Takeaway Capacity in Appalachia

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RANGE RESOURCES®

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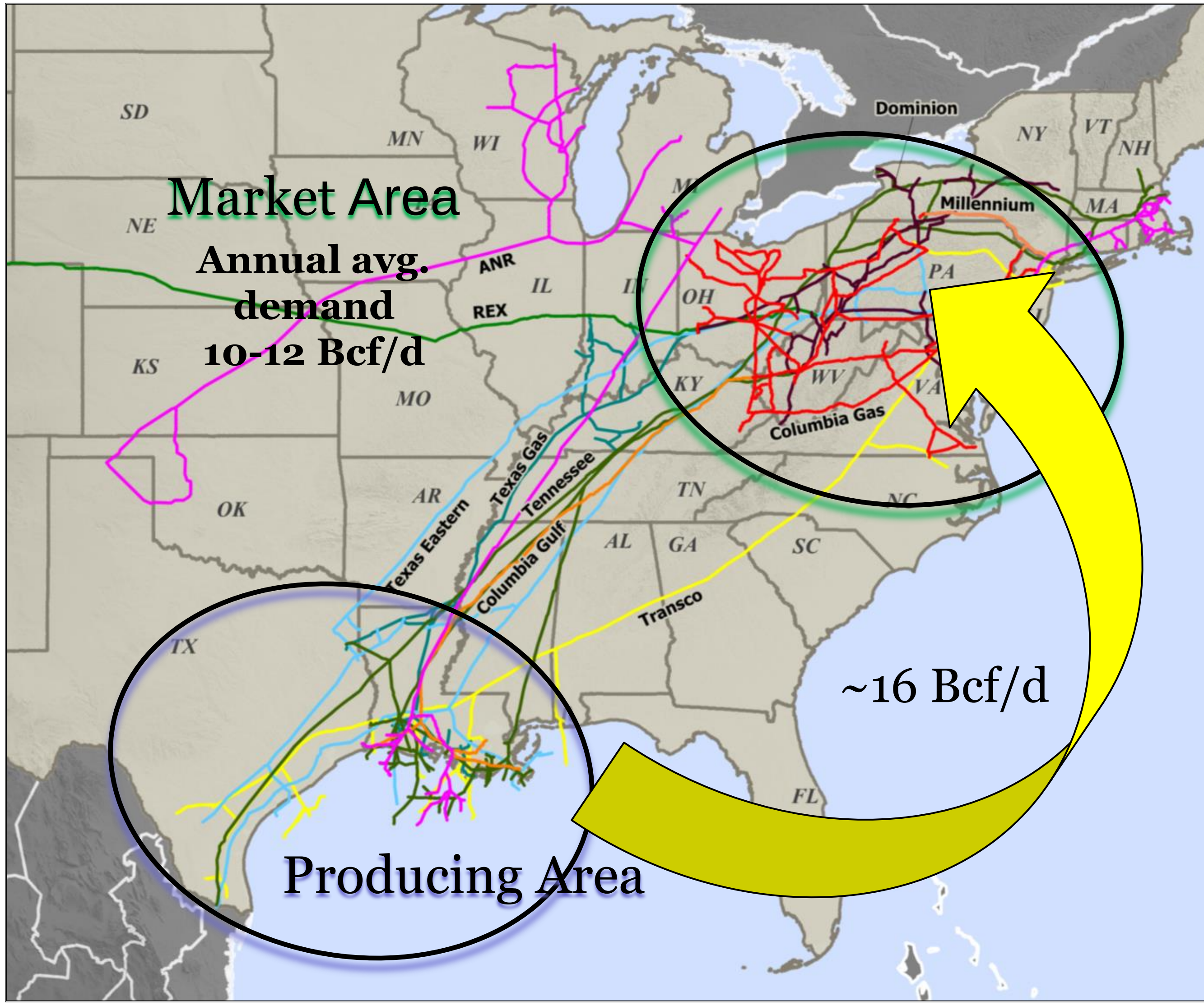
NE Pipelines: Pre-Marcellus Demand Pull

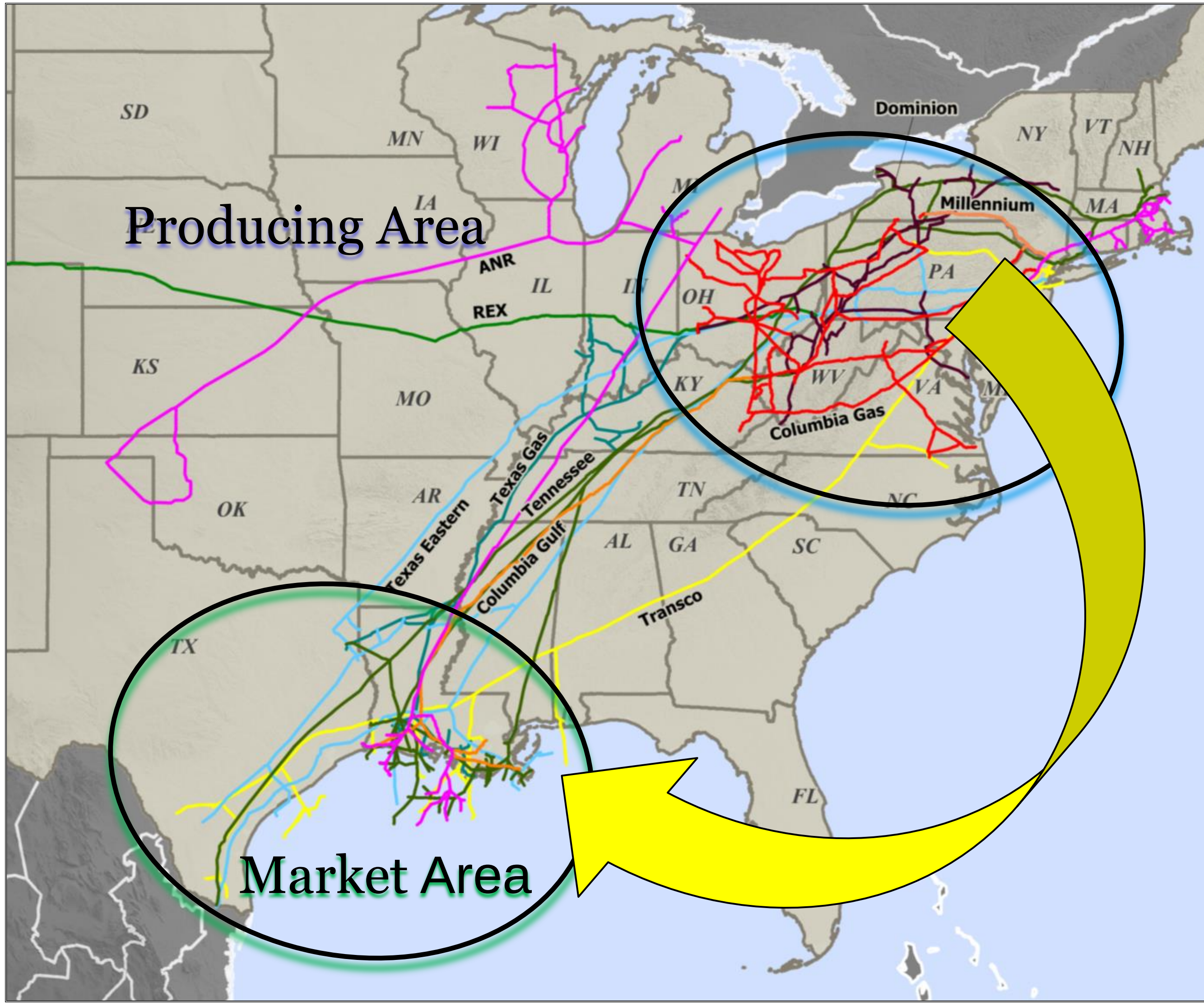
- Long-haul pipelines built from the Gulf Producing Areas to North East Markets
- North East Markets historically traded at a premium to the Producing Areas



Map Source: Bentek

NE Pipeline – Marcellus Supply Push

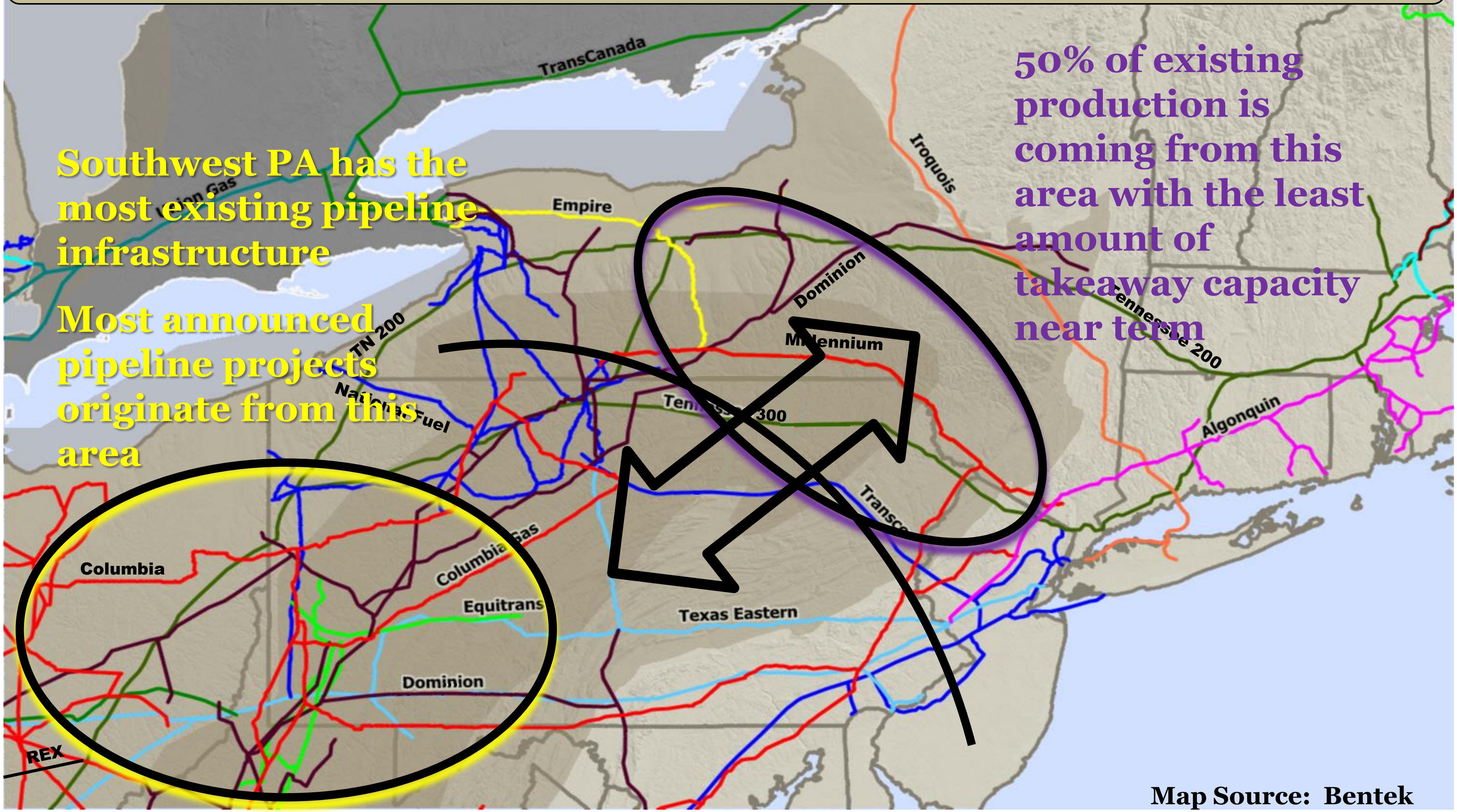
- Range discovers the Marcellus in 2004
- The North East region became the Producing Area
- The Gulf Coast, Southeast and Midwest are becoming the premium Market Areas



Map Source: Bentek

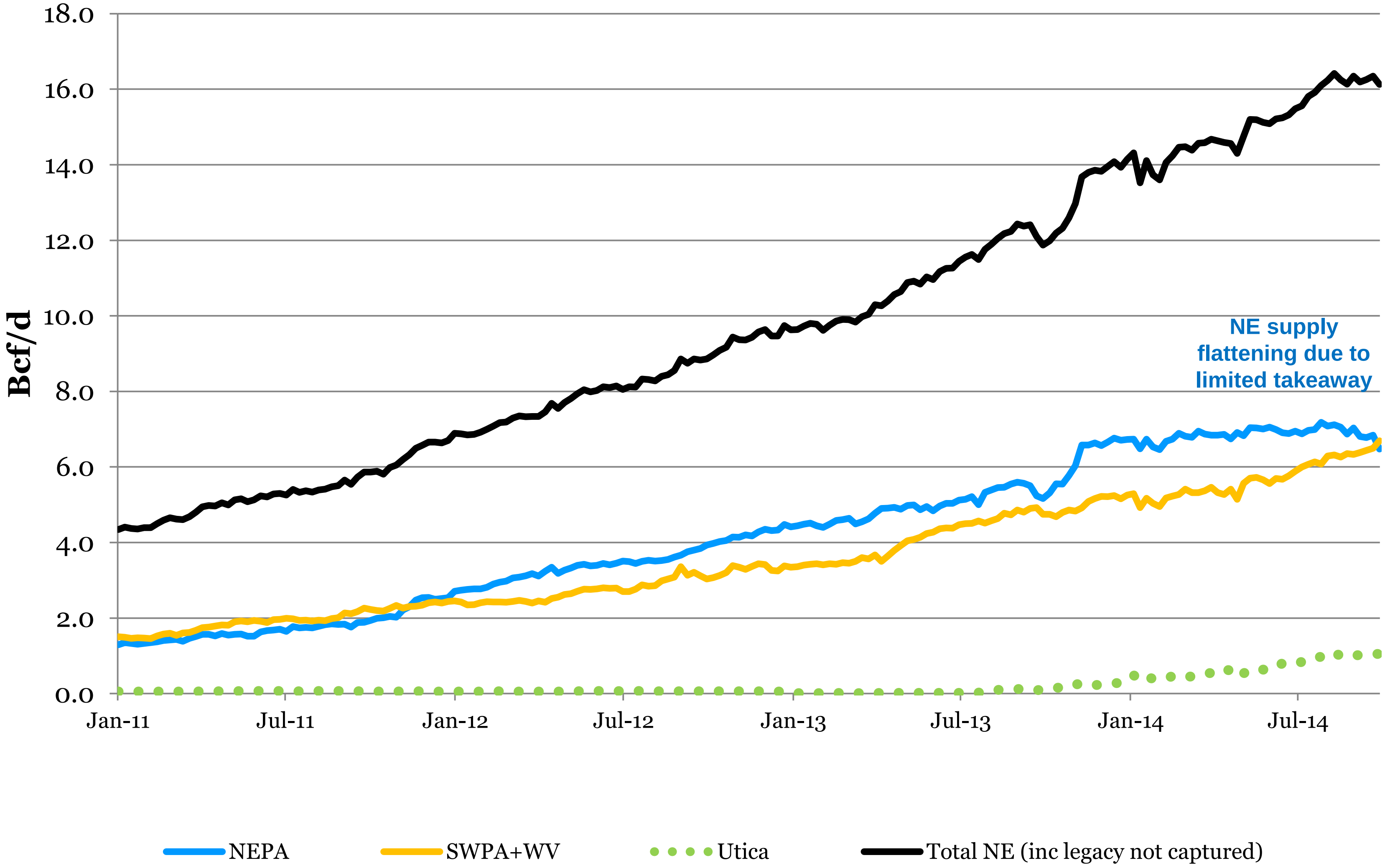
Major Marcellus / Utica Pipeline Overview

Geographical location of pipelines dictates reversals and expansions



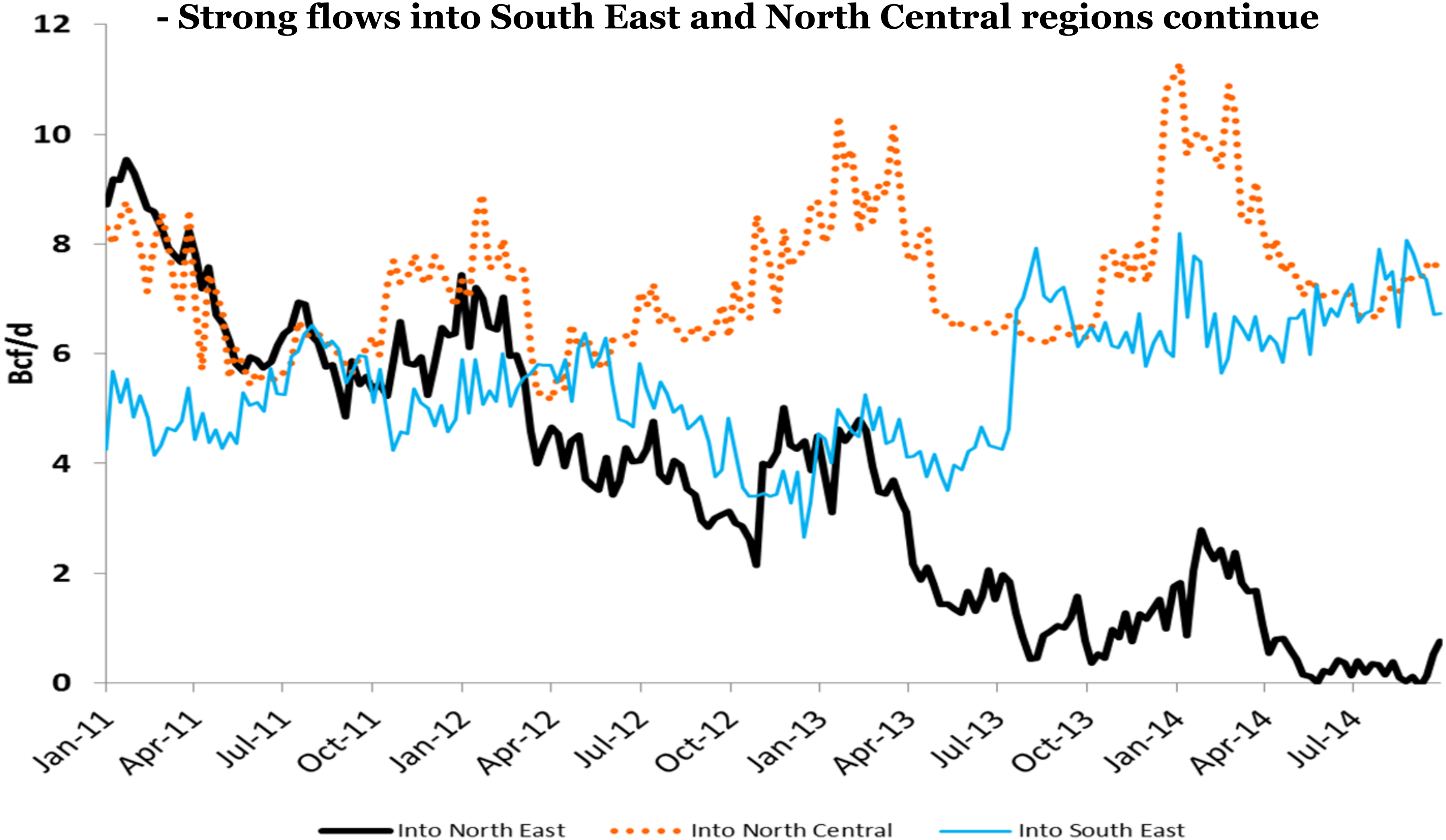
Map Source: Bentek

Appalachian Natural Gas Production



Natural gas flow into the North East now minimal

- Net flows into North East reduced dramatically
- Strong flows into South East and North Central regions continue



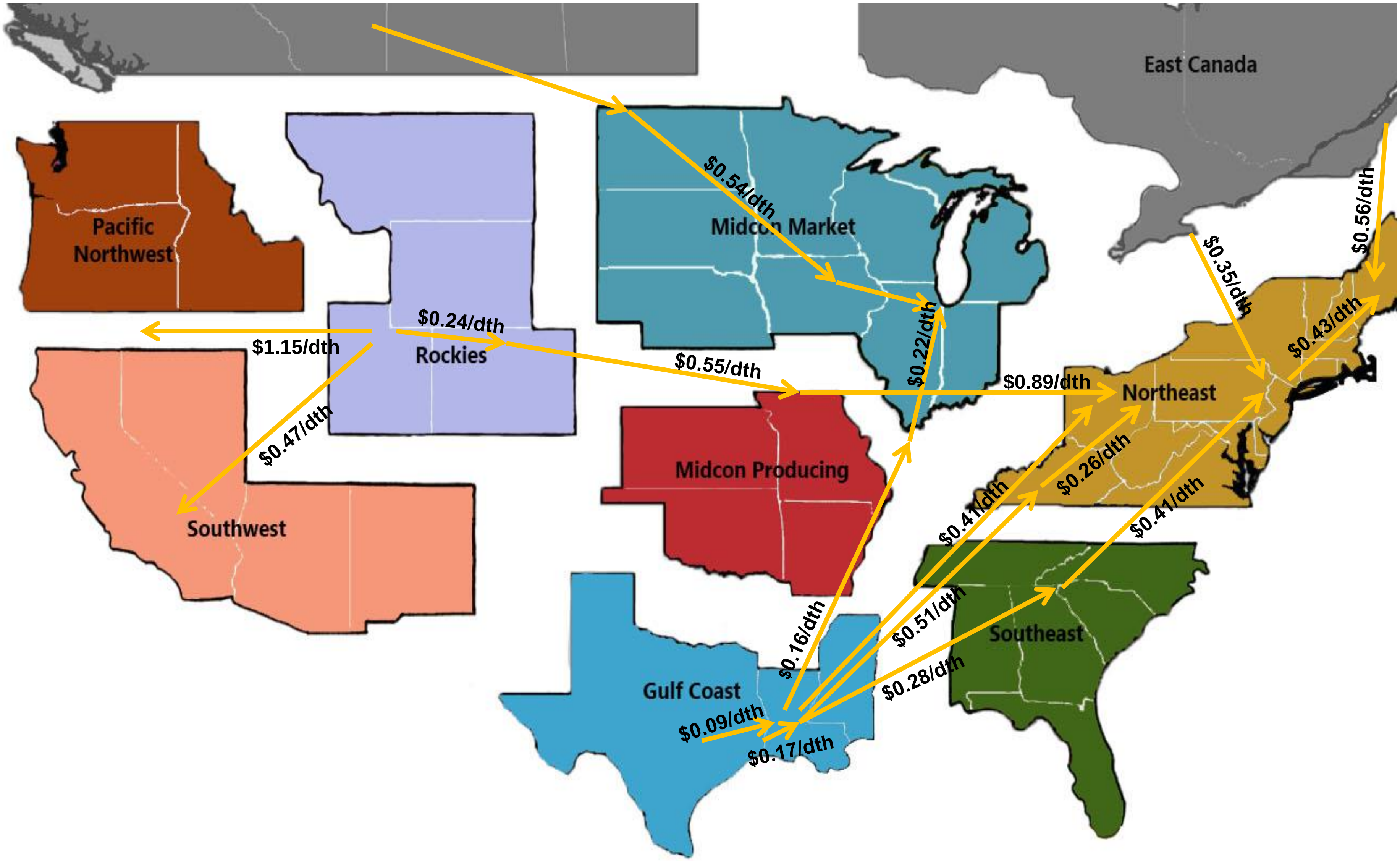
NE Supply and Transportation Fundamentals

- NE region demand:
  - Winter peak 20 to 25 Bcf/d
  - Summer 8 to 10 Bcf/d
- Current supply exceeds summer and shoulder months demand
- Increased regional supply has created negative basis differentials in summer/shoulder months
- Producers with the right takeaway capacity can improve netback prices
- Demand exceeds supply in the winter, creating positive differential opportunities

The differentiating factors are:

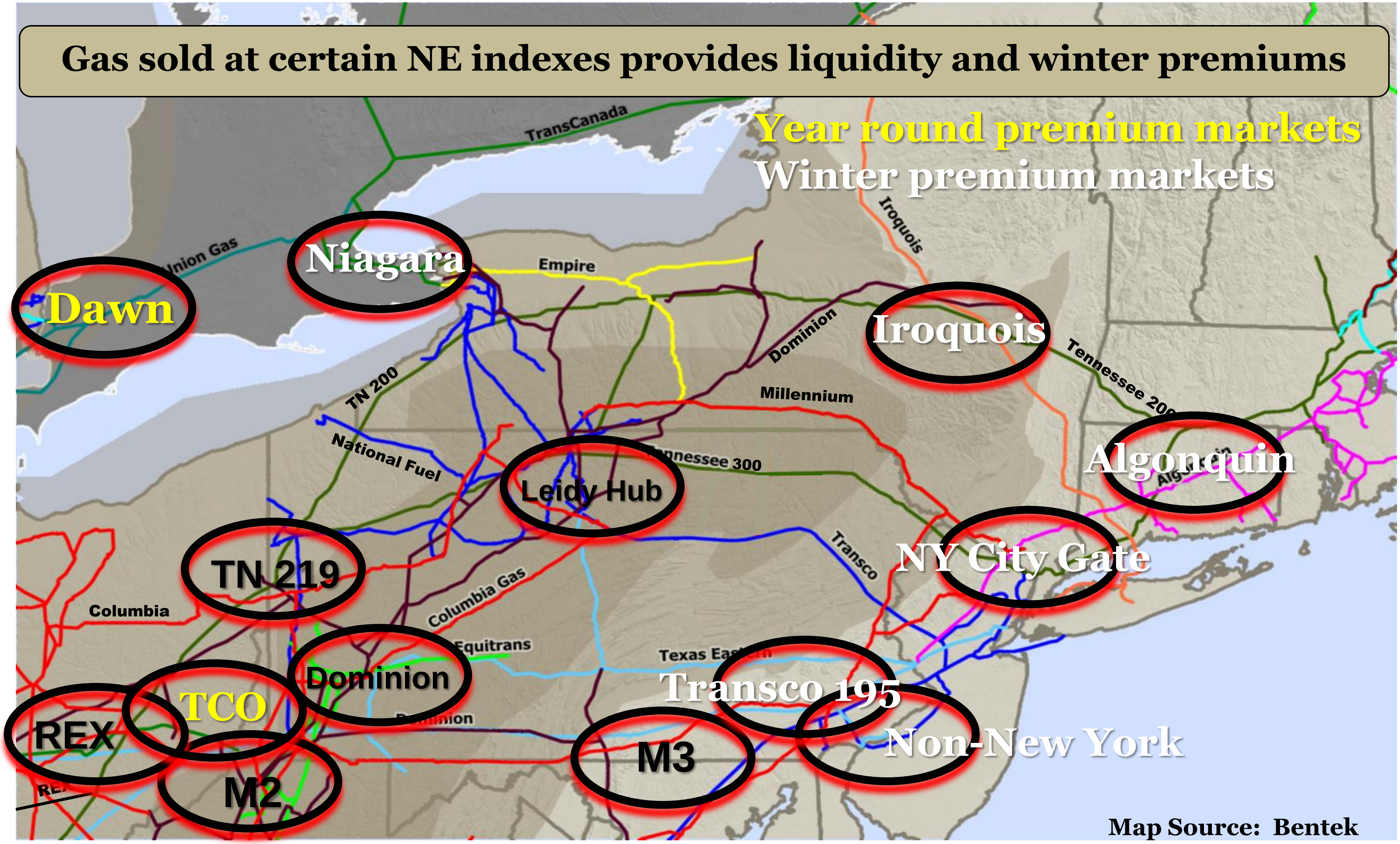
(i) how much gas can a producer move to a demand region
(ii) at what transportation cost
(iii) to which markets?

Historic rates to move gas between various regions



Source = Goldman Sachs, "*Independence Day for Natural Gas v6 Building a new Appalachian trail: Where Marcellus/Utica gas will go*", May 15, 2014

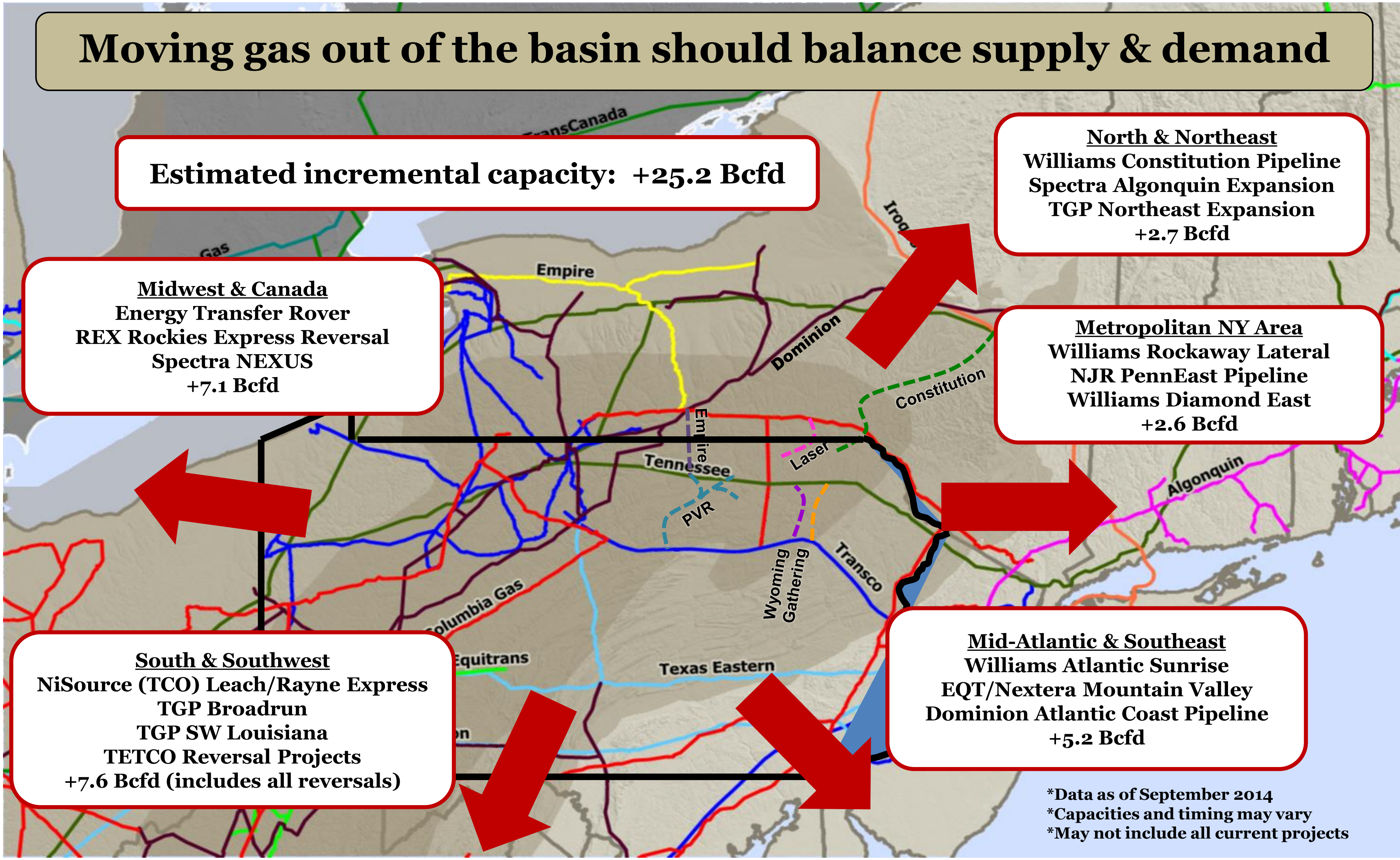
Major Sales Points in NE Region



Map Source: Bentek

Planned and proposed pipeline projects through 2018

Moving gas out of the basin should balance supply & demand



Estimated incremental capacity: +25.2 Bcfd

Midwest & Canada
Energy Transfer Rover
REX Rockies Express Reversal
Spectra NEXUS
+7.1 Bcfd

North & Northeast
Williams Constitution Pipeline
Spectra Algonquin Expansion
TGP Northeast Expansion
+2.7 Bcfd

Metropolitan NY Area
Williams Rockaway Lateral
NJR PennEast Pipeline
Williams Diamond East
+2.6 Bcfd

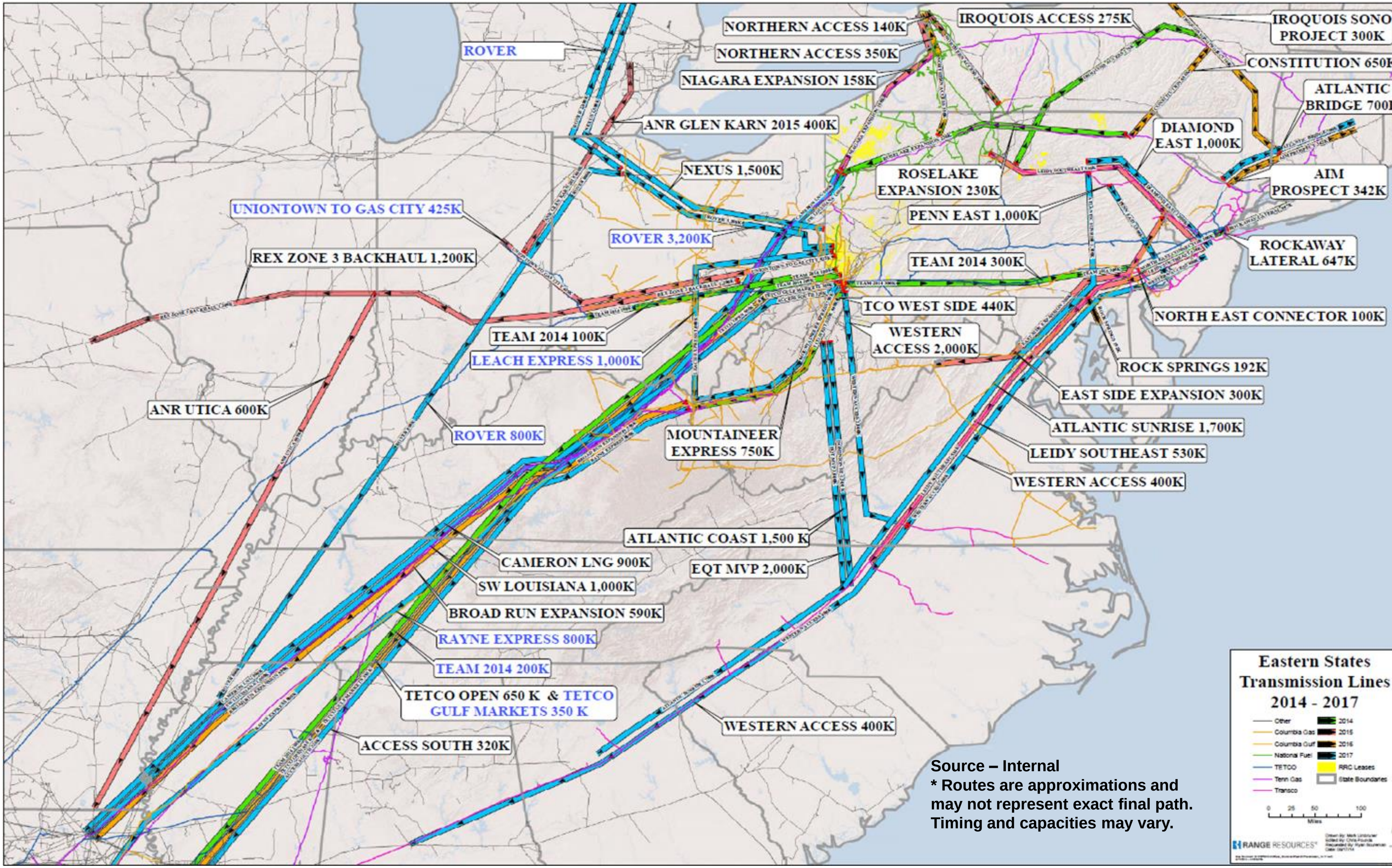
South & Southwest
NiSource (TCO) Leach/Rayne Express
TGP Broadrun
TGP SW Louisiana
TETCO Reversal Projects
+7.6 Bcfd (includes all reversals)

Mid-Atlantic & Southeast
Williams Atlantic Sunrise
EQT/Nextera Mountain Valley
Dominion Atlantic Coast Pipeline
+5.2 Bcfd

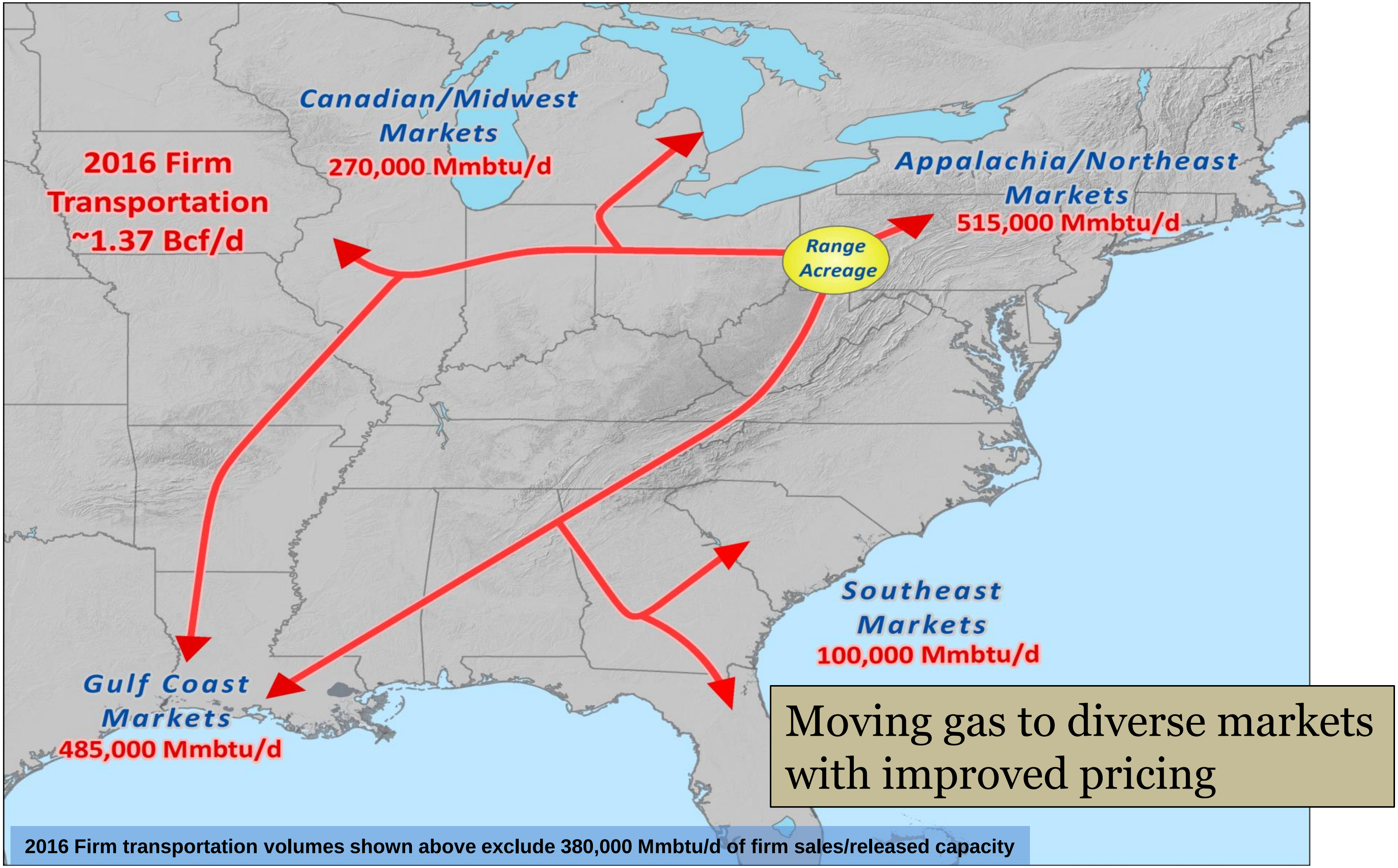
*Data as of September 2014
*Capacities and timing may vary
*May not include all current projects

Source – Internal

North East Takeaway Projects Announced (Mmbtu/d)



Range's Portfolio of Transportation Arrangements



Announced Appalachian Basin Takeaway Projects – 1 of 2

	NORTH EAST PA	Operator	Main Line	Market	Start-up	Capacity - Bcf/d
2014	Northeast Connector	Williams	Transco	NE	Q4'14	0.1
	Iroquois Access	Dominion	Iroquois	NE	Q4'14	0.3
	Rose Lake Expansion	Kinder Morgan	TGP	NE	Q4'14	0.2
2015	Niagara Expansion	Kinder Morgan	TGP	Canada	Q4'15	0.2
	Northern Access 2015	NFG	National Fuel	Canada	Q4'15	0.1
	Leidy Southeast	Williams	Transco	Mid-Atlantic/SE	Q4'15	0.5
	East Side Expansion	Nisource	Columbia	Mid-Atlantic/SE	Q4'15	0.3
2016	Northern Access 2016	NFG	National Fuel	Canada	2016	0.4
	SoNo Iroquois Access	Dominion	Iroquois	Canada	Q2'16	0.3
	Constitution	Williams	Constitution	NE	H1'16	0.7
	Algonquin AIM	Spectra	Algonquin	NE	Q4'16	0.4
2017	Atlantic Sunrise	Williams	Transco	Mid-Atlantic/SE	H2'17	1.7
	PennEast	AGT		NE	H2'17	1.0
	Atlantic Bridge	Spectra	Algonquin	NE	H2'17	0.7
2018	Access Northeast	Spectra	Algonquin	NE	H2'18	1.0
	Diamond East	Williams	Transco	NE	H2'18	1.0
	TGP Northeast Expansion	Kinder Morgan	TGP	NE	H2'18	1.0

	SOUTH WEST	Operator	Main Line	Market	Start-up	Capacity - Bcf/d
2014	Lebanon Lateral Reversal	Transcanada	ANR	Midwest	Q1'14	0.4
	Utica Backhaul	Kinder Morgan	TGP	Gulf Coast	Q2'14	0.5
	REX Seneca Lateral	Tall Grass	REX	Midwest	H1'14	0.6
	TEAM 2014	Spectra	TETCO	Gulf Coast	Q4'14	0.6
	TEAM South	Spectra	TETCO	Gulf Coast	Q4'14	0.3
	West Side Expansion	Nisource	Columbia	Gulf Coast	Q4'14	0.4
2015	REX Zone 3 Full Reversal	Tall Grass	REX	Midwest	Q2'15	1.2
	TGP Backhaul / Broad Run	Kinder Morgan	TGP	Gulf Coast	Q4'15	0.6
	TETCO OPEN	Spectra	TETCO	Gulf Coast	Q4'15	0.6
	Uniontown to Gas City	Spectra	TETCO	Midwest	Q4'15	0.4
	Glen Karn 2015	Transcanada	ANR	Midwest	Q4'15	0.8
	QuickLink	Nisource	Columbia	Midwest	Q4'15	0.5

Note: Data subject to change as projects are approved and built.
Highlighted projects where Range is participating.

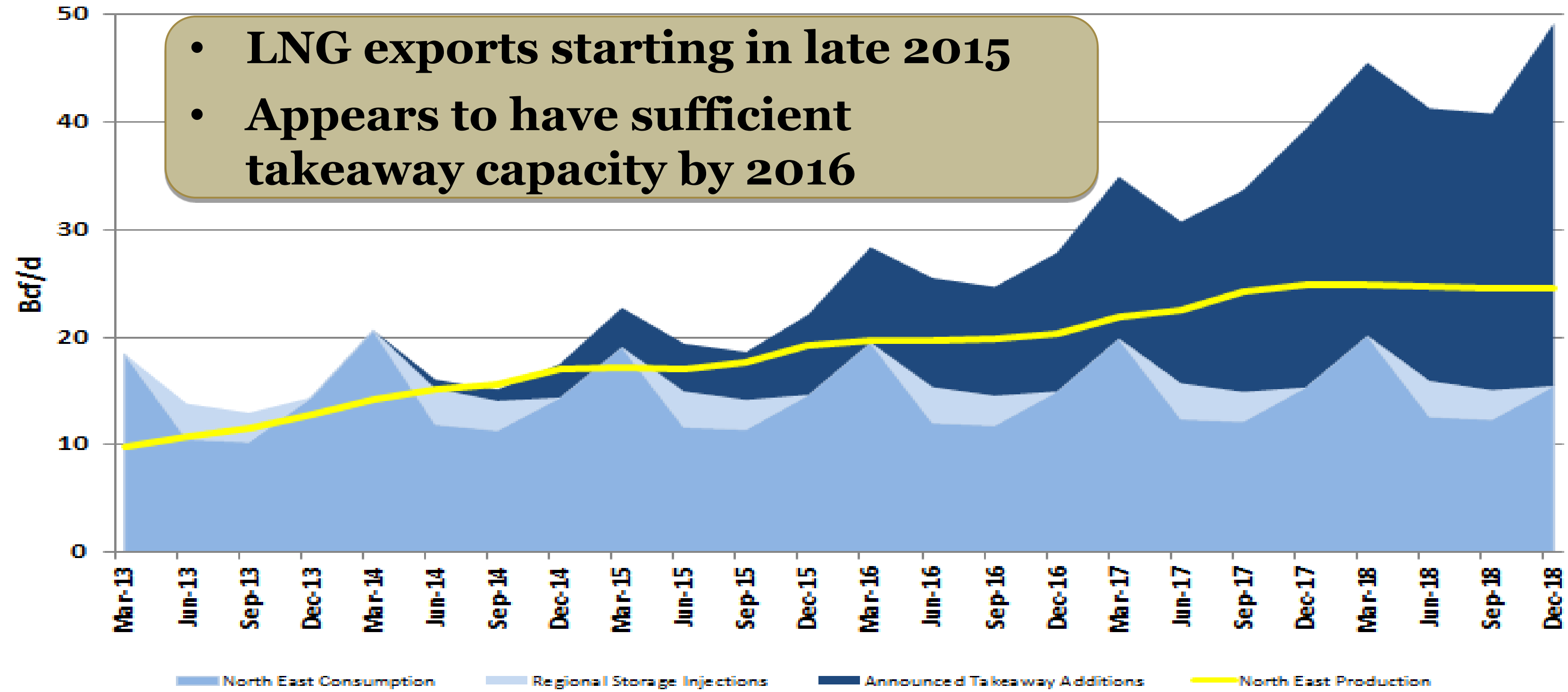
Announced Appalachian Basin Takeaway Projects – 2 of 2

	SOUTH WEST	Operator	Main Line	Market	Start-up	Capacity - Bcf/d
2016	Gulf Expansion Ph1	Spectra	TETCO	Gulf Coast	Q4'16	0.3
	Clarington West Expansion	Tall Grass	REX	Midwest	Q4'16	2.4
	Rover Ph1	ETP		Midwest/Canada/Gulf Coast	Q4'16	1.9
2017	Rayne/Leach Xpress	Nisource	Columbia	Gulf Coast	Q3'17	1.5
	SW Louisiana	Kinder Morgan	TGP	Gulf Coast	Q3'17	0.9
	Rover Ph2	ETP		Midwest/Canada/Gulf Coast	Q3'17	1.3
	TGP Backhaul / Broad Run Expansion	Kinder Morgan	TGP	Gulf Coast	Q4'17	0.2
	Adair SW	Spectra	TETCO	Gulf Coast	Q4'17	0.2
	Access South	Spectra	TETCO	Gulf Coast	Q4'17	0.3
	Gulf Expansion Ph2	Spectra	TETCO	Gulf Coast	Q4'17	0.4
	NEXUS	Spectra		Midwest/Canada	Q4'17	1.5
	ANR Utica	Transcanada	ANR	Midwest/Canada	Q4'17	0.6
	Cove Point LNG	Dominion		NE	Q4'17	0.7
2018	Mountain Valley Pipeline	NextEra/EQT		Mid-Atlantic/SE	Q4'18	2.0
	Western Marcellus	Williams	Transco	Mid-Atlantic/SE	Q4'18	1.5
	Atlantic Coast Pipeline	Duke/Dominion		Mid-Atlantic/SE	Q4'18	1.5

Total NE to Canada	**1.0**
Total NE to NE	**6.2**
Total NE to Mid-Atlantic/SE	**2.5**
Total NE Additions	**9.7**
Total SW to Mid-Atlantic/SE	**5.0**
Total SW to Midwest/Canada	**9.9**
Total SW to Gulf Coast	**8.4**
Total SW to NE	**0.7**
Total SW Additions	**24.0**
Overall Total Additions for Appalachian Basin	**33.7**

Note: Data subject to change as projects are approved and built. Highlighted projects where Range is participating.

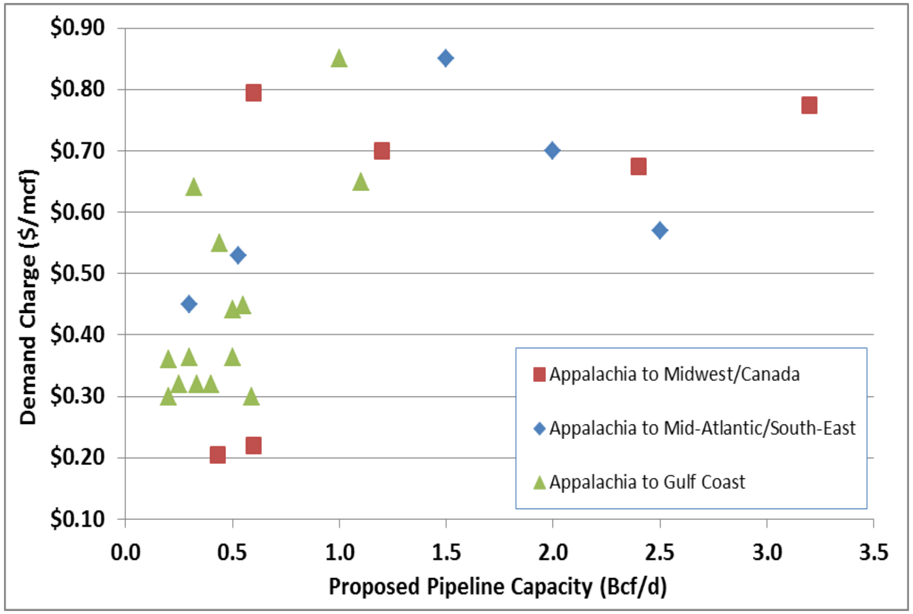
Appalachia Supply & Demand



		2013	2014	2015	2016	2017	2018
	North East Production	11.2	15.5	17.8	19.9	23.4	24.7
	North East Consumption + Injections	13.4	14.6	14.2	14.6	15.0	15.2
A	**North East Gas Surplus for Export**	**(2.2)**	**0.9**	**3.6**	**5.3**	**8.4**	**9.5**
	Announced Takeaway Additions (Annualized)		3.4	5.2	6.2	11.0	8.0
B	Cumulative Takeaway Additions		3.4	8.6	14.8	25.7	33.7
	Excess Takeaway (B – A)		**2.5**	**5.0**	**9.5**	**17.3**	**24.2**

Potential Industry Weighted Average Transport Tariffs by End Market

Pipeline Flow	Weighted-Average Demand Charge 2018 ($/mcf)
Appalachia to Midwest/Canada	$0.67
Appalachia to Mid-Atlantic/South-East	$0.66
Appalachia to Gulf Coast	$0.51
Appalachian Exports Total	$0.62

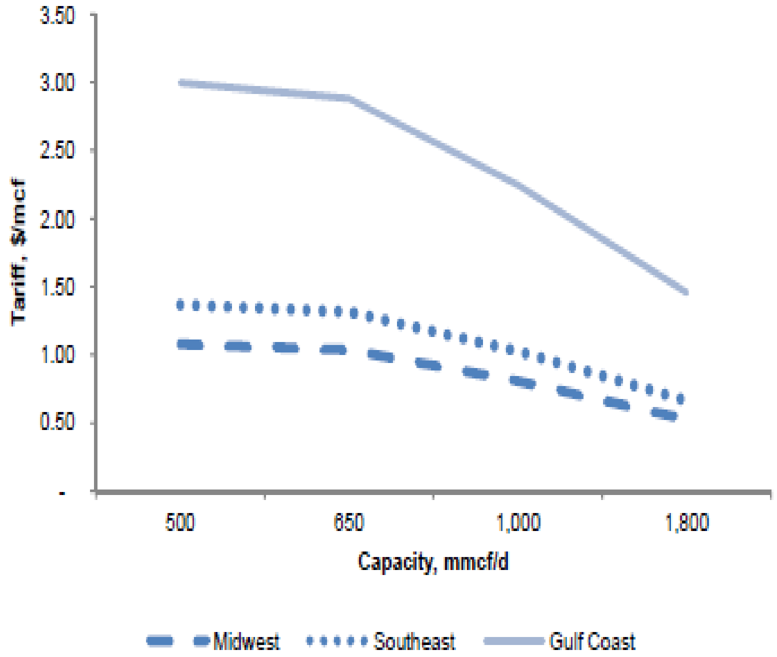


- Available data representing 22 Bcf/d of new export capacity for <$0.90/mcf.
- Brownfields comprise 60% of this capacity.
- GS/INGA data suggests if more than 22 Bcf/d of export capacity is needed then newbuilds to Atlanta and Chicago would cost $1.03/mcf and $0.81/mcf (36" pipe), these costs could be lower assuming larger diameter/capacity pipe.

GS/INGA Newbuild Pipeline Cost Estimates*

assumes 36" pipeline

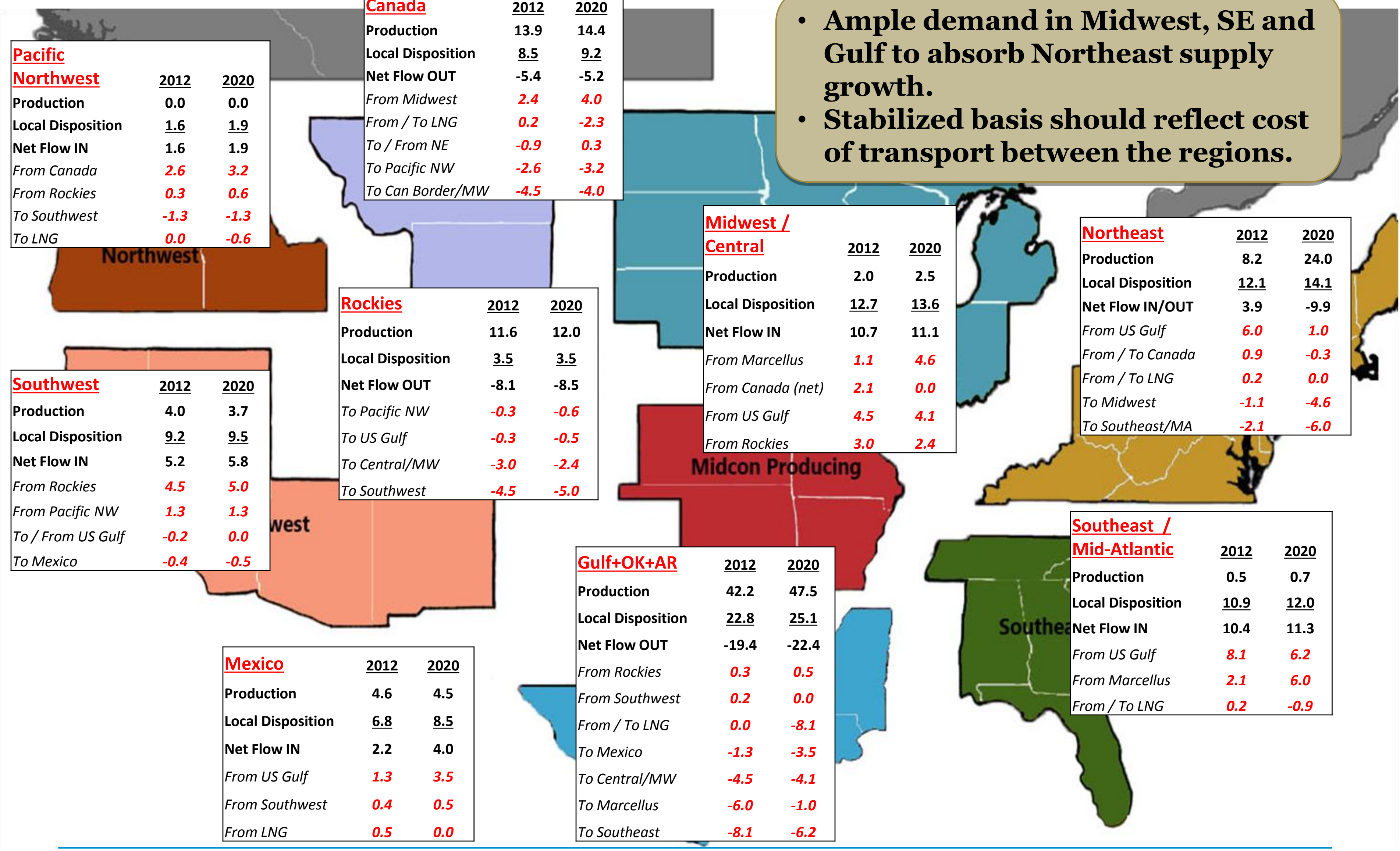
Bigger pipelines can deliver more gas cheaply. Sensitivity of tariff at various capacities; assume $150k/inch-mile capital cost and 12% return on capital.



Source = Internal estimates/FERC, Goldman Sachs, "*Independence Day for Natural Gas v6 Building a new Appalachian trail: Where Marcellus/Utica gas will go*", May 15, 2014

How are gas flows expected to change?
Historical and potential net inter-region pipeline flows 2012, 2020E Bcf/d

- **Ample demand in Midwest, SE and Gulf to absorb Northeast supply growth.**
- **Stabilized basis should reflect cost of transport between the regions.**



Pacific Northwest	2012	2020
Production	0.0	0.0
Local Disposition	1.6	1.9
Net Flow IN	1.6	1.9
From Canada	*2.6*	*3.2*
From Rockies	*0.3*	*0.6*
To Southwest	*-1.3*	*-1.3*
To LNG	*0.0*	*-0.6*

Canada	2012	2020
Production	13.9	14.4
Local Disposition	8.5	9.2
Net Flow OUT	-5.4	-5.2
From Midwest	*2.4*	*4.0*
From / To LNG	*0.2*	*-2.3*
To / From NE	*-0.9*	*0.3*
To Pacific NW	*-2.6*	*-3.2*
To Can Border/MW	*-4.5*	*-4.0*

Southwest	2012	2020
Production	4.0	3.7
Local Disposition	9.2	9.5
Net Flow IN	5.2	5.8
From Rockies	*4.5*	*5.0*
From Pacific NW	*1.3*	*1.3*
To / From US Gulf	*-0.2*	*0.0*
To Mexico	*-0.4*	*-0.5*

Rockies	2012	2020
Production	11.6	12.0
Local Disposition	3.5	3.5
Net Flow OUT	-8.1	-8.5
To Pacific NW	*-0.3*	*-0.6*
To US Gulf	*-0.3*	*-0.5*
To Central/MW	*-3.0*	*-2.4*
To Southwest	*-4.5*	*-5.0*

Midwest / Central	2012	2020
Production	2.0	2.5
Local Disposition	12.7	13.6
Net Flow IN	10.7	11.1
From Marcellus	*1.1*	*4.6*
From Canada (net)	*2.1*	*0.0*
From US Gulf	*4.5*	*4.1*
From Rockies	*3.0*	*2.4*

Northeast	2012	2020
Production	8.2	24.0
Local Disposition	12.1	14.1
Net Flow IN/OUT	3.9	-9.9
From US Gulf	*6.0*	*1.0*
From / To Canada	*0.9*	*-0.3*
From / To LNG	*0.2*	*0.0*
To Midwest	*-1.1*	*-4.6*
To Southeast/MA	*-2.1*	*-6.0*

Southeast / Mid-Atlantic	2012	2020
Production	0.5	0.7
Local Disposition	10.9	12.0
Net Flow IN	10.4	11.3
From US Gulf	*8.1*	*6.2*
From Marcellus	*2.1*	*6.0*
From / To LNG	*0.2*	*-0.9*

Gulf+OK+AR	2012	2020
Production	42.2	47.5
Local Disposition	22.8	25.1
Net Flow OUT	-19.4	-22.4
From Rockies	*0.3*	*0.5*
From Southwest	*0.2*	*0.0*
From / To LNG	*0.0*	*-8.1*
To Mexico	*-1.3*	*-3.5*
To Central/MW	*-4.5*	*-4.1*
To Marcellus	*-6.0*	*-1.0*
To Southeast	*-8.1*	*-6.2*

Mexico	2012	2020
Production	4.6	4.5
Local Disposition	6.8	8.5
Net Flow IN	2.2	4.0
From US Gulf	*1.3*	*3.5*
From Southwest	*0.4*	*0.5*
From LNG	*0.5*	*0.0*

Source – CIBC Commodities Strategy, 09/09/2014. *Assumes 2012-20 US demand growth of +18.9 Bcf/d, o/w US LNG Exports = +9.6 Bcf/d; MX Exports = +2.4 Bcf/d*

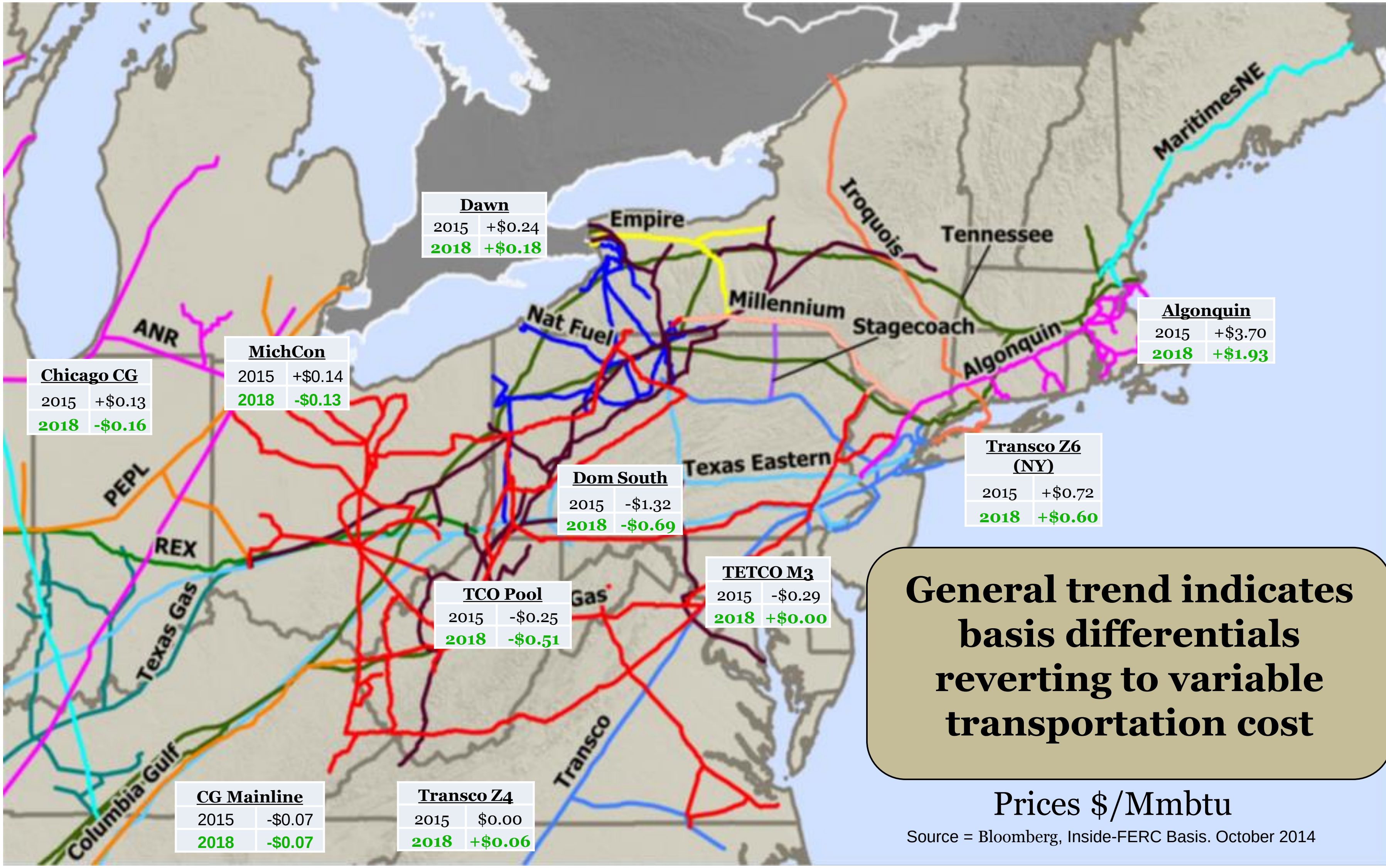
What is the expected price in the NE when supply and demand balances?

- As supply and demand balance, NE prices should revert back to Henry Hub +/- variable transportation cost

- Seasonal winter demand in excess of basin supply should create premium regional prices in the market

- NE markets will need to create an incentive for the gas to remain in the basin rather then seeking better priced markets, once supply and demand reach equilibrium

What does the futures price indicate for regional basis?



General trend indicates basis differentials reverting to variable transportation cost

Prices $/Mmbtu

Source = Bloomberg, Inside-FERC Basis. October 2014

How will Gulf Coast demand affect the market?

