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Maine Public Utilities Commission
Review of Natural Gas Capacity Options

February 26, 2014

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Contents

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1. Introduction: Legislative Background

- Based on the recently enacted H.P. 1128 – L.D. 1559 (i.e., An Act to Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment), the Maine Public Utilities Commission ("Maine PUC") has the ability to execute contracts for natural gas pipeline capacity:

  3. Parties to an energy cost reduction contract. The commission may execute, or direct to be executed, an energy cost reduction contract that contains the following provisions.

  A. The commission may direct one or more transmission and distribution utilities, gas utilities or natural gas pipeline utilities to be a counterparty to an energy cost reduction contract. In determining whether and to what extent to direct a utility to be a counterparty to a contract under this subsection, the commission shall consider the anticipated reduction in the price of gas or electricity, as applicable, accruing to the customers of the utility as a result of the contract as determined by the commission in an adjudicatory proceeding.

  Any economic loss, including but not limited to any effects on the cost of capital resulting from an energy cost reduction contract for a transmission and distribution utility, a gas utility or a natural gas pipeline utility, is deemed to be prudent and the commission shall allow full recovery through the utility's rates.

  B. If the commission concludes that an energy cost reduction contract can be achieved with the participation of other entities, the commission may contract jointly with other entities, including other state agencies and instrumentalities, governments in other states and nations, utilities and generators.

  C. The commission may execute an energy cost reduction contract as a principal and counterparty.

1. Introduction: Project Objective and Report Organization

- Sussex Economic Advisors, LLC ("Sussex") was retained by the Maine PUC to review the various natural gas pipelines serving New England, their related open seasons for capacity, and the potential costs and benefits of incremental natural gas deliverability into New England. The remainder of this report is organized as follows:
  - Section 2 – Executive Summary: Provides an executive summary of the key observations and findings
  - Section 3 – Natural Gas Market Overview: Provides an overview of the current natural gas markets in New England, with a particular focus on Maine; discusses the regional natural gas demand and supply drivers; and reviews natural gas prices and basis values
  - Section 4 – Natural Gas Pipeline Capacity Options: Identifies and reviews the natural gas pipeline capacity options into New England
  - Section 5 – Cost / Benefit Analysis: Provides an estimate of the costs and benefits associated with incremental pipeline capacity into the New England region
  - Section 6 – Summary and Conclusions: Summarizes the observations and conclusions based on the analyses and research presented herein

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Contents

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2. Executive Summary: Natural Gas Demand Drivers

- There is significant activity affecting natural gas demand in the New England, New York City and Atlantic Canada region
  - Maine: local distribution companies ("LDCs") have significant natural gas expansion plans
  - Connecticut Comprehensive Energy Strategy ("CT CES"): potential for 300,000 new natural gas customers over the next seven to ten years
  - Massachusetts: Department of Energy Resources ("DOER") has sponsored a study regarding potential policy changes associated with LDC expansion
  - New York City: no permits for No. 4 and 6 fuel oil unless emissions are equivalent to No. 2 oil, which has resulted in significant conversion to natural gas; Con Edison estimated peak day growth of approximately 4%
  - Atlantic Canada: increasing demand for natural gas from the LDC and power generation segments
  - ISO New England ("ISO-NE"): increasing reliance on natural gas, as over half of the generation in the interconnection queue is natural gas-fired; nearly 10% of ISO-NE's total generating capacity is scheduled to be retired over the next three years

2. Executive Summary: Natural Gas Supply Drivers

- Eastern Canada:
  - Decreasing production from the Sable Offshore Energy Project ("SOEP")
  - Deep Panuke is on-line and at full volume (i.e., approximately 300 MMcf/day); however, there are uncertainties regarding sustainability and duration of production

- Liquefied Natural Gas ("LNG"):
  - Massachusetts off-shore facilities have not received any cargoes in the past 3 years
  - Canaport LNG and GDF SUEZ volumes are approximately 50% of previous levels
  - Alternative market prices for LNG are currently more attractive than New England market index prices

- Dawn Gas Supply Hub ("Dawn Hub") / Western Canada:
  - TransCanada Pipelines Limited ("TCPL") Mainline, the primary pipeline delivering Canadian natural gas supplies to New England, has reached a toll and service settlement with the major eastern Canadian LDCs. The settlement was submitted for review by the National Energy Board ("NEB") in December 2013, and as a result, the tolls for service on the TCPL Mainline will be subject to the results and timing of that proceeding

- Algonquin Gas Transmission ("AGT") / Tennessee Gas Pipeline ("TGP"):
  - Marcellus Shale gas production continues to grow, which has increased the utilization of the AGT and TGP pipelines and has resulted in increased interruptible or non-firm service restrictions

2. Executive Summary: Resultant Natural Gas Price Signals

- Although natural gas prices in New England, as represented by the Algonquin Citygates ("ALGCG") price index, have historically been at a premium to the Gulf of Mexico prices, as represented by the Henry Hub price index, the level of that premium has increased substantially over the past few years

ALGCG-Henry Hub Basis Differential ($/MMBtu)		Number of Days					
		2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014*
Greater than or equal to	$10.00	1	0	2	0	25	28
Greater than or equal to	$5.00	13	1	24	3	53	38
Greater than or equal to	$2.00	40	27	61	21	124	56
Greater than or equal to	$1.00	78	43	113	85	164	64
Greater than or equal to	$0.50	154	118	191	218	207	79
Greater than or equal to	$0.25	339	360	323	295	257	85
Greater than	$0.00	362	365	365	365	334	86
Less than or equal to	$0.00	3	0	0	0	31	4

