National Fuel Gas Company

Investor Presentation

November 2014

National Fuel Gas Company

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.

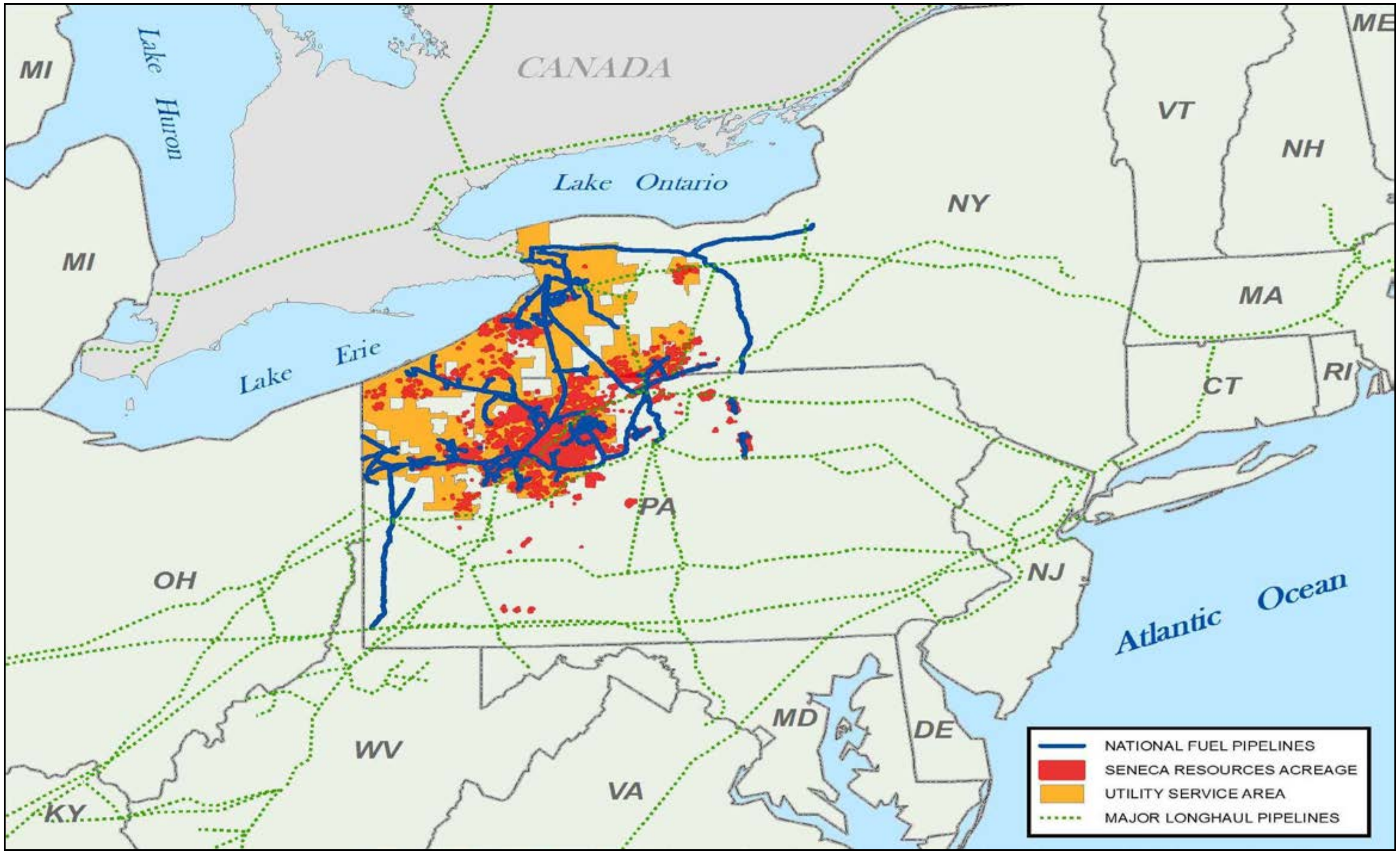
In addition to other factors, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements: factors affecting the Company's ability to successfully identify, drill for and produce economically 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; the cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company; 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; 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 the price of natural gas or oil; 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; impairments under the SEC's full cost ceiling test for natural gas and oil reserves; uncertainty of oil and gas reserve estimates; significant differences between the Company's projected and actual production levels for natural gas or oil; 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; changes in demographic patterns and weather conditions; changes in the availability, price or accounting treatment of derivative financial instruments; 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; 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; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; 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, 2013 and the Forms 10-Q for the quarters ended December 31, 2013, March 31, 2014 and June 30, 2014. 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.

National Fuel Gas Company

Quality Assets - Exceptional Location - Unique Integration

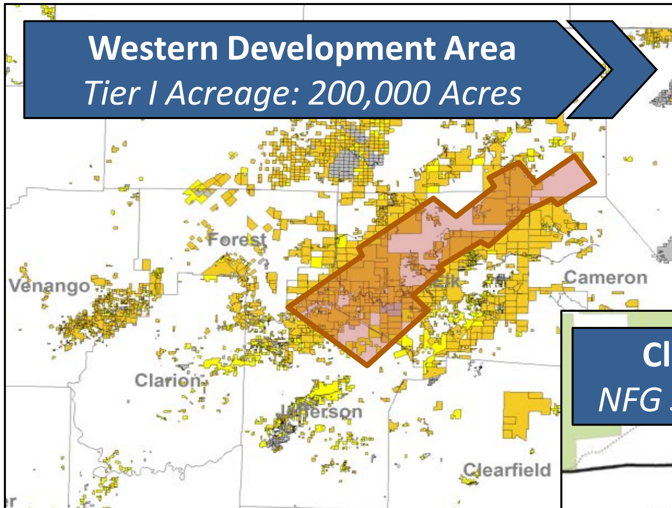


- ✓ 1.914 Tcfe of Proved Reserves(1)
- ✓ 3 Million Bbls of Crude Oil Production(2)
- ✓ 811,000 Net Acres in Pennsylvania
- ✓ $250 Million of Midstream Adjusted EBITDA(2)(3)

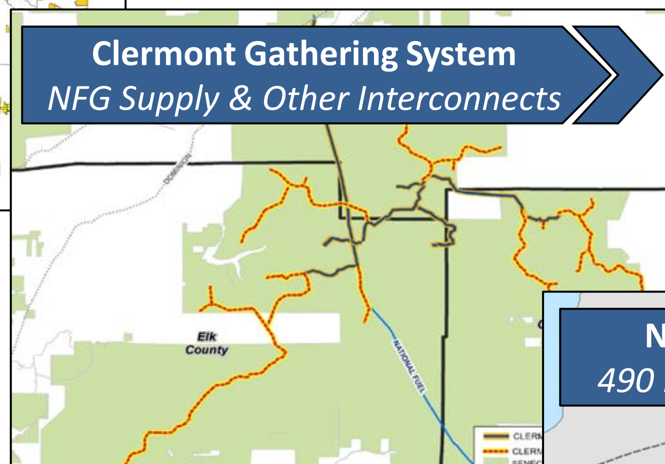
(1) As of September 30, 2014
(2) Fiscal year ended September 30, 2014. Midstream includes the Pipeline & Storage segment and Gathering segment.
(3) A reconciliation of Adjusted EBITDA to Net Income is included at the end of this presentation.

National Fuel Gas Company

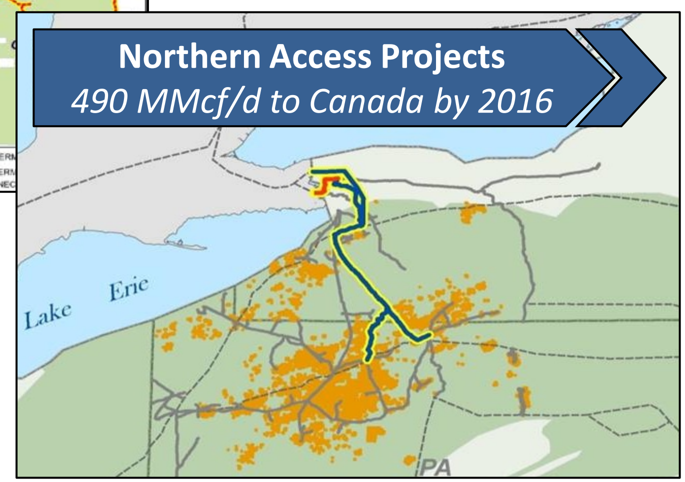
Upstream and Midstream – Common Vision For Growth



High quality Marcellus acreage



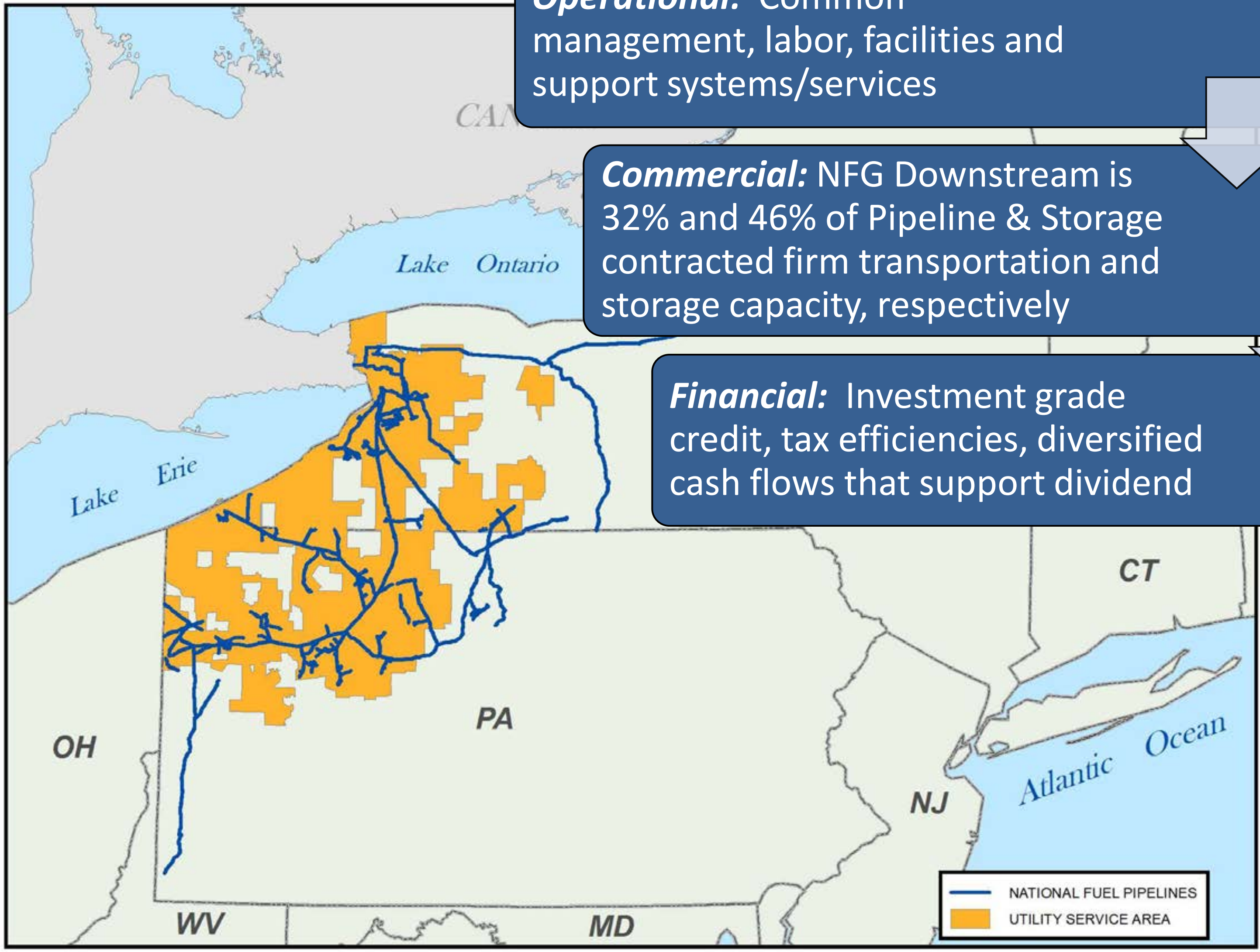
Connected to our interstate pipeline network



Pipeline capacity to premium and alternate markets

National Fuel Gas Company

Regulated Operations Provide Significant Synergies



Operational: Common management, labor, facilities and support systems/services

Commercial: NFG Downstream is 32% and 46% of Pipeline & Storage contracted firm transportation and storage capacity, respectively

Financial: Investment grade credit, tax efficiencies, diversified cash flows that support dividend

National Fuel Gas Company

What Makes NFG Unique, Also Maximizes Value

Operational Synergies

Strategic Commercial Relationships

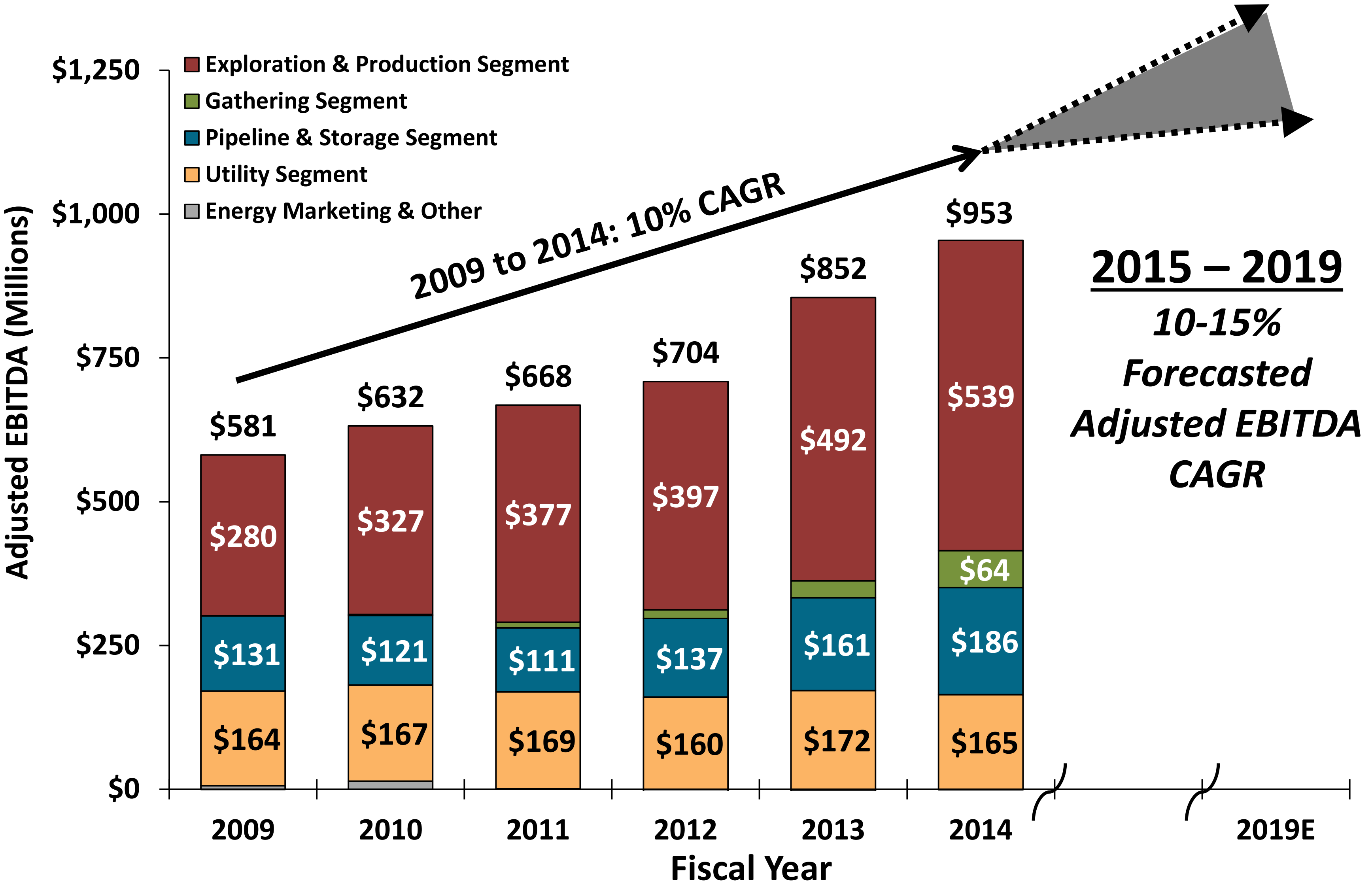
Financial Efficiencies

High Quality Assets
+ Lower Cost of Capital
+ Lower Operating Costs
+ Efficient Capital Spend
+ More Competitive Projects
+ Higher Free Cash Flow
+ Growing Dividend

= **Foundation of Our Appalachian Growth Strategy**

National Fuel Gas Company

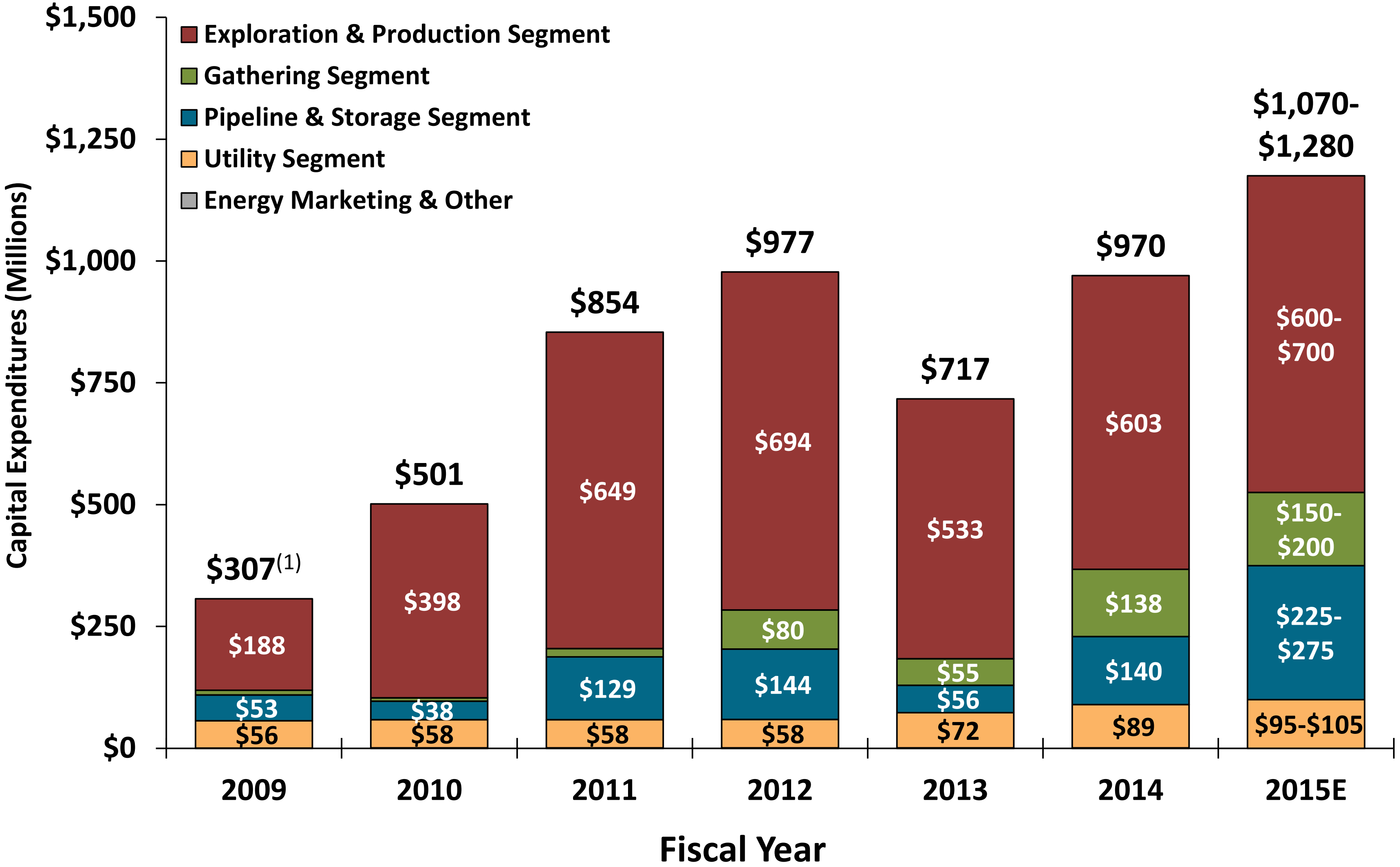
Targeting Sustained EBITDA Growth over the next Five Years



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.

National Fuel Gas Company

Capital Spending Adjusts to Capitalize on Opportunities



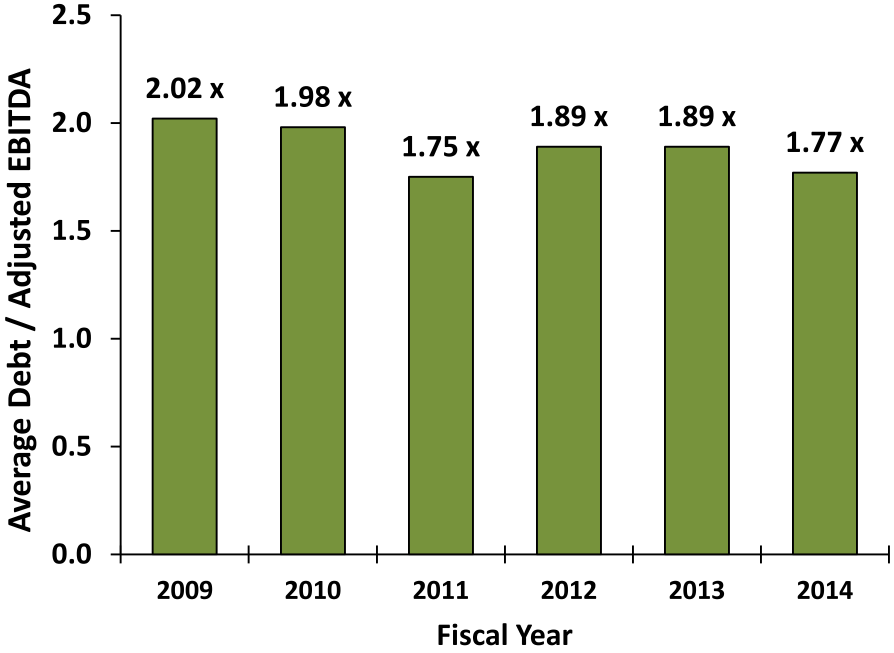
Note: A reconciliation to Capital Expenditures as presented on the Consolidated Statement of Cash Flows is included at the end of this presentation.

(1) Does not include the $34.9 MM Seneca Resources Corporation's acquisition of Ivanhoe's U.S.-based assets in California, as this was accounted for as an investment in subsidiaries on the Statement of Cash Flows, and was not included in the Exploration & Production segment's Capital Expenditures.

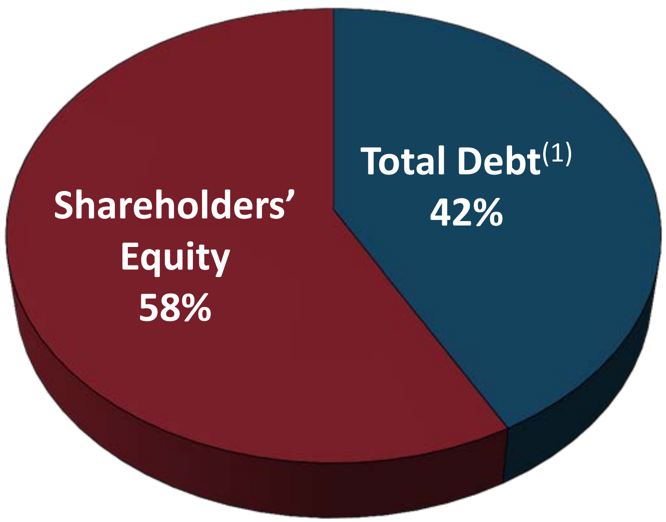
National Fuel Gas Company

Maintaining a Strong Balance Sheet

Debt/Adjusted EBITDA



Capitalization



$4.1 Billion

As of September 30, 2014

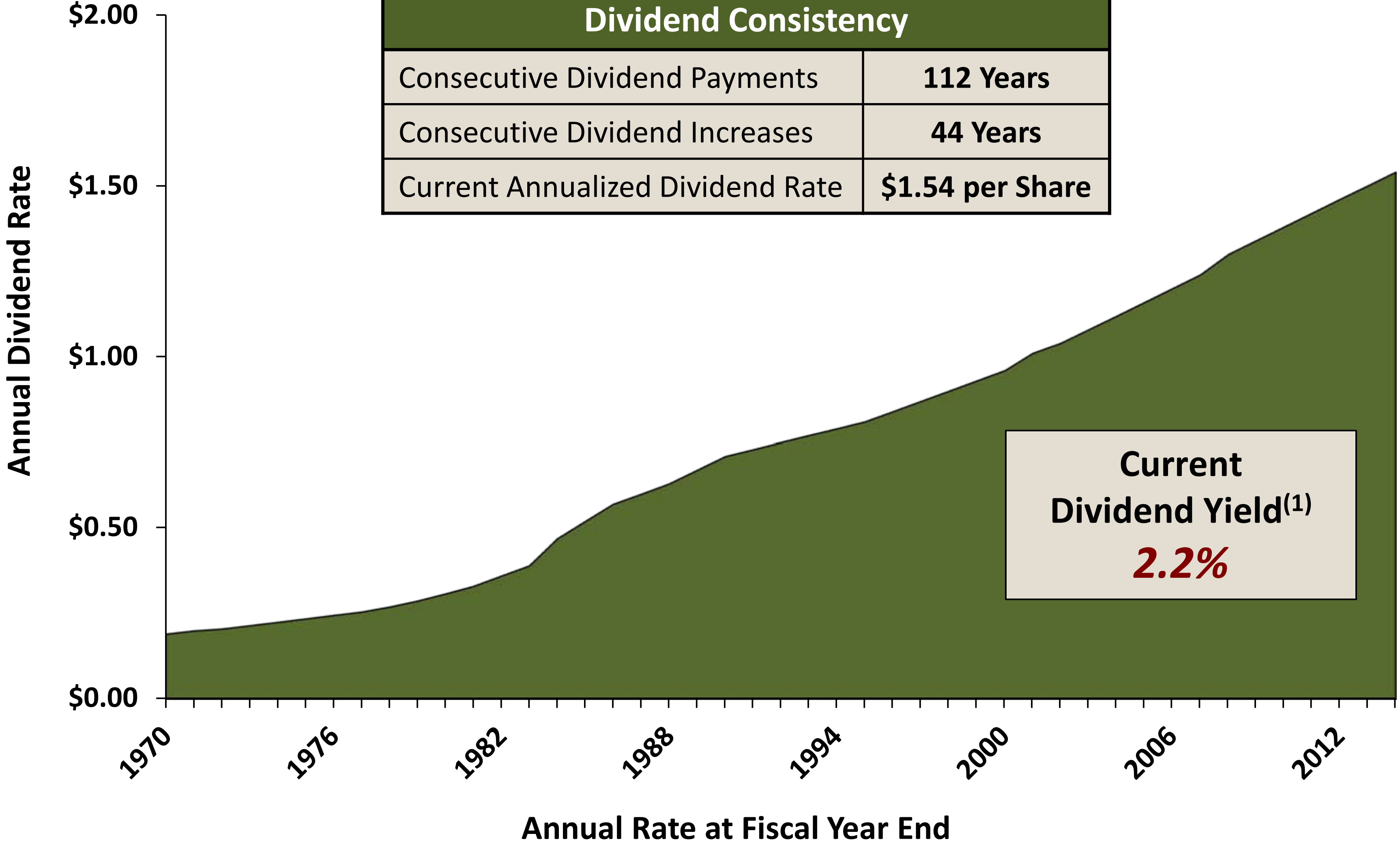
Note: A reconciliation of Adjusted EBITDA to Net Income is included at the end of this presentation.