- DOE/FERC approved LNG export projects of approximately 8 Bcf/d
- LNG exports forecasted to begin in late 2015 and ramp up through 2020
- Increased demand from Texas and Louisiana petrochemical industry expected to begin in late 2015
- Exports to Mexico projected to increase through 2018

Incremental Gulf Coast demand by 2020 could be 14 to 16 Bcf/d

What is Range's philosophy for committing to firm pipeline transportation?

Range has a detailed 10+ year drilling plan

- Range's transportation portfolio follows our projected production volumes
- Planned volume ramp matches in-service date for projects to which we have committed
- Avoid paying for unutilized capacity

Range analyzes each and every project, but participates in those that provide:

- The highest netback prices
- Access to developing demand and premium markets
- Market liquidity and flow assurance
- Diversity of customers
- Lowest transportation cost

Range's Appalachia Gas Transportation Arrangements

	Projected 2014		Projected 2016		Projected 2018	
Regional Direction	Mmbtu/day (Gross)	Transport Cost per Mmbtu	Mmbtu/day (Gross)	Transport Cost per Mmbtu	Mmbtu/day (Gross)	Transport Cost per Mmbtu
Firm Transportation						
Appalachia/Local	325,000	$ 0.21	330,000	$ 0.22	430,000	$ 0.30
Gulf Coast	260,000	$ 0.31	485,000	$ 0.43	935,000	$ 0.51
Midwest/Canada	70,000	$ 0.20	270,000	$ 0.26	470,000	$ 0.41
Northeast	185,000	$ 0.60	185,000	$ 0.60	185,000	$ 0.60
Southeast	100,000	$ 0.39	100,000	$ 0.39	100,000	$ 0.39
Firm Sales/Released Capacity	175,000	--	380,000	--	270,000	--
Total Takeaway Capacity	**1,115,000**	**$ 0.28**	**1,750,000**	**$ 0.28**	**2,390,000**	**$ 0.39**

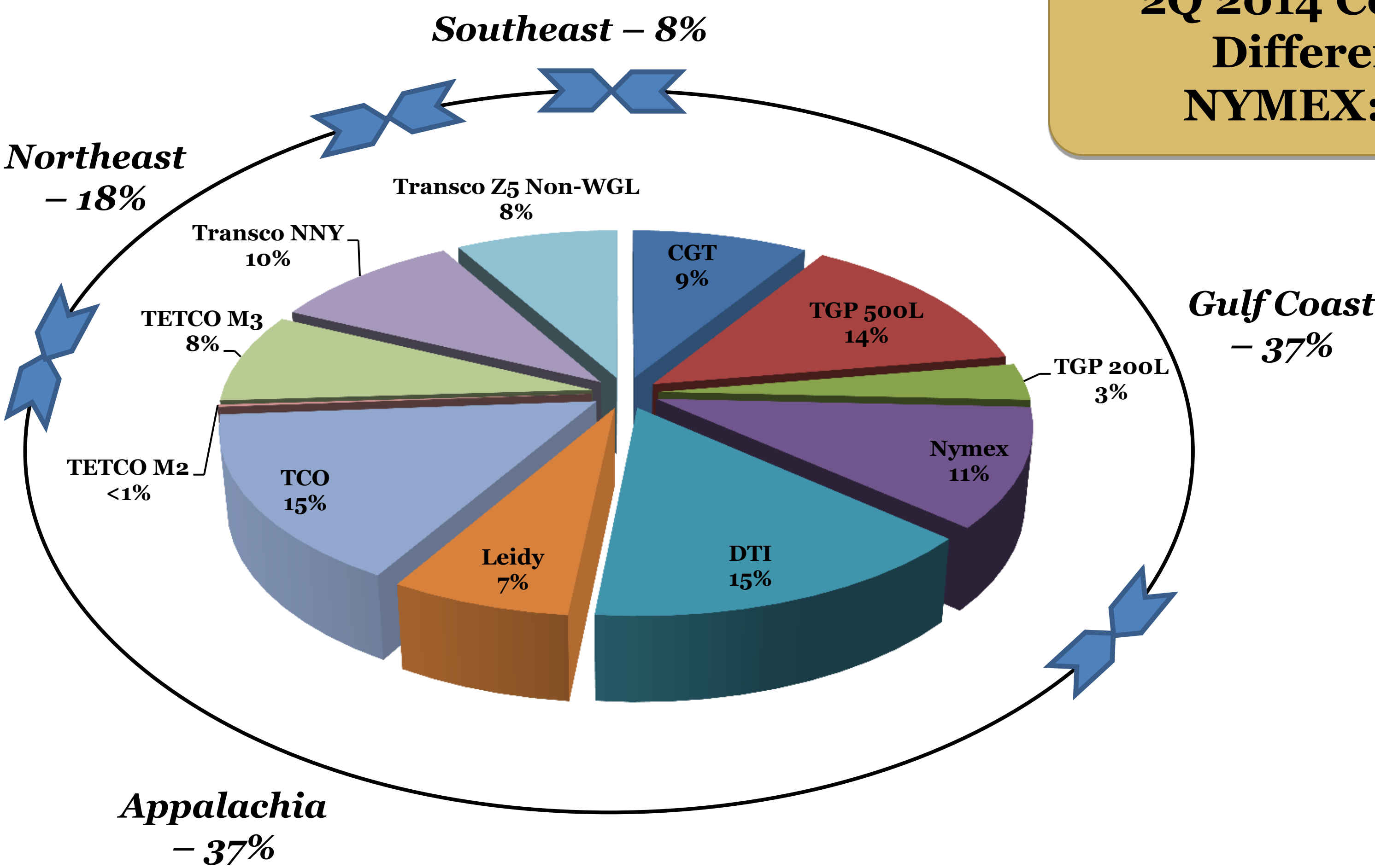
Capacity listed above reflects actual amounts of production that can flow under these arrangements. We believe these firm arrangements provide adequate capacity to meet our growth projections through 2018.

Range net production would be approximately 83% of the gross amounts shown. Does not include current intermediary pipeline capacity of >800,000 Mmbtu/day, and assumes full utilization. Cost associated with Firm Sales/Released Capacity is assumed as a deduction to price. Based on anticipated project start dates.

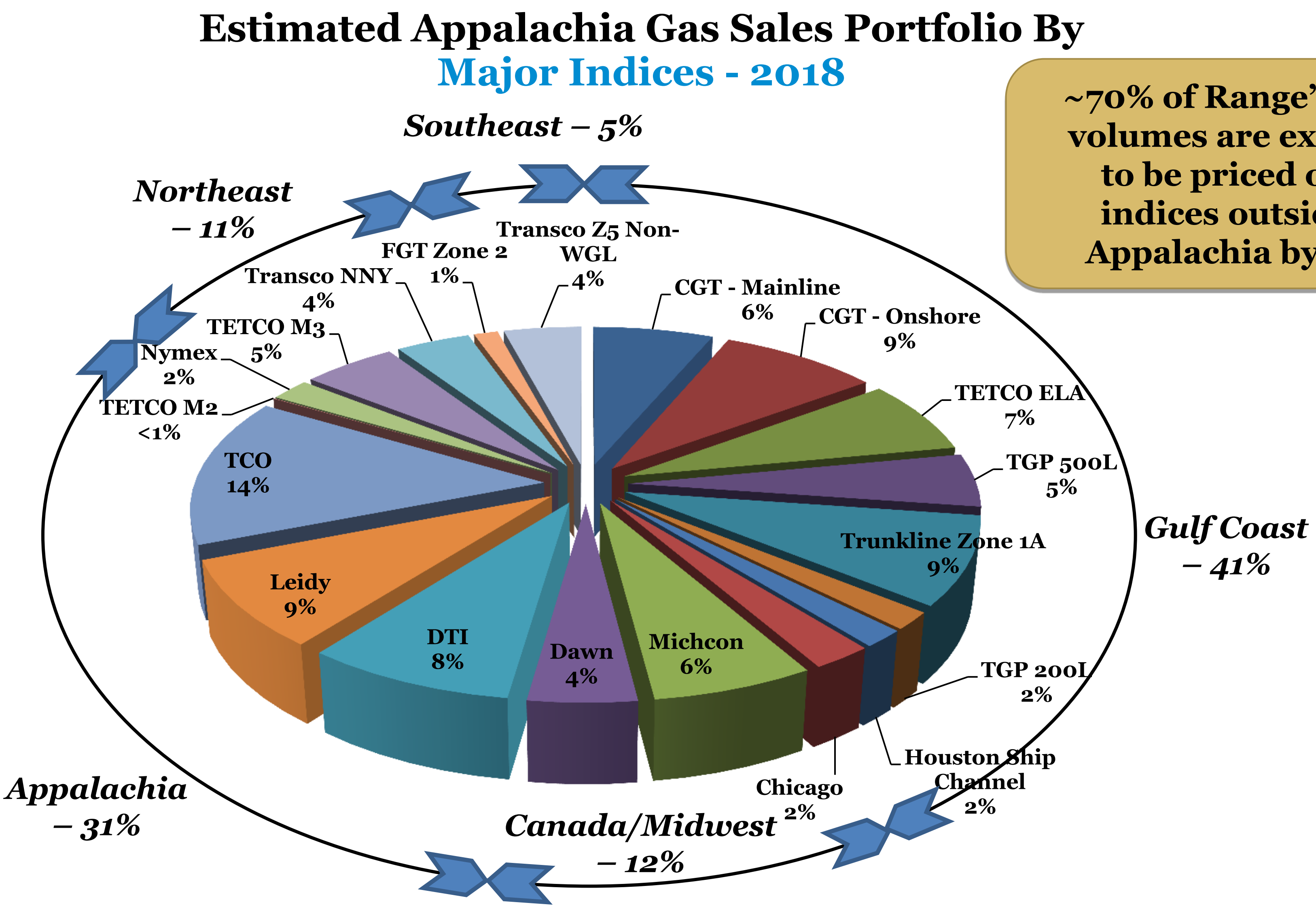
2014 Diversified Portfolio by Major Indices

Estimated Appalachia Gas Sales Portfolio By Major Indices - 2014

2Q 2014 Corporate Differential to NYMEX: ($0.58)



Projected 2018 Diversified Portfolio by Major Indices



~70% of Range's gas volumes are expected to be priced off of indices outside of Appalachia by 2018

Conclusions

- Marcellus and Utica volumes are expected to reach an estimated 25 Bcf/d by 2018
- Cumulative takeaway capacity is expected to be sufficient to move gas away from the Appalachian basin
- Range has contracted sufficient firm transportation capacity to allow it to meet its 20%-25% production growth goals
- Range's firm transport capacity is designed to achieve diversity of markets and customers
- As a first mover, Range's firm transport cost is one of the lowest among the Appalachia peer group
- Supply and demand is expected to balance through exports, industrial growth and power generation

How can you assess a producer's takeaway capacity?

First need to understand two concepts:

1. **What is total cost of takeaway capacity?**
   - Demand/Reservation charges
   - Fuel charges
   - Commodity charges

2. **How do E&P companies account for takeaway capacity?**
   - Sales method
   - Entitlement method

Additional detail in Appendix Section

Peer Group Transport Capacity Comparison

	Average Capacity [1]			Gross Production [2]			Calculated Utilization			Calculated Utilization Labels
	2015	2016	2017	2015	2016	2017	2015	2016	2017	
RRC [3]	1,200	1,520	1,820	1,145	1,386	1,651	**95%**	**91%**	**91%**	
AR	2,250	3,375	3,700	1,458	2,024	2,166	**65%**	**60%**	**59%**	< 20% over/under capacity
ECR	127	143	413	253	596	675	**199%**	**417%**	**163%**	> 20% over/under capacity
EQT	1,712	1,793	1,831	1,783	2,205	2,386	**104%**	**123%**	**130%**	
GPOR [3]	638	750	825	386	614	807	**61%**	**82%**	**98%**	
REXX	213	235	343	163	228	229	**76%**	**97%**	**67%**	
RICE	811	918	958	660	825	976	**81%**	**90%**	**102%**	

(1) - Annual estimate based on company presentations

(2) - Bloomberg/CapIQ consensus net production grossed up using 83% working interest assumption

(3) - Assuming 95% of GPOR and RRC gas production is related to Appalachian capacity

Note: Capacity may not be expressed in actual volumes that can be moved, but rather totaling all segments under contract

Data from Marcellus SW PA and Utica Peer Group shows that some producers have right-sized transportation capacity, like Range, for the next three years. Others have either more capacity than needed for projected growth, less capacity than projected growth or appear to grow into their capacity from 2015 to 2017.

Effective Cost of Transport – Assuming No Released Capacity

	Average Capacity (1)			Calculated Utilization			Transport Cost (2)			Calculated Trans. Cost w/ Utilization % (3)		
	2015	2016	2017	2015	2016	2017	2015	2016	2017	2015	2016	2017
RRC	1,200	1,520	1,820	95%	91%	91%	$0.28	$0.28	$0.37	**$0.29**	**$0.31**	**$0.41**
AR	2,250	3,375	3,700	65%	60%	59%	$0.35	$0.50	$0.52	**$0.54**	**$0.83**	**$0.89**
ECR	127	143	413	199%	417%	163%	$0.26	$0.47	$0.55	**$0.26**	**$0.47**	**$0.55**
EQT	1,712	1,793	1,831	104%	123%	130%	$0.30	$0.29	$0.27	**$0.30**	**$0.29**	**$0.27**
GPOR	638	750	825	61%	82%	98%	$0.58	$0.63	$0.65	**$0.96**	**$0.77**	**$0.66**
REXX	213	235	343	76%	97%	67%	$0.21	$0.32	$0.39	**$0.28**	**$0.33**	**$0.58**
RICE	811	918	958	81%	90%	102%	$0.60	$0.60	$0.62	**$0.74**	**$0.67**	**$0.62**
									Wt. Avg.	**$0.49**	**$0.59**	**$0.62**

(1) - Estimate based on company presentations

(2) - Estimate based on company presentations, SEC filings and accounting method

(3) - When utilization >100%, cost remains flat and *there is no further assumption on gas sales ability*

Under Wt. Avg.

Over Wt. Avg.

For producers with excess capacity (Utilization < 100%) and no sold capacity in the "released transport" market, effective cost increases as the full capacity cost is carried by current production.

For producers with insufficient takeaway capacity (Utilization > 100%), capacity costs would stay the same (or decrease on a weighted average) but would effectively be more exposed to the local markets with less attractive sales prices.

Effective Cost of Transport - Assuming Release Capacity Market

	Average Capacity (1)			Calculated Utilization			Transport Cost (3)			Calculated Trans. Cost - w/ Released Mkt (2)		
	2015	2016	2017	2015	2016	2017	2015	2016	2017	2015	2016	2017
RRC	1,200	1,520	1,820	95%	91%	91%	$0.28	$0.28	$0.37	**$0.27**	**$0.27**	**$0.38**
AR	2,250	3,375	3,700	65%	60%	59%	$0.35	$0.50	$0.52	**$0.32**	**$0.57**	**$0.68**
ECR	127	143	413	199%	417%	163%	$0.26	$0.47	$0.55	**$0.43**	**$0.72**	**$0.61**
EQT	1,712	1,793	1,831	104%	123%	130%	$0.30	$0.29	$0.27	**$0.31**	**$0.39**	**$0.37**
GPOR	638	750	825	61%	82%	98%	$0.58	$0.63	$0.65	**$0.70**	**$0.68**	**$0.66**
REXX	213	235	343	76%	97%	67%	$0.21	$0.32	$0.39	**$0.15**	**$0.32**	**$0.43**
RICE	811	918	958	81%	90%	102%	$0.60	$0.60	$0.62	**$0.65**	**$0.62**	**$0.62**
									Wt. Avg.	**$0.38**	**$0.49**	**$0.55**

Assumptions

	Release Capacity Mkt. $		
	2015	2016	2017
Bid	$0.40	$0.40	$0.30
Ask	$0.60	$0.80	$0.70

(1) - Estimate based on company presentations

(2) - Estimate based on an ability to freely buy/sell capacity at the bid/ask assumptions

(3) - Estimate based on company presentations, SEC filings and accounting method

Note: Analysis does not differentiate by geographical access. In reality, all capacity will not be available to all producers

Under Wt. Avg.

Over Wt. Avg.

If producers do not sell their excess capacity in the released market, pipeline companies may sell as "interruptible" capacity to others.

We would expect a bid/ask pricing to develop for the use of excess capacity among producers. However, because not all producers have access to multiple pipelines, the release capacity market may not be fully available to all producers, thus increasing transportation cost for those producers.

What can you conclude from this comparison?

1. Transportation costs will be a differentiating component of total cash costs in the future.

2. Not fully utilizing transportation costs in the short-term will raise the effective costs for certain producers unless excess capacity cost can be recouped in the release market.

3. Location of production and interconnection to pipelines are vital to optimize transportation agreements.

4. Each producer will have unique transportation costs to different markets which will impact net realized gas prices for each.

Range's Perspective

- Range believes it has demonstrated a comprehensive understanding of today's market.
- Range was years ahead in identifying the growth of the Marcellus/Utica and the need for transportation out of the basin for natural gas, ethane and other NGLs.
- With a first mover advantage, Range believes that it has the most flexible and cost effective portfolio of transportation and sales contracts for all its products. New contracts and innovations will continue to be announced.
- Combining Range's size and scale with our long-range business plan, we believe that our same strategy can identify early trends and opportunities that will allow our growth to continue.

Appendix

What is the total cost of takeaway capacity?

All costs are based on dekatherms (dth) or Mmbtu basis. Gas production is reported in mcf. If gas production averages 1,060 Btu per cubic foot, demand costs will be 106% of the dth cost for each mcf produced.

Pipeline quality gas, dictated by each pipeline segment, is generally 1,060 to 1,100 Btu. If NYMEX is $4.00 per Mmbtu at sales point, sales value is $4.24 per mcf, given 1060 Btu per cubic foot gas ($4.00 x 106%).

What is included in transport cost:

Demand or Reservation charges – Fee per dth for volume committed by producer whether or not actual volume is delivered (take or pay) for the term of the contract

Fuel charges – Additional charge for fuel used in the delivery and compression process; generally 1 % to 5 % (x gas price) for each pipeline segment; some anchor shippers have fuel charges capped

Commodity charge – Additional charge generally ranging from zero to 2 % (x gas price); fee may be waived for some anchor shippers

How do E&P companies account for takeaway capacity?

There are two methods to account for production revenue recognition. Natural gas, NGL and oil sales are recognized when the products are sold and delivered to customers:

Sales method - based on actual volumes sold to customers.

Entitlement method - based on volumes entitled to by working interest percentage.

All E&P companies will record the Demand and Commodity charges as a cash cost. However, for Fuel charges:

Sales method - deliver more gas to cover fuel so that capacity delivers total volume to customer (less production, less cash cost). (example – RRC and ECR)

Entitlement method - gross up sales for the Fuel charge as a non-cash cost and add to transportation expense (more production, more cash cost). (example - AR and GPOR)

How can you assess a producer's takeaway capacity?

Producers having takeaway capacity on the same pipeline can have dramatically different costs. ($0.15 to $0.30 in cases)

Anchor shippers most often have the lowest cost. Anchor shippers give the project size and scale and in return receive better pricing. Remaining shippers add more volume at higher costs.

What are the term lengths of the contracts? Does the producer have ROFR to extend the contract on the same or better terms? What markets does the producer reach with its capacity? Can they reach markets along the route?

How can you assess a producer's takeaway capacity?

What volume of production can the producer move on its capacity? Are there pipeline connections that limit how much production can actually flow? Telescoping connections are limited by the lowest capacity and adds additional costs for volumes that cannot be moved on the large pipes.

How much capacity can producers utilize each year until their capacity is full?

Does the producer have a direct link between production in the field to the capacity contracted for? Producers are buying firm transportation on the projects being offered in the market, but they may not have the interconnections built (or secured) to actually flow gas into their contracted capacity or there might be a timing difference between capacity and production.

What markets do they have under contract at the end of their capacity or along their capacity? Without attractive markets, sales prices may not justify the cost of transportation.

Understanding Takeaway Capacity in Appalachia

Transportation takeaway requires size and scale and therefore smaller producers are at an inherent competitive disadvantage until play matures.

Markets are more important than takeaway transportation since the goal is better net back realizations after transport costs. Lower cost transport to a bad market does not compete with reasonable transport cost to good markets.

The time to lock in good markets and reasonable transport cost has probably passed. Demand will grow so good markets will expand but reasonably priced transport has probably been fully contracted. Now the opportunities are determining if all the transport is being utilized.

The released transport capacity market could be a significant new market, potentially at a lower cost than new construction. Until the released market is fully utilized, there might be no need for new transportation capacity except where specific demand pull markets need more gas and are willing to underwrite the cost.

Understanding Takeaway Capacity in Appalachia

Size and scale is essential at the beginning of any project. Transportation will be available to balance supply and demand only if the producers with size and scale sponsor the construction of infrastructure.

Financial discipline is required to make sure that producers sponsoring projects do not overbuild infrastructure which out paces demand or adds too much upfront cost. Building infrastructure to meet peak rates creates a large financial burden in the later years when capacity is under-utilized, leaving high fixed payment amounts.

Smaller producers can commercially come into a project after the infrastructure has been built if there is excess capacity. This allows smaller producers to use incremental infrastructure to get production to market without the large ongoing financial commitments. However, excess capacity may not line up with production timing and/or location.

Understanding Takeaway Capacity in Appalachia

Takeaway capacity should be a function of getting to better markets. A large number of the takeaway projects over the last few years were motivated by pipelines creating more take or pay fee income to any indiscriminate markets that producers were willing to subscribe to avoid negative basis.

The market will rationalize the capital spent and some producers could have cash flow penalized as net realized prices drop at over-supplied markets.

In almost every market there is an amount of existing demand that will pay Henry Hub prices or more. But when those contracts are satisfied, the next layer of supply is discounted in order to move the gas from that point.

The objective is clearly identifying premium markets and locking in contracts in those markets. Transportation is then required to get to those markets. Producers need BOTH and it takes a multi-year plan to obtain both.

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