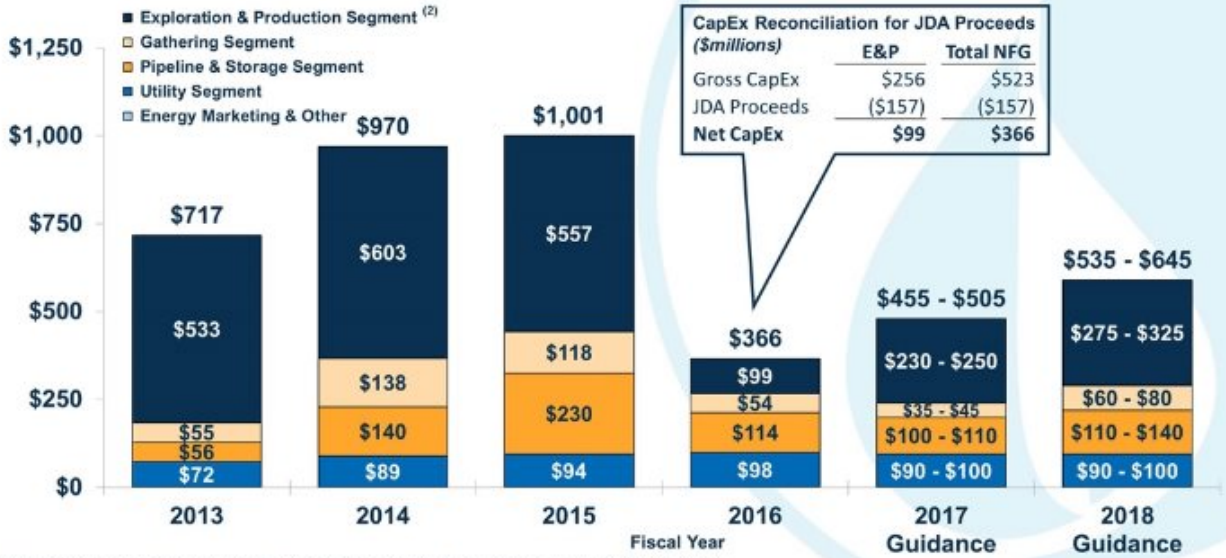


(1) A reconciliation of Adjusted EBITDA to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.

Disciplined, Flexible Capital Allocation

National Fuel

Capital Expenditures by Segment ($ millions)[1]



CapEx Reconciliation for JDA Proceeds

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

(1) A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.
(2) 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 and FY 2018 guidance also reflects the netting of anticipated proceeds received from the joint development partner.

Near-term Growth Strategy

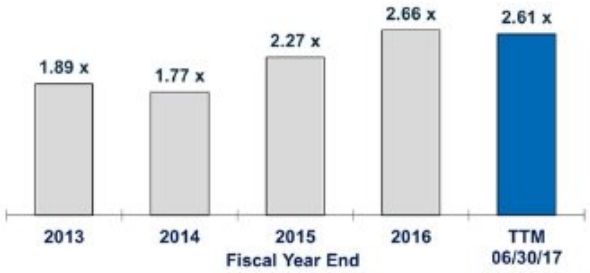
National Fuel

National Fuel Will Continue to Grow Integrated Businesses While We Sort Through Northern Access Delay

Exploration & Production Strategy	✓ **Grow Marcellus and Utica production at a 10%+ CAGR over next 3 years** ▪ ***WDA Development (1-rig program)*** ▪ Return to developing 100% NRI Seneca wells post-JDA in FY18 ▪ Optimize Utica D&C designs and transition to a Utica development program by FY19 ▪ ***EDA Development (1-rig program)*** ▪ Develop highly economic acreage in Lycoming County and prepare well inventory for Atlantic Sunrise capacity ▪ Commence Utica development in FY18 at Tract 007 (Tioga County) to add another 100 to 150 MMcf/d by FY20
Midstream Strategy	✓ **Gathering: System throughput and revenues will benefit from Seneca's production growth** ▪ Minimal incremental investment required to accommodate Seneca's WDA Utica development ✓ **Pipeline & Storage: Opportunities for system expansion and modernization** ▪ Foundation shipper agreements in place for Empire North Project and new Line N expansion ▪ Need for system modernization will result in Pipeline & Storage rate base growth
Corporate Strategy	✓ **Near-term improvement in balance sheet/credit metrics** ✓ **Maintain commitment to growing the dividend** ✓ **Continue to leverage operational, financial and strategic benefits of the integrated model**

Strong Balance Sheet & Liquidity

Debt/Adjusted EBITDA



Capitalization

$3.7 Billion Total Capitalization as of June 30, 2017

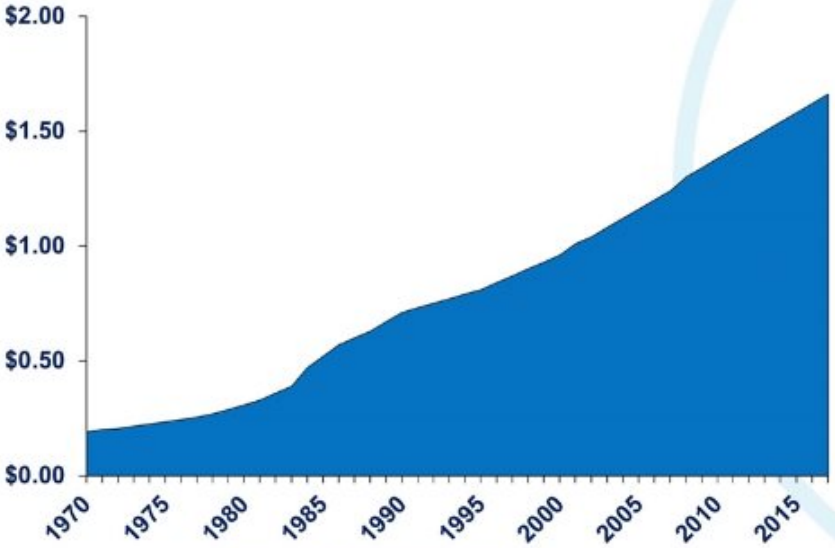
Debt Maturity Profile ($MM)

Liquidity

Committed Credit Facilities	$ 1,250 MM
Short-term Debt Outstanding	$ 0 MM
Available Short-term Credit Facilities	$ 1,250 MM
Cash Balance at 06/30/17	$ 285 MM
Total Liquidity at 06/30/17	**$ 1,535 MM**

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

Committed to the Dividend



NFG's Dividend Consistency

Consecutive Payments	115 Years
Consecutive Increases	47 Years
Current Dividend Rate	$1.66 per Share
Current Dividend Yield (1)	2.8%

(1) As of August 3, 2017.

Upstream Overview

Exploration & Production

Growing Production within Disciplined Capital Program

SENECA RESOURCES

E&P Net Capital Expenditures[1] ($ millions)

E&P Net Production (Bcfe)

Seneca's Near-term Operational Plan

Appalachia Natural Gas

- ✓ 2-rig development program
- ✓ Target 10%+ production 3-year CAGR
- ✓ Resume development on prolific Marcellus acreage in Lycoming County, Pa.
- ✓ Return to developing 100% NRI wells in the WDA (last JDA pad expected on-line in 1H FY18)
- ✓ Transition to Utica development in WDA and EDA in FY18/19
- ✓ Layer-in firm sales to reduce spot market risk and take advantage of attractive regional pricing

California Oil

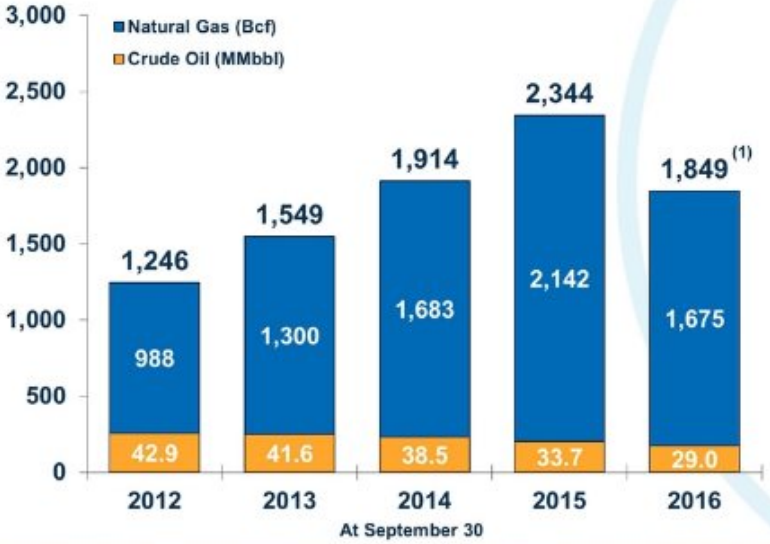
- ✓ Flat to modest growth on minimal capital investment
- ✓ Development focus on new farm-in acreage in Midway Sunset
- ✓ Low capital and operational costs generate FCF at $50/bbl

(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 and FY 2018 guidance also reflects the netting of anticipated proceeds received from the joint development partner.

Proved Reserves

SENECA RESOURCES

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 68 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.

Significant Appalachian Acreage Position

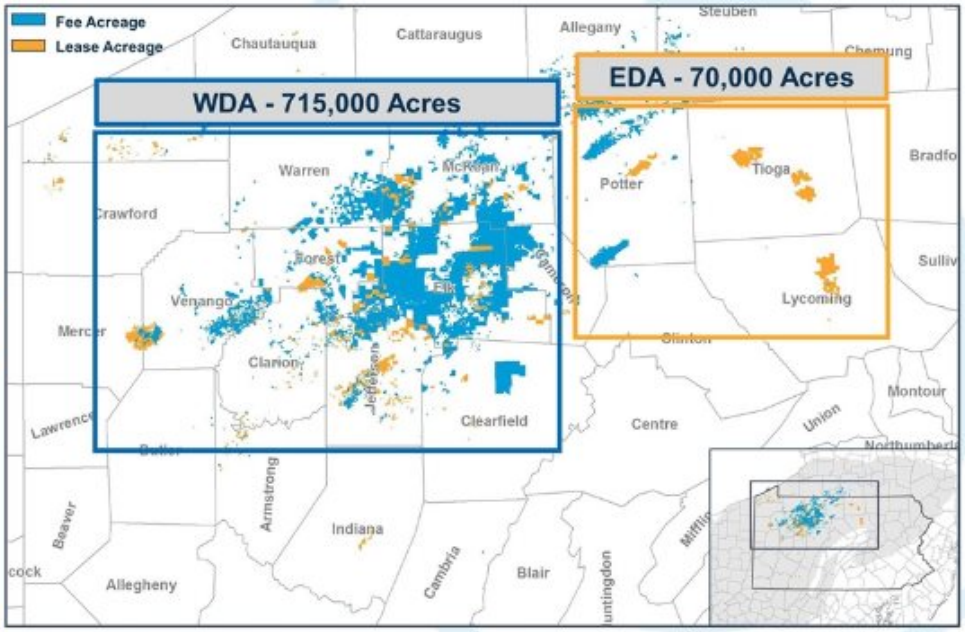
SENECA RESOURCES

Western Development Area (WDA)

- Current gross production: ~340 MMcf/d
- Large inventory of high quality Marcellus and Utica acreage economic under $2.00/Mcf
- Fee ownership – lack of royalty enhances economics
- Highly contiguous nature drives cost and operational efficiencies

Eastern Development Area (EDA)

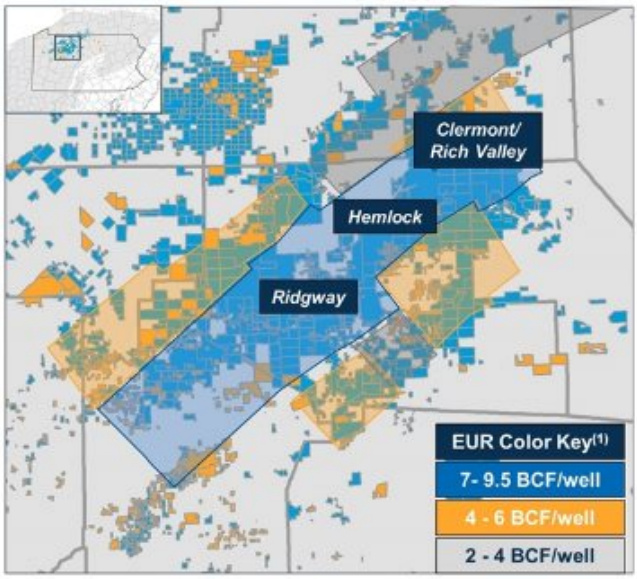
- Current gross production: ~255 MMcf/d
- Mostly leased (16-18% royalty) with no significant near-term lease expirations
- > 100 remaining Marcellus and Utica locations economic under $1.80/Mcf
- Additional Utica & Geneseo potential
- Near-term development tailored to fill capacity on Atlantic Sunrise in mid-2018



Western Development Area

SENECA RESOURCES

WDA Marcellus Tier 1 Acreage – 200,000 Acres



- ✓ **Significant multi-zone drilling inventory economic under $2.00 /Mcf**
  - Marcellus Shale : 1,000+ well locations
  - Utica Shale: 125 to 500+ well locations (2)
- ✓ **Fee acreage / stacked pay provides flexibility & enhances economics**
  - No royalty or lease expirations on most acreage
  - Expected Utica development will re-use existing upstream and midstream infrastructure to maximize ROI
- ✓ **Highly contiguous position drives best in class well costs**
  - Multi-well pad drilling with laterals approaching 8,000 ft.
  - Water management operations lowering water costs to under $1 /Bbl
- ✓ **Long-term firm sales and firm transport contracts support growth**
  - Recently added fixed price deals through FY24 at $2.30 to $2.40 /MMBtu

WDA Firm Contracts

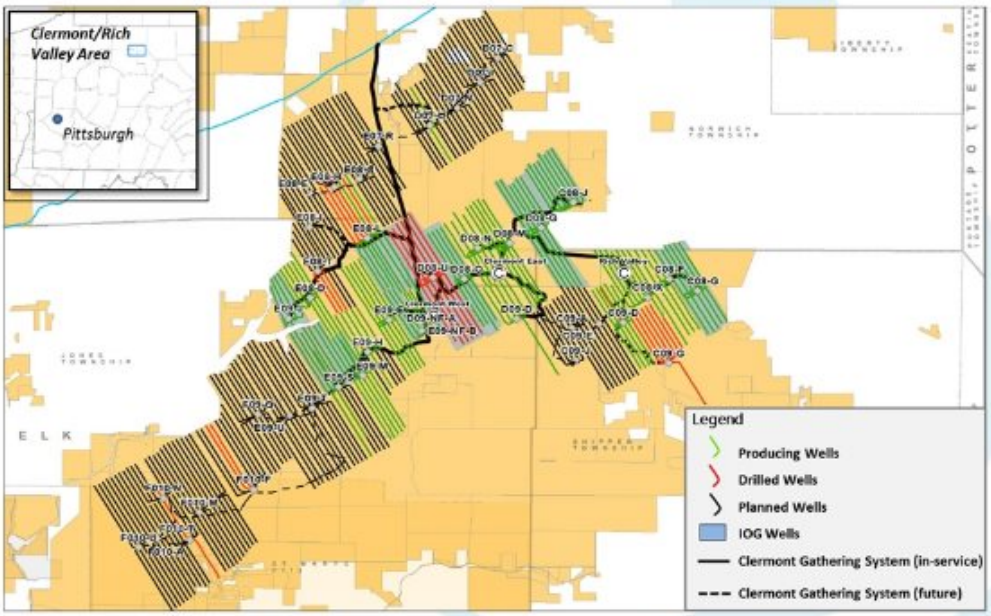
(1) Marcellus EURs only.
(2) The Utica Shale lies approx. 5,000 feet beneath Seneca's WDA Marcellus acreage. Appraisal program currently in progress to determine extent of economic Utica inventory on acreage.

WDA Marcellus: Clermont/Rich Valley Development

SENECA RESOURCES

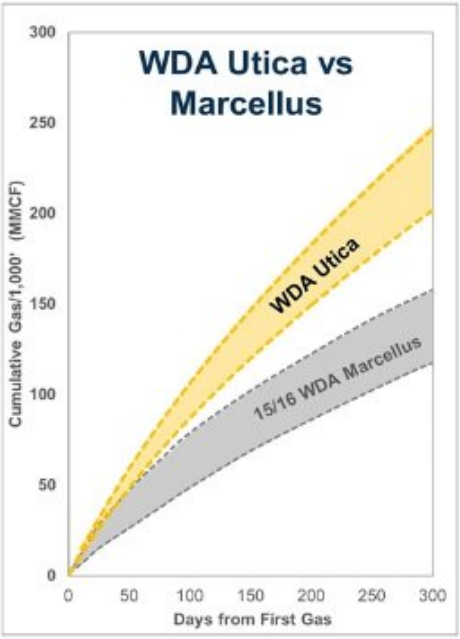
CRV Development Summary

- Gross daily production: ~315 MMcf/d
- 1-rig / daylight only frac crew
- Developing 75 Marcellus wells with joint development partner (IOG)
  - 75 wells drilled
  - 63 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



WDA Utica: Early Results and Economic Impact

SENECA RESOURCES



Utica Early Test Results:

- ✓ Drawdown management is important
  - Restricted drawdown improves well EURs
- ✓ Higher pressure significantly enhances well productivity
  - (Utica ~5,000' deeper than Marcellus)
- ✓ Completion design
  - Successful results without high strength proppant indicate completion costs will be on par with the Marcellus

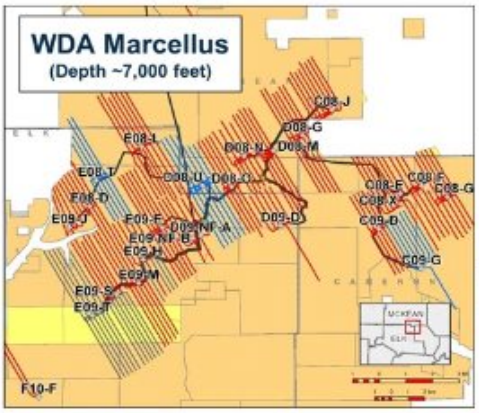
Utica Economic Impact:

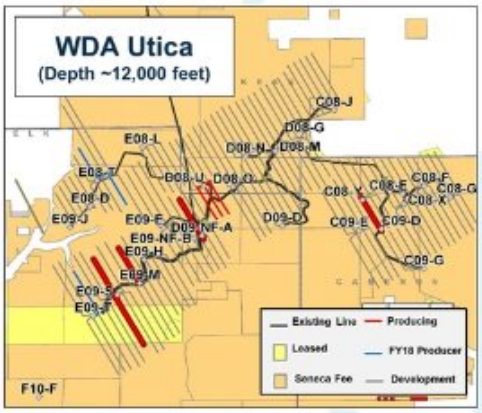
- ✓ Utica generates lower F&D costs and higher returns than WDA Marcellus
  - 60-80% higher EUR for ~35% higher capital cost
- ✓ Leverage existing upstream and midstream infrastructure
  - Over 125 well locations with established midstream and upstream infrastructure
  - Enhances IRRs on consolidated upstream / midstream investment

WDA Utica: Transition to Development

SENECA RESOURCES

Seneca and NFG Midstream can leverage existing upstream and midstream infrastructure to drive capital, operational, and marketing efficiencies





NEXT STEPS:

FY 2018: Optimize D&C design

- ✓ Continue Marcellus development
- ✓ Test 5 more Utica wells off Marcellus pads
- ✓ Optimize stage spacing, landing zone targets, and well spacing

FY 2019+: Transition to Utica development

- ✓ 125+ Utica well locations in WDA-CRV with ability to reuse existing pad, water and gathering infrastructure
- ✓ Expect Utica WDA development costs to be $5.0 to $6.0 million per well

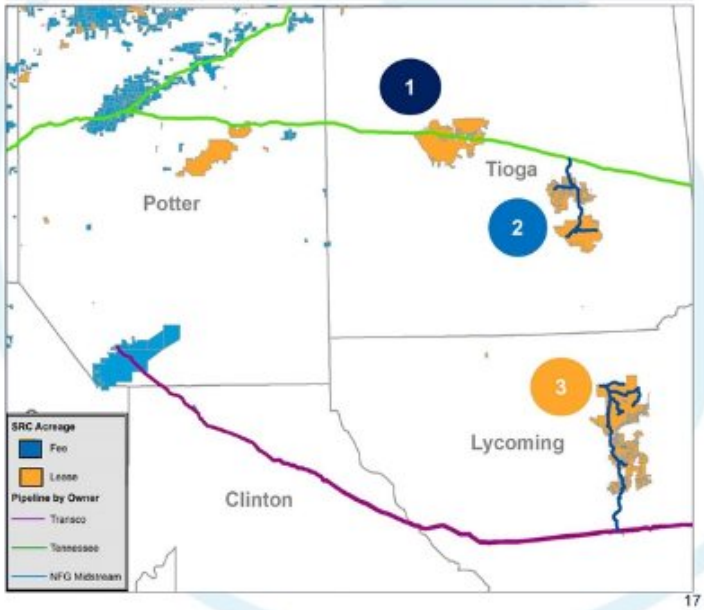
Eastern Development Area

SENECA RESOURCES

EDA Highlights

1. **DCNR Tract 007 (Tioga Co., Pa)**
   - 1 Utica and 1 Marcellus producing well
   - Utica 30-day IP = 15.8 MMcf/d
   - Utica development expected to begin in fiscal 2018
   - 59 remaining Utica locations economic under $1.95 /Mcf
2. **Covington & DCNR Tract 595 (Tioga Co., Pa.)**
   - Gross daily production: ~85 MMcf/d
   - Marcellus locations fully developed
   - Opportunity for future Utica appraisal
3. **DCNR Tract 100 & Gamble (Lycoming Co., Pa.)**
   - Gross daily production: ~160 MMcf/d
   - 63 remaining Marcellus locations economic < $1.65 /Mcf
   - Atlantic Sunrise capacity (190 MDth/d) in mid-2018
   - Geneseo shale to provide 100-120 additional locations

EDA Acreage – 70,000 Acres

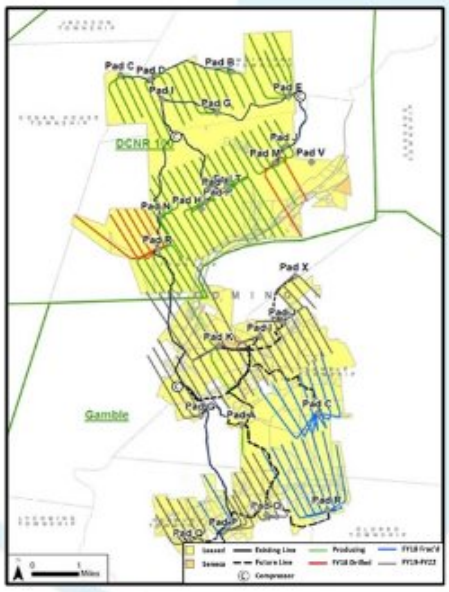


EDA Marcellus: Lycoming County Development

SENECA RESOURCES

Marcellus Development in Lycoming County has Resumed in Anticipation of Atlantic Sunrise

- ✓ **Prolific Marcellus acreage with peer leading well results**
  - 60 Marcellus wells producing w/ average IP rate of 17.0 MMcf/d
  - 63 remaining Marcellus locations economic under $1.65 /Mcf
- ✓ **Near-term development focused on filling Atlantic Sunrise capacity forecasted to be available in July 2018**



EDA Utica: Tioga County Development

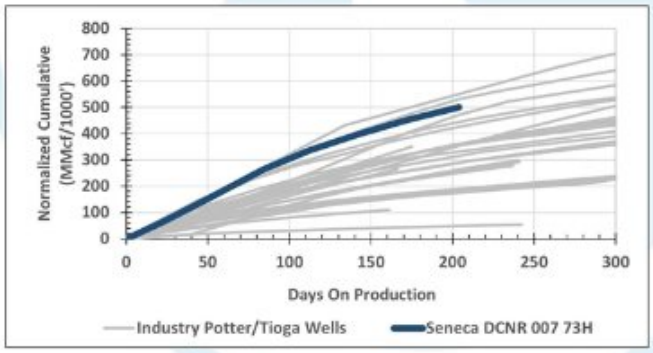
SENECA RESOURCES

Utica Development in Tioga County – Tract 007 Expected to Begin in FY18

- ✓ **Inventory:** 59 locations economic under $1.95 /Mcf
  - Targeting to grow production by 100 to 150 MDth/d by FY20
- ✓ **Expected Development Costs:** $5.5 to $6.5 million per well
- ✓ **Gathering Infrastructure:** NFG Midstream Wellsboro
  - Modest build-out required to connect to TGP 300
- ✓ **Sales/Takeaway Strategy:** TGP 300 (Marcellus Zone 4)
  - Recently executed firm sales at fixed prices $2.00 to $2.15 per Dth extending from 2019 to 2024

	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

EDA – TGP 300 Firm Contracts

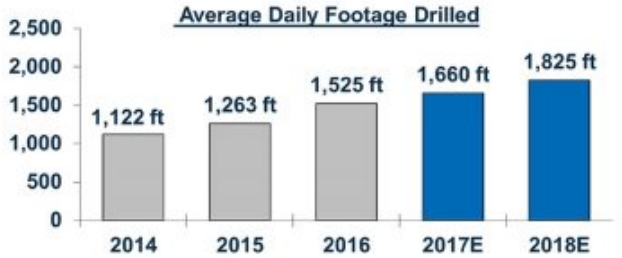


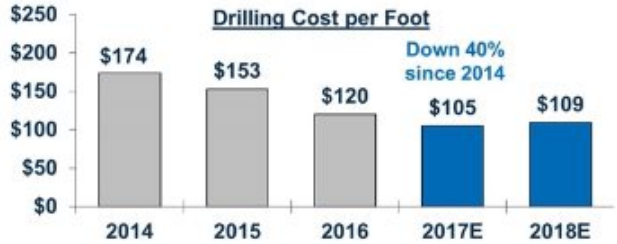
Marcellus: Drilling & Completions Efficiencies

SENECA RESOURCES

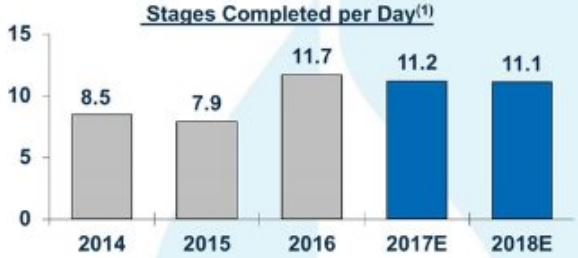
Operational Efficiencies and Investment in Water Infrastructure Have Resulted in Peer Leading Well Costs

Marcellus Drilling





Marcellus Completions



(1) Normalized to adjust for daylight only frac operations that began in 2016.

Appalachia Drilling Program Economics

SENECA RESOURCES

~1,300 Locations Economic Below $2.00/MMBtu[1]

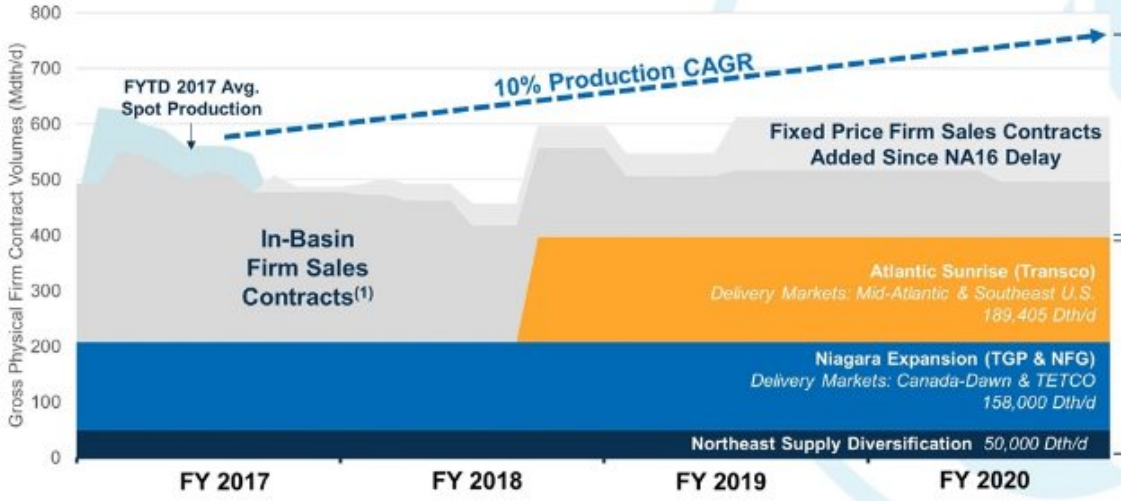
	Prospect	Reservoir	Locations Remaining to Be Drilled	Completed Lateral Length (ft)	Average EUR (Bcf)	Internal Rate of Return % [2]			Realized Price[1] Required for 15% IRR	Anticipated Delivery Markets
						$2.50 Realized	$2.25 Realized	$2.00 Realized		
EDA	DCNR 100 *Lycoming*	Marcellus	11	5,600	13.5-14.5	88%	67%	48%	$1.52	Transco Leidy & Atlantic Sunrise Southeast US (NYMEX+)
EDA	Gamble *Lycoming*	Marcellus	52	4,700	10.5-11.5	66%	50%	36%	$1.64	
EDA	DCNR 007 *Tioga*	Utica	59	7,000	12.5-13.5	42%	28%	17%	$1.94	TGP 300
WDA	CRV	Utica	125 - 500+	7,500	13-14	40%	30%	22%	$1.77	TGP 300 & Niagara Expansion Canada (Dawn)
WDA	CRV	Marcellus	14	8,000	8.5-9.5	35%	26%	19%	$1.86	
WDA	Hemlock/ Ridgway	Marcellus	631	8,800	8-9	32%	25%	17%	$1.92	
WDA	Remaining Tier 1	Marcellus	406	8,500	7-8	33%	25%	17%	$1.95	

(1) Net realized price reflects either (a) price received at the gathering system interconnect or (b) price received at delivery market net of firm transportation charges.
(2) 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.

Long-term Contracts Supporting Appalachian Production

SENECA RESOURCES

Seneca will continue to layer-in firm sales contracts with attractive realizations at regional pricing points to lock-in drilling economics and minimize spot exposure as it waits for Northern Access



Regional Firm Sales

- Converting 95 Mdth/d of Northern Access sales from Dawn back to basin
- Recent deals providing attractive realizations
- Further regional basis improvement expected as pipeline projects are placed in-service

Firm Transportation

Long-term firm sales contracts in place at physical delivery points realizing NYMEX / Dawn less transport cost

(1) Represents 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.

Firm Transportation Commitments

SENECA RESOURCES

		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
Currently In-Service	**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
Currently In-Service			12,000	TETCO (SE Pa.)	NFG pipelines = $0.12	
Future Capacity	**Atlantic Sunrise** *WMB - Transco In-service: Mid-2018*	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
Future Capacity	**Northern Access** *NFG – Supply & Empire Delayed*	WDA – Clermont/ Rich Valley	350,000	Canada (Dawn)	NFG pipelines = $0.50 3rd party = $0.21	Firm Sales Contracts At Dawn When Project Goes In-Service
Future Capacity			140,000	TGP 200 (NY)	NFG pipelines = $0.38	

Firm Sales Provide Market for Appalachian Production

SENECA RESOURCES

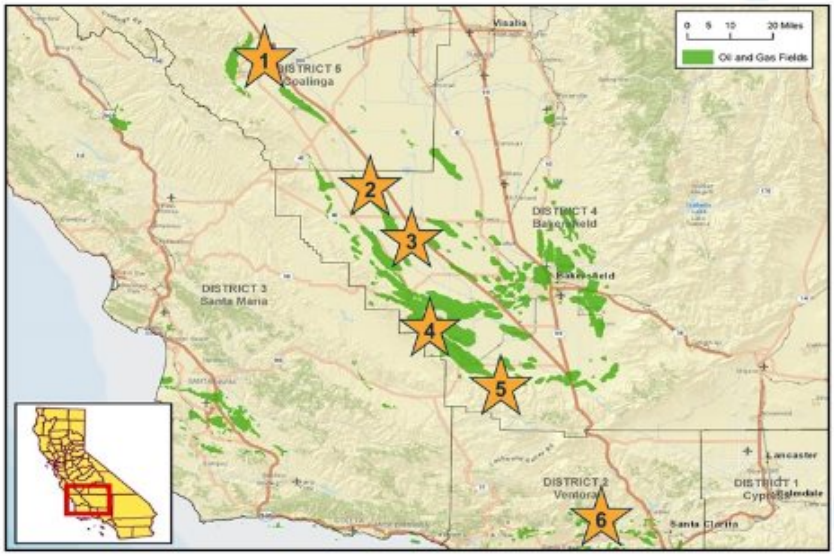
Net Contracted Firm Sales Volumes (Dth per day)
Contracted Index Price Differentials ($ per Dth)[1]

(1) Values shown represent the price or differential to a reference price (netback price) at the point of sale less any associated transportation costs..

California Oil

SENECA RESOURCES

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

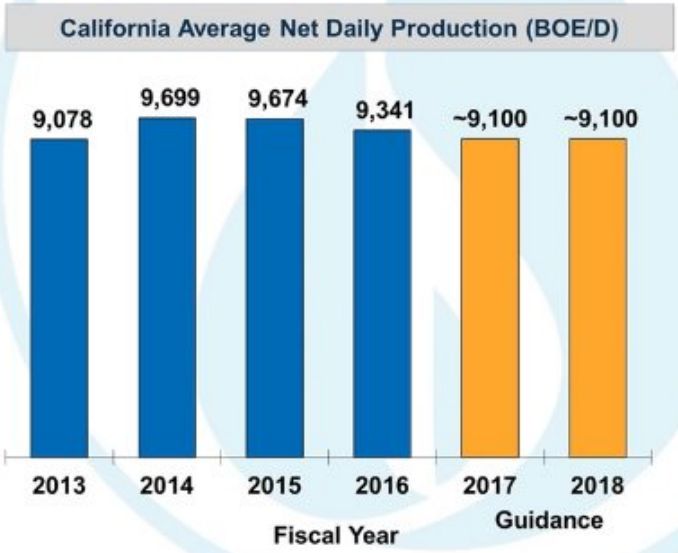


	Location	Formation	Production Method	FY16 Gross Daily Production *(Boe/d)*
1	East Coalinga	Temblor	Primary	770
2	North Lost Hills	Tulare & Etchegoin	Primary/ Steam flood	1,000
3	South Lost Hills	Monterey Shale	Primary	1,680
4	North Midway Sunset	Tulare & Potter	Steam flood	3,640
5	South Midway Sunset	Antelope	Steam flood	1,760
6	Sespe	Sespe	Primary	1,350

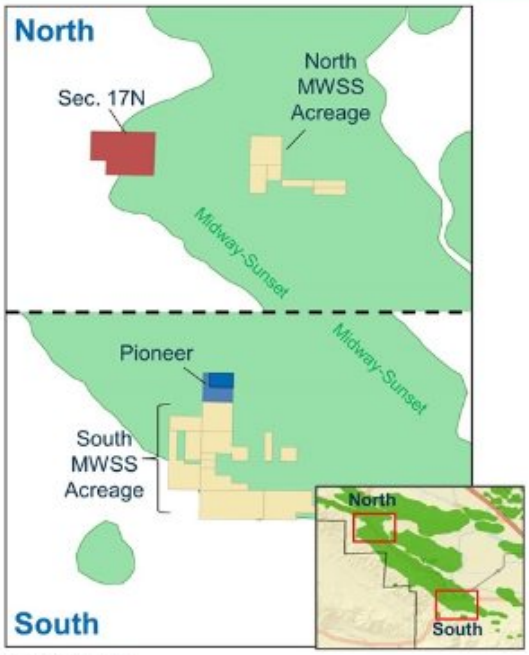
California Average Daily Net Production

SENECA RESOURCES

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

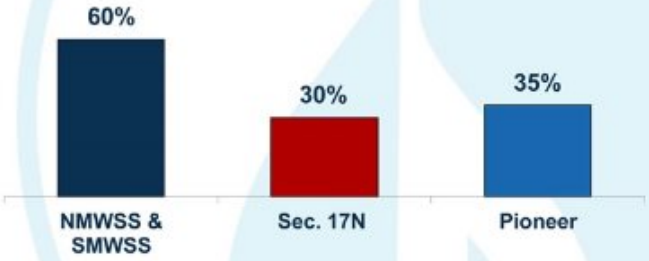


Future Development Focused on Midway Sunset



Midway Sunset Economics

MWSS Project IRRs at $50/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 $50/Bbl WTI.

Seneca Production

SENECA RESOURCES

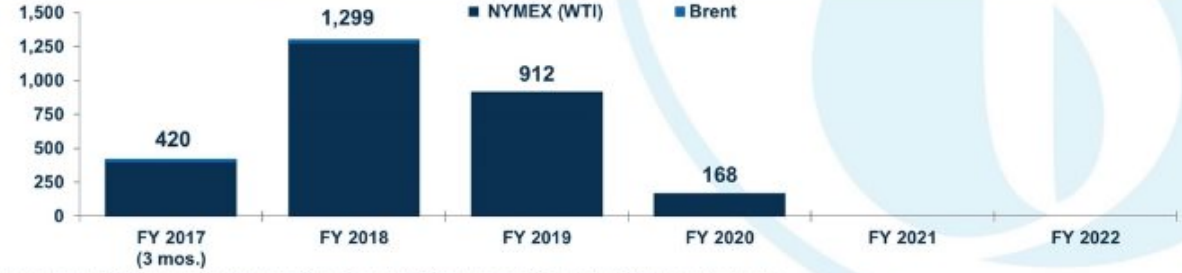
Net Production (Bcfe)

Strong Hedge Book in FY 2018

SENECA RESOURCES

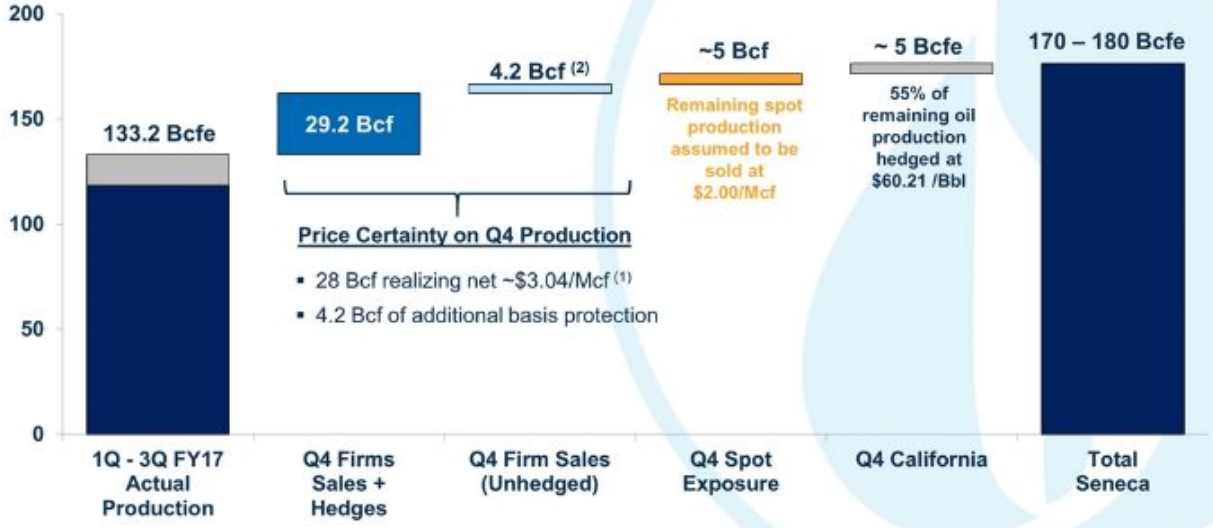
Natural Gas Swap & Fixed Physical Sales Contracts (Millions MMBtu)

Crude Oil Swap Contracts (Thousands Bbls)



(1) 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



(1) Average realized price reflects uplift from financial hedges less fixed differentials under firm sales contracts and any firm transportation costs.
(2) Indicates firm sales contracts with fixed index differentials but not backed by a matching NYMEX financial hedge.

Fiscal 2018 Production and Price Certainty

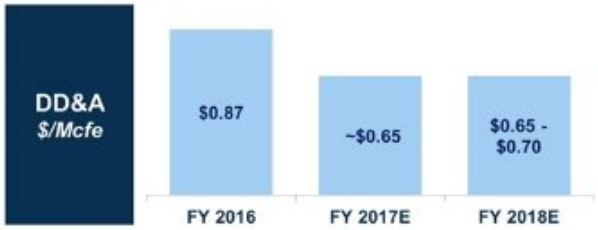
SENECA RESOURCES

FINANCIAL HEDGE + FIRM SALE = PRICE CERTAINTY

(1) Average realized price reflects uplift from financial hedges less fixed differentials under firm sales contracts and any firm transportation costs.
(2) Indicates firm sales contracts with fixed index differentials but not backed by a matching NYMEX financial hedge.

Seneca Operating Costs

SENECA RESOURCES



- 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

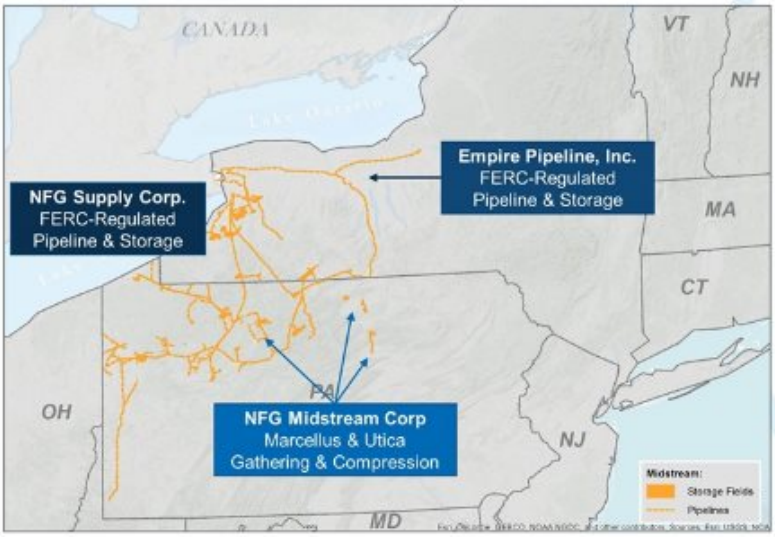
(1) Excludes $7.9 million, or $0.05 per Mcfe, of professional fees relating to the joint development agreement announced in December 2015.
(2) The total of the two LOE components represents the midpoint of the LOE guidance range of ~$0.95 for fiscal 2017 and $0.90 to $1.00 for fiscal 2018.

Midstream Businesses

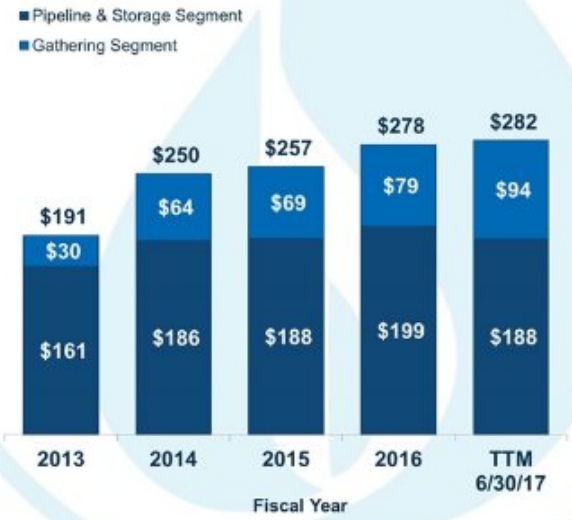
Midstream Businesses

National Fuel

Midstream Businesses System Map



Midstream Businesses Adjusted EBITDA ($MM)



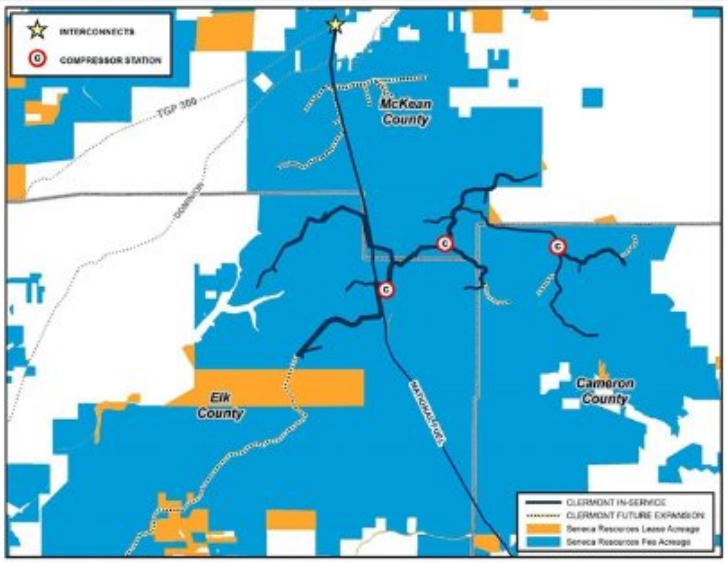
Note: A reconciliation of Adjusted EBITDA to Net Income as presented on the Consolidated Statement of Income and Earnings Reinvested in the Business is included at the end of this presentation.

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 / 31,220 HP of compression
- Current Capacity: 470 MMcf per day
- Interconnects with TGP 300
- Total Investment to Date: $277 million
- FY 2018 CapEx: ~$10 million
- Modest Midstream compression and pipeline investment required to support Utica development
- Timing and extent of gathering and compression investments are flexible to match Seneca's modified development schedule and maximize returns

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

National Fuel

Gathering Segment Supporting Seneca's EDA Production & Future Development

Wellsboro Gathering System

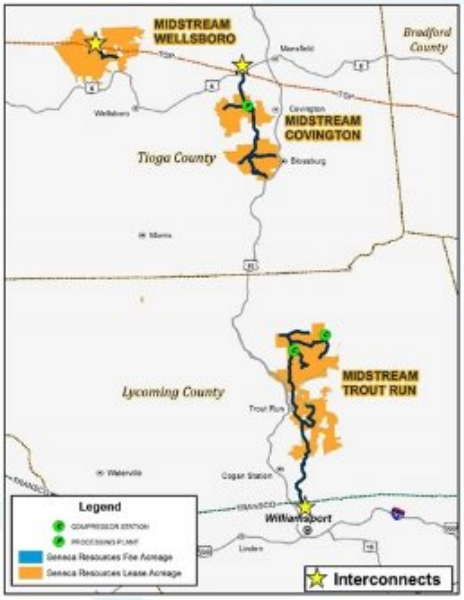
- **Total Investment (to date):** $7 million
- **FY 2018 Capital Expenditures:** ~$15 million
- **Capacity:** 200,000 Dth per day (Interconnect w/ TGP 300)
- **Production Source:** Seneca Resources – Tioga Co. (DCNR Tract 007)

Covington Gathering System

- **Total Investment (to date):** $33 million
- **Capacity:** 220,000 Dth per day (Interconnect w/ TGP 300)
- **Production Source**: Seneca Resources – Tioga Co. (Covington and DCNR Tract 595)

Trout Run Gathering System

- **Total Investment (to date):** $173 million
- **FY 2018 Capital Expenditures:** ~$45 million
- **Capacity:** 466,000 to 585,000 Dth per day (Interconnect w/ Transco)
- **Production Source:** Seneca Resources – Lycoming Co. (DCNR Tract 100 and Gamble)
- Future third-party volume opportunities



Infrastructure Expansions Bolster Supply Diversity

National Fuel

Expanding Our Pipelines to Assure Supply Security for New York Markets

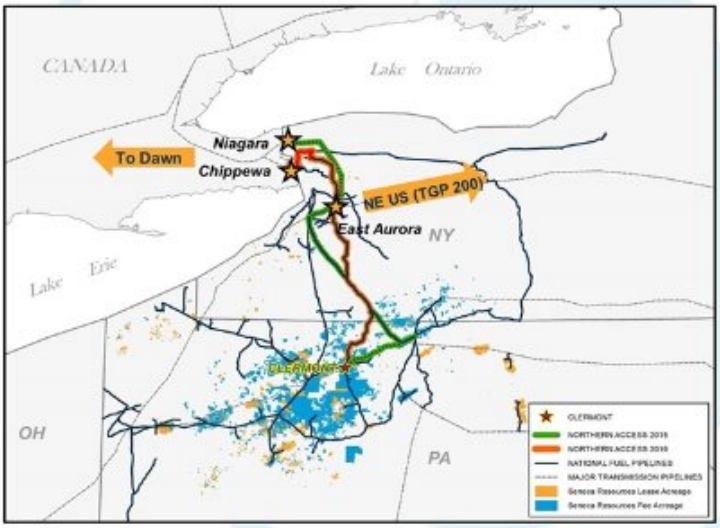
Integration of Seneca's WDA Production Into Broader Interstate System

Northern Access 2015 (In-Service[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)
- Total Cost: $67.1 million
- Annual Revenues: $13.3 million

Northern Access 2016 (Delayed)

- **In-Service:** TBD
- **Systems:** NFG Supply Corp. & Empire Pipeline
- **Capacity:** 490,000 Dth per day
- **Total Expected Cost:** ~$500 million
- **Project Status:** Delayed pending appeal of NYS DEC WQC notice of denial 401



(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 Project Status

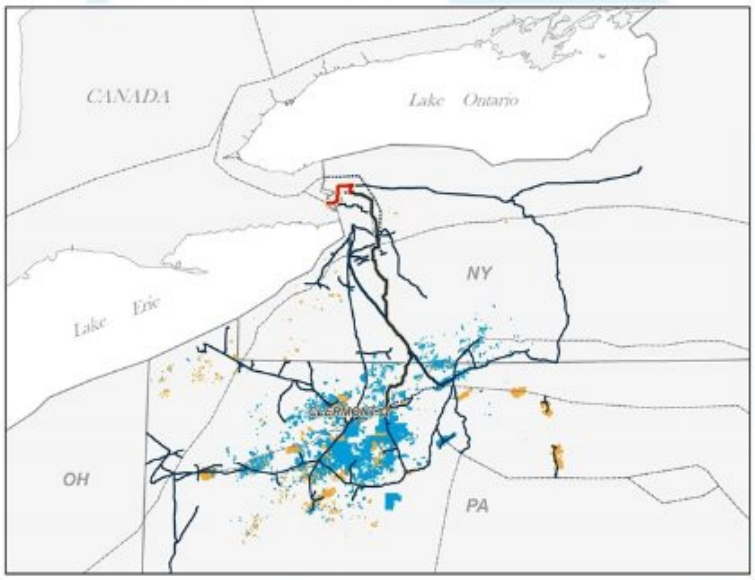
National Fuel Remains Committed to Building the Northern Access Pipeline Project

Project in-service not expected before 2019 due to regulatory delays

- **February 3, 2017 –** NFG received FERC 7(c) certificate
- **March 3, 2017 –** NFG filed petition for rehearing with FERC seeking waiver of NYS DEC Clean Water Act Section 401 Water Quality Certification (WQC) and preemption on state level permits
- **April 7, 2017 –** NY DEC issued notice of denial of WQC and other state stream and wetland permits for NY portion of project (PA DEP WQC received in January 2017)
- **April 21, 2017 –** NFG filed appeal of NY DEC WQC notice of denial with US Court of Appeals for the 2nd Circuit

Project Spending Update:

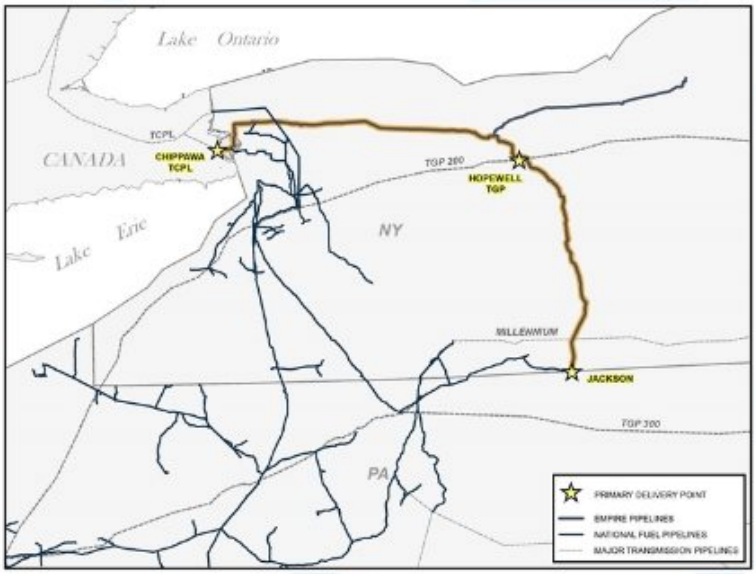
- Total project spending to-date: ~$74 million
- Minimal remaining commitments



Empire System Expansion

Foundation Shipper Agreement Provides Major Commitment Needed for the Empire North Project

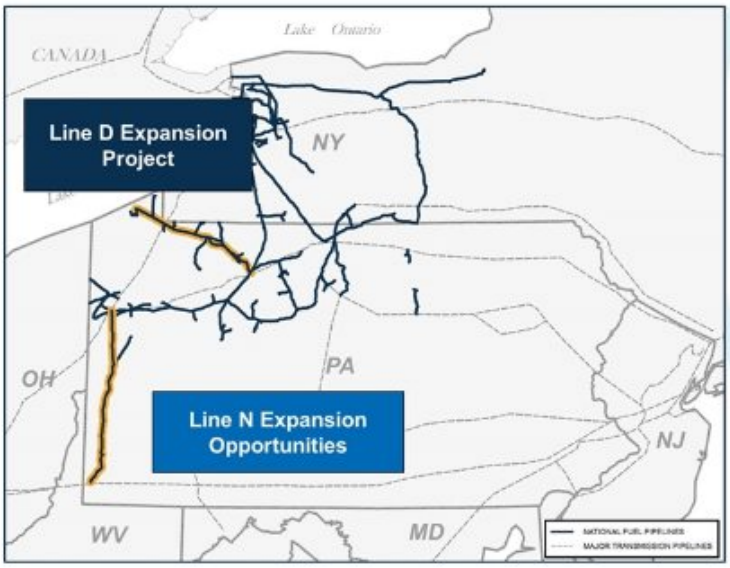
- **Target In-Service:** November 2019
- **System:** Empire Pipeline
- **Estimated Cost:** $135 million
- **Receipt Point:** Jackson (Tioga Co., Pa. production)
- **Design Capacity and Delivery Points:**
  - 175,000 Dth/d to Chippawa (TCPL interconnect)
  - 30,000 Dth/d to Hopewell (TGP 200 interconnect)
- **Customers:**
  - Precedent agreements in-place for 185,000 Mdth/d
  - Negotiating commitments on remaining capacity
- **Major Facilities:**
  - 2 new compressor stations in NY (1) & Pa. (1)
  - No new pipeline construction



Continued Expansion of the NFG Supply System

National Fuel

Future NFG Supply System Expansions



Line D Expansion Project

- **Target In-Service:** November 2017
- **Contracted Capacity:** 77,500 Dth/d from an interconnect with TGP 300 at Lamont, Pa. into Erie, Pa. market
- **Estimated Cost:** $28 million ($8 million modernization)
- **Project Status:** In-construction

Line N Expansion Opportunities

Line N Expansion Opportunity #1 (Supply OS #220)

- **Project:** Firm transportation service to a new ethylene cracker facility being built by Shell Chemical Appalachia, LLC.
- **Target In-Service:** July 2019
- **Contracted Capacity:** 133,000 Dth/d with foundation shipper

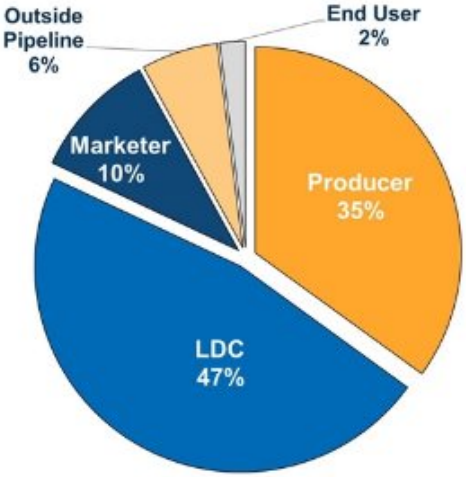
Line N Expansion Opportunity #2 (Supply OS #221)

- **Project:** New firm transportation service for on-system demand
- **Target In-Service:** July 2020
- **Open Season Capacity:** Awarded 165,000 to foundation shipper. Precedent agreement in negotiations.

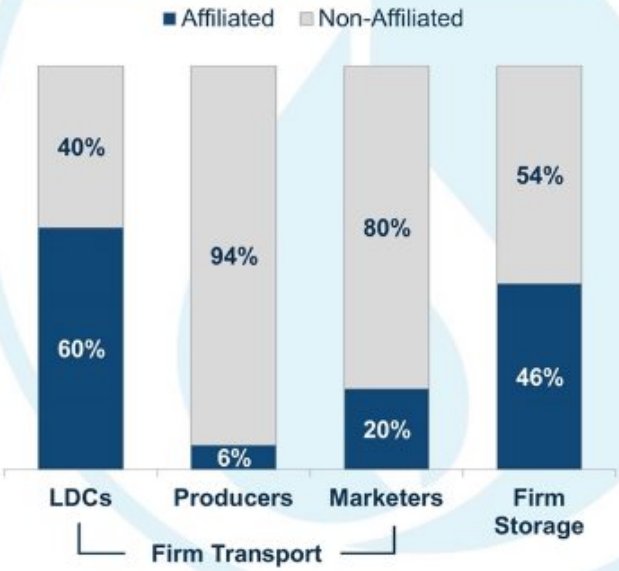
Pipeline & Storage Customer Mix

Customer Transportation by Shipper Type(1)

4.1 MMDth/d



Affiliated Customer Mix (Contracted Capacity)



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

Downstream Overview

Utility ~ Energy Marketing

New York & Pennsylvania Service Territories

New York

Total Customers[1]: 528,312

ROE: 8.7% (NY PSC Rate Case Order, April 2017)

Rate Mechanisms:

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

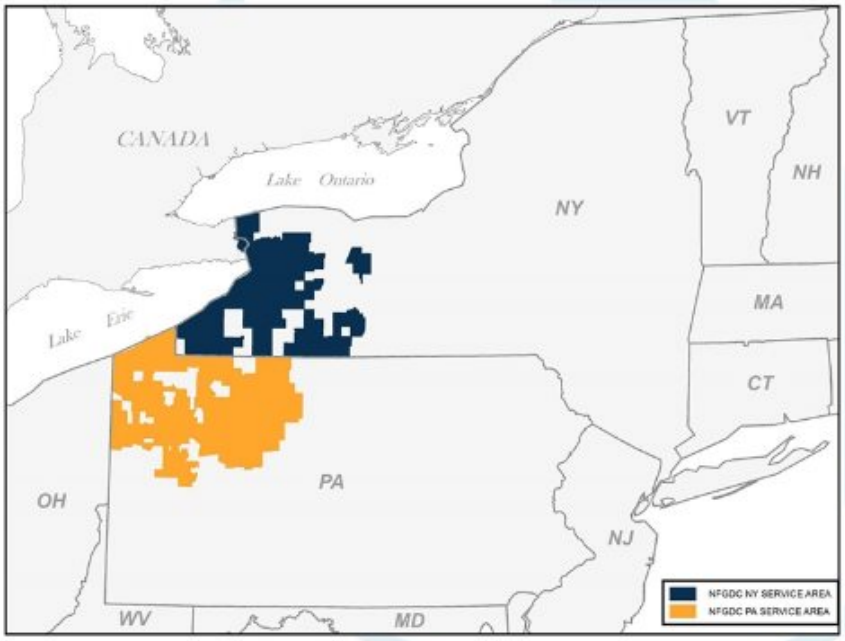
Pennsylvania

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 Outcome

On April 20, 2017, the New York Public Service Commission issued a Rate Order relating to NFG Distribution's rate case (No. 16-G-0257) filed in April 2016.

Rate Order Summary:

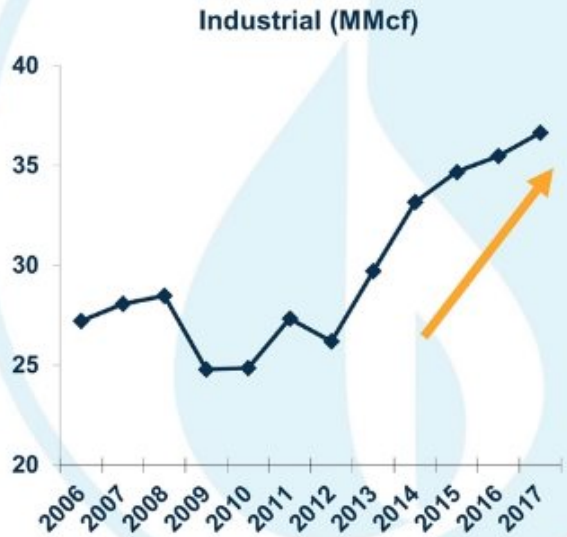
- **Revenue Requirement:** $5.9 million
- **Rate Base:** $704 million (prior case $632 million[1])
- **Allowed Return on Equity (ROE):** 8.7% (prior case allowed 9.1%[1])
- **Capital Structure:** 42.9% equity
- **Other notable items:**
  - New rates effective 5/1/17
  - Retains rate mechanisms in place under prior order (revenue decoupling, weather normalization, merchant function charge, 90/10 large customer sharing)
  - No stay-out clause
  - Earnings sharing would start 4/1/18 if NFG Distribution Corp. does not file for new rates to become effective on or before 10/1/18 (50/50 sharing starts at earnings in excess of 9.1%)
  - Article 78 appeal filed on 7/28/17

(1) Case 13-G-0136 rate year ended September 30, 2015.

Utility: Shifting Trends in Customer Usage

National Fuel

Usage Per Account [1]

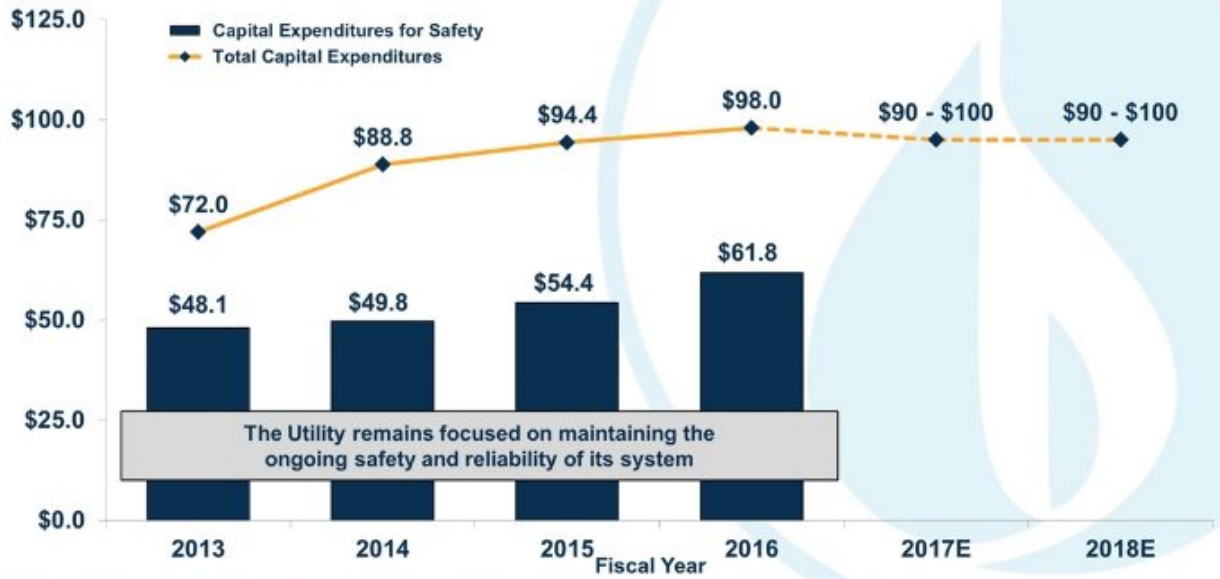


12-Months Ended June 30

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

Utility: Strong Commitment to Safety

Capital Expenditures ($ millions)[1]



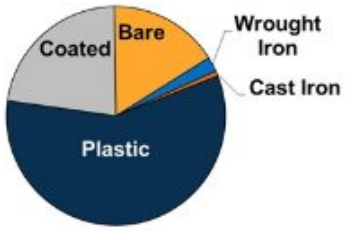
(1) A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

Accelerating Pipeline Replacement & Modernization

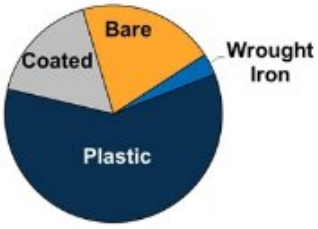
National Fuel

Utility Mains by Material

NY
9,700 miles



PA*
4,830 miles



** No Cast Iron Mains in Pa.**

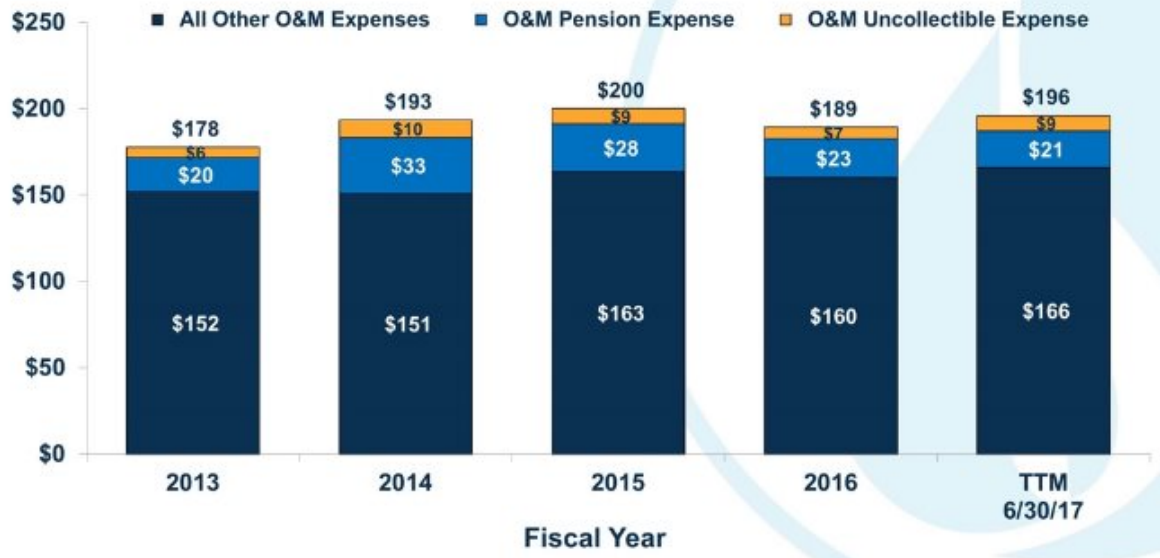
Miles of Utility Main Pipeline Replaced(1)

(1) As reported to the Department of Transportation on calendar year basis.

A Proven History of Controlling Costs

National Fuel

O&M Expense ($ millions)



Appendix

Earnings Guidance

National Fuel

Decline in FY18 Earnings Guidance Predominantly Due to Lower Commodity Price Realizations

	Fiscal 2017 EPS Guidance		Fiscal 2018 EPS Guidance
	$3.25/sh to $3.35/sh	→	$2.70/sh to $3.05/sh

Key Guidance Drivers			
Non-regulated Businesses *Exploration & Production* *Gathering*	↑	**Production**	▪ Seneca Net Production: 185 to 200 Bcfe *(up 17.5 Bcf or 10% vs FY 17)* ▪ Gathering Revenues: $115 to $125 million *(up $10 million or 9% vs FY17)*
	↓	**Realized natural gas & oil prices (after-hedge)**	▪ Natural Gas : ~$2.55 /Mcf[1] *(down $0.41 /Mcf vs. $2.96 /Mcf FYTD 2017)* ▪ Crude Oil: ~$49.50 /Bbl[2] *(down $4.08 /Bbl vs. $53.58 /Bbl FYTD 2017)*
Regulated Businesses *Pipeline & Storage* *Utility*	↔	**Pipeline & Storage Revenues**	▪ ~$295 million in revenues *(flat vs. FY17)*
	↑	**Utility Normal Weather**	▪ Guidance assumes normal weather ▪ Warmer than normal weather impacted FY17 earnings by ~$0.06/sh

(1) Assumes NYMEX natural gas pricing of $3.00 /MMBtu and basin spot pricing of $2.40 /MMbtu and reflects the impact of existing financial hedge, firm sales and firm transportation contracts.
(2) Assumes NYMEX (WTI) oil pricing of $50.00 /Bbl and California-MWSS pricing differentials of 92% to WTI, and reflects impact of existing financial hedge contracts.

Marcellus Operated Well Results

SENECA RESOURCES

WDA Development Wells:

Area	Producing Well Count	Average IP Rate (MMcfd)	Average 30-Day (MMcf/d)	Average Treatable Lateral Length
Clermont/Rich Valley (CRV) & Hemlock *Elk, Cameron & McKean counties*	135[1]	6.7	5.1	7,131 ft

EDA Development Wells:

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

(1) Excludes 2 wells now operated by Seneca that were drilled by another operator as part of a joint-venture. Excludes 5 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.

Hedge Positions

SENECA RESOURCES

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

	Fiscal 2017 (last 3 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	9,990	$4.35	42,570	$3.34	27,060	$3.17	16,880	$3.07	4,840	$3.01
Dominion Swaps	450	$3.82	180	$3.82	-	-	-	-	-	-
Dawn Swaps	3,330	$3.71	8,400	$3.08	7,200	$3.00	7,200	$3.00	600	$3.00
Fixed Price Physical[1]	17,382	$2.45	42,903	$2.42	32,328	$2.51	38,233	$2.30	38,561	$2.22
Total	**31,152**	**$3.21**	**94,053**	**$2.90**	**66,588**	**$2.83**	**62,313**	**$2.59**	**44,001**	**$2.31**

Crude Oil Volumes & Prices in Bbl

	Fiscal 2017 (last 3 mos.)		Fiscal 2018		Fiscal 2019		Fiscal 2020	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Brent Swaps	**24,000**	**$91.00**	**24,000**	**$91.00**	-	-	-	-
NYMEX Swaps	396,000	$58.34	1,275,000	$54.79	912,000	$53.84	168,000	$50.08
Total	**420,000**	**$60.21**	**1,299,000**	**$55.46**	**912,000**	**$53.84**	**168,000**	**$50.08**

(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 06/30/17
Total Adjusted EBITDA					
Exploration & Production Adjusted EBITDA	$ 492,383	$ 539,472	$ 422,289	$ 363,830	380,832
Pipeline & Storage Adjusted EBITDA	161,226	186,022	188,042	199,446	187,796
Gathering Adjusted EBITDA	29,777	64,060	68,881	78,685	94,137
Utility Adjusted EBITDA	171,669	164,643	164,037	148,683	149,631
Energy Marketing Adjusted EBITDA	6,963	10,335	12,237	6,655	3,299
Corporate & All Other Adjusted EBITDA	(9,920)	(11,078)	(11,900)	(8,238)	(11,316)
Total Adjusted EBITDA	**$ 852,098**	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 804,379**
Total Adjusted EBITDA	**$ 852,098**	**$ 953,454**	**$ 843,586**	**$ 789,061**	**$ 804,379**
Minus: Interest Expense	(94,111)	(94,277)	(99,471)	(121,044)	(118,763)
Plus: Interest and Other Income	9,032	13,631	11,961	14,055	11,814
Minus: Income Tax Expense	(172,758)	(189,614)	319,136	232,549	(164,287)
Minus: Depreciation, Depletion & Amortization	(326,760)	(383,781)	(336,158)	(249,417)	(224,929)
Minus: Impairment of Oil and Gas Properties (E&P)	-	-	(1,126,257)	(948,307)	(32,755)
Plus: Reversal of Stock-Based Compensation	-	-	7,776	-	-
Minus: New York Regulatory Adjustment (Utility)	(7,500)	-	-	-	-
Minus: Joint Development Agreement Professional Fees	-	-	-	(7,855)	-
Rounding	-	-	-	-	-
Consolidated Net Income	**$ 260,001**	**$ 299,413**	**$ (379,427)**	**$ (290,958)**	**$ 275,459**
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	$ 1,799,000
Current Portion of Long-Term Debt (End of Period)	-	-	-	-	300,000
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	-	-
Total Debt (Start of Period)	$ 1,570,000	$ 1,649,000	$ 1,734,600	$ 2,099,000	$ 2,099,000
Average Total Debt	**$ 1,609,500**	**$ 1,691,800**	**$ 1,916,800**	**$ 2,099,000**	**$ 2,099,000**
Average Total Debt to Total Adjusted EBITDA	**1.89 x**	**1.77 x**	**2.27 x**	**2.66 x**	**2.61 x**

Non-GAAP Reconciliations – Capital Expenditures

National Fuel

Reconciliation of Segment Capital Expenditures to Consolidated Capital Expenditures ($ Thousands)

	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017 Forecast	FY 2018 Forecast
Capital Expenditures from Continuing Operations						
Exploration & Production Capital Expenditures	$ 533,129	$ 602,705	$ 557,313	$ 256,104	$230,000 - $250,000	$275,000 - $325,000
Pipeline & Storage Capital Expenditures	$ 56,144	$ 139,821	$ 230,192	$ 114,250	$100,000 - $110,000	$110,000 - $140,000
Gathering Segment Capital Expenditures	$ 54,792	$ 137,799	$ 118,166	$ 54,293	$35,000 - $45,000	$60,000 - $80,000
Utility Capital Expenditures	$ 71,970	$ 88,810	$ 94,371	$ 98,007	$90,000 - $100,000	$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	$455,000 - $505,000	$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**	**$455,000 - $505,000**	**$535,000 - $645,000**

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.