(1) Long-term debt of $1.649 billion and short-term debt of $85.6 million

National Fuel Gas Company

Dividend Track Record

Dividend Consistency	
Consecutive Dividend Payments	**112 Years**
Consecutive Dividend Increases	**44 Years**
Current Annualized Dividend Rate	**$1.54 per Share**



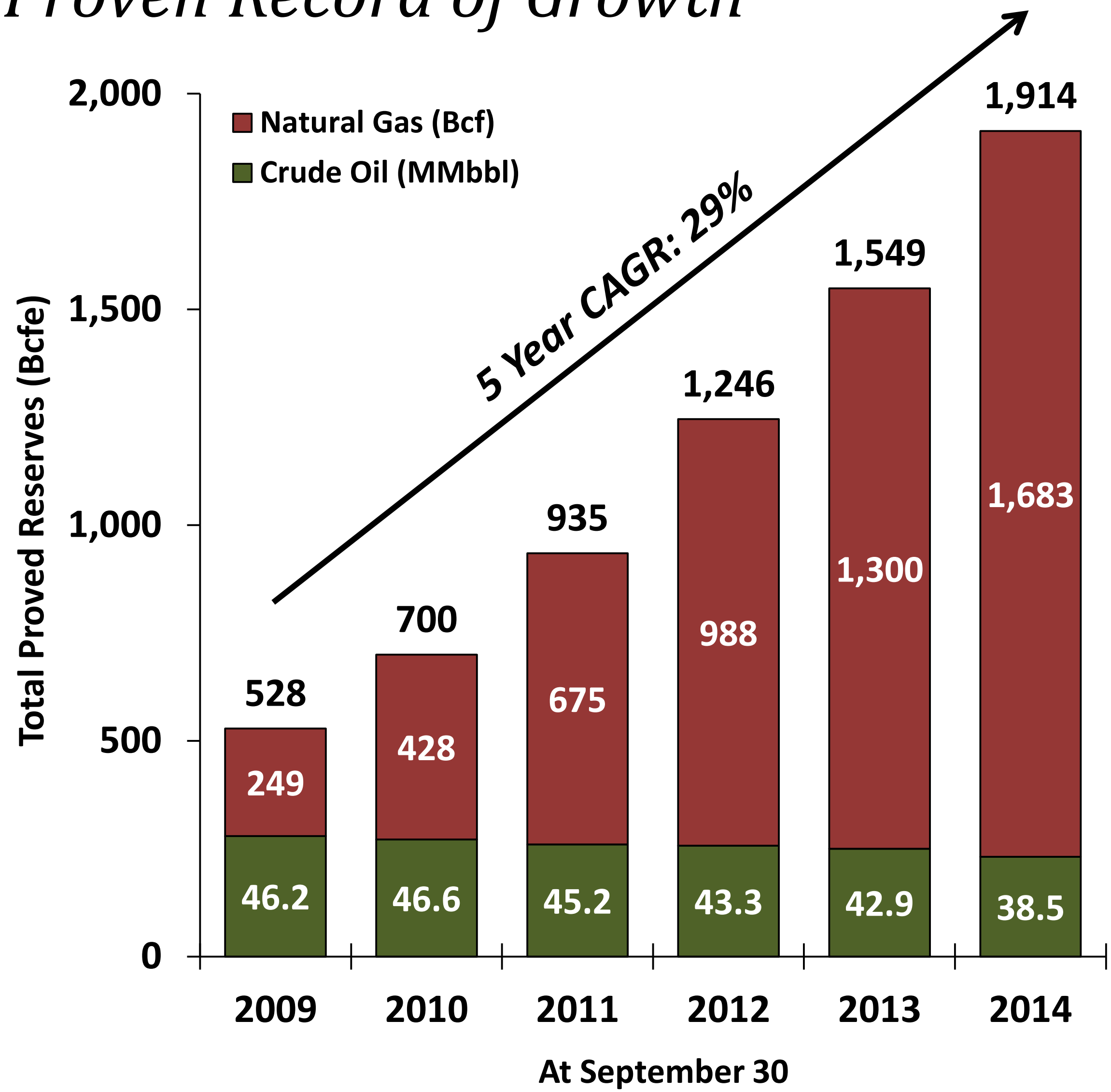
Current Dividend Yield(1)
2.2%

(1) As of November 5, 2014

Exploration & Production Overview

Seneca Resources

Proven Record of Growth



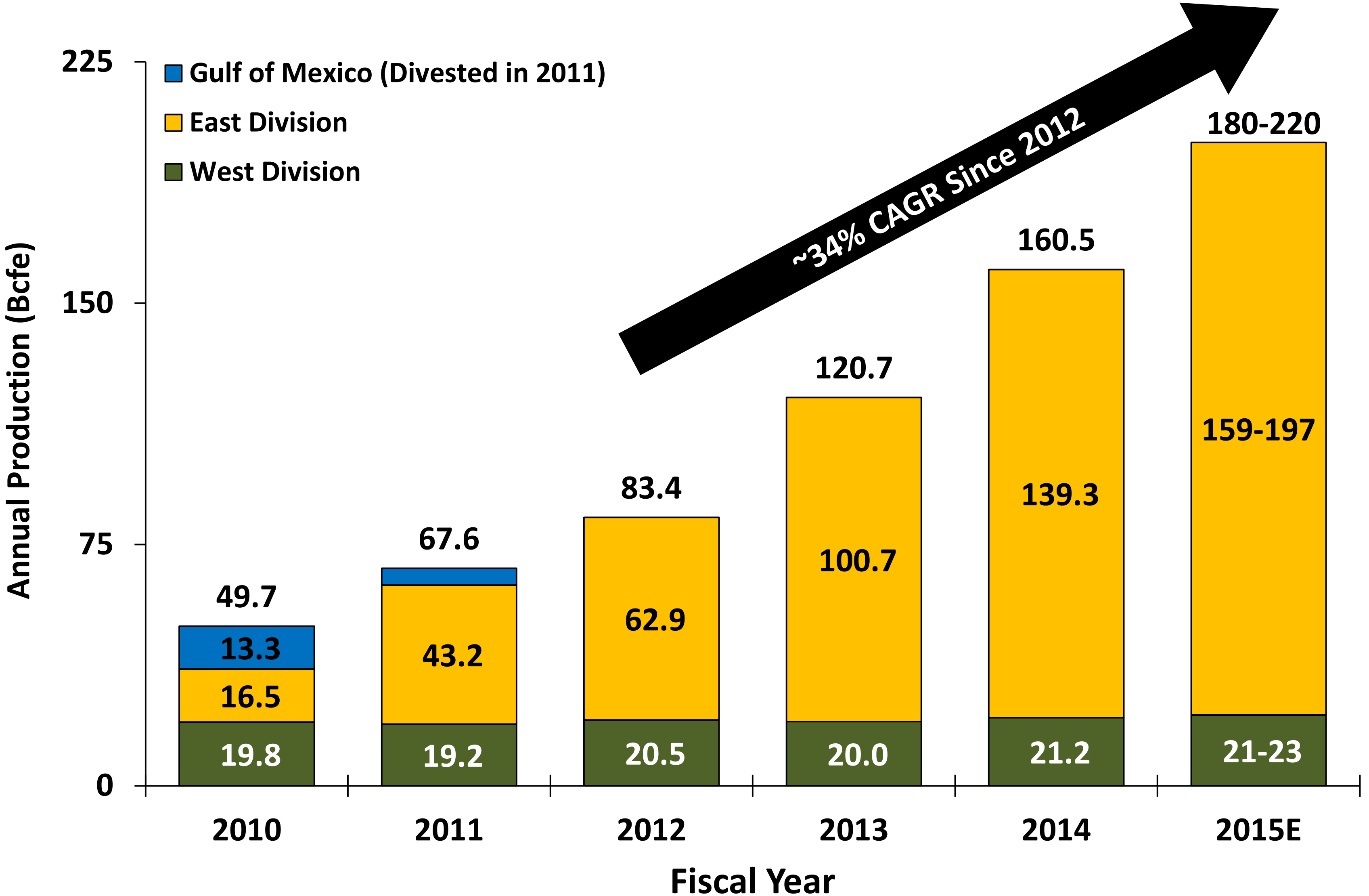
Fiscal Years	3-Year F&D Cost[(1)] ($/Mcfe)
2007-2009	$5.35
2008-2010	$2.37
2009-2011	$2.09
2010-2012	$1.87
2011-2013	$1.67
2012-2014	$1.38

- ✓ ***2014 F&D Cost = $1.15***
  - ➢ *Marcellus F&D: $1.00*
- ✓ ***327% Reserve Replacement Rate***
- ✓ ***73% Proved Developed***

(1) Represents a three-year average U.S. finding and development cost

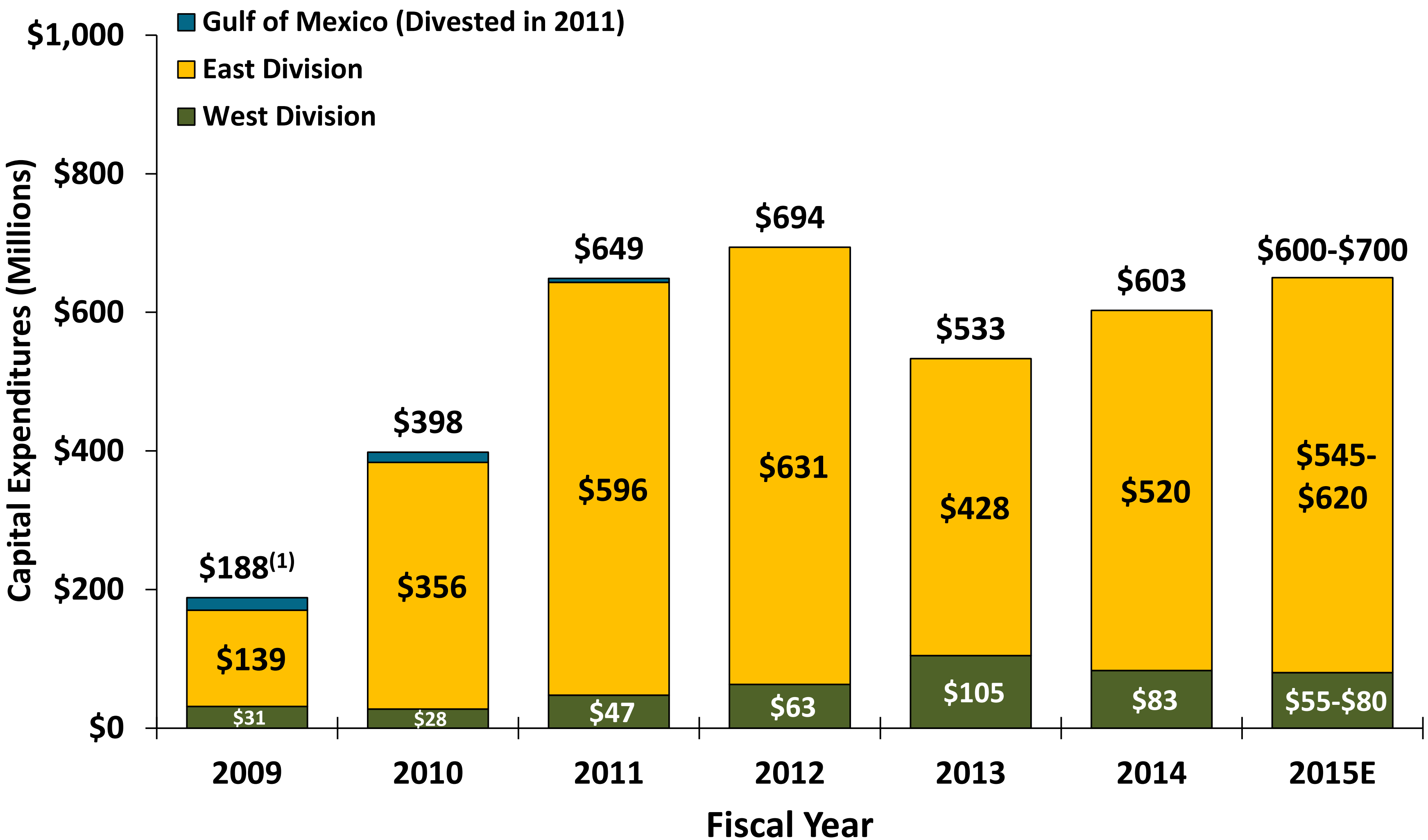
Seneca Resources

Delivering Tremendous Production Growth



Seneca Resources

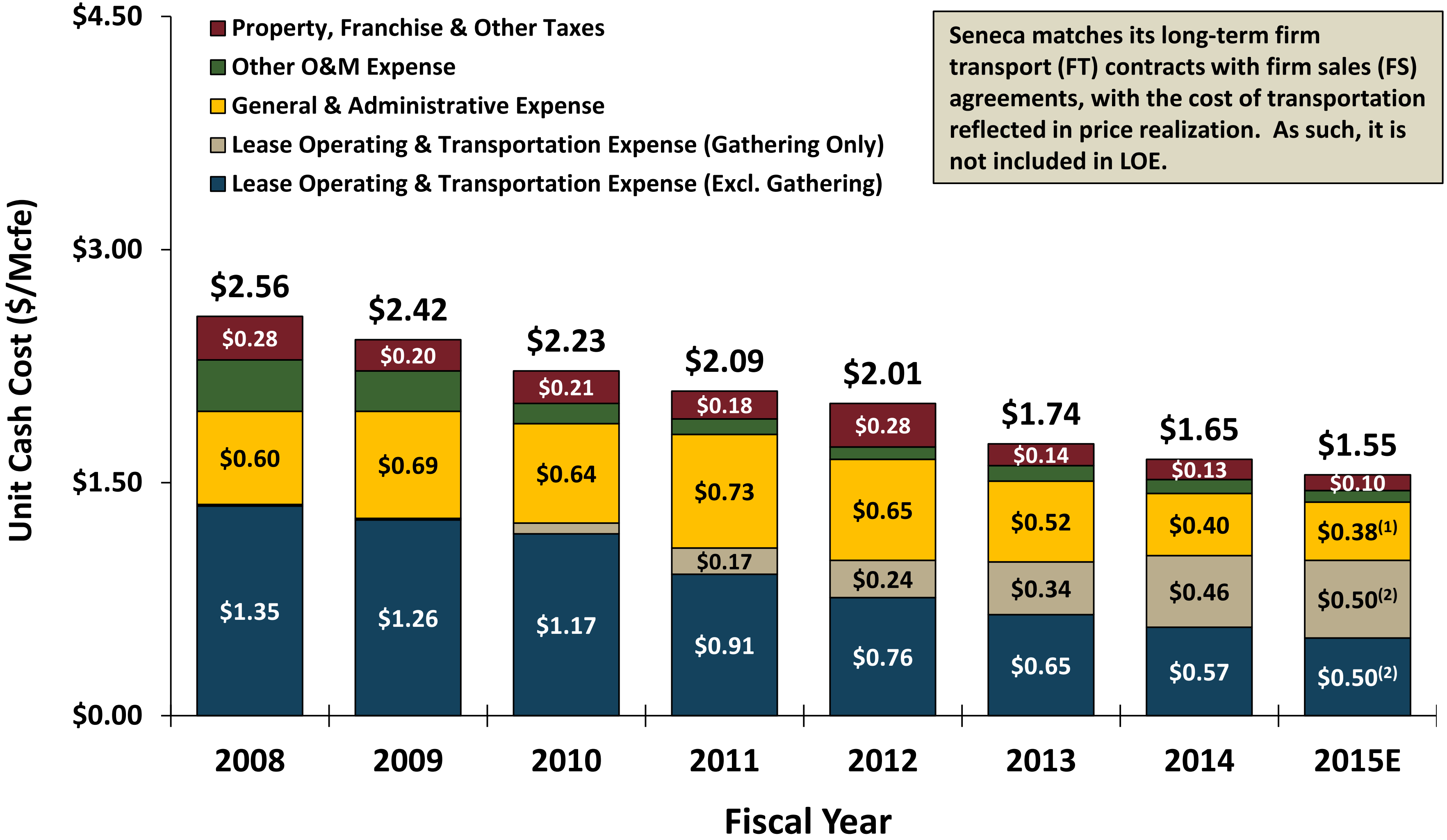
Disciplined Capital Spending



(1) Does not include the $34.9 MM Seneca Resources Corporation's acquisition of Ivanhoe's U.S.-based assets in California, as this was accounted for as an investment in subsidiaries on the Statement of Cash Flows, and was not included in the Exploration & Production segment's Capital Expenditures.

Seneca Resources

LOE: Operating Costs down; Transportation Costs up

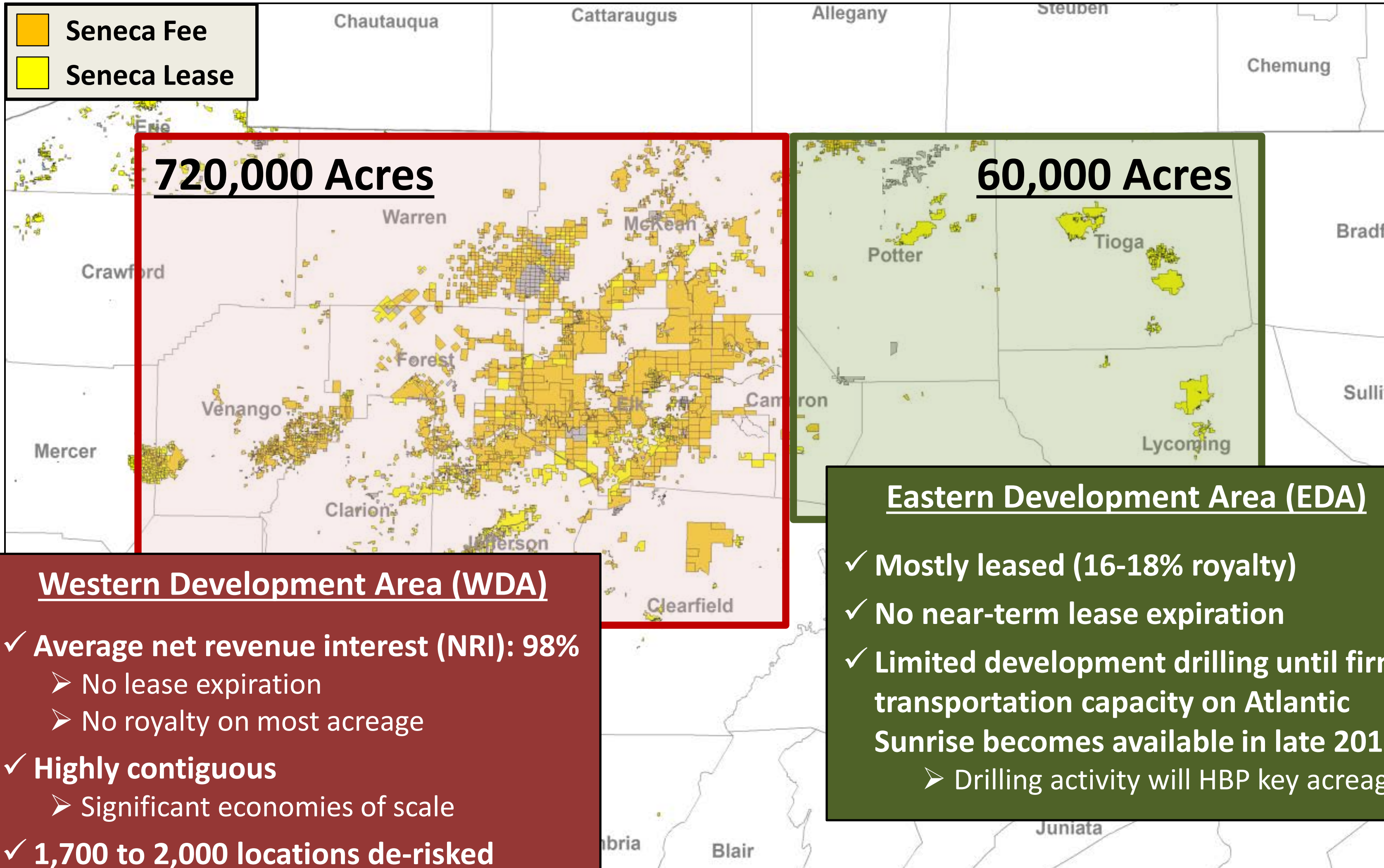


Seneca matches its long-term firm transport (FT) contracts with firm sales (FS) agreements, with the cost of transportation reflected in price realization. As such, it is not included in LOE.

(1) Represents the midpoint of current General & Administrative Expense guidance of $0.35 to $0.40 per Mcfe for fiscal 2015
(2) The total of the two LOE components represents the midpoint of current LOE guidance of $0.95 to $1.05 per Mcfe for fiscal 2015

Marcellus Shale

Prolific Pennsylvania Acreage



Western Development Area (WDA)

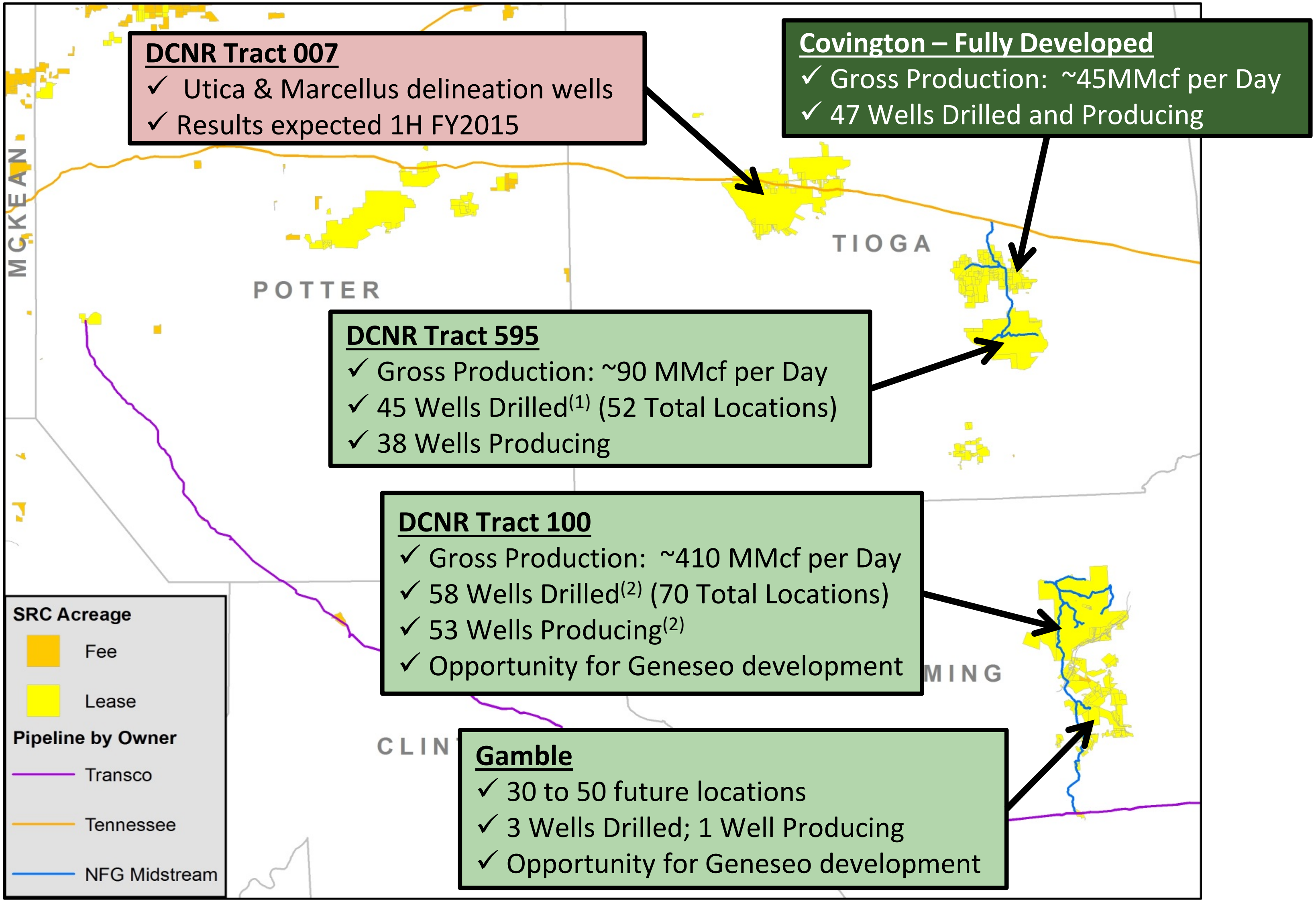
- ✓ **Average net revenue interest (NRI): 98%**
  - ➢ No lease expiration
  - ➢ No royalty on most acreage
- ✓ **Highly contiguous**
  - ➢ Significant economies of scale
- ✓ **1,700 to 2,000 locations de-risked**

Eastern Development Area (EDA)

- ✓ **Mostly leased (16-18% royalty)**
- ✓ **No near-term lease expiration**
- ✓ **Limited development drilling until firm transportation capacity on Atlantic Sunrise becomes available in late 2017**
  - ➢ Drilling activity will HBP key acreage

Marcellus Shale

EDA Delivering Significant Growth



(1) One well included in this total is drilled into the Geneseo Shale
(2) One well included in this total is drilled into and producing from the Geneseo Shale

Marcellus Shale

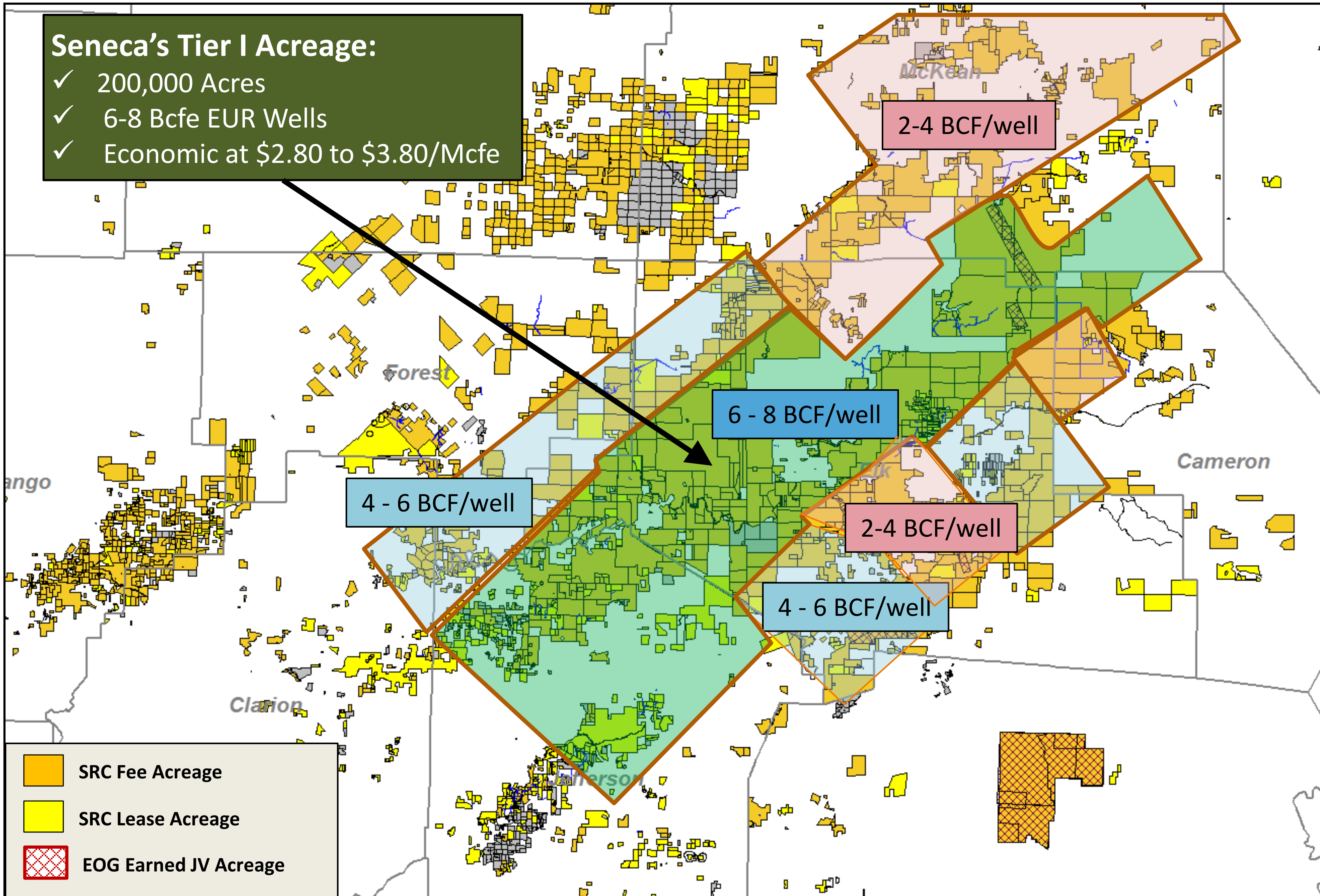
EDA – Historical Well Results are Exceptional

Development Area	Producing Well Count	Average IP Rate (MMcf/d)	Average 7-Day (MMcf/d)	Average 30-Day (MMcf/d)	Average EUR per Well (Bcf)	Average Lateral Length	EUR per 1,000' of Lateral (Bcfe)
Covington *Tioga County*	47	5.2	4.7	4.1	5.8	4,023'	1.44
Tract 595 *Tioga County*	38	7.2	6.0	5.2	8.0	4,716'	1.70
Tract 100 *Lycoming County*	52[(1)]	17.0	14.9	12.7	12.6	5,304'	2.38

(1) Does not include a well drilled into and producing from the Geneseo Shale

Marcellus Shale

Focusing on WDA Development



Note: Assumes 6,000' treated lateral length

Marcellus Shale

Strong Wells Currently Producing Across WDA Acreage

WDA Development Areas:

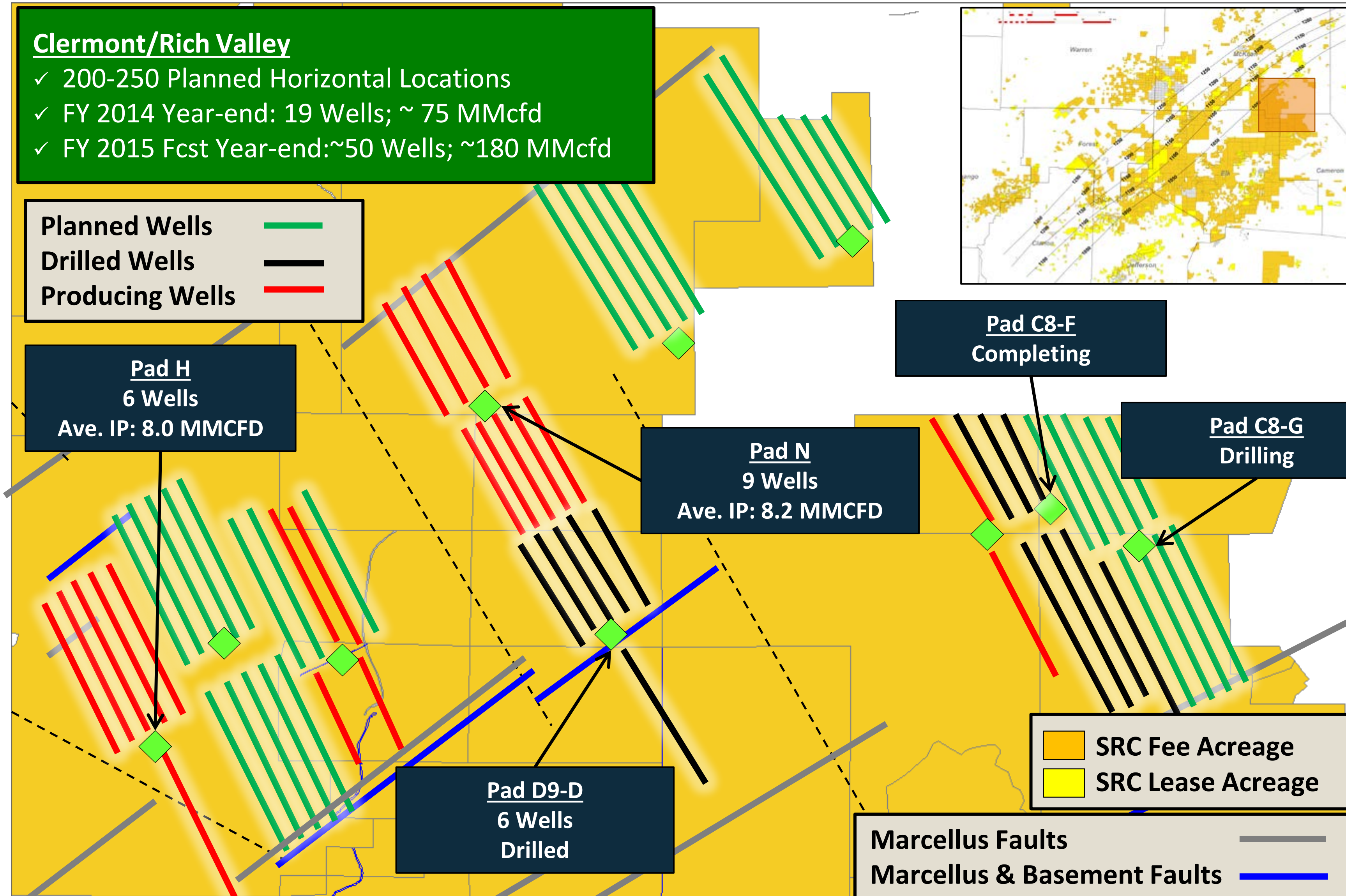
Area	Producing Well Count	Peak 24-Hour Rate (MMcfd)	Average 7-Day (MMcf/d)	Average Treatable Lateral Length
Clermont/Rich Valley *Elk, Cameron & McKean counties*	19	8.1	7.2	5,710’

WDA Delineation Areas:

Area	Producing Well Count	Peak 24-Hour Rate (MMcfd)	Average 7-Day (MMcf/d)	Average Treatable Lateral Length
Ridgway *Elk County*	1	7.1	6.4	5,537’
Church Run *Elk & Jefferson counties*	2	4.8	4.5	4,690’
Owl’s Nest *Elk & Forest counties*	1	6.1	5.8	6,137’
Sulger Farms *Jefferson County*	1	6.1	5.6	5,778’

Marcellus Shale

Clermont / Rich Valley (CRV) Area



Marcellus Shale

WDA Mineral Interests Significantly Enhance Returns

Clermont/Rich Valley Example

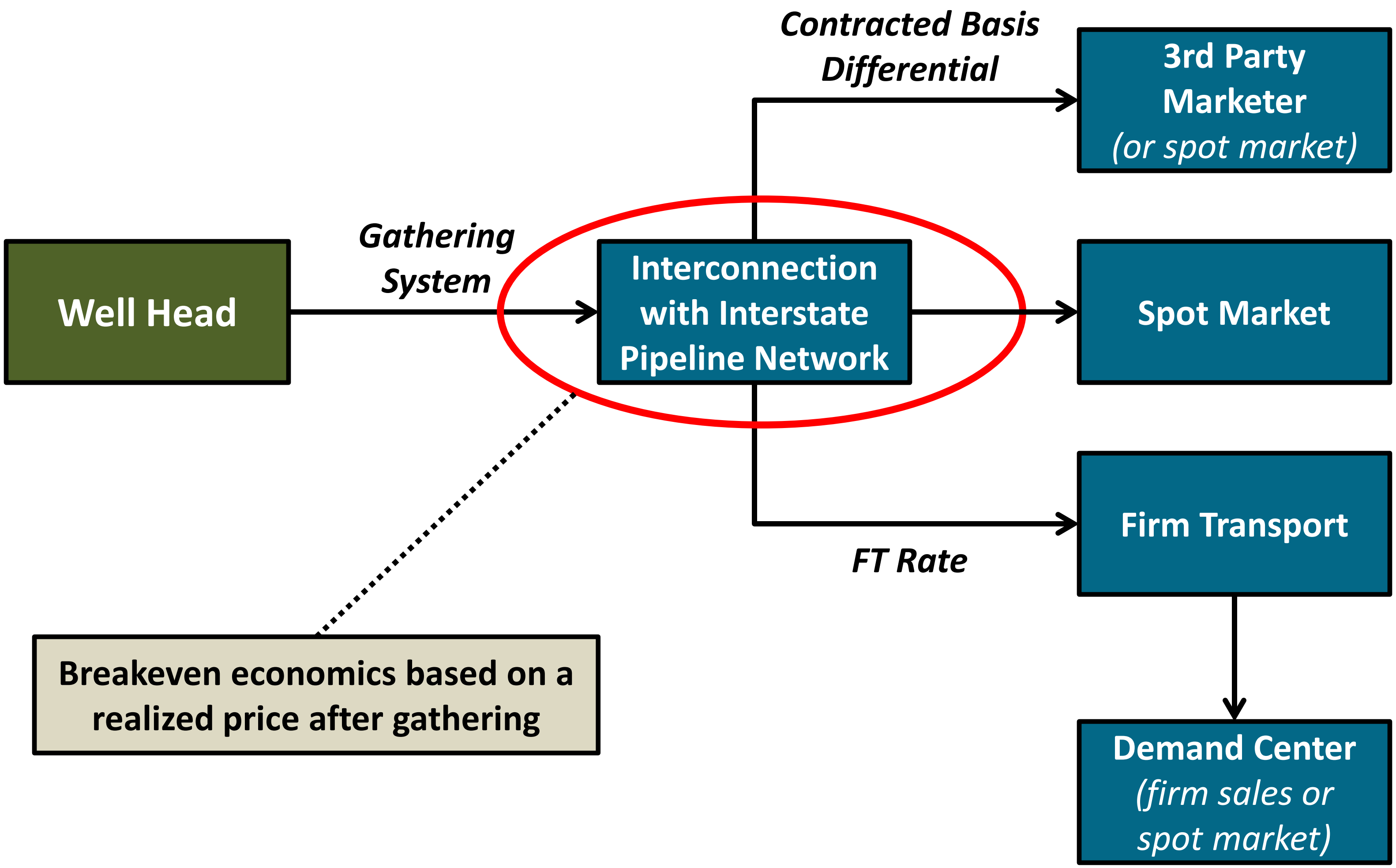
($/Mcf)	Typical Producer 15% Royalty	The Seneca Advantage 0% Royalty
Average Net Realized Price	$ 3.27	$ 2.80
Less: Cash Operating Expenses	(0.65)	(0.65)
Less: Royalty Payment	(0.47)	(0.00)
Cash Margin	**$ 2.15**	**$ 2.15**
Before Tax IRR (1)	***15%***	***15%***

*In Clermont/Rich Valley, a typical producer burdened by a 15% royalty would require a **$0.47 higher net realized price** to achieve same level of economics as Seneca Resources*

(1) Internal Rate of Return (IRR) includes estimated well costs under current cost structure, LOE, and Gathering tariffs anticipated for each prospect.

Natural Gas Marketing

How Does Seneca Sell its Production?



Natural Gas Marketing

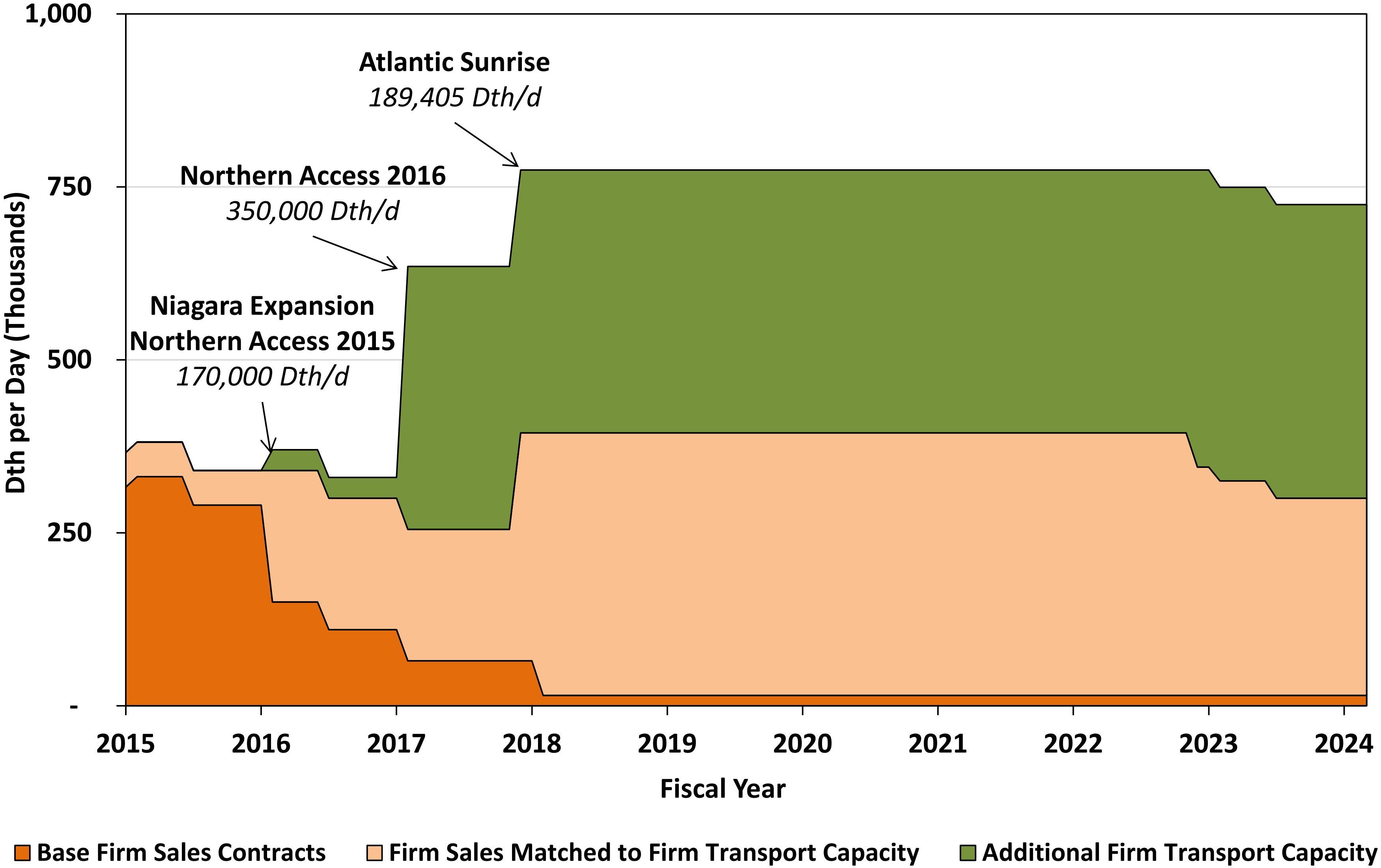
Adding Long-Term Firm Transport to the Portfolio

Project (Counterparty)	In-Service Date	Contract Term	Delivery Market	FT Capacity (Dth/day)				Matched Firm Sales
				Fiscal 2015	Fiscal 2016	Fiscal 2017	Fiscal 2018	
Northeast Supply Diversification Project (TGP)	Nov. 2012	15 years	Canada	50,000	50,000	50,000	50,000	**Executed Contracts** 50,000 Dth/d for 10 years
Niagara Expansion/ TETCO (TGP/ NFG/TETCO)	Nov. 2015	15 years	Canada/ TETCO	---	170,000	170,000	170,000	**Executed Contracts** 140,000 Dth/d for 15 years
Northern Access 2016 (NFG/ TransCanada/ Union)	Nov. 2016	15 years	Canada	---	---	350,000	350,000	Evaluating marketing opportunities
Atlantic Sunrise (Transco)	Nov. 2017	15 years	Mid-Atlantic/ Southeast	---	---	---	189,405	**Executed Contracts** 189,405 Dth/d for first 5 years[(1)]
Total Firm Transportation Capacity				**50,000**	**220,000**	**570,000**	**759,405**	

(1) A large majority of the executed firm sales agreements continue for the remainder of the firm transportation contract term.

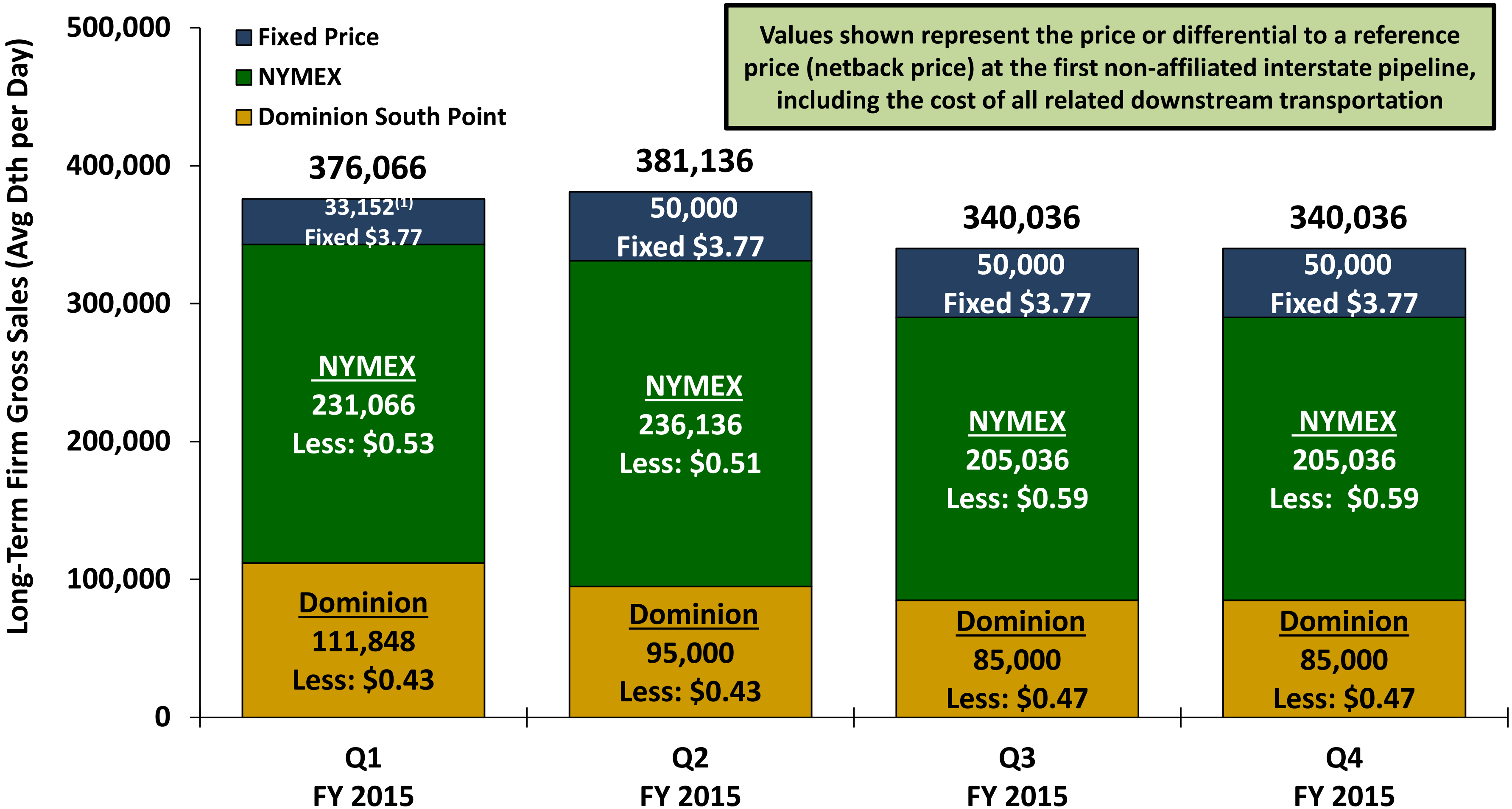
Natural Gas Marketing

Significant Base of Long-Term Firm Contracts



Natural Gas Marketing

Firm Sales Provide a Market for Appalachian Production

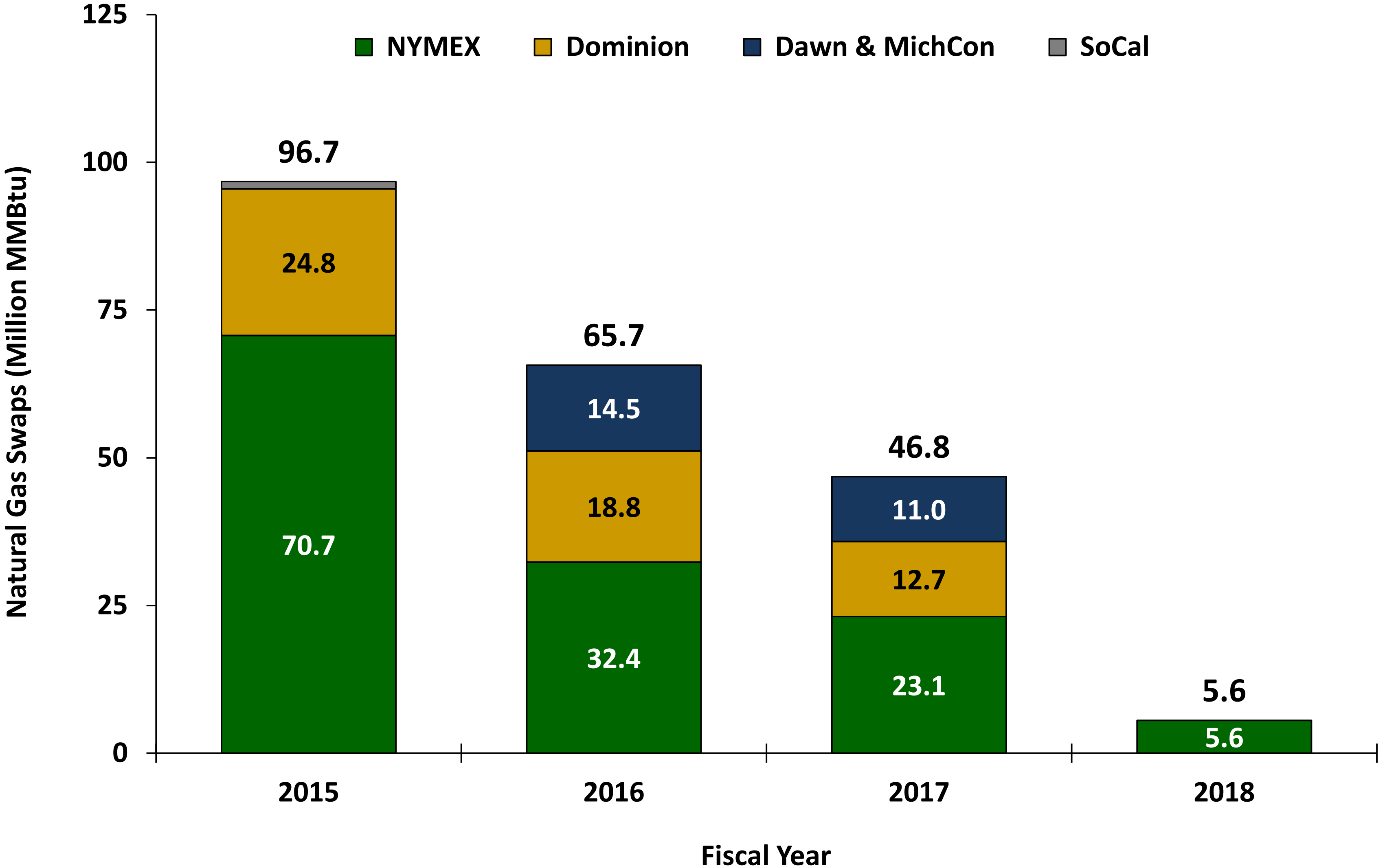


EDA (2)	318,033 Dth/d	320,036 Dth/d	280,036 Dth/d	280,036 Dth/d
WDA (2)	58,034 Dth/d	61,100 Dth/d	60,000 Dth/d	60,000 Dth/d

(1) Fixed price sales contracts totaling 50,000 Dth/day at an average fixed price of $3.77 per Dth starting November 2014 through October 2017
(2) EDA and WDA carry an average net revenue interest (NRI) of 82% - 84% and 98%, respectively

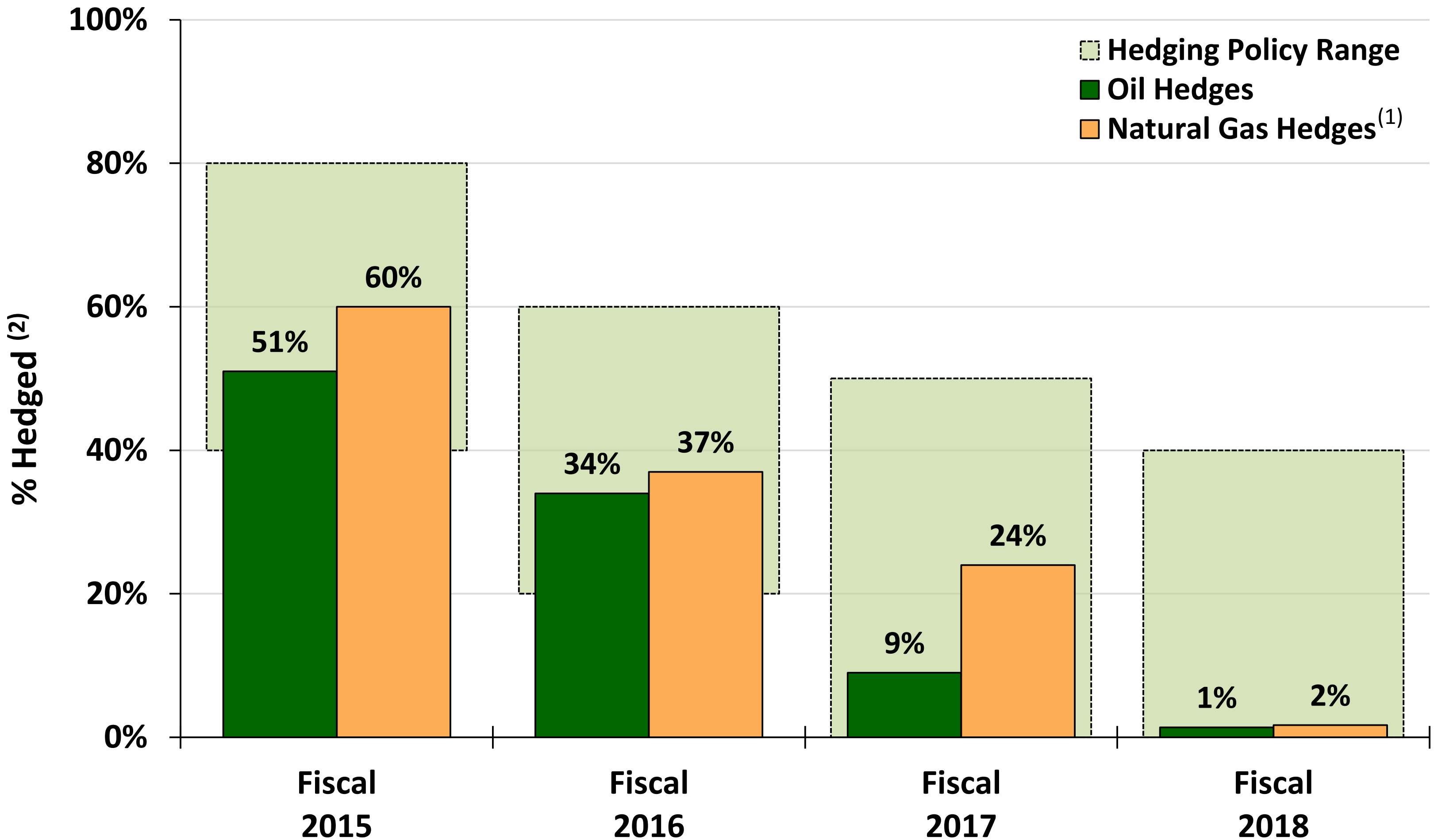
Natural Gas Marketing

Current Natural Gas Hedge Positions



Natural Gas Marketing

Current Hedge Book has Seneca Positioned Very Well

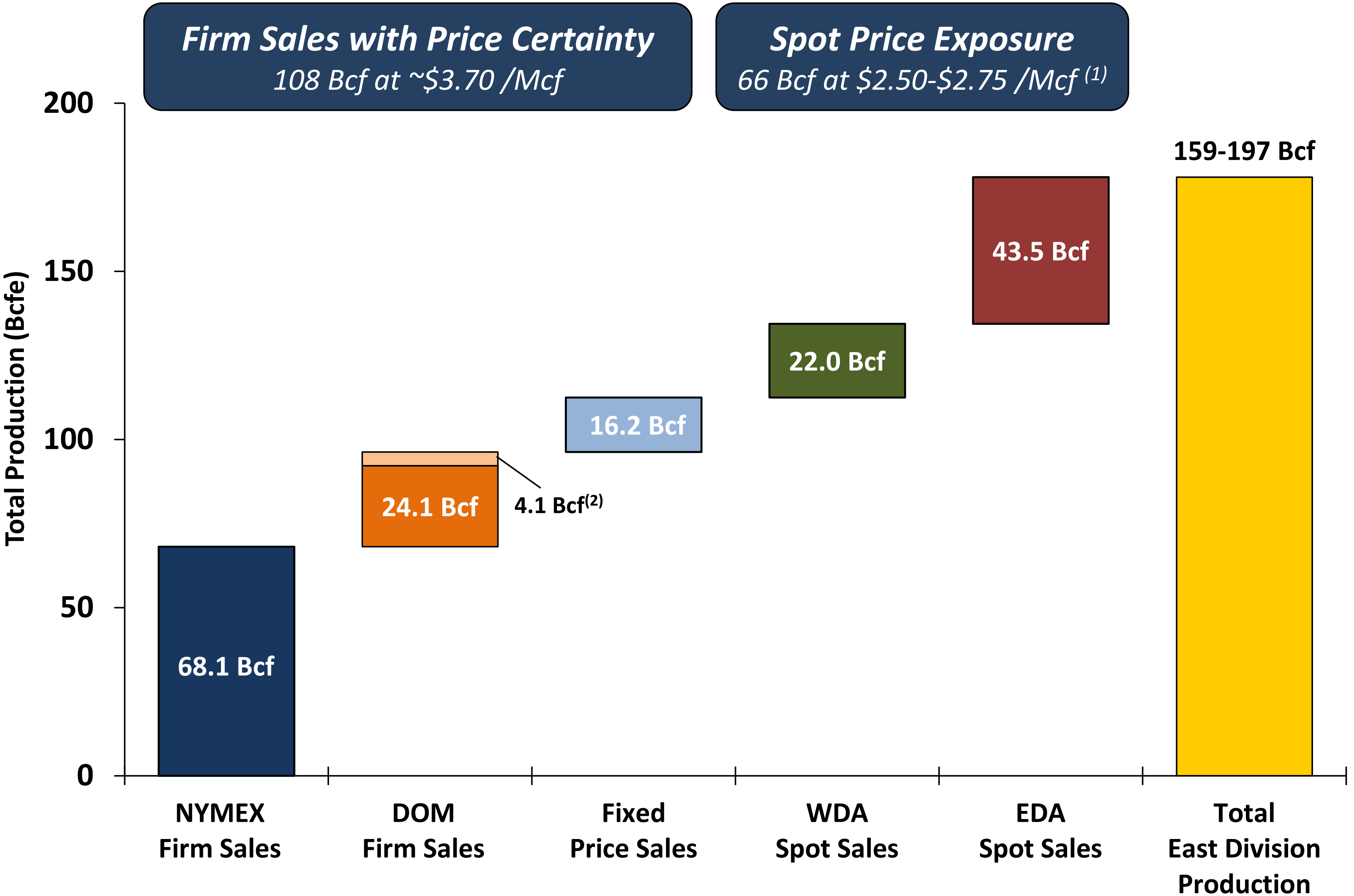


Natural Gas	$4.01/MMBtu	$4.03/MMBtu	$4.11/MMBtu	$4.41/MMBtu
Crude Oil	$95.27/Bbl	$92.95/Bbl	$92.30/Bbl	$91.00/Bbl

(1) Natural gas hedges include fixed price firm sales
(2) Hedge positions reflect the midpoint of Seneca's target annual production growth (20%) starting with the midpoint of Fiscal 2015 guidance (180-220 Bcfe)

Natural Gas Marketing

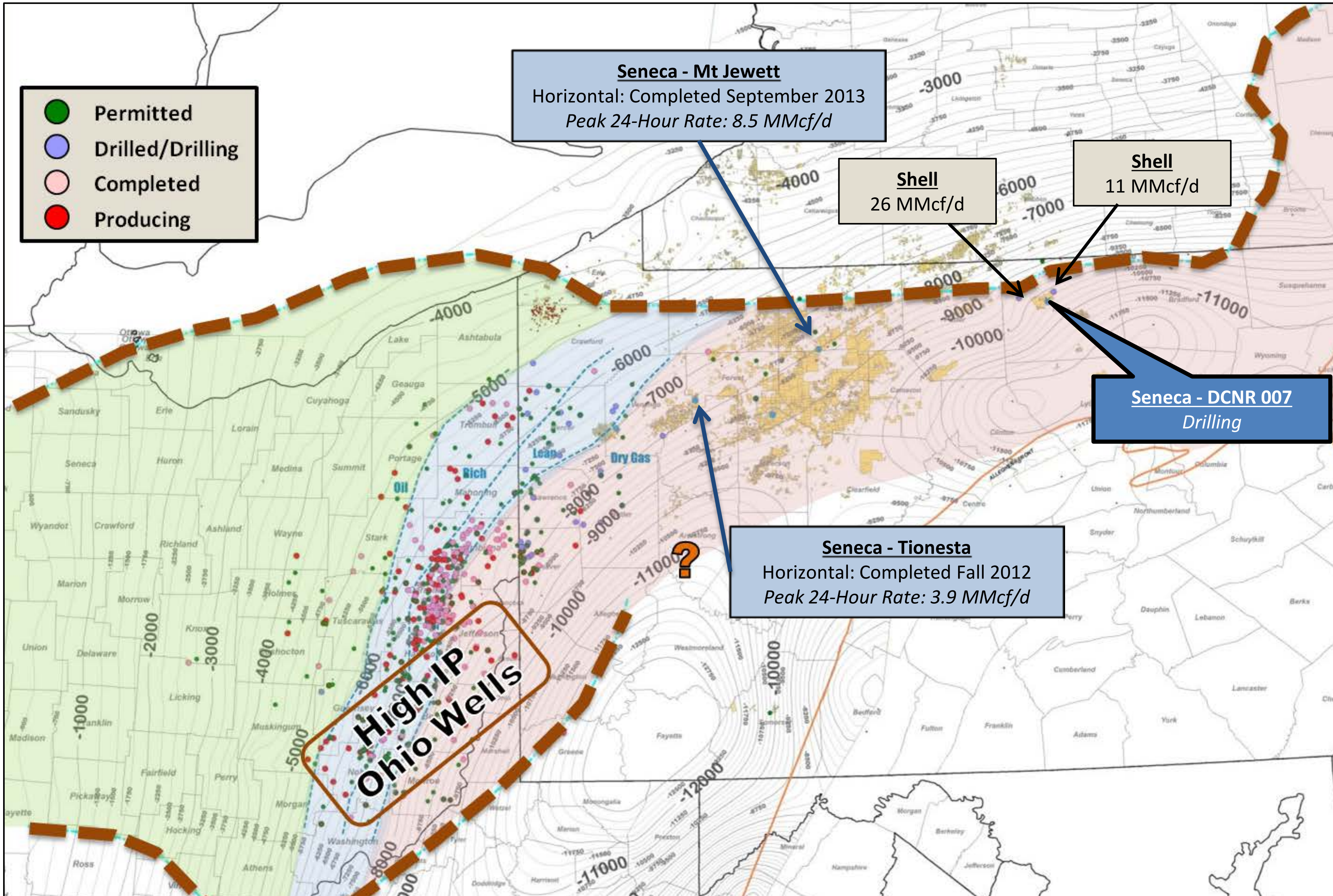
FY 2015 Production – Firm Sales & Hedge Composition



(1) Spot price assumptions reflected in fiscal 2015 earnings guidance range
(2) Dominion based firm sales contracts without a matching Dominion financial hedge

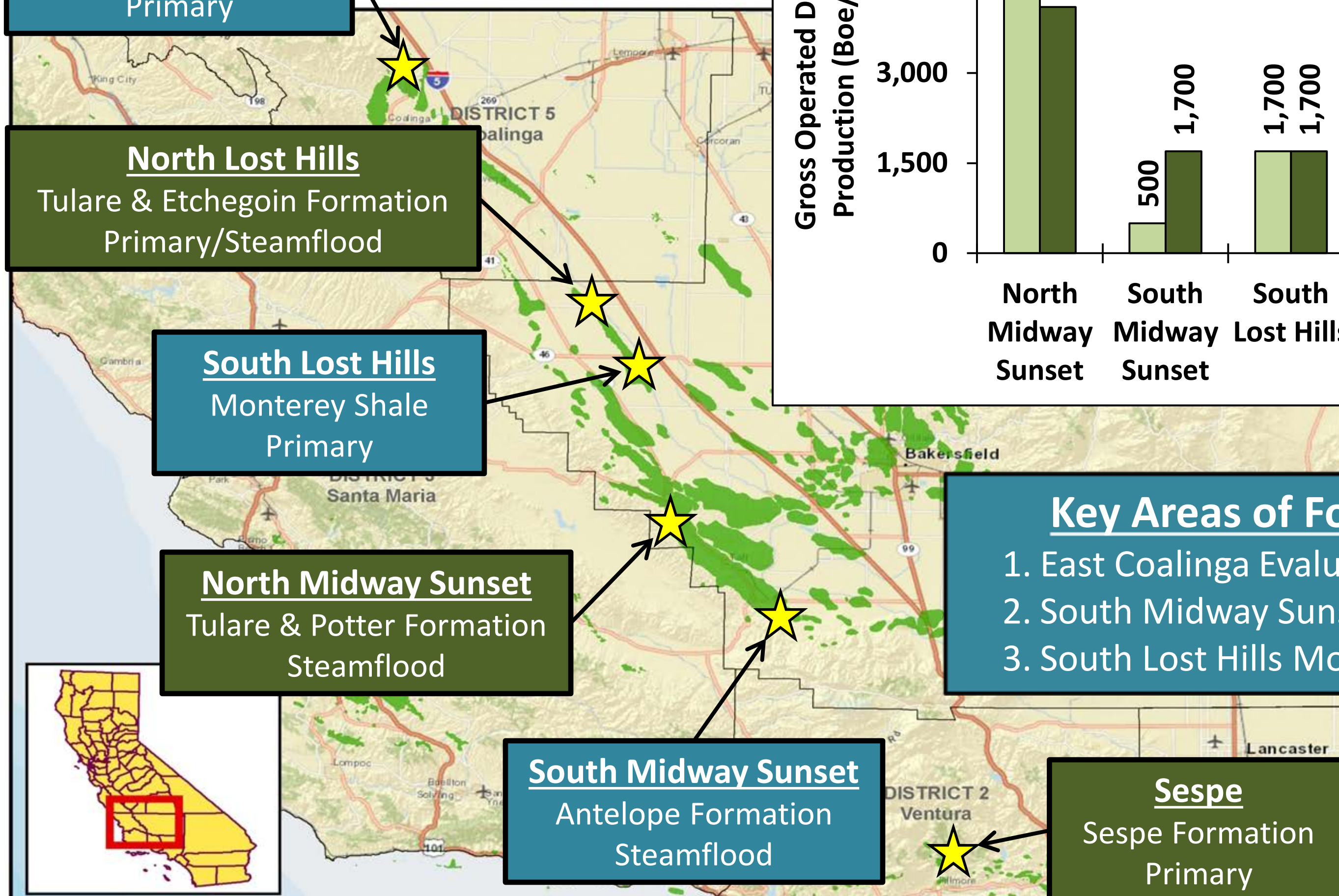
Utica Shale

Seneca Activity in Tioga County



California

Stable Production Fields; Modest Growth Potential



East Coalinga
Temblor Formation
Primary

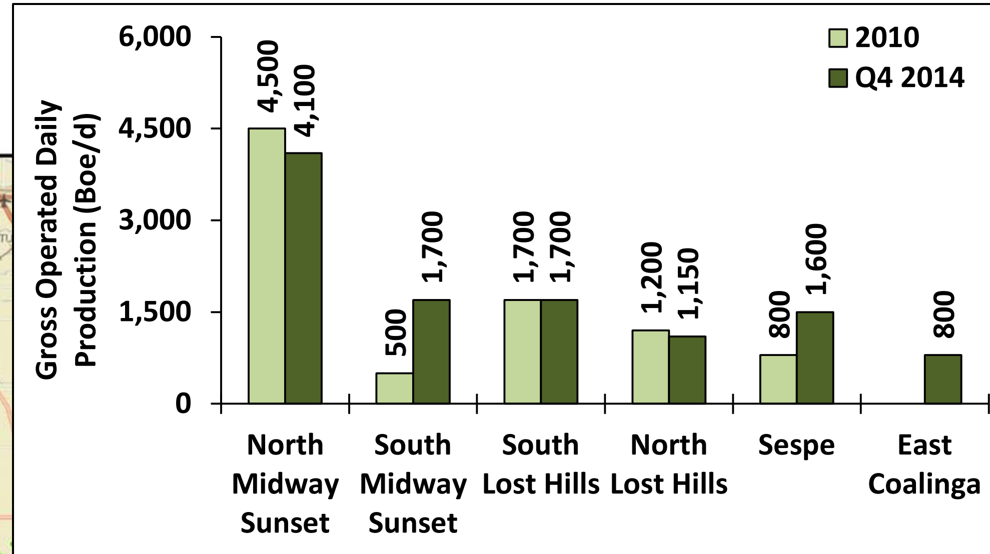
North Lost Hills
Tulare & Etchegoin Formation
Primary/Steamflood

South Lost Hills
Monterey Shale
Primary

North Midway Sunset
Tulare & Potter Formation
Steamflood

South Midway Sunset
Antelope Formation
Steamflood

Sespe
Sespe Formation
Primary



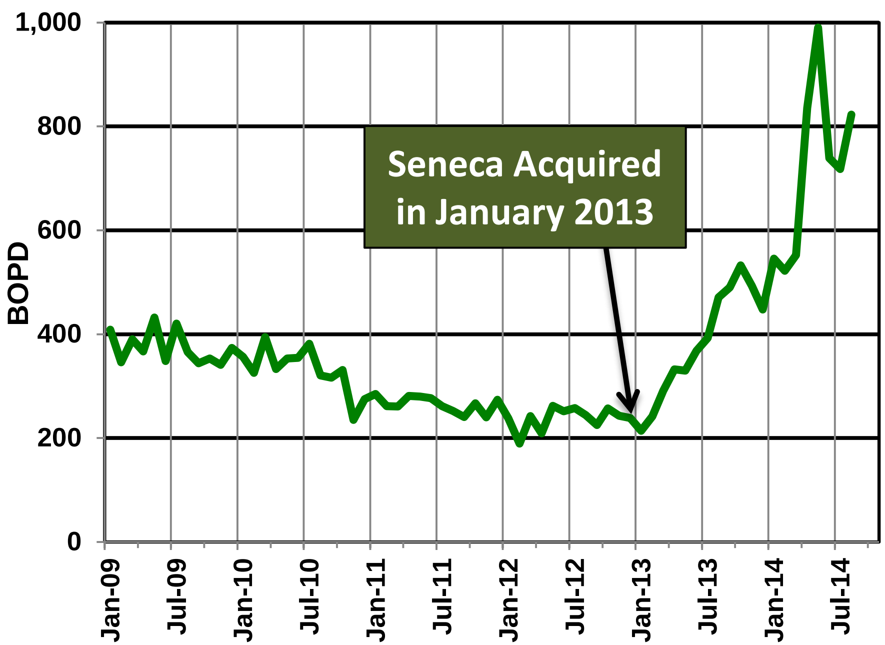
Key Areas of Focus in 2015:

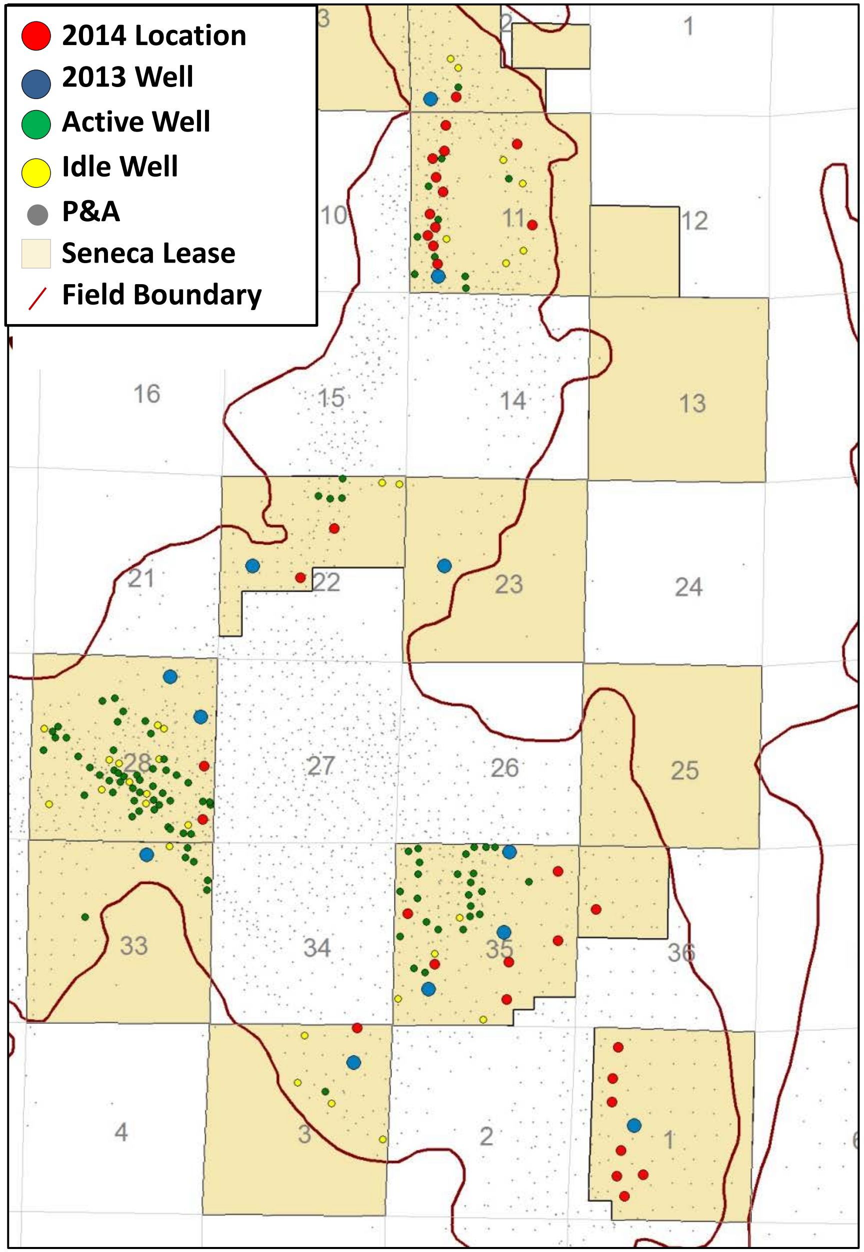
1. East Coalinga Evaluation
2. South Midway Sunset Extensions
3. South Lost Hills Monterey Evaluation

California

East Coalinga Summary

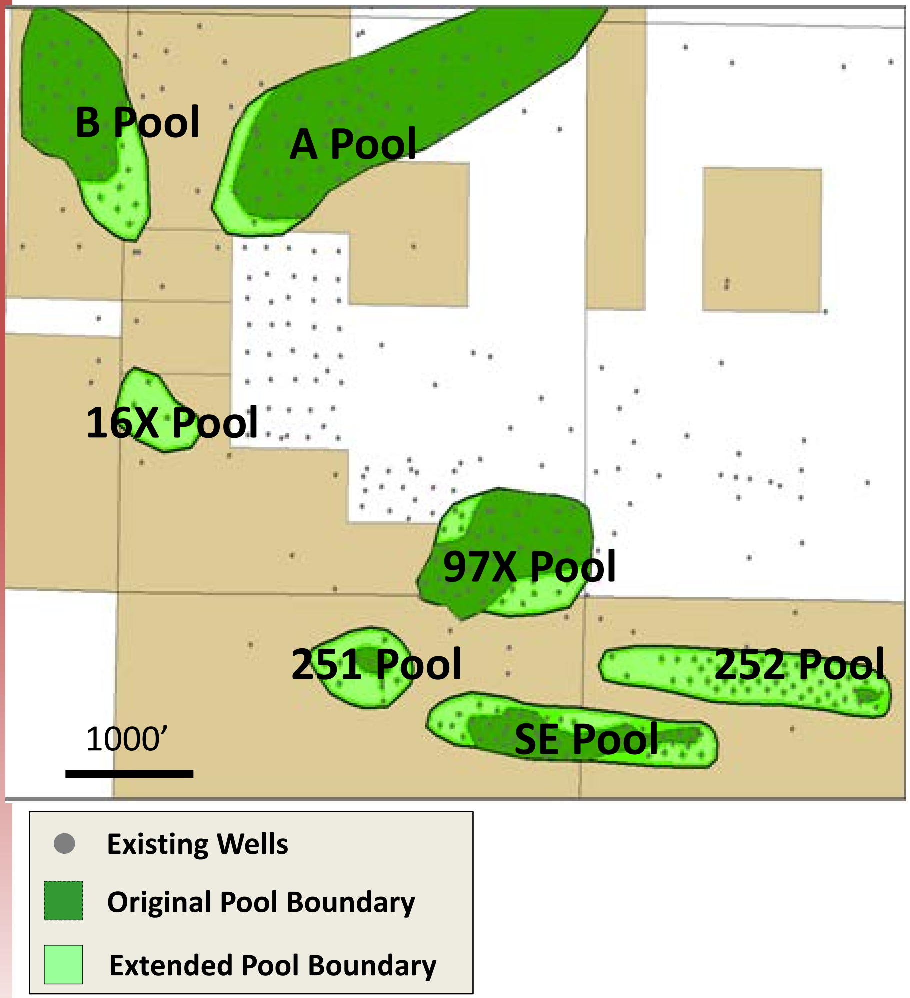
- Production has increased from 214 BOPD to 800 BOPD
  - Highest on leases since 2000
- Drilled 12 evaluation wells in 2013
  - Producing ~150 BOPD
- Drilled 31 new producers and 1 water disposal well in 2014. Currently have 27 of the new producers on line.

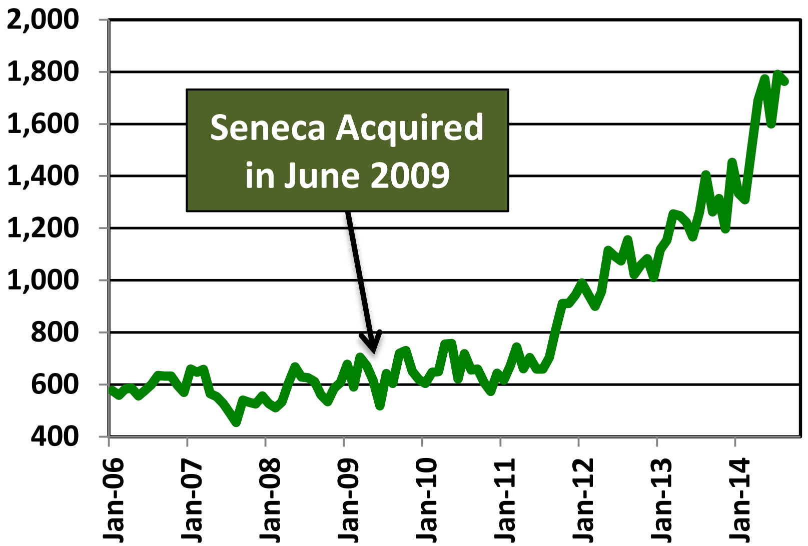




California

South Midway Sunset Has Delivered Significant Growth



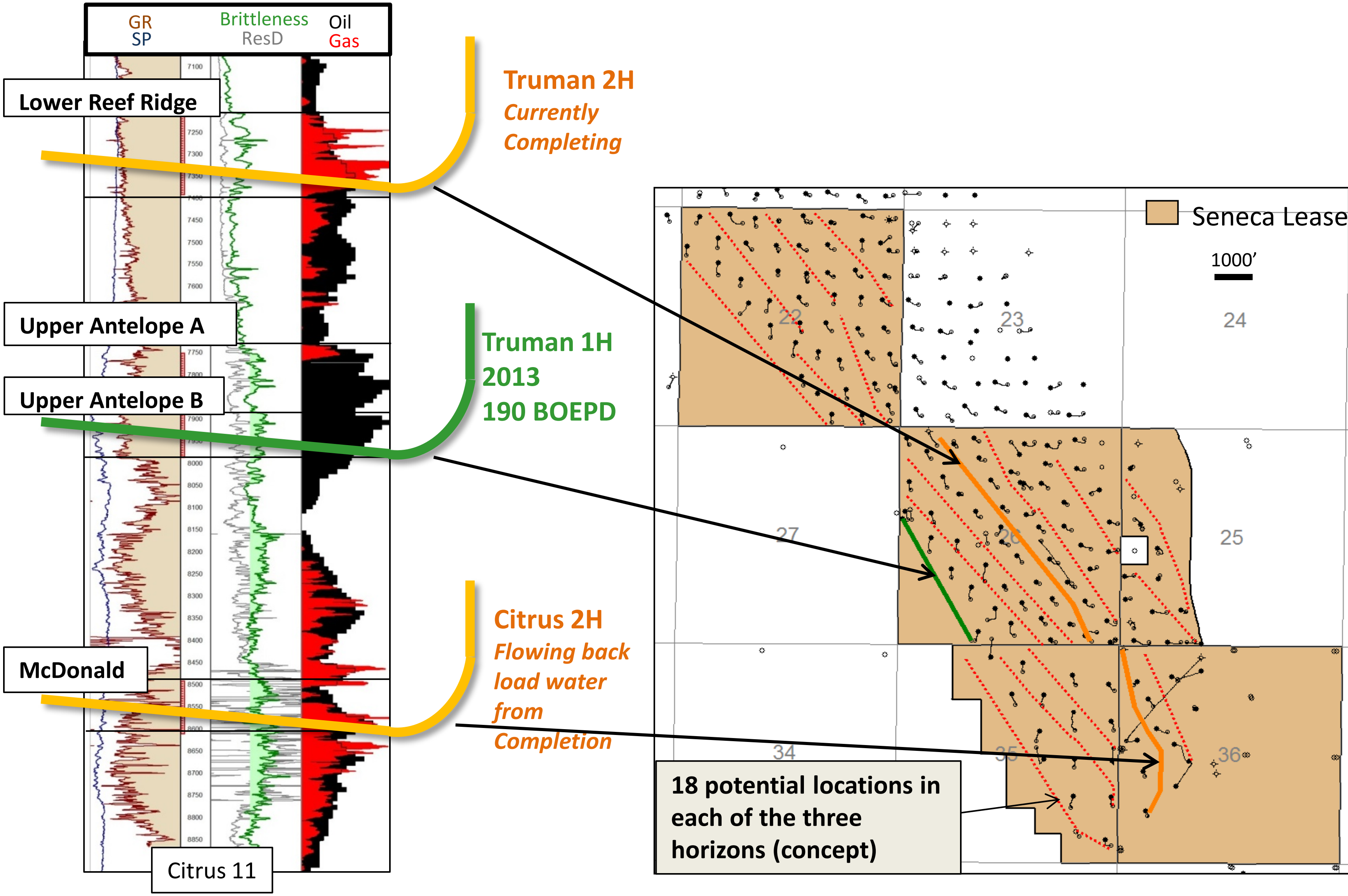


Highlights Since Acquisition

- Increased daily production 310% to approximately 1,700 BOPD
- Drilled 102 new producers
- Added 3.3 MMBO of proven reserves
- Increased steam capacity by 280%
- Identified opportunities for additional pool development

California

Evaluating the Monterey Shale at South Lost Hills



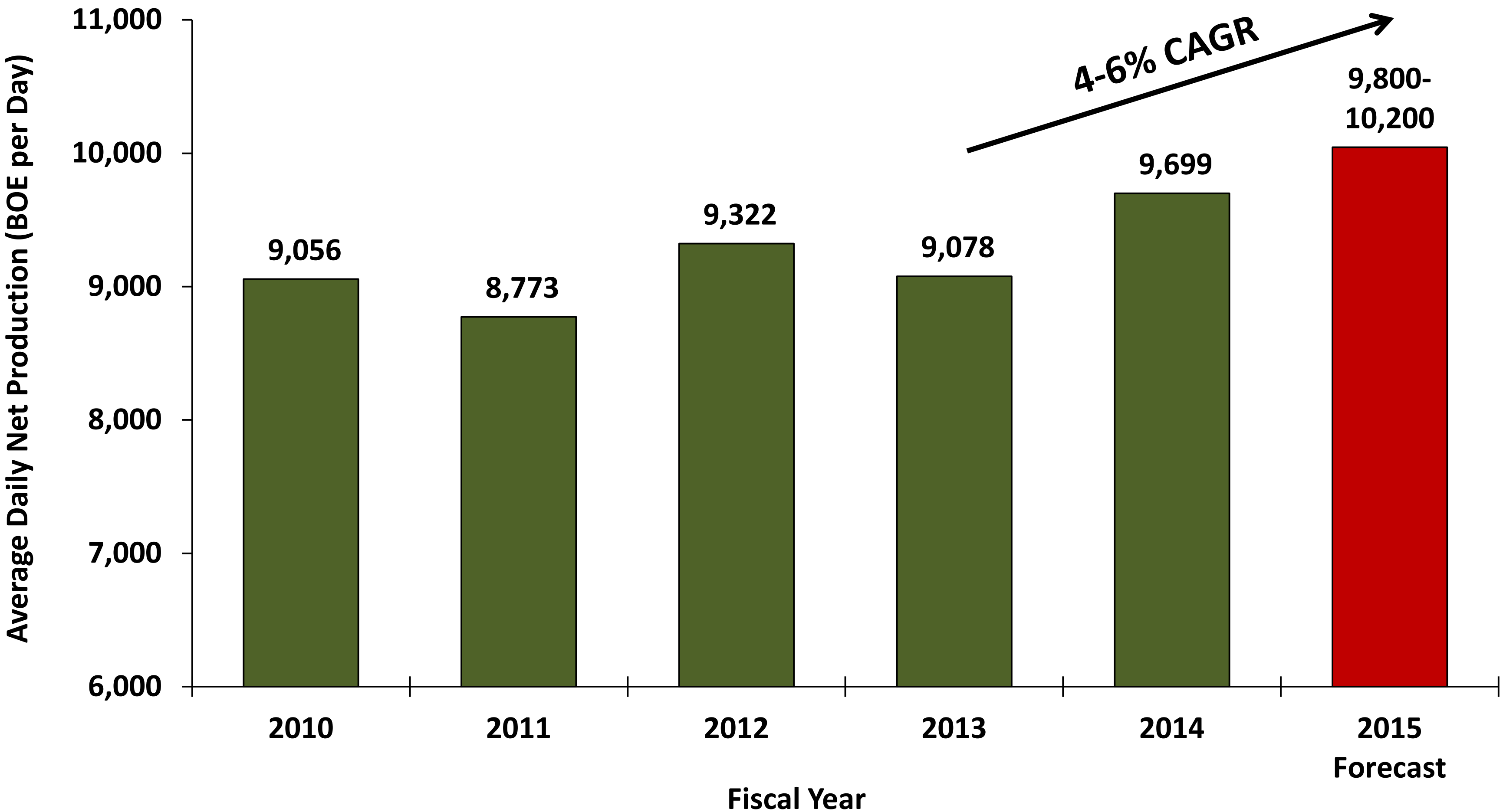
California

Modest Growth Opportunities, But Strong Economics

Field	Average Well Cost	Average EUR (MBO)	Estimated IRR @$85/Bbl	Fiscal 2015 Locations
North Midway Sunset	$300,000	32	59%	29
South Midway Sunset	$300,000	38	96%	42
East Coalinga	$580,000	35	30%	25

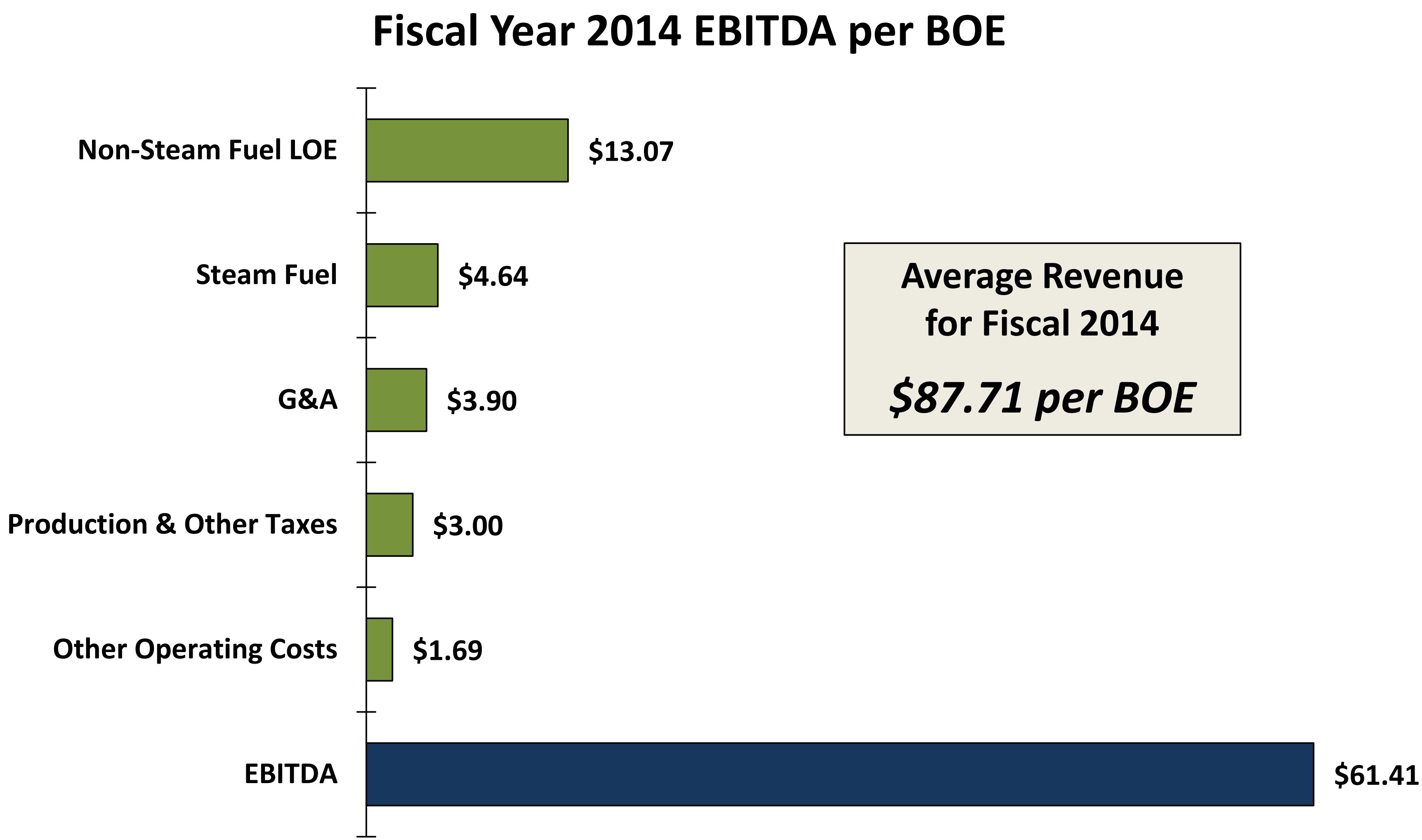
California

Modest Growth Anticipated in 2015



California

Strong Margins Support Significant Free Cash Flow



Average Revenue for Fiscal 2014

$87.71 per BOE

Note: A reconciliation of Exploration & Production West Division EBITDA to Exploration & Production Segment Net Income is included at the end of this presentation.

Seneca Resources

What Will Seneca Look Like Moving Forward?

Consistent Production Growth: 15-25% CAGR

Driven by a very large, high-quality Appalachian acreage position

Disciplined Spending Driven by Firm

Pace of development adapts to changing market dynamics

Maintain Oil Production → Expand When Possible

Excellent operator and significant cash flow generation

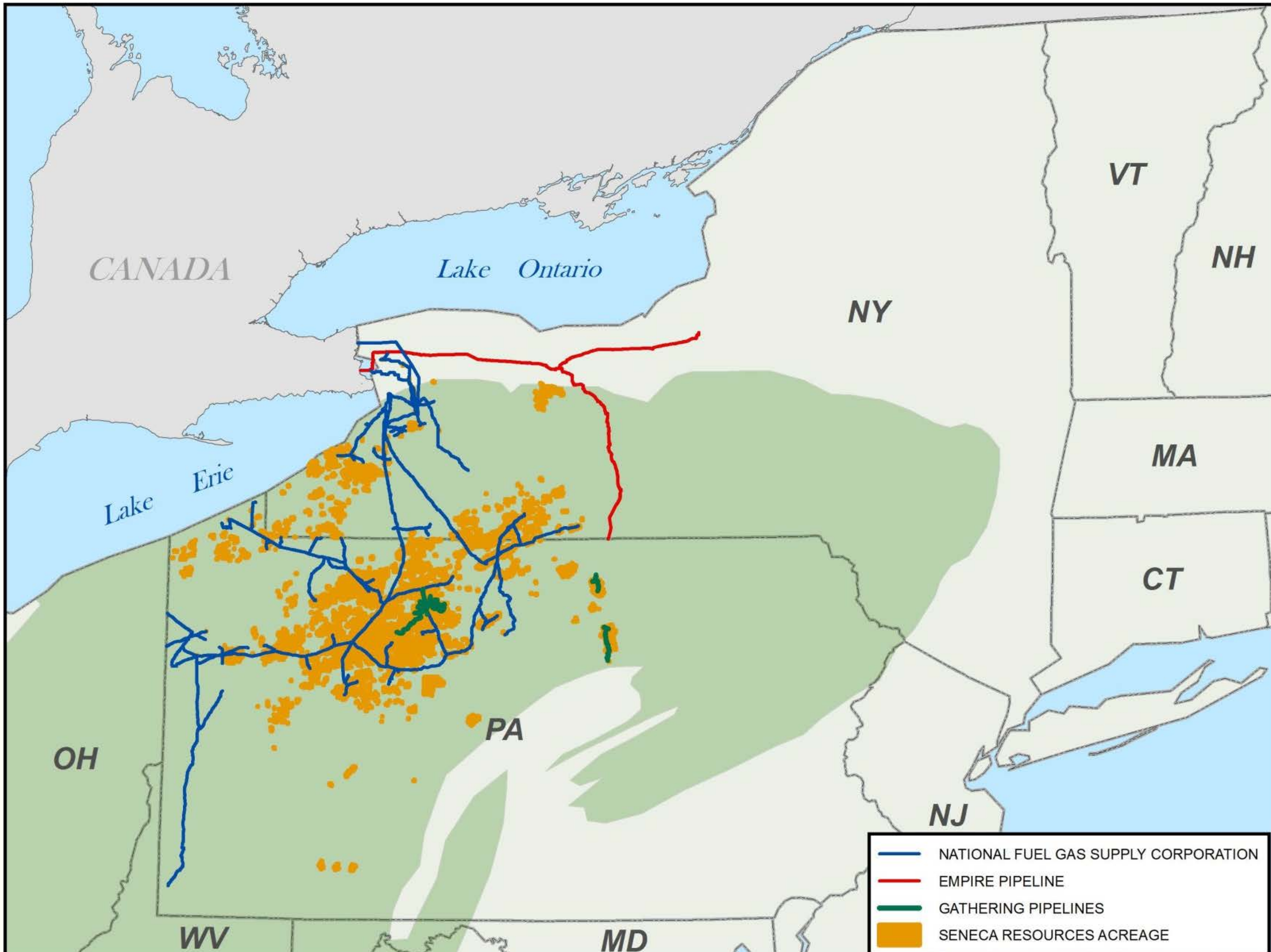
A Leader in Technology, Safety & Environmental Responsibility

Maintain a leadership role in using technology and developing best practices

Midstream Businesses Overview

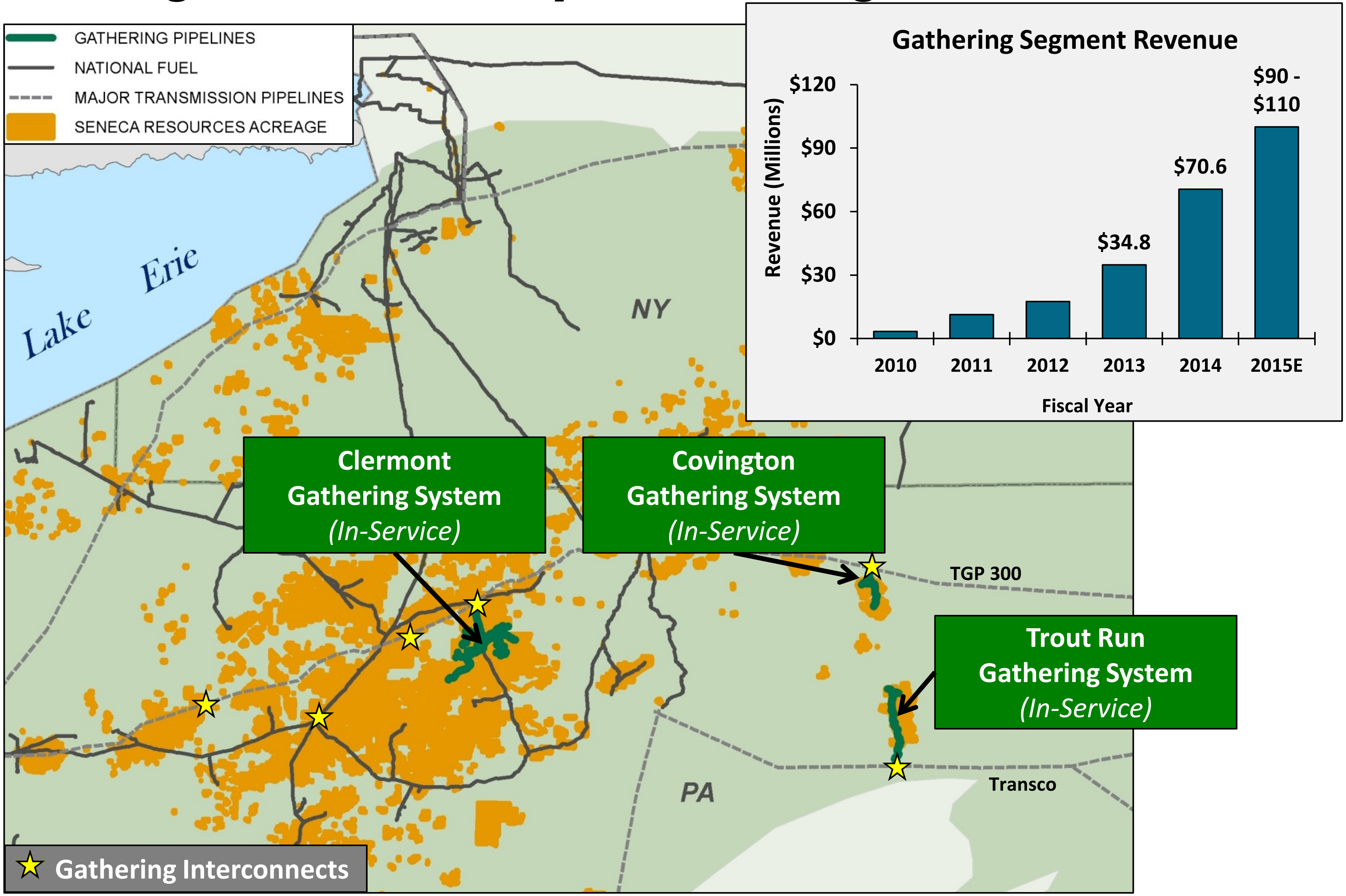
Midstream Businesses

Positioned to Serve Rapidly Growing Production in Appalachia



Gathering

Gathering is the First Step to Reaching a Market



Gathering

Gathering Systems Supporting Seneca's EDA Production

Covington Gathering System

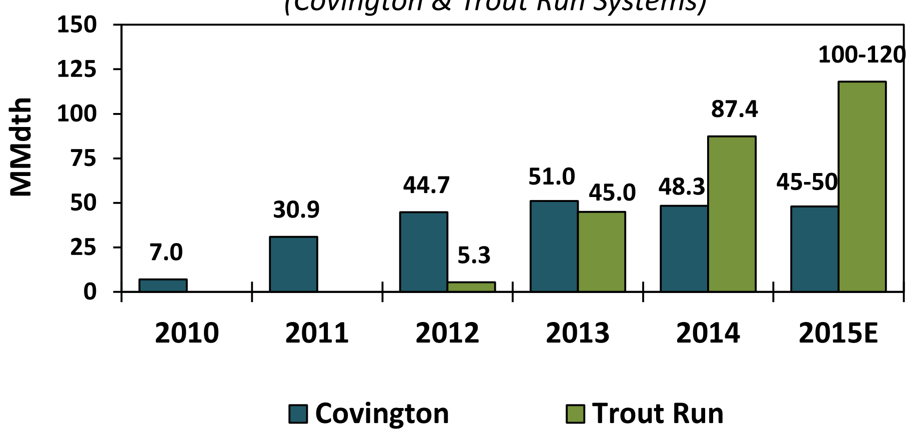
- In-Service Date: November 2009
- Capacity: 220,000 Dth per day
- Interconnect: TGP 300
- Capital Expenditures (to date): $32 Million

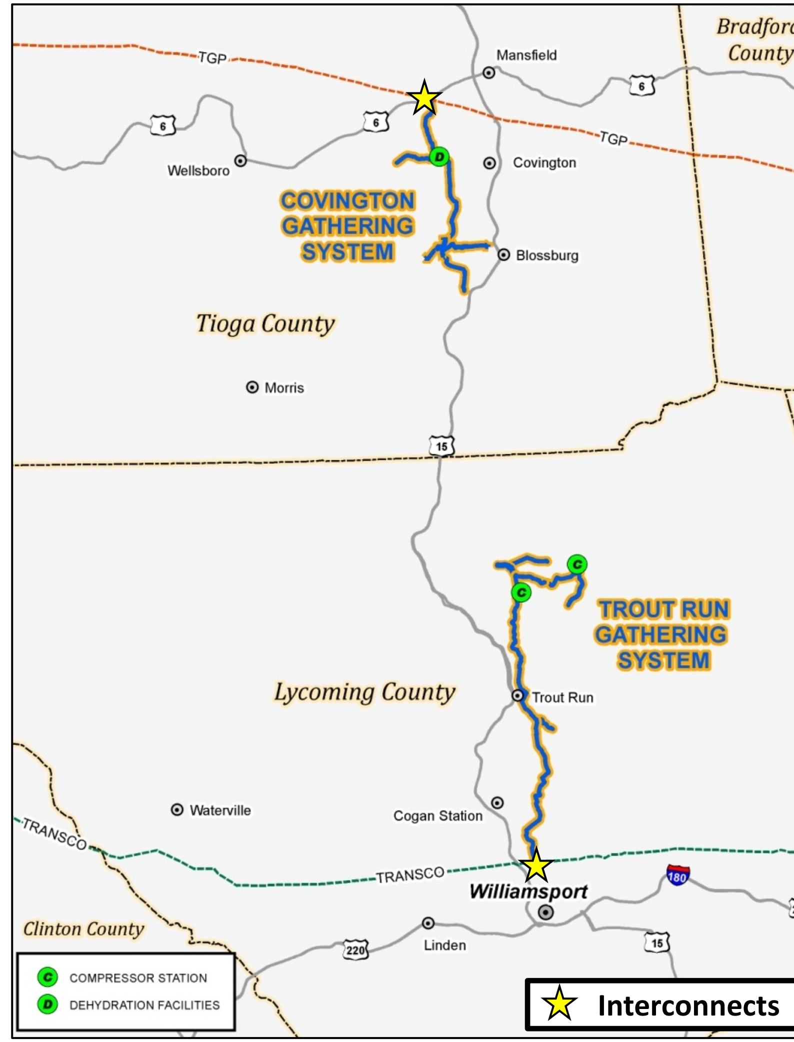
Trout Run Gathering System

- In-Service Date: May 2012
- Capacity: 466,000 to 585,000 Dth per day
- Interconnect: Transco – Leidy Lateral
- Capital Expenditures (to date): $162 Million
- Capital Expenditures (future): $30 to $70 Million

Fiscal Year Throughput by Project

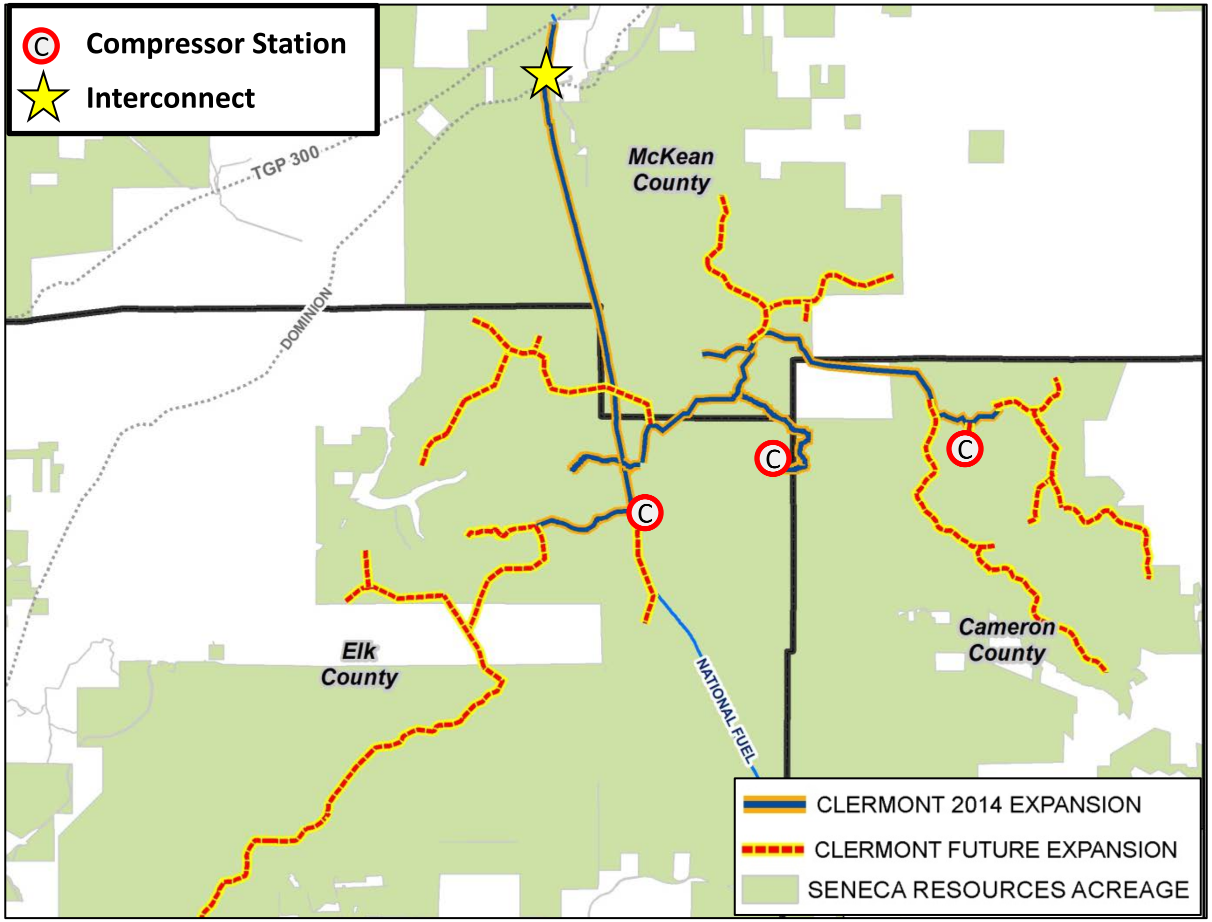
(Covington & Trout Run Systems)





Gathering

Clermont Gathering System has Large Expandability

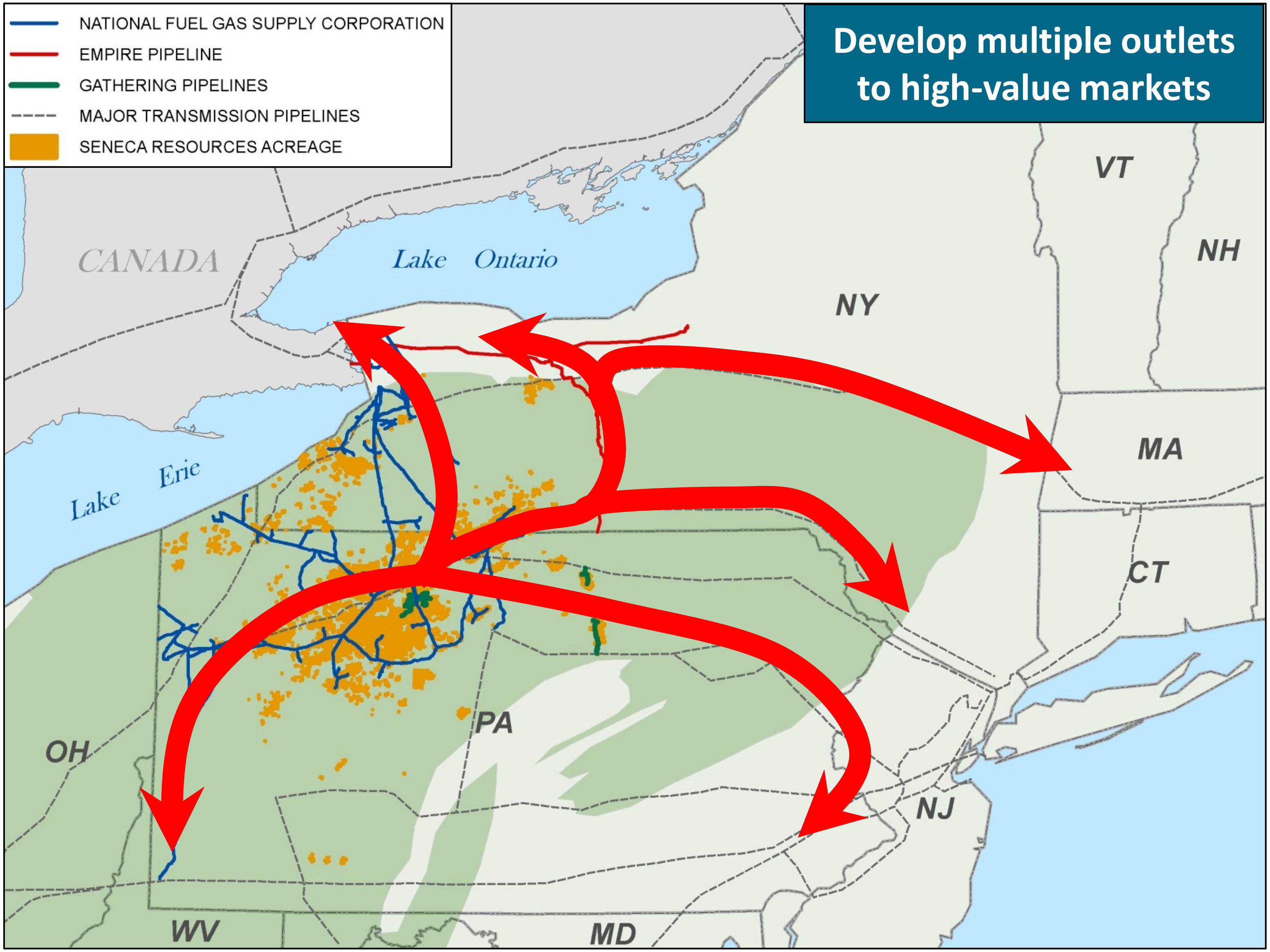


Clermont Gathering System

- In-Service: July 2014
- Ultimate Trunkline Capacity: 1+ Bcf per day
- Interconnects
  - TGP 300 (current)
  - NFG Supply Corporation (Northern Access 2016)
- Capital:
  - 2014: $96 Million
  - 2015: $110 - $160 Million
- Seneca Pads Connected
  - SRC Pad N (9 wells) connected July 2014
  - SRC Pad H (6 wells) connected September 2014
  - Up to 25 pads connected following the 2015 expansion

Pipeline & Storage

Project Opportunities to Support Appalachian Growth



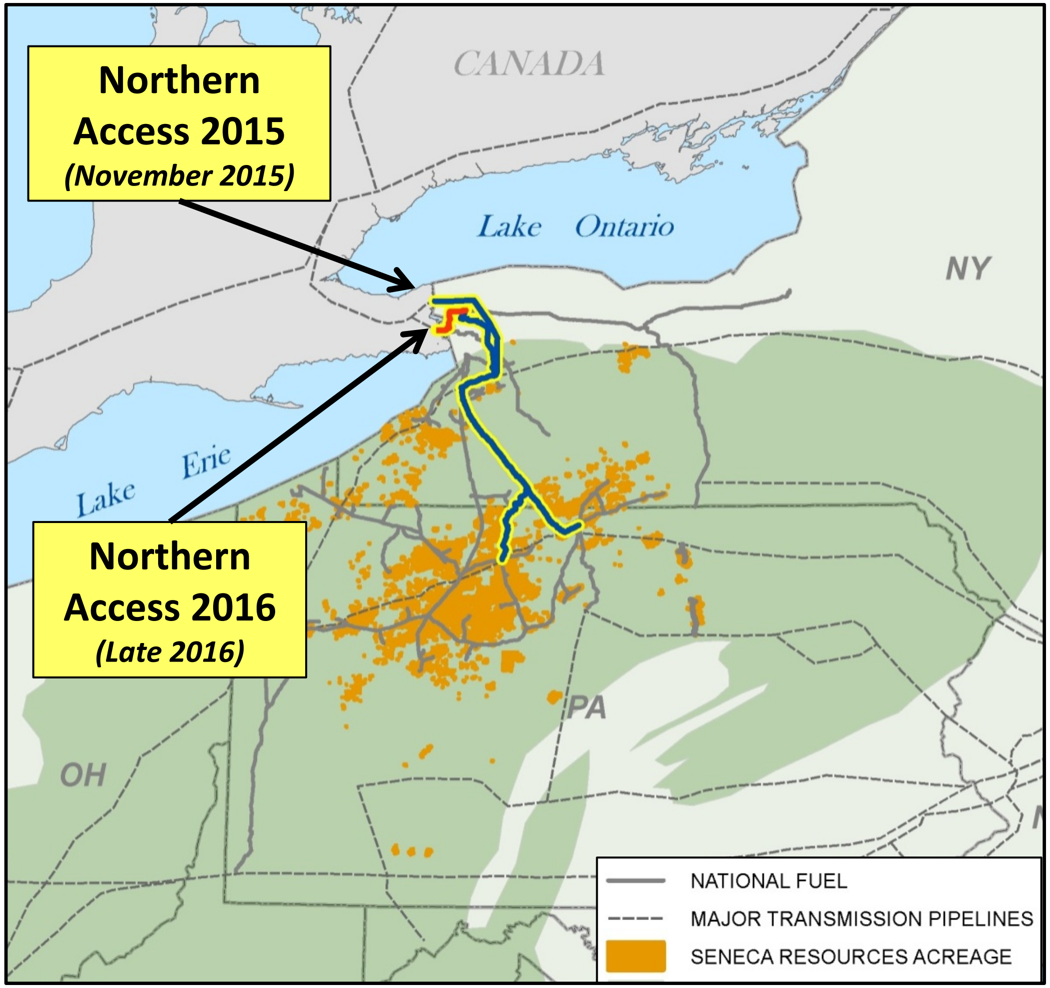
Pipeline & Storage

Expansions to Move Gas from the WDA Are Significant

Projects to Support WDA Growth

Project	Capacity (Dth/day)
Northern Access 2015	140,000
Northern Access 2016	350,000
Total New Capacity	**490,000**

Project	Capital Cost
Northern Access 2015	$66 Million
Northern Access 2016	$410 Million
Total Capital Expenditures	**$476 Million**

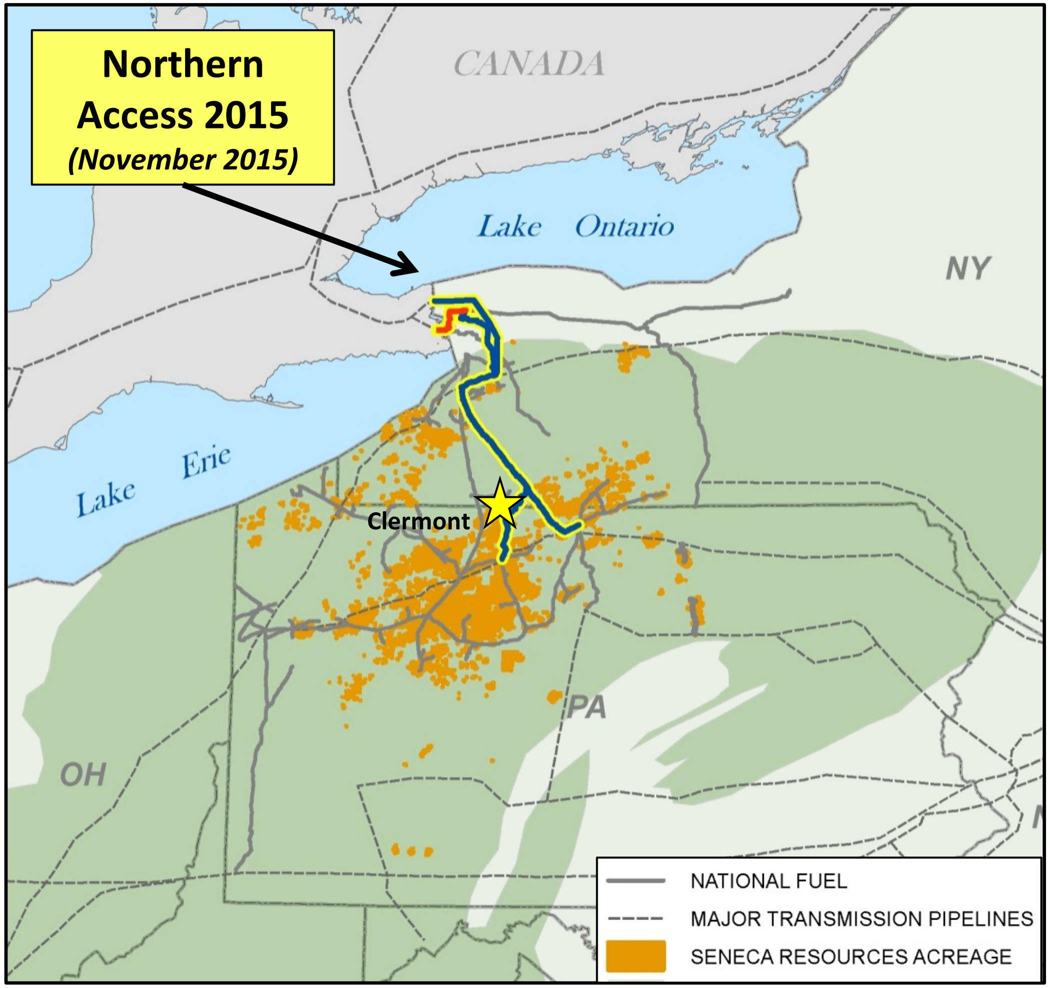


Pipeline & Storage

Major Expansion Designed for Canadian Deliveries

Northern Access 2015

- Customer: Seneca Resources
- In-Service: November 2015
- System: NFG Supply Corp.
- Capacity: 140,000 Dth per day
  - Lease to TGP as part of their Niagara Expansion project
- Interconnect
  - Niagara (TransCanada)
- Total Cost: $66 Million
- Major Facilities
  - 23,000 HP Compression

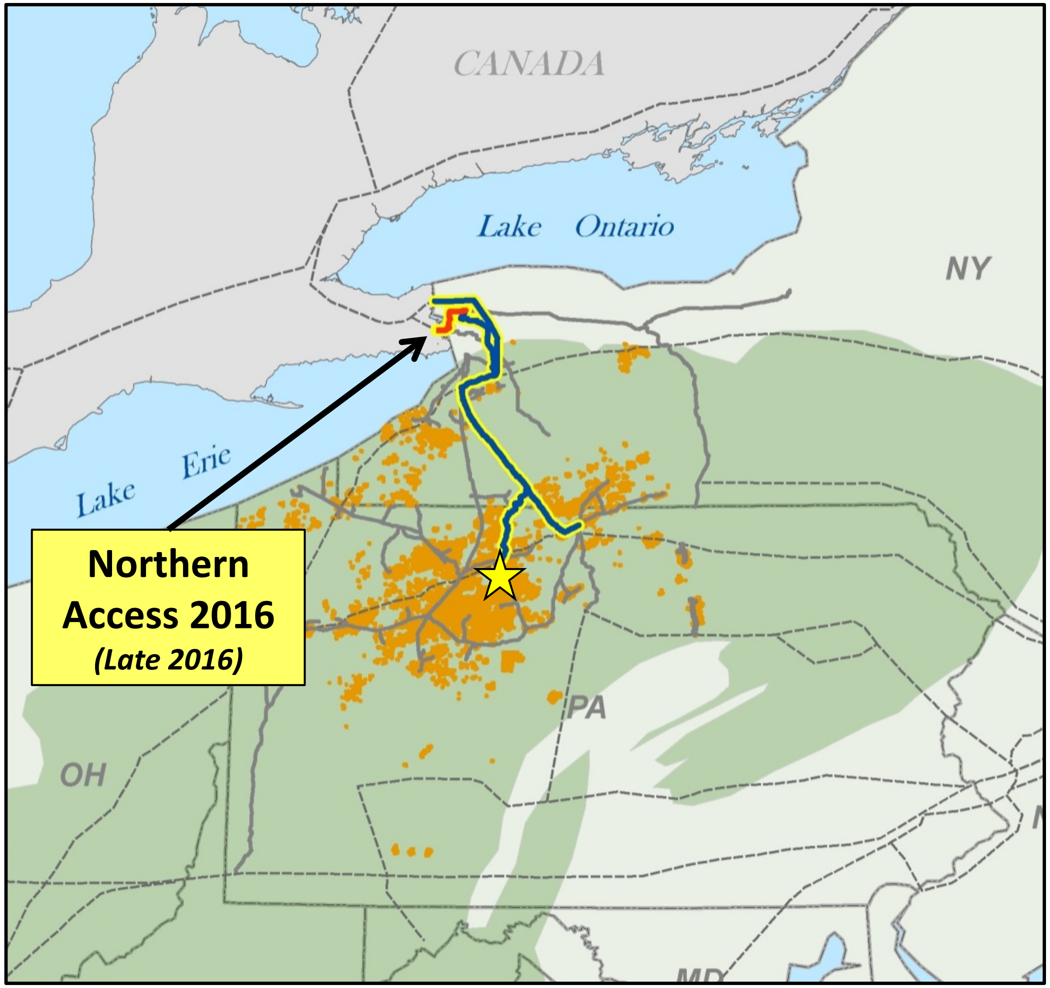


Pipeline & Storage

Northern Access 2016 Provides Additional Access to Canada

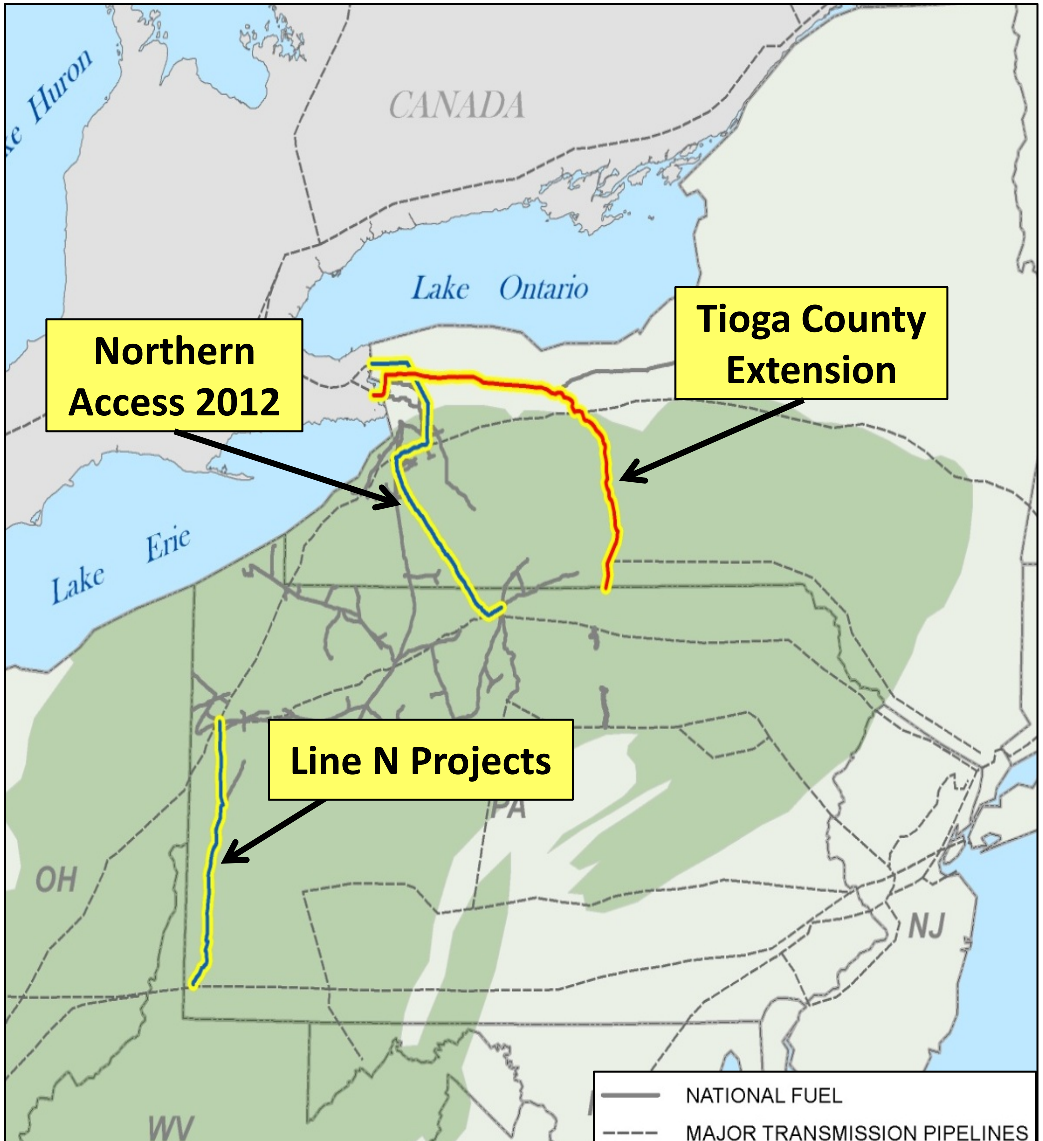
Northern Access 2016

- Customer: Seneca Resources
- In-Service: Late 2016
- System: NFG Supply Corp. & Empire Pipeline, Inc.
- Capacity
  - 350,000 Dth per day
- Interconnect
  - Chippawa (TransCanada)
- Total Cost: ~$410 Million
- FERC Timing
  - Pre-filing: July 2014
  - Certificate filing: anticipated Q2 FY2015



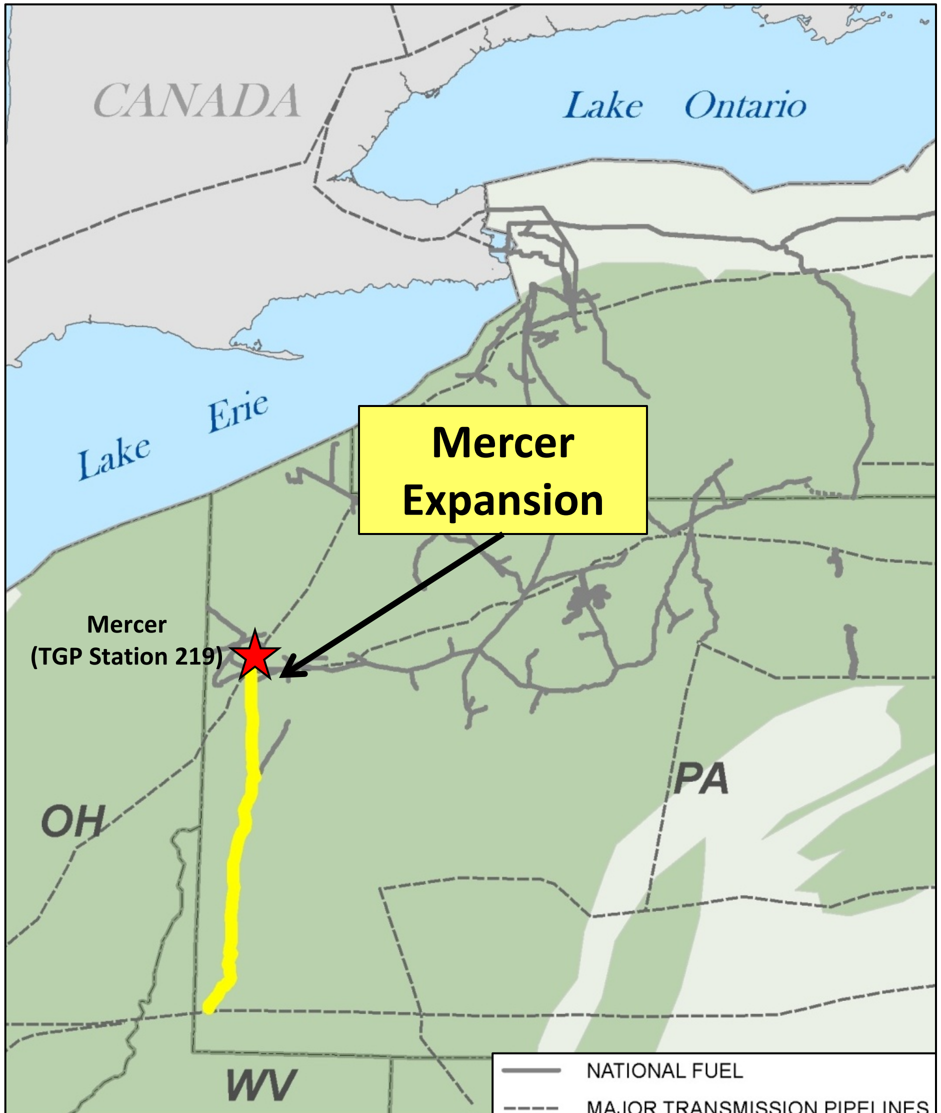
Pipeline & Storage

Recent 3rd Party Expansions Have Been Highly Successful



Completed Expansions for 3rd Parties	
Capacity (Dth/day)	
Northern Access 2012	320,000
Tioga County Extension	350,000
Line N (2011, 2012 & 2013)	353,000
Total New Capacity	1,023,000
Capital Cost ($Millions)	
Northern Access 2012	$72
Tioga County Extension	$58
Line N (2011, 2012 & 2013)	$ 104
Total Capital Expenditures	$234
Annual Reservation Charges ($Millions)	
Northern Access 2012	$ 14.5
Tioga County Extension	$ 41.9
Line N (2011, 2012 & 2013)	$ 16.0
Total Reservation Charges	$ 72.4

Pipeline & Storage
Additional Line N Expansions

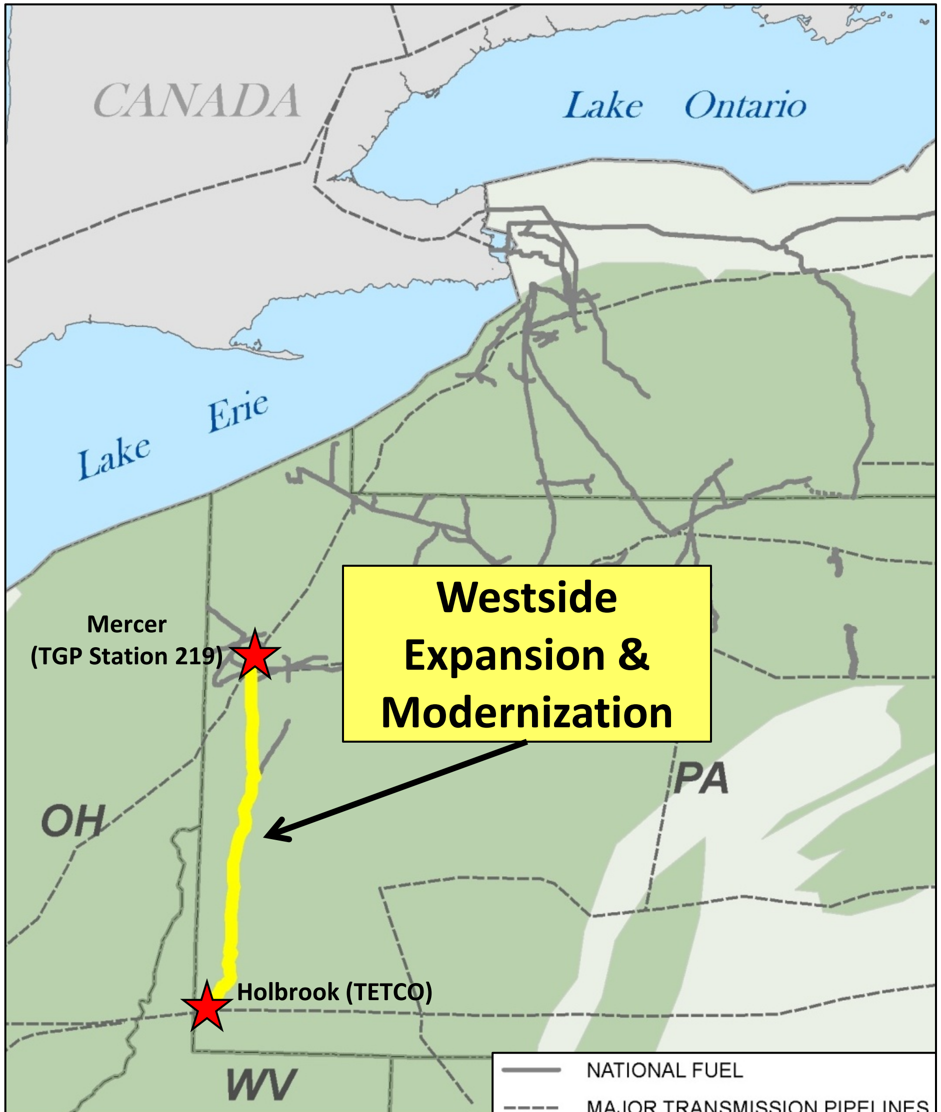


Mercer Expansion

- Customer: Third Party
- Placed in-service November 1, 2014
- System: NFG Supply Corp.
- Capacity: 105,000 Dth per day
  - Precedent agreements signed for all available capacity
- Interconnect
  - Mercer (TGP Station 219)
- Total Cost: $34 Million
  - Expansion: $30 Million
  - System Modernization: $4 Million
- Major Facilities
  - 3,550 HP Compressor
  - 2.1 miles – 24” Replacement Pipeline

Pipeline & Storage

Pairing Line N Expansions with System Modernization



Westside Expansion & Modernization

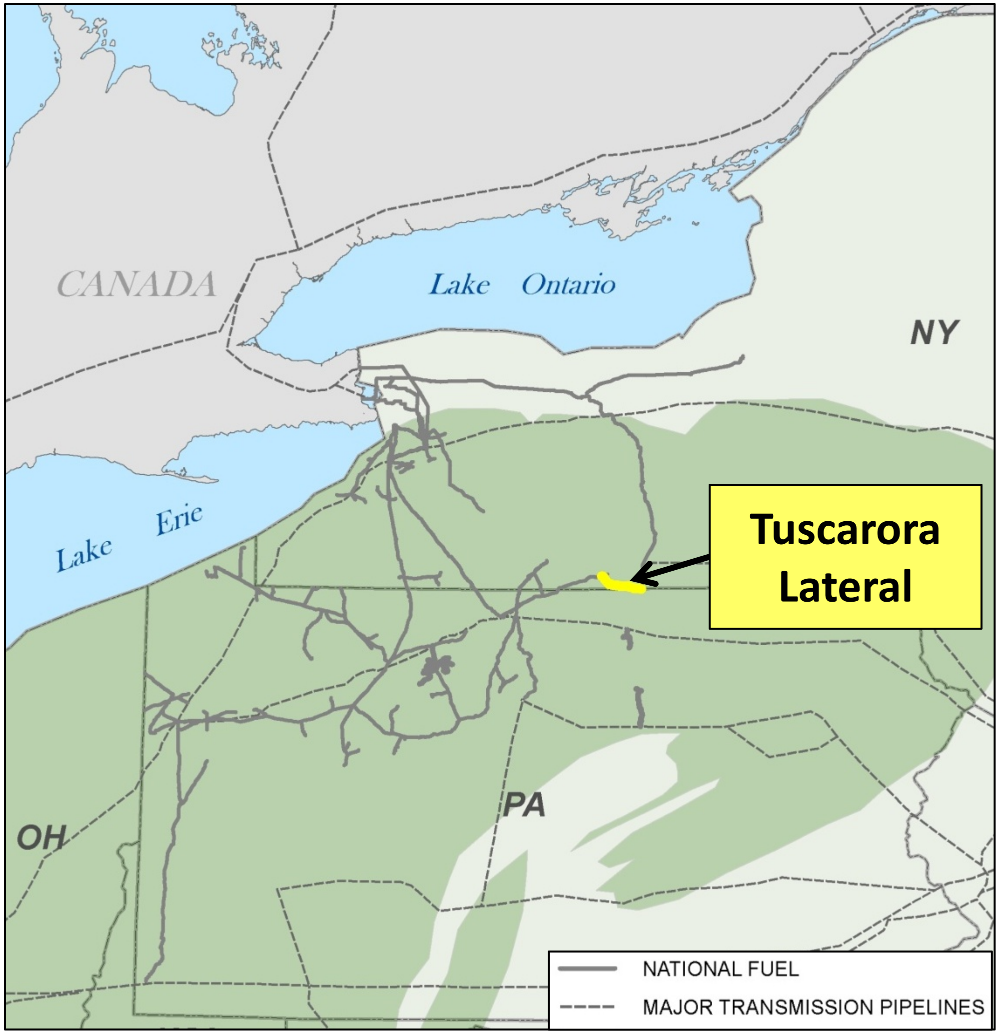
- Customer: Third Party
- In-Service: November 2015
- System: NFG Supply Corp.
- Capacity: 175,000 Dth per day
  - Precedent agreements signed for all available capacity
- Interconnect
  - Mercer (TGP Station 219)
  - Holbrook (TETCO)
- Total Cost: $76 Million
  - Expansion: $39 Million
  - Modernization: $37 Million
- Major Facilities
  - 3,550 HP Compressor
  - 23.3 miles – 24” Replacement Pipeline

Pipeline & Storage

Developing Unique Solutions for Shippers

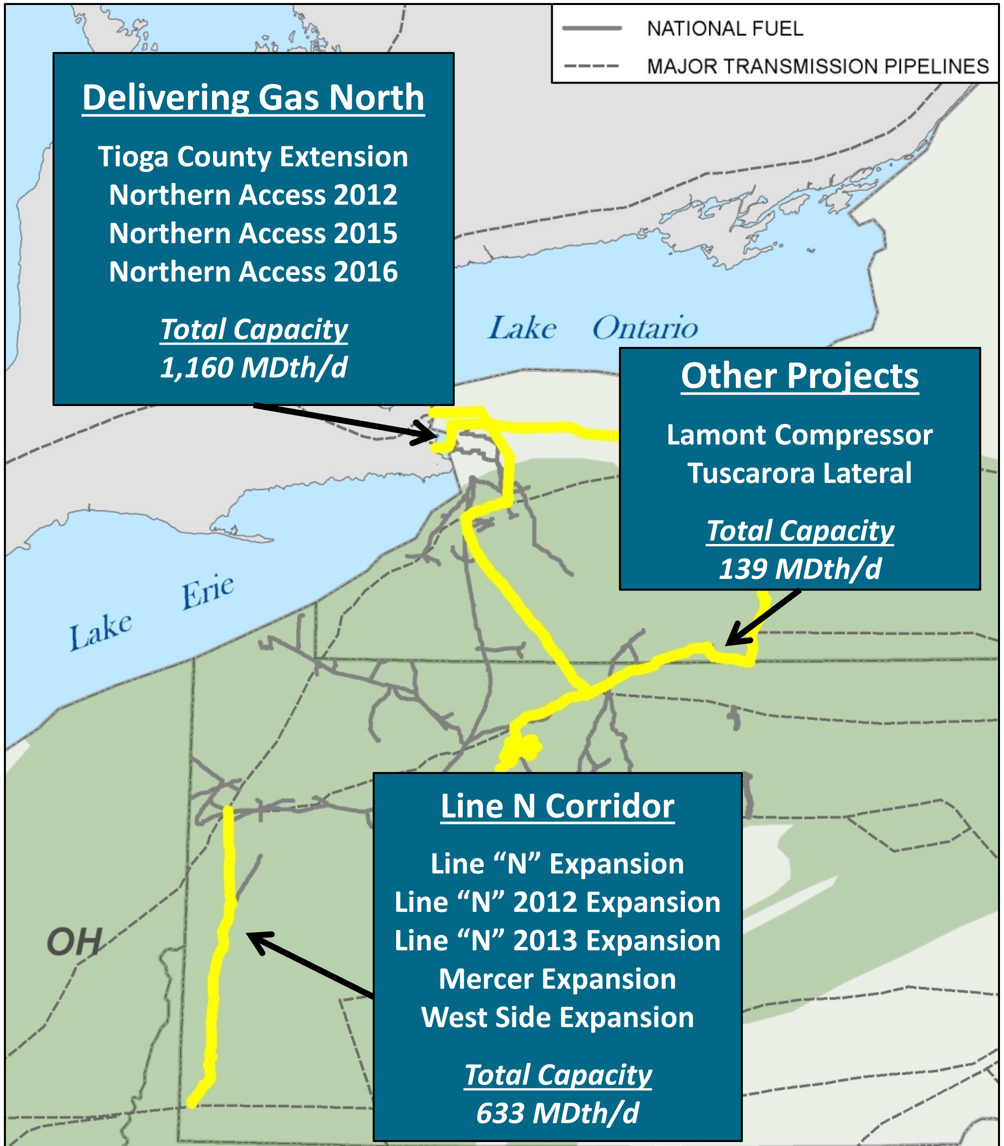
Tuscarora Lateral

- In-Service: November 2015
- System: NFG Supply & Empire Pipeline
- New No-Notice Services
  - Precedent agreements executed with RG&E, NYSEG & NFG Utility
  - Preserving 172,500 Dth per day (RG&E)
  - Preserving 20,000 Dth per day (NYSEG)
  - Retained Storage: 3.3 Bcf
  - New incremental transportation capacity of 49,000 Dth per day
- Interconnect
  - Tuscarora (NFG/Supply)
- Total Cost: $45 Million
- Major Facilities
  - 1,500 HP Compressor
  - 17 miles – 12”/16” Pipeline



Pipeline & Storage

Significant Expansions Are Driving Growth



Completed Projects (Since 2009)	
Recent Capacity Additions	1,113,000 Dth/day

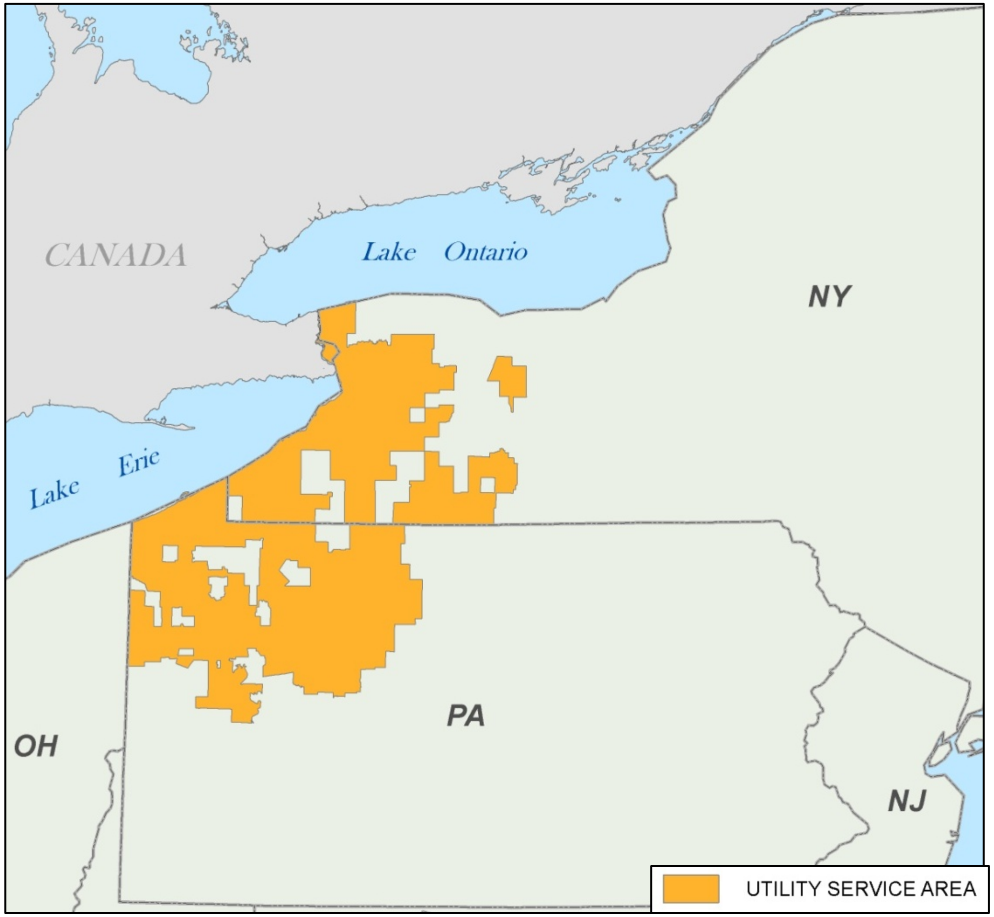
Planned Projects (2014+) *Precedent Agreements Executed*	
In-Service 2014	105,000 Dth/day
In-Service 2015	364,000 Dth/day
In-Service 2016+	350,000 Dth/day

Total Expansion (2009-2016+)	
Capacity Additions	1,932,000 Dth/day

Utility Overview

Utility

New York & Pennsylvania Service Territories



New York

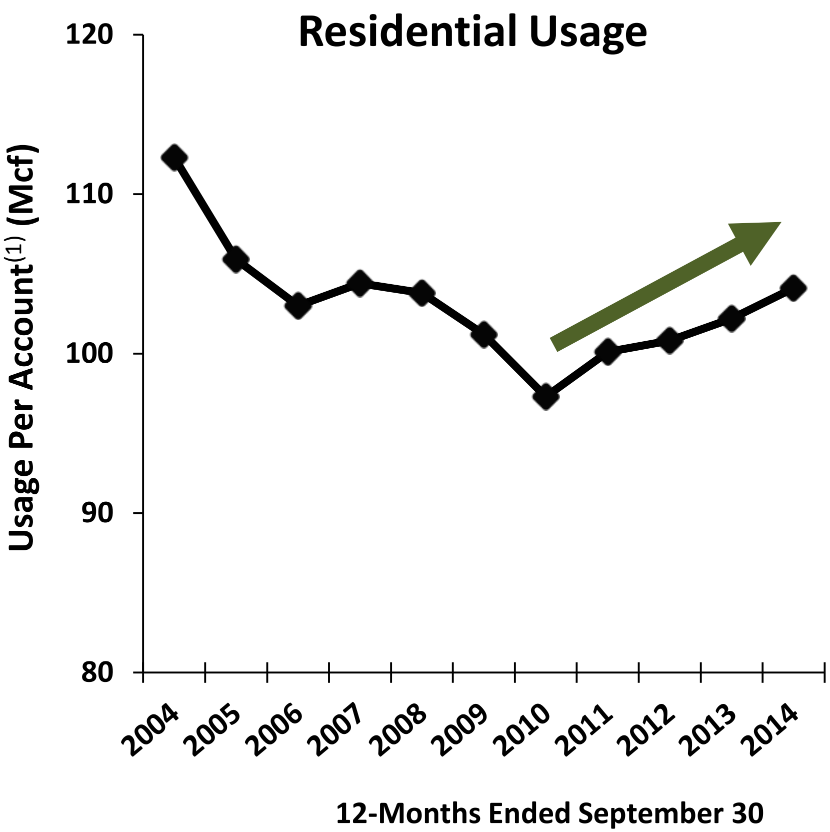
- **Total Customers: 524,300**
- **Rate Mechanisms:**
  - ✓ Revenue Decoupling
  - ✓ Weather Normalization
  - ✓ Low Income Rates
  - ✓ Merchant Function Charge (Uncollectibles Adjustment)
  - ✓ 90/10 Sharing (Large Customers)
- **NY PSC Rate Case Settlement, May 2014**
  - ✓ Rates Unchanged
  - ✓ 9.1% ROE Confirmed
  - ✓ 2-Tier Earnings Sharing Mechanism
    - ✓ 9.5% to 10.5% - Share 50%
    - ✓ 10.5% > - Share 80%
  - ✓ $8.2 MM CapEx - system replacement
  - ✓ $8.0 MM incremental O&M (post-retirement benefits)
- **Natural Gas Vehicle Pilot Program**

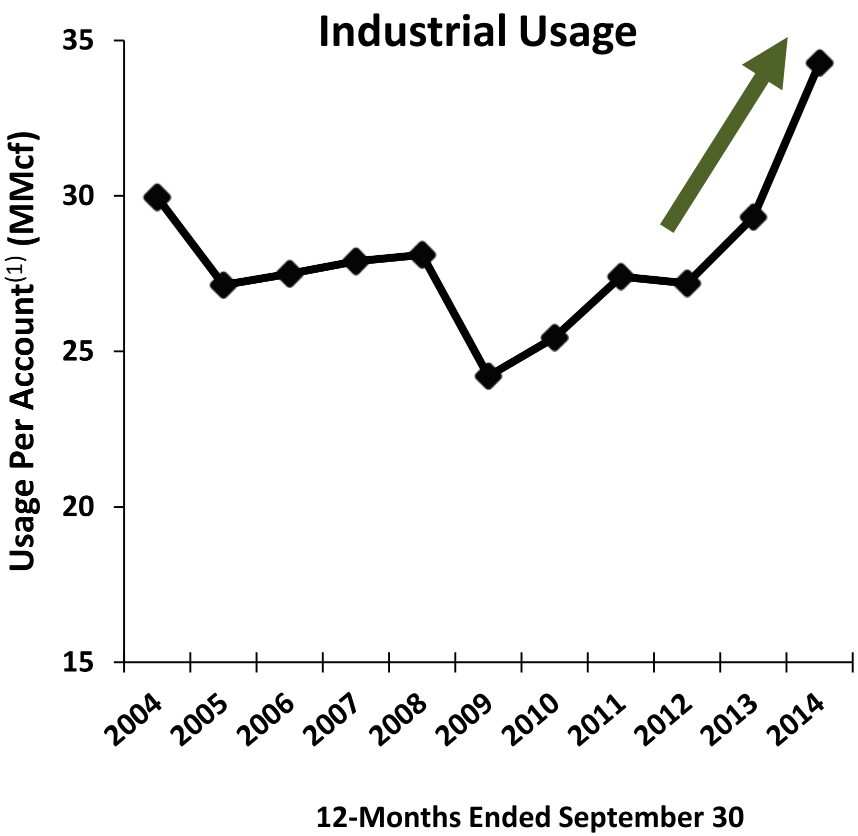
Pennsylvania

- **Total Customers: 213,500**
- **Rate Mechanisms:**
  - ✓ Low Income Rates
  - ✓ Merchant Function Charge
- **ROE: Black Box Settlement (2007)**

Utility

Shifting Trends in Customer Usage

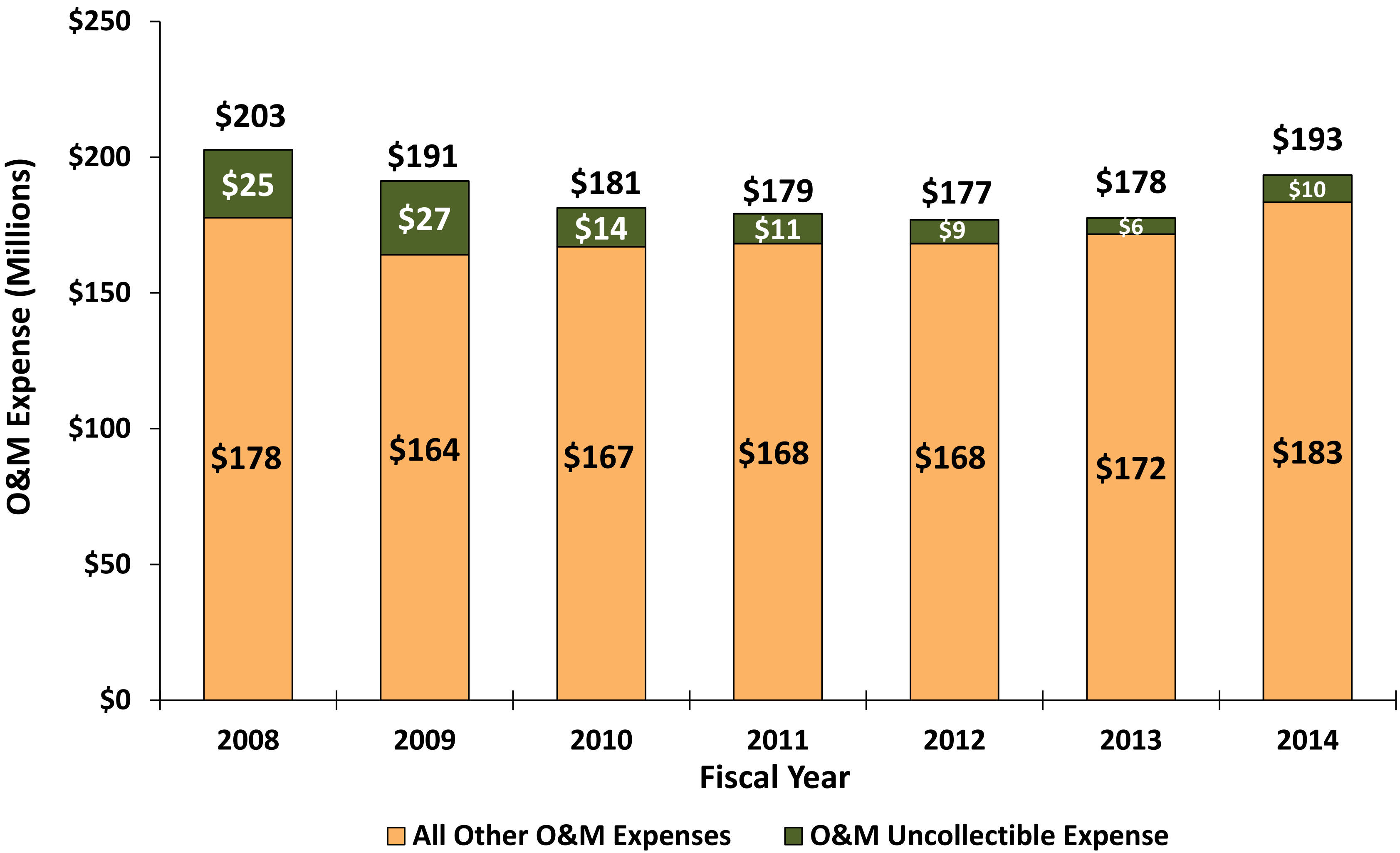




(1) Weighted Average of New York and Pennsylvania service territories (assumes normal weather)

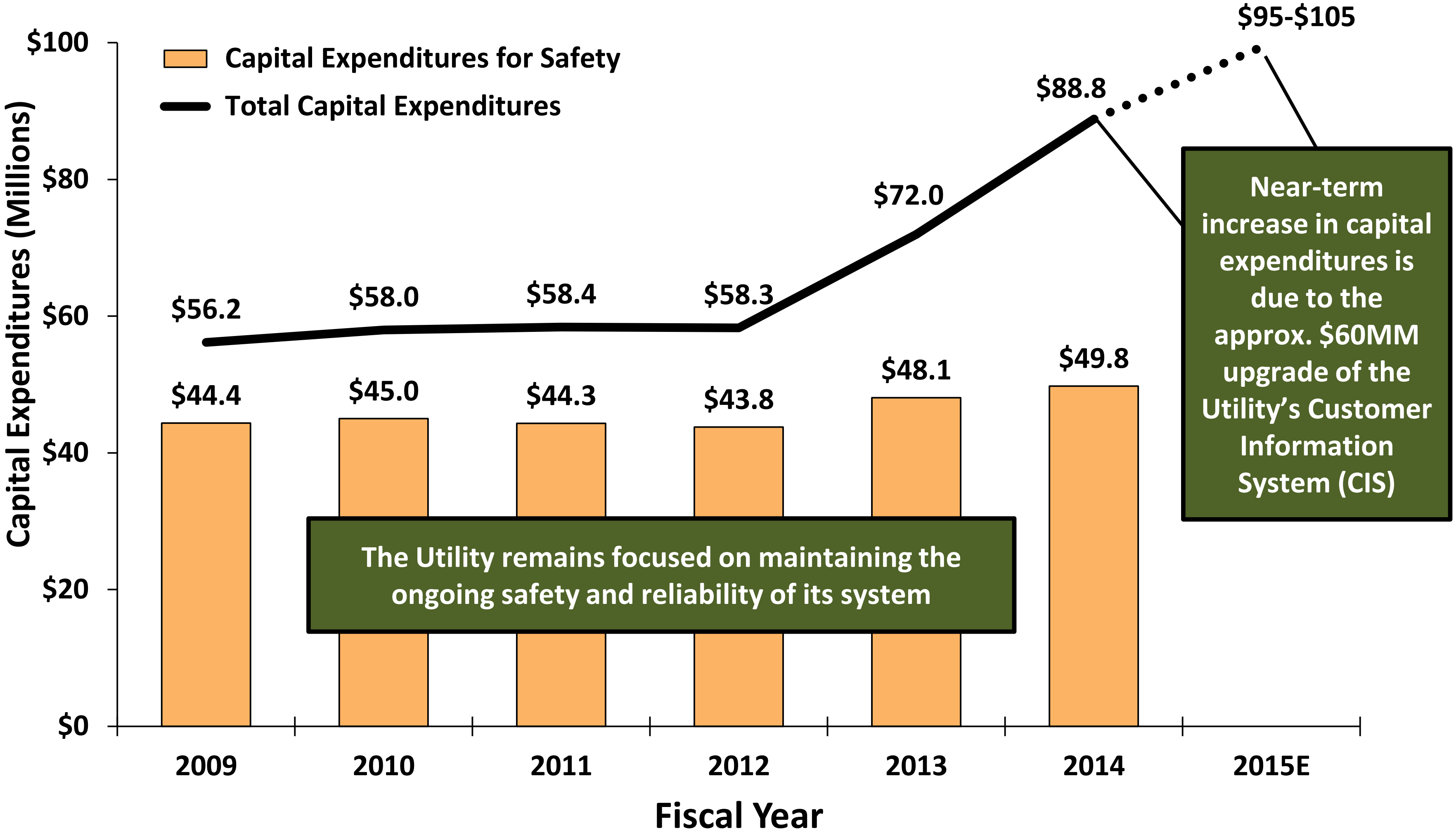
Utility

A Proven History of Controlling Costs



Utility

Strong Commitment to Safety



National Fuel Gas Company

A History of Success & A Future of Opportunity

A History of Success		A Future of Opportunity	
Adjusted EBITDA Growth	**11% CAGR** *Since 2010*	Adjusted EBITDA Growth	**10-15% CAGR** *2015 to 2019*
Production Growth	**32% CAGR** *Since 2010*	Production Growth	**15-25% CAGR** *2015 to 2019*
Midstream Businesses Adjusted EBITDA	**19% CAGR** *Since 2010*	Midstream Businesses Adjusted EBITDA	**10-15% CAGR** *2015 to 2019*

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

Appendix

National Fuel Gas Company

Natural Gas Hedge Positions

(Volumes in thousands Mmbtu; Prices in $/Mmbtu)

	Fiscal 2015		Fiscal 2016		Fiscal 2017		Fiscal 2018	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
NYMEX Swaps	70,690	$4.16	32,350	$4.24	23,130	$4.50	5,550	$4.59
Dominion Swaps	24,840	$3.74	18,840	$3.78	12,720	$3.87	-	-
SoCal Swaps	1,200	$4.35	-	-	-	-	-	-
MichCon Swaps	-	-	9,000	$4.10	3,000	$4.10	-	-
Dawn Swaps	-	-	5,490	$4.36	7,950	$4.14	-	-
Fixed Price Physical Sales	16,700	$3.77	18,300	$3.77	18,250	$3.77	1,550	$3.77
Total	**113,430**	**$4.01**	**83,980**	**$4.03**	**65,050**	**$4.11**	**7,100**	**$4.41**

National Fuel Gas Company

Crude Oil Hedge Positions

(Volumes & Prices in Bbl)

	Fiscal 2015		Fiscal 2016		Fiscal 2017		Fiscal 2018	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
Midway Sunset (MWSS) Swaps	258,000	$92.10	36,000	$92.10	-	-	-	-
Brent Swaps	903,000	$98.42	933,000	$95.18	384,000	$92.30	75,000	$91.00
NYMEX Swaps	396,000	$90.14	300,000	$86.09	-	-	-	-
Total	**1,557,000**	**$95.27**	**1,269,000**	**$92.95**	**384,000**	**$92.30**	**75,000**	**$91.00**

Marcellus Shale

Position Offers Attractive Economics at $2.00 to $3.80/Mcfe

Prospect	County	Product	Approx. Remaining Locations	EUR (Bcfe)	BTU	IRR[1] @ $4/MMBtu	15% IRR[1] Breakeven Price ($/Mcf)
EASTERN DEVELOPMENT AREA (EDA)							
Tract 100	Lycoming	Dry Gas	18	11.5-12.5	1,030	**90%**	**$1.92**
Gamble	Lycoming	Dry Gas	29	10-11	1,030	**77%**	**$2.05**
Tract 595	Tioga	Dry Gas	14	8.1	1,030	**45%**	**$2.63**
Covington	Tioga	Dry Gas	Developed	5.8	1,030	**22%**	**$3.49**
WESTERN DEVELOPMENT AREA (WDA)							
Clermont/Rich Valley	Elk/Cameron	Dry Gas	213	6-8	1,050	**38%**	**$2.80**
Ridgway	Elk	Dry Gas	450-570	6-8	1,111	**26%**	**$3.30**
Hemlock	Elk	Dry Gas	130-170	6-8	1,070	**23%**	**$3.40**
Church Run	Elk	Dry Gas	60-70	6-8	1,125	**22%**	**$3.45**
(W) West Branch	McKean	Dry Gas	47	6-8	1,050	**22%**	**$3.48**
Heath	Jefferson	Dry Gas	260-330	5-8	1,060	**19%**	**$3.65**
Sulger Farms	Jefferson	Dry Gas	170-210	5-8	1,020	**19%**	**$3.66**
Owl's Nest/James City	Elk/Forest	Dry Gas	120-160	5-8	1,125	**18%**	**$3.69**
Boone Mt.	Elk	Dry Gas	230-290	4-6	1,020	**18%**	**$3.76**
Church Run	Elk	Wet Gas	40-50	2-4	1,140	**13%**	**$4.32**
Tionesta	Forest/Venango	Wet Gas/ Liquids	300-340	4-6	1,325	**12%**	**$4.50**
Owl's Nest/James City	Elk/Forest	Wet Gas	150-180	4-6	1,140	**11%**	**$4.51**
Mt. Jewett	McKean	Wet Gas	90-110	2-4	1,140	**6%**	**$5.50**
Beechwood	Cameron	Dry Gas	210-280	2-4	1,030	**2%**	**$7.14**
Red Hill	Cameron	Dry Gas	150-200	2-4	1,030	**2%**	**$7.14**

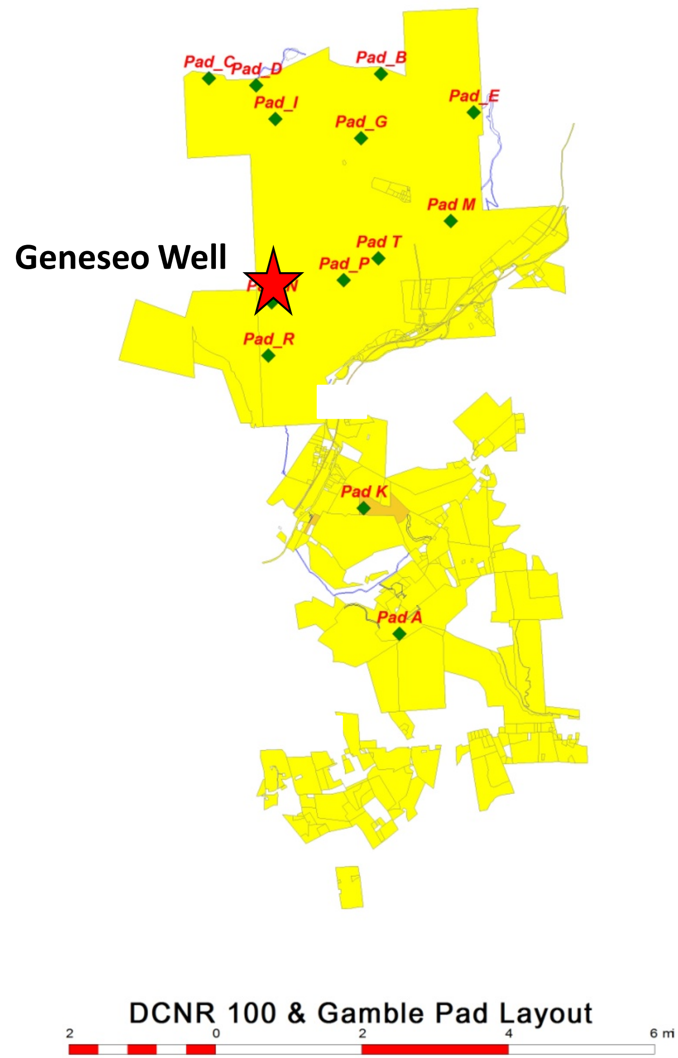
(1) Internal Rate of Return (IRR) includes estimated well costs under current cost structure, LOE, and Gathering tariffs anticipated for each prospect.

Geneseo Shale

Path to Geneseo Development – 2018/2019 Start

- 1st Well (Tract 100 – Pad N)
  - Peak IP: 14.1 MMcf per day
  - 30-Day Average Rate: 8.6 MMcf per day
  - Estimated EUR: 7.0 Bcf
  - Lateral Length: 4,920’
  - Frac Stages: 33 stages
- Current developed infrastructure from DCNR 100 & Gamble:
  - 13 well pads
  - 3 compressor pads
  - 3 water impoundments
  - Gathering infrastructure
- Savings estimate of ~$300,000 per well from shared infrastructure
  - >125 Wells
  - Water Infrastructure = $13MM
  - Usable Pads = $16MM
  - Road Infrastructure = $16MM

Tract 100/Gamble (Lycoming County)



National Fuel Gas Company

Comparable GAAP Financial Measure Slides and 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, 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.

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.

National Fuel

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

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
Exploration & Production - West Division Adjusted EBITDA	$ 171,572	$ 187,838	$ 187,603	$ 226,897	$ 215,042	$ 217,150
Exploration & Production - All Other Divisions Adjusted EBITDA	108,139	139,624	189,854	170,232	277,341	322,322
Total Exploration & Production Adjusted EBITDA	$ 279,711	$ 327,462	$ 377,457	$ 397,129	$ 492,383	$ 539,472
Total Adjusted EBITDA						
Exploration & Production Adjusted EBITDA	$ 279,711	$ 327,462	$ 377,457	$ 397,129	$ 492,383	$ 539,472
Pipeline & Storage Adjusted EBITDA	130,857	120,858	111,474	136,914	161,226	186,022
Gathering Adjusted EBITDA	(141)	2,021	9,386	14,814	29,777	64,060
Utility Adjusted EBITDA	164,443	167,328	168,540	159,986	171,669	164,643
Energy Marketing Adjusted EBITDA	11,589	13,573	13,178	5,945	6,963	10,335
Corporate & All Other Adjusted EBITDA	(5,434)	408	(12,346)	(10,674)	(9,920)	(11,078)
Total Adjusted EBITDA	**$ 581,025**	**$ 631,650**	**$ 667,689**	**$ 704,114**	**$ 852,098**	**$ 953,454**
Total Adjusted EBITDA	**$ 581,025**	**$ 631,650**	**$ 667,689**	**$ 704,114**	**$ 852,098**	**$ 953,454**
Minus: Net Interest Expense	(81,013)	(90,217)	(75,205)	(82,551)	(89,776)	(90,107)
Plus: Other Income	9,762	6,126	5,947	5,133	4,697	9,461
Minus: Income Tax Expense	(52,859)	(137,227)	(164,381)	(150,554)	(172,758)	(189,614)
Minus: Depreciation, Depletion & Amortization	(170,620)	(191,199)	(226,527)	(271,530)	(326,760)	(383,781)
Minus: Impairment of Oil and Gas Properties (E&P)	(182,811)	-	-	-	-	-
Plus/Minus: Income/(Loss) from Discontinued Operations, Net of Tax (Corp. & All Other)	(2,776)	6,780	-	-	-	-
Plus: Gain on Sale of Unconsolidated Subsidiaries (Corp. & All Other)	-	-	50,879	-	-	-
Plus: Elimination of Other Post-Retirement Regulatory Liability (P&S)	-	-	-	21,672	-	-
Minus: Pennsylvania Impact Fee Related to Prior Fiscal Years (E&P)	-	-	-	(6,206)	-	-
Minus: New York Regulatory Adjustment (Utility)	-	-	-	-	(7,500)	-
Minus: Plugging and Abandonment Accrual (E&P)	-	-	-	-	-	-
Rounding	-	-	-	(1)	-	-
Consolidated Net Income	**$ 100,708**	**$ 225,913**	**$ 258,402**	**$ 220,077**	**$ 260,001**	**$ 299,413**
Consolidated Debt to Total Adjusted EBITDA						
Long-Term Debt, Net of Current Portion (End of Period)	$ 1,249,000	$ 1,049,000	$ 899,000	$ 1,149,000	$ 1,649,000	$ 1,649,000
Current Portion of Long-Term Debt (End of Period)	-	200,000	150,000	250,000	-	-
Notes Payable to Banks and Commercial Paper (End of Period)	-	-	40,000	171,000	-	85,600
Total Debt (End of Period)	$ 1,249,000	$ 1,249,000	$ 1,089,000	$ 1,570,000	$ 1,649,000	$ 1,734,600
Long-Term Debt, Net of Current Portion (Start of Period)	999,000	1,249,000	1,049,000	899,000	1,149,000	1,649,000
Current Portion of Long-Term Debt (Start of Period)	100,000	-	200,000	150,000	250,000	-
Notes Payable to Banks and Commercial Paper (Start of Period)	-	-	-	40,000	171,000	-
Total Debt (Start of Period)	$ 1,099,000	$ 1,249,000	$ 1,249,000	$ 1,089,000	$ 1,570,000	$ 1,649,000
Average Total Debt	**$ 1,174,000**	**$ 1,249,000**	**$ 1,169,000**	**$ 1,329,500**	**$ 1,609,500**	**$ 1,691,800**
Average Total Debt to Total Adjusted EBITDA	**2.02 x**	**1.98 x**	**1.75 x**	**1.89 x**	**1.89 x**	**1.77 x**

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

	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015 Forecast
Capital Expenditures from Continuing Operations							
Exploration & Production Capital Expenditures	$ 188,290	$ 398,174	$ 648,815	$ 693,810	$ 533,129	$ 602,705	$600,000-700,000
Pipeline & Storage Capital Expenditures	52,504	37,894	129,206	144,167	$ 56,144	$ 139,821	$225,000-275,000
Gathering Segment Capital Expenditures	9,433	6,538	17,021	80,012	$ 54,792	$ 137,799	$1250,000-200,000
Utility Capital Expenditures	56,178	57,973	58,398	58,284	$ 71,970	$ 88,810	$95,000-105,000
Energy Marketing, Corporate & All Other Capital Expenditures	396	773	746	1,121	$ 1,062	$ 772	-
Total Capital Expenditures from Continuing Operations	$ 306,801	$ 501,352	$ 854,186	$ 977,394	$ 717,097	$ 969,907	$1,070,000-1,238,000
Capital Expenditures from Discountinued Operations							
All Other Capital Expenditures	216	$ 150	$ -	$ -	$ -	$ -	$ -
Plus (Minus) Accrued Capital Expenditures							
Exploration & Production FY 2014 Accrued Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ (80,108)	
Exploration & Production FY 2013 Accrued Capital Expenditures	-	-	-	-	(58,478)	58,478	-
Exploration & Production FY 2012 Accrued Capital Expenditures	-	-	-	(38,861)	38,861	-	-
Exploration & Production FY 2011 Accrued Capital Expenditures	-	-	(103,287)	103,287	-	-	-
Exploration & Production FY 2010 Accrued Capital Expenditures	-	(78,633)	78,633	-	-	-	-
Exploration & Production FY 2009 Accrued Capital Expenditures	(9,093)	19,517	-	-	-	-	-
Pipeline & Storage FY 2014 Accrued Capital Expenditures	-	-	-	-	-	(28,122)	
Pipeline & Storage FY 2013 Accrued Capital Expenditures	-	-	-	-	(5,633)	5,633	-
Pipeline & Storage FY 2012 Accrued Capital Expenditures	-	-	-	(12,699)	12,699	-	-
Pipeline & Storage FY 2011 Accrued Capital Expenditures	-	-	(16,431)	16,431	-	-	-
Pipeline & Storage FY 2010 Accrued Capital Expenditures	-	-	3,681	-	-	-	-
Pipeline & Storage FY 2008 Accrued Capital Expenditures	16,768	-	-	-	-	-	-
Gathering FY 2014 Accrued Capital Expenditures	-	-	-	-	-	(20,084)	
Gathering FY 2013 Accrued Capital Expenditures	-	-	-	-	(6,700)	6,700	-
Gathering FY 2012 Accrued Capital Expenditures	-	-	-	(12,690)	12,690	-	-
Gathering FY 2011 Accrued Capital Expenditures	-	-	(3,079)	3,079	-	-	-
Gathering FY 2009 Accrued Capital Expenditures	(715)	715	-	-	-	-	-
Utility FY 2014 Accrued Capital Expenditures	-	-	-	-	-	(8,315)	
Utility FY 2013 Accrued Capital Expenditures	-	-	-	-	(10,328)	10,328	-
Utility FY 2012 Accrued Capital Expenditures	-	-	-	(3,253)	3,253	-	-
Utility FY 2011 Accrued Capital Expenditures	-	-	(2,319)	2,319	-	-	-
Utility FY 2010 Accrued Capital Expenditures	-	-	2,894	-	-	-	-
Total Accrued Capital Expenditures	$ 6,960	$ (58,401)	$ (39,908)	$ 57,613	$ (13,636)	$ (55,490)	$ -
Eliminations	$ (344)	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Expenditures per Statement of Cash Flows	$ 313,633	$ 443,101	$ 814,278	$1,035,007	$ 703,461	$ 914,417	$1,070,000-1,238,000