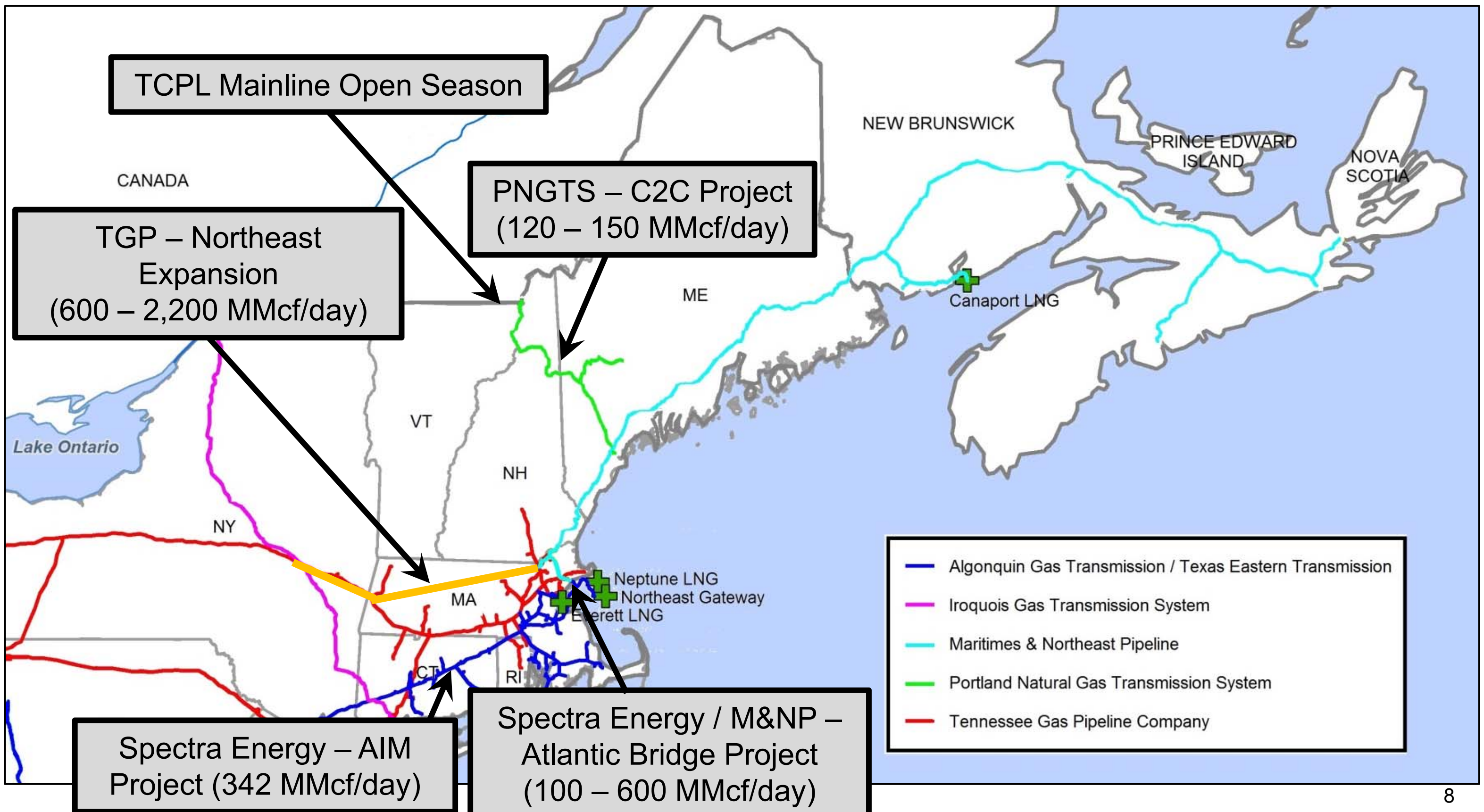
* 2013/2014 data through January 29, 2014

- As illustrated by the table, the premium between New England and Henry Hub natural gas prices exceeded $10.00/MMBtu three times during the 2008/2009 through 2011/2012 time period; however, in 2012/2013, there were 25 observations where the basis was equal to or greater than $10.00/MMBtu
- So far in 2013/2014, there have been 28 observations of a basis greater than $10.00/MMBtu

Source: Historical prices through January 29, 2014 from SNL Financial

2. Executive Summary: Natural Gas Pipeline Capacity Options

- As illustrated below, there are several natural gas infrastructure projects proposed for the New England region, including the Spectra Energy Algonquin Incremental Market ("AIM") Project, the Spectra Energy/Maritimes & Northeast Pipeline ("M&NP") Atlantic Bridge Project, the Kinder Morgan/TGP Northeast Expansion, and the Portland Natural Gas Transmission System ("PNGTS") Continent to Coast ("C2C") Project



Source: SNL Financial

2. Executive Summary: Cost / Benefit Analysis – New England

- Based on the relationship between natural gas prices and electricity locational marginal prices ("LMPs") in ISO-NE, Sussex calculated the potential reduction in LMPs as a result of a reduction in wholesale natural gas prices to estimate the potential energy cost savings to electricity customers for the 2012/2013 split-year[1]
- As illustrated by the tables below, a 40% reduction in the New England natural gas basis (i.e., a lowering of the premium between New England and Gulf of Mexico natural gas price indices) would offset 1,000,000 Dth/day of incremental pipeline capacity, assuming a daily pipeline charge as high as $2.00/Dth

Estimated Benefits		
Basis Reduction of:	Annual Energy Cost Savings for Maine Customers ($)	Annual Energy Cost Savings for ISO-NE Customers ($)
25%	$40,047,605	$467,668,031
30%	$48,057,127	$561,201,637
35%	$56,066,648	$654,735,243
40%	**$64,076,169**	**$748,268,849**
45%	$72,085,690	$841,802,455
50%	$80,095,211	$935,336,062
55%	$88,104,732	$1,028,869,668
60%	$96,114,253	$1,122,403,274
65%	$104,123,774	$1,215,936,880
70%	$112,133,295	$1,309,470,486
75%	$120,142,816	$1,403,004,092

Cost Assumptions (1,000,000 Dth)		
Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)
$1.00	1,000,000	$365,000,000
$1.10	1,000,000	$401,500,000
$1.20	1,000,000	$438,000,000
$1.30	1,000,000	$474,500,000
$1.40	1,000,000	$511,000,000
$1.50	1,000,000	$547,500,000
$1.60	1,000,000	$584,000,000
$1.70	1,000,000	$620,500,000
$1.80	1,000,000	$657,000,000
$1.90	1,000,000	$693,500,000
$2.00	**1,000,000**	**$730,000,000**

Note: [1] Split-year is defined as the twelve-month period from November to October

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2. Executive Summary: Cost / Benefit Analysis – Maine

- A cost / benefit analysis was also conducted for Maine using an approach similar to the ISO-NE analysis discussed earlier and under two volume scenarios (i.e., 50,000 Dth and 200,000 Dth)
- As indicated in the tables below, the estimated annual benefits to Maine under a scenario in which the natural gas basis is reduced by 40% is approximately $64 million, which would offset a 50,000 Dth/day contract assuming a daily rate as high as $2.00/Dth
- However, the estimated annual benefits to Maine of approximately $64 million would not offset a 200,000 Dth/day contract at a daily rate of a $1.00/Dth

Estimated Benefits		Cost Assumptions (50,000 Dth)			Cost Assumptions (200,000 Dth)		
Basis Reduction of:	Annual Energy Cost Savings for Maine Customers ($)	Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)	Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)
25%	$40,047,605	$1.00	50,000	$18,250,000	**$1.00**	**200,000**	**$73,000,000**
30%	$48,057,127	$1.10	50,000	$20,075,000	$1.10	200,000	$80,300,000
35%	$56,066,648	$1.20	50,000	$21,900,000	$1.20	200,000	$87,600,000
40%	**$64,076,169**	$1.30	50,000	$23,725,000	$1.30	200,000	$94,900,000
45%	$72,085,690	$1.40	50,000	$25,550,000	$1.40	200,000	$102,200,000
50%	$80,095,211	$1.50	50,000	$27,375,000	$1.50	200,000	$109,500,000
55%	$88,104,732	$1.60	50,000	$29,200,000	$1.60	200,000	$116,800,000
60%	$96,114,253	$1.70	50,000	$31,025,000	$1.70	200,000	$124,100,000
65%	$104,123,774	$1.80	50,000	$32,850,000	$1.80	200,000	$131,400,000
70%	$112,133,295	$1.90	50,000	$34,675,000	$1.90	200,000	$138,700,000
75%	$120,142,816	**$2.00**	**50,000**	**$36,500,000**	$2.00	200,000	$146,000,000

Contents

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3. Market Context: Natural Gas Infrastructure – New England

❖ Five interstate natural gas pipelines serve the New England region:

Pipeline	Owner(s)	Primary Supply Sources
Algonquin Gas Transmission, LLC (“Algonquin” or “AGT”)	Spectra Energy Partners, LP	Gulf of Mexico, Appalachian Basin, Rockies Basin, LNG
Iroquois Gas Transmission, L.P. (“Iroquois”)	Iroquois Gas Transmission, L.P.	Western Canadian Sedimentary Basin (“WCSB”) / Dawn Hub
Maritimes & Northeast Pipeline (“M&NP”) (U.S.)	Spectra Energy Partners, LP (77.53%); Emera, Inc. (12.92%); ExxonMobil Corp. (9.55%)	SOEP / Deep Panuke / LNG
Portland Natural Gas Transmission System (“PNGTS”)	TransCanada Pipelines Limited (61.71%); Gaz Metro (38.29%)	WCSB / Dawn Hub
Tennessee Gas Pipeline Company, L.L.C. (“Tennessee” or “TGP”)	Kinder Morgan Energy Partners, L.P.	Gulf of Mexico, Appalachian Basin, Rockies Basin, LNG

Sources: Company websites; and SNL Financial

3. Market Context: Natural Gas Infrastructure – New England (cont.)

❖ LNG import terminals:

- LNG imports provided approximately 17% of New England's total natural gas supply in the winter of 2012/2013, and historically up to 60% of New England's total natural gas supply on a peak winter day

LNG Import Terminal	Owner(s)	Location	Max. Sendout Capacity (MMcf/day)	Storage Capacity (Bcf)	In-Service Date
Canaport LNG	Repsol Energy North America Corp. (75%); Irving Oil (25%)	St. John. New Brunswick	1,200	10.0	2009
Everett LNG	Distrigas of Massachusetts LLC, a subsidiary of GDF SUEZ Gas NA	Everett, MA	715; 100 (by truck)	3.4	1971
Neptune LNG	GDF SUEZ Gas NA	Offshore – Gloucester, MA	750	n/a	2010
Northeast Gateway	Excelerate Energy	Offshore – Cape Ann, MA	800	n/a	2008

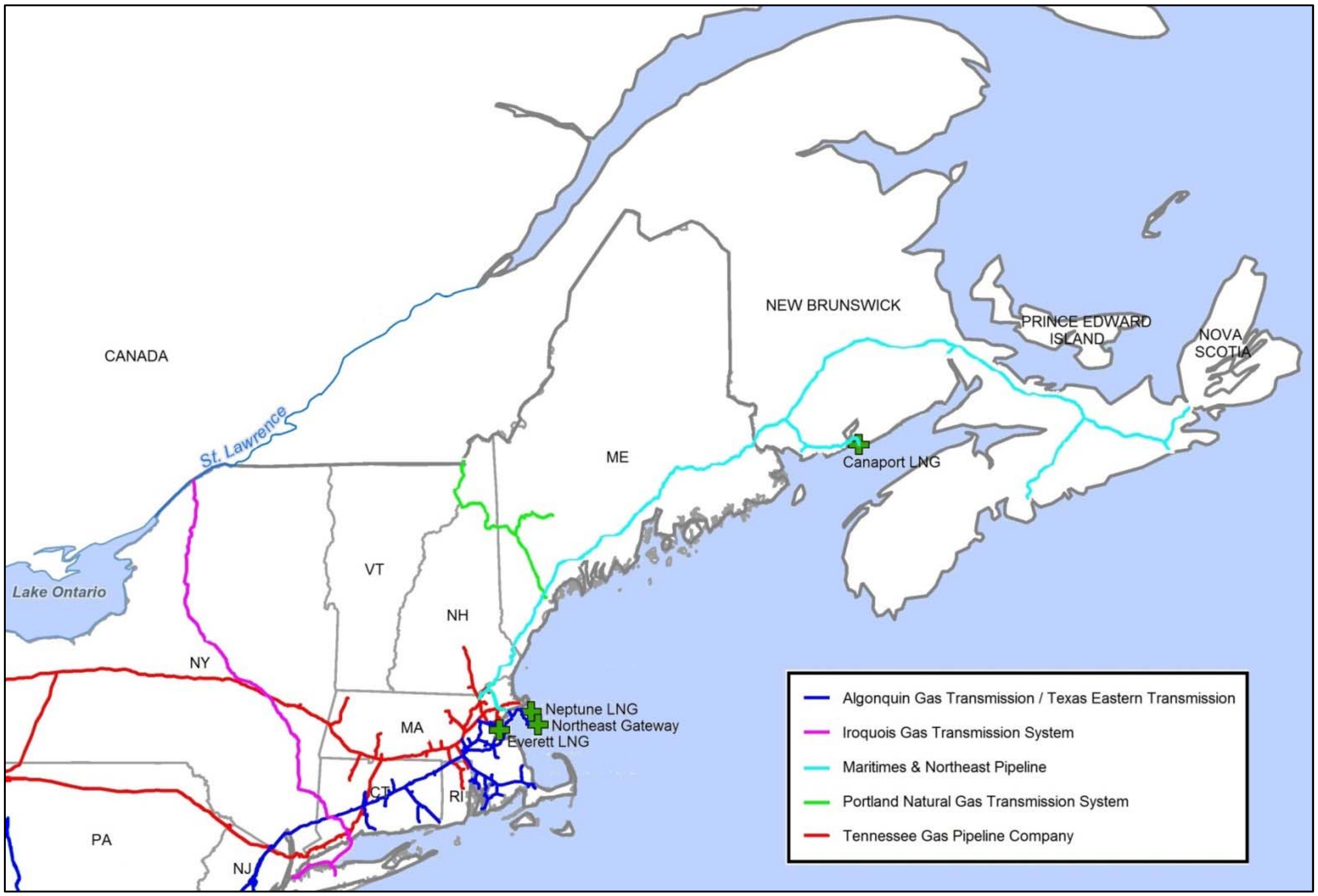
❖ In addition to LNG importation facilities, the New England region also relies on LDC LNG peak-shaving facilities to meet regional peak day requirements:

- 45 LDC LNG tanks in five New England states (i.e., CT, ME, MA, NH, and RI)
- Total storage capacity of the New England LNG facilities is approximately 16.5 Bcf with vaporization capacity of approximately 1.4 Bcf/day

Sources: Company websites; SNL Financial; Federal Energy Regulatory Commission, Winter 2012-13 Energy Market Assessment, November 15, 2012; Northeast Gas Association, Statistical Guide to the Northeast U.S. Natural Gas Industry 2013, December 2013; and based on a review of each LDC's most recent forecast and supply plan filing with their respective state regulatory commissions

3. Market Context: Natural Gas Infrastructure – New England (cont.)

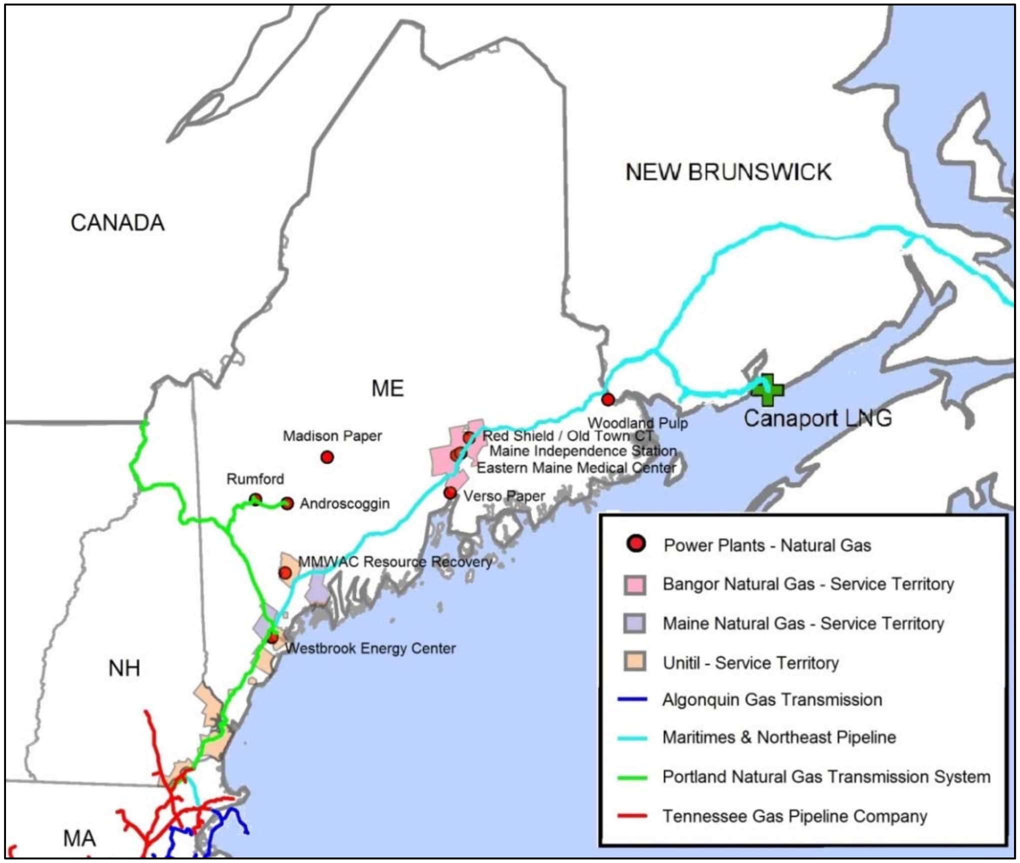
- There are five major interstate pipelines and four LNG import terminals that deliver natural gas to New England



Source: SNL Financial

3. Market Context: Natural Gas Infrastructure – Maine

❖ The Maine natural gas market is primarily served by M&NP and PNGTS; in addition, there are four LDCs that provide distribution service

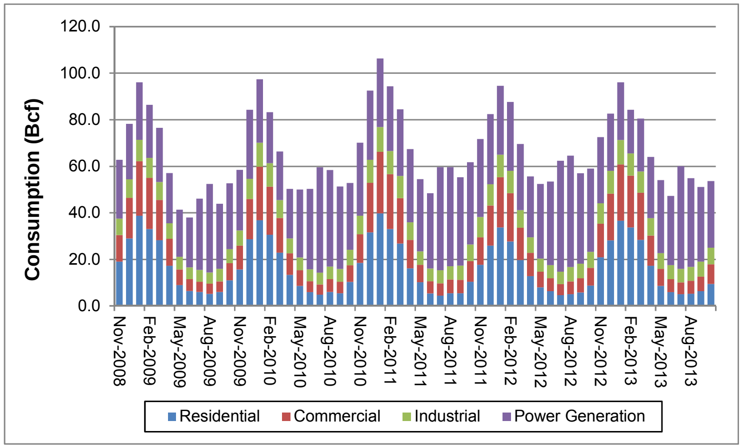


<u>Notes</u>:
[1] The map above shows the service territories for the Maine LDCs prior to the natural gas pipeline expansions to the city of Augusta, Maine by Maine Natural Gas and Summit Natural Gas in late 2013
[2] Madison Paper is currently served by LNG, and is expected to be served by Summit Natural Gas in 2014

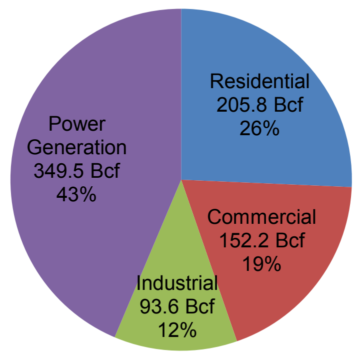
Source: SNL Financial

3. Market Context: Historical Demand – New England (excluding Maine)

- Over the past five split-years (i.e., 2008/2009 to 2012/2013):
  - Total annual demand for natural gas increased by a compound annual growth rate ("CAGR") of 2.3% from 731.7 Bcf (i.e., 2,005 MMcf/day) to 801.1 Bcf (i.e., 2,195 MMcf/day)
  - Winter natural gas demand increased by a CAGR of 1.0% from 400.0 Bcf (i.e., 2,649 MMcf/day) to 416.0 Bcf (i.e., 2,755 MMcf/day)
  - Summer natural gas demand increased by a CAGR of 3.8% from 331.7 Bcf (i.e., 1,550 MMcf/day) to 385.1 Bcf (i.e., 1,800 MMcf/day)
- In 2012/2013, the power generation segment accounted for approximately 43% of total natural gas demand, followed by the residential, commercial and industrial segments with 26%, 19% and 12%, respectively



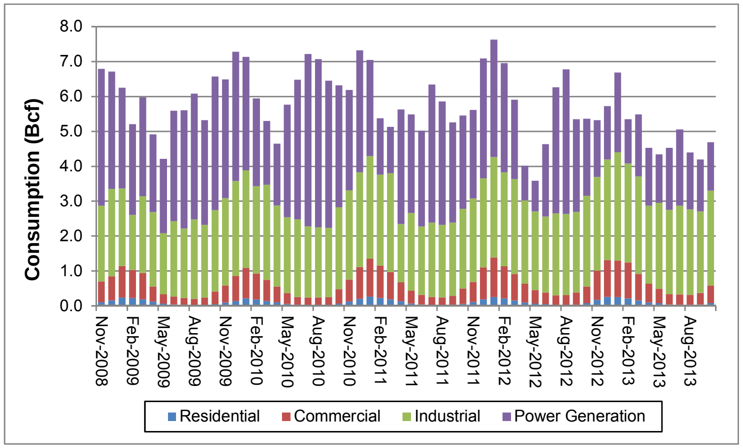
Total 2012/2013 Natural Gas Demand = 801.1 Bcf



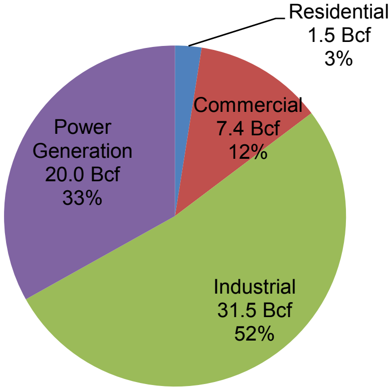
Note: Data for 2013 for certain states based on Sussex estimates (Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, release date January 7, 2014)

3. Market Context: Historical Demand – Maine

- Over the past five split-years (i.e., 2008/2009 to 2012/2013):
  - Total annual demand for natural gas decreased by a CAGR of 3.4% from 69.2 Bcf (i.e., 190 MMcf/day) to 60.3 Bcf (i.e., 165 MMcf/day)
  - Winter natural gas demand decreased by a CAGR of approximately 2.0% from 30.9 Bcf (i.e., 205 MMcf/day) to 28.6 Bcf (i.e., 189 MMcf/day)
  - Summer natural gas demand decreased by a CAGR of 4.6% from 38.3 Bcf (i.e., 179 MMcf/day) to 31.7 Bcf (i.e., 148 MMcf/day)
  - While the residential, commercial and industrial segments all have experienced increases in consumption, the demand for natural gas by the power generation segment has declined from 36.9 Bcf (i.e., 101 MMcf/day) to 20.0 Bcf (i.e., 55 MMcf/day), likely driven by higher gas supply costs
- In 2012/2013, the power generation segment accounted for approximately 33% of Maine's total natural gas demand, while the industrial segment accounted for 52% of the total demand



Total 2012/2013 Natural Gas Demand = 60.3 Bcf



Note: Data for January-April 2013 for the residential and commercial segments based on Sussex estimates (Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, release date January 7, 2014)

3. Natural Gas Demand Drivers: Maine

- The four Maine LDCs have significant natural gas infrastructure development and expansion plans:
  - Unitil, which serves natural gas customers in Maine, New Hampshire and Massachusetts, has plans to increase its number of customers from 74,000 to 92,000 (i.e., an approximately 25% increase in customer base) by 2016 through additions and conversions
  - Summit Natural Gas ("Summit") is currently undertaking multiple projects to provide natural gas service to new areas within Maine
    - The $350 million Kennebec Valley Project, which consists of an 88-mile transmission pipeline to supply natural gas to two paper mills, along with 1,600 miles of distribution pipeline to expand Summit's service territory into seventeen communities in the Kennebec Valley region
    - Summit also received approval for a $42 million project, which consists of 32 miles of transmission lines and 213 miles of distribution lines, to provide natural gas distribution service to the towns of Cumberland, Falmouth and Yarmouth
  - The new $23 million natural gas pipeline built by Maine Natural Gas from an interconnect with M&NP in Windsor, Maine to Augusta, Maine commenced service in November 2013
  - In late October 2013, Bangor Natural Gas announced plans to construct a five-phase, $7.5 million natural gas pipeline to Lincoln, Maine

Sources: Unitil, Presentation for Second Quarter 2013 Earnings Conference Call, July 24, 2013; Summit Natural Gas, "Gas is Turned On, Summit Now Serving Customers", January 6, 2014; Bangor Daily News, "Falmouth releases map detailing natural gas line expansion", December 23, 2013; SNL Financial, "Maine Natural Gas completes 1st gas pipeline to Augusta, Maine", October 28, 2013; and SNL Financial, "Report: Bangor Natural proposes $7.5M pipeline in Maine", October 23, 2013

3. Natural Gas Demand Drivers: Connecticut

- On February 19, 2013, the Connecticut Department of Energy and Environmental Protection issued its Comprehensive Energy Strategy for Connecticut ("CT CES")
- One of the main objectives addressed by the CT CES was to increase the consumption of natural gas through natural gas conversions. The CT CES set a goal of increasing the availability of natural gas to approximately 300,000 additional customers over the next seven years, by promoting:
  - "[A]n enhanced regulatory structure designed to provide fuel flexibility and diversity. It offers a path toward greater consumer fuel choice and long overdue investments in infrastructure that will make it easier for many Connecticut residents and businesses to take advantage of the opportunity to heat with lower cost and cleaner burning natural gas – if they would like to do so."
- To meet the growing natural gas demand, the Connecticut LDCs have supported natural gas capacity projects on both TGP and AGT:
  - TGP Connecticut Expansion – 72,100 Dth/day with an in-service date of November 2016
  - Spectra Energy AIM Project – 342,000 Dth/day with an in-service date of November 2016

Sources: Connecticut Department of Energy and Environmental Protection, 2013 Comprehensive Energy Strategy for Connecticut, February 19, 2013; and Connecticut Public Utilities Regulatory Authority, Docket No. 13-06-02, PURA Investigation of Connecticut's Local Distribution Companies' Proposed Expansion Plans to Comply with Connecticut's Comprehensive Energy Strategy, Decision, November 22, 2013

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3. Natural Gas Demand Drivers: Massachusetts

- The Massachusetts DOER has sponsored a study to analyze the net economic and environmental benefits of expanding natural gas distribution service to more Massachusetts households and businesses ("the Natural Gas Study")
- The purpose of the Natural Gas Study is to develop an analytical framework, findings, and recommendations regarding natural gas distribution expansion in light of changing market conditions and environmental issues
- The DOER anticipates that the outcome of the Natural Gas Study, along with its renewable thermal expansion study, could result in new approaches with respect to thermal policies in Massachusetts
- The Natural Gas Study will evaluate the benefits, costs, and challenges associated with natural gas LDC expansion under a range of potential strategy options

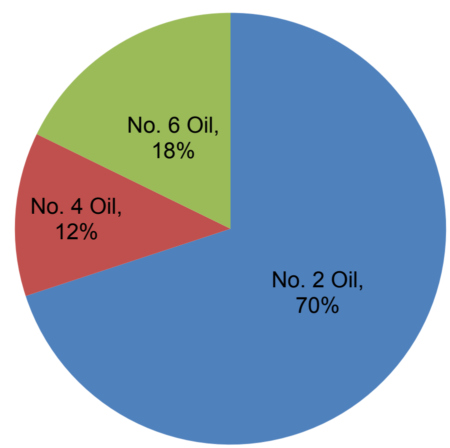
3. Natural Gas Demand Drivers: New York City

- Gas conversion requests have increased between 2010 and 2013
- PlaNYC calls for the elimination of the use of No. 4 and 6 heating oil
  - No permits for new No. 4 or 6 boilers (unless emissions as clean as No. 2 oil)
  - No certificate of operation will be renewed for No. 6 boiler as of July 2012 (unless emissions as clean as No. 4 oil)
  - All boilers must use No. 2 oil, natural gas or equivalent upon retirement or by 2030
- Con Edison is forecasting peak usage over the next five years to increase
  - CECONY Gas: 3.8% annually
  - O&R Gas: 0.7% annually

Number of Conversions – CECONY Gas
Multi-Family and Commercial Buildings

Year	Number of Conversions
2010	73
2011	310
2012	855
Through Sep. 2013	870

Potential Conversions by Fuel Type
Multi-Family and Commercial Buildings



Source: Con Edison, Investor Presentation at the Edison Electric Institute Finance Conference, November 10-12, 2013

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3. Natural Gas Demand Drivers: Maritimes Canada

❖ According to a recent Nova Scotia Department of Energy ("NS DOE") Study:

- Natural Gas Demand:
  - Maritimes Canada natural gas consumption will increase from approximately 62 Bcf in 2012 (i.e., 170 MMcf/day) to approximately 70 Bcf by 2020 (i.e., 192 MMcf/day), largely driven by the power generation segment
  - Gas-fired generation in Nova Scotia has increased from 3% of total generation in 2006 to over 20% in 2012
- Natural Gas Supply:
  - Maritimes Canada natural gas supply is expected to shift from a reliance on offshore natural gas resources (i.e., SOEP, Deep Panuke) to external sources of natural gas supply (e.g., LNG, or imports from the U.S.)
  - One of the focus areas of the NS DOE Study was upstream capacity contracting, specifically: "[g]iven the need for external supply, ICF believes there is a strong argument for Maritimes Canada consumers to contract for firm pipeline capacity on one of the proposed pipeline expansions into New England that would allow shippers to buy gas at one of the Marcellus basin hubs to an interconnection with M&NP. This would ensure a reliable source of gas as well as avoid the price volatility in New England."

Source: Nova Scotia Department of Energy, The Future of Natural Gas Supply for Nova Scotia, prepared by ICF Consulting Canada, Inc., March 28, 2013

3. Natural Gas Demand Drivers: Power Generation

- There are approximately 350 generating units in the ISO New England region – a total of over 32,000 MW of generating capacity – with natural gas-fired generators representing approximately 43% of total generating capacity and 52% of total electric energy production in 2012
- Several key generating facilities, which represent nearly 10% of the region's total capacity, have announced plans to retire over the next three years:
  - Salem Harbor (750 MW) – scheduled to be retired by June 2014; expected to be replaced by a new approximately 700 MW combined cycle gas turbine facility
  - Vermont Yankee (604 MW) – expected to be decommissioned in late 2014; since 2007, has generated approximately 4% of the total annual electricity supply in New England
  - Brayton Point (1,492 MW) – three coal-fired units and several oil-fired units scheduled to retire by 2017
  - Norwalk Harbor (340 MW) – oil-fired generating facility scheduled to be retired by June 2017
- As of January 1, 2014, there are 70 generation projects in various stages of development in the ISO New England region totaling 4,980 MW
  - Seven of the 70 projects are dual fuel (i.e., natural gas and oil-fired) generation projects located in Massachusetts and Connecticut, for a total of 2,230 MW, with in-service dates between 2014 and 2017; and two projects are natural gas combined-cycle generation projects, for a total of 503 MW, with in-service dates in 2014 and 2017
  - Stated differently, of the 4,980 MW of generation being developed, over half (i.e., 2,733 MW) will be fueled by natural gas

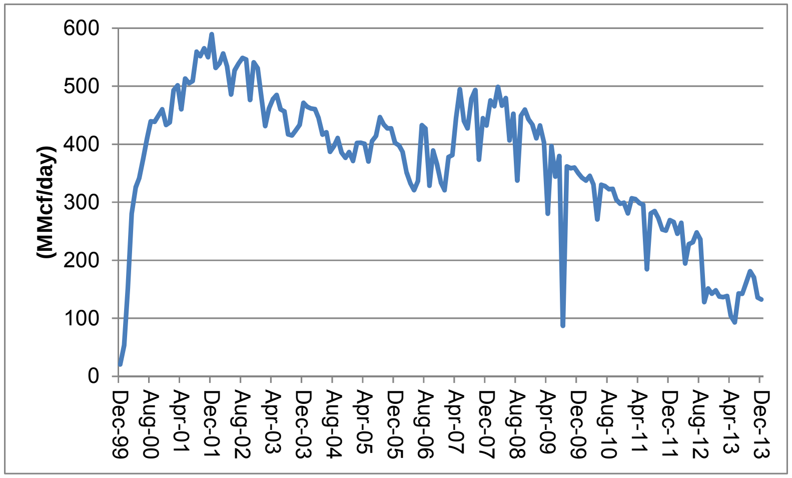
Sources: ISO New England, New England 2012-13 Regional Profile and Maine 2012-13 State Profile, February 2013; ISO New England, Seasonal Claimed Capacity Monthly Report, October 1, 2013; ISO New England, Status of Non-Price Retirement Requests, December 20, 2013; and ISO New England, Interconnect Request Queue, January 1, 2014

3. Natural Gas Supply Drivers: Atlantic Canada

❖ <u>Sable Offshore Energy Project</u>:

- Natural gas production from SOEP declined from a peak of nearly 600 MMcf/day in December 2001 to 240 MMcf/day in August 2012; since September 2012, average daily SOEP production has declined to approximately 140 MMcf/day

Year	Total Annual Production (MMcf)	Avg. Daily Production (MMcf/day)
2000	126,983	347
2001	189,755	520
2002	193,273	530
2003	164,706	451
2004	152,779	417
2005	149,174	409
2006	133,957	367
2007	155,432	426
2008	163,687	447
2009	126,469	346
2010	116,454	319
2011	99,895	274
2012	75,806	207
2013	51,020	140



❖ <u>Deep Panuke</u>:

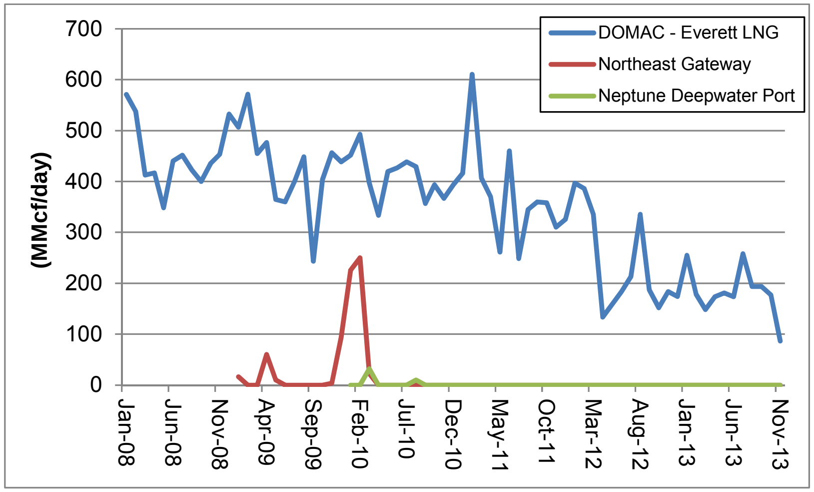
- Initial production of 200 MMcf/day, with peak gas production of 300 MMcf/day
- December 2013: Reached production of 290 MMcf/day
- The natural gas production profile for Deep Panuke was addressed by a recent Nova Scotia Department of Energy study:
  - "Deep Panuke, is projected to come online in mid-2013, with peak production volumes of 300 MMcfd by 2014-15. After 2015, production from Deep Panuke is projected to decline, reaching 90 MMcfd by 2020 and less than 20 MMcfd by 2035."

Sources: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, as of January 21, 2014; Nova Scotia Department of Energy, *The Future of Natural Gas Supply for Nova Scotia*, prepared by ICF Consulting Canada, Inc., March 28, 2013; and The Chronicle Herald, "Deep Panuke back in full swing", December 11, 2013

3. Natural Gas Supply Drivers: Imported LNG

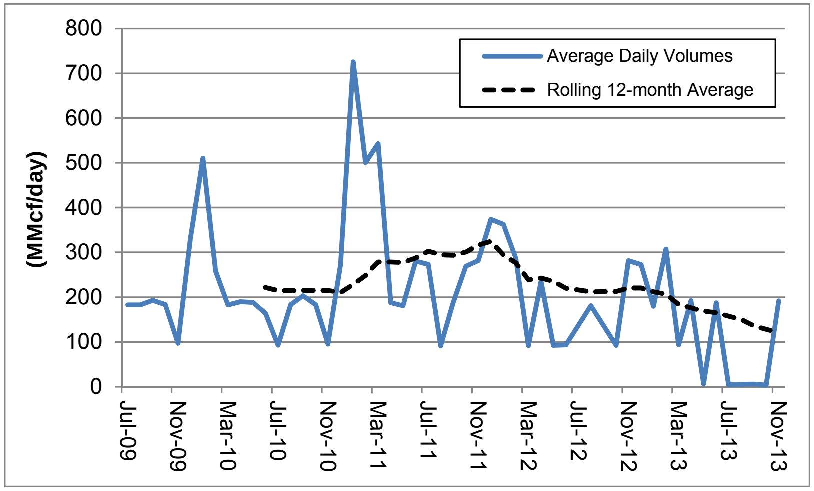
❖ <u>Massachusetts LNG facilities</u>:

- Imports into DOMAC's Everett LNG terminal declined from an average of approximately 400 MMcf/day over the 2008 to 2011 time period to an average of less than 200 MMcf/day in 2013
- The Northeast Gateway terminal has not received any LNG cargoes since March 2010, while the Neptune LNG Deepwater Port has received only four shipments since it came online in February 2010, with no shipments in 2011, 2012 or 2013



❖ <u>Canaport LNG</u>:

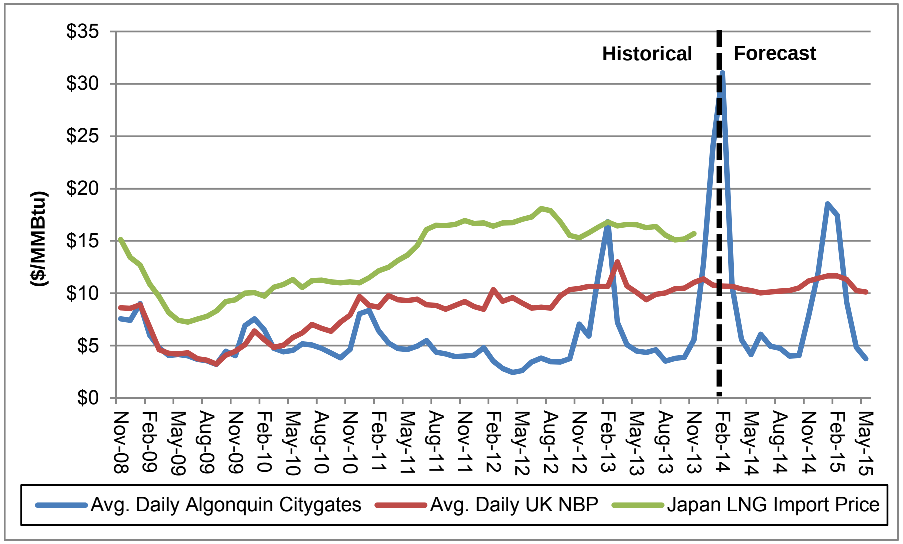
- Import volumes from the Canaport LNG facility, based on a twelve-month rolling average, peaked at approximately 300 MMcf/day in the 2011/2012 winter and have declined to below 200 MMcf/day since March 2013
- In terms of peak volume sendout, the Canaport LNG facility provided over 700 MMcf/day on an average day basis in January 2011 declining to a peak month average day volume sendout of 200 MMcf/day in November 2013



Sources: U.S. Department of Energy, LNG Monthly Reports; and National Energy Board, LNG Shipment Details, as of January 27, 2014

3. Natural Gas Supply Drivers: LNG Market Signals

- New England natural gas prices have historically traded at a premium to other North American locations
- However, New England natural gas prices (as represented by the Algonquin Citygates natural gas price index) usually trade at a discount to the United Kingdom natural gas prices (i.e., National Balancing Point ("UK NBP")) and Asian LNG prices, which has reduced the number of LNG deliveries to the region



According to the FERC: "…LNG is likely to remain in short supply this winter with price spikes in New England not sustained long enough to incentivize LNG cargos. GDF Suez, the owner of the Everett LNG plant in Massachusetts, is under contract to divert almost half of its supplies to higher priced areas elsewhere in the world…Repsol, the owner of Canaport LNG, does not anticipate receiving many cargos this winter or going forward. As of mid-2013, Repsol is under contract to receive about two shipments of LNG a year, just enough to keep the terminal operating."

Sources: Historical prices through January 29, 2014 from SNL Financial and Bloomberg Professional; forward settlement prices as of January 28, 2014 from Bloomberg Professional; and FERC, Winter 2013-14 Energy Market Assessment Report to the Commission, October 17, 2013

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3. Natural Gas Supply Drivers: TransCanada PipeLines Limited

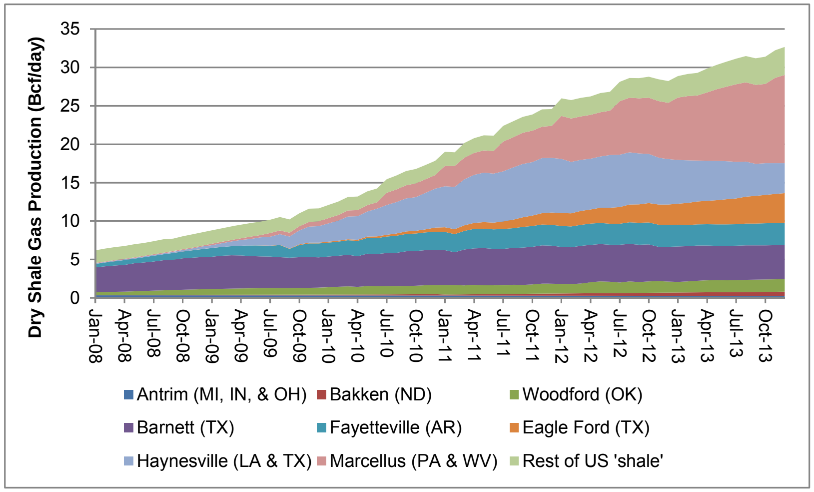
- In December 2013, TCPL filed with the NEB its Mainline Settlement Agreement with the eastern Canadian LDCs (i.e., Union Gas Ltd., Gaz Metro Limited Partnership and Enbridge Gas Distribution) in connection with access to Dawn and Niagara supplies and long-term tolls
  - According to the TCPL application: "The Settlement builds upon the RH-003-2011 Decision and resolves various regulatory and judicial proceedings that arose since the Board's decision in the RH-003-2011 proceeding and addresses the requirement that TransCanada file a tolls application in the event that one of the off-ramps is reached before the end of the period of fixed tolls established by the Decision."
  - The Mainline Settlement Agreement must be approved by the NEB before being placed into effect in January 2015
  - Over 20 intervening parties have submitted comments in response to the TCPL application
- From November 29, 2013 to January 15, 2014, TCPL conducted a binding open season for capacity on the TCPL Mainline. The binding open season is premised on NEB approval of the Mainline Settlement Agreement

Sources: TransCanada Pipelines Limited, Application for Approval of Mainline 2013-2013 Settlement, December 2013; and company website

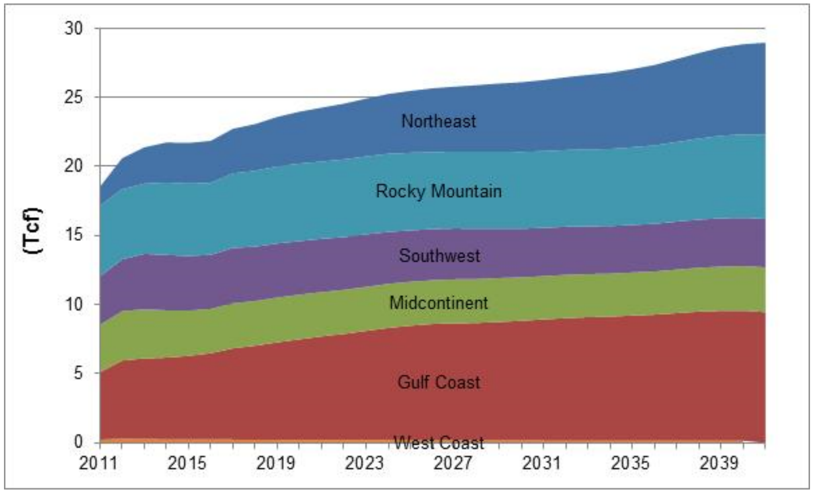
3. Natural Gas Supply Drivers: Marcellus Shale Production

- Dry shale gas production from the Marcellus Shale basin has significantly increased from less than 0.5 Bcf/day in August 2009 to approximately 11.5 Bcf/day in December 2013
- The U.S. Energy Information Administration ("EIA") is forecasting natural gas production from the Northeast U.S. will increase from less than 4.0 Tcf in 2013 to approximately 5.3 Tcf in 2020, and over 8.0 Tcf in 2040
- The increase in Marcellus Shale production coupled with the EIA's projection of continued development of this natural gas shale play results in the Marcellus Shale becoming a critical natural gas supply source for the New England region

Dry Shale Gas Production (2008 – 2013)



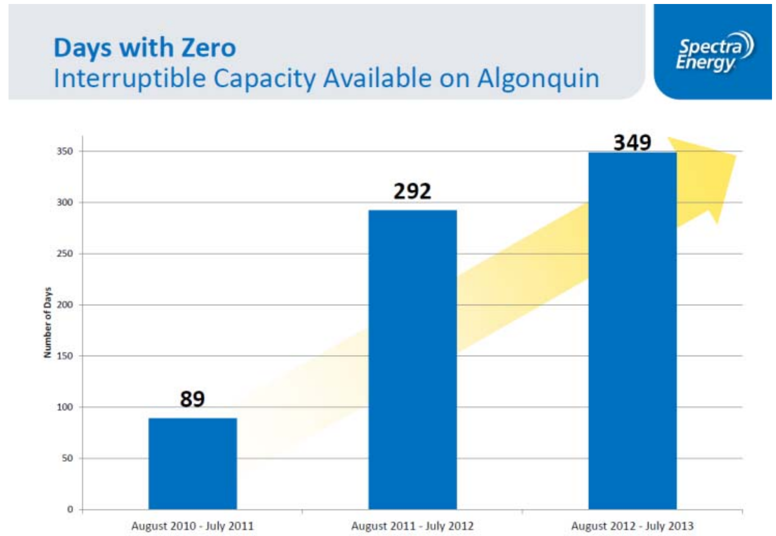
Forecasted Natural Gas Production (2011 – 2040)



Sources: U.S. Energy Information Administration, Natural Gas Weekly Update for week ending January 22, 2014; and U.S. Energy Information Administration, Annual Energy Outlook 2014 with projections to 2040, Lower 48 Natural Gas Production and Supply Prices by Supply Region, December 16, 2013

3. Natural Gas Supply Drivers: Capacity Constraints

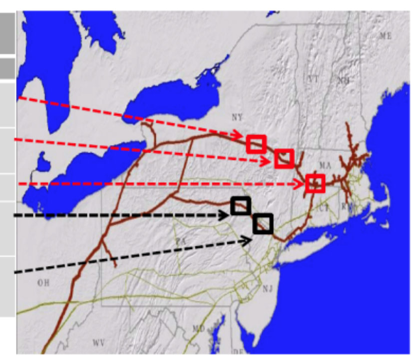
- Both AGT and TGP are fully subscribed (into New England) and have experienced significant interruptible or non-firm capacity constraints due to increased utilization associated with Marcellus Shale supply
- In a recent presentation, AGT reported an increasing number of days with no interruptible capacity available on its pipeline
- TGP also has experienced high utilization in the Northeast U.S. during both the winter and summer periods
  - Most recently, TGP experienced interruptible transportation restrictions at Compressor Station 245 in New York 94% of the days in the 2012 summer and 100% of the days in the 2012/2013 winter



Tennessee Gas Pipeline Company, L.L.C.
a Kinder Morgan company

Increased Restrictions of Interruptible Services: Winter

Locations	Percent Days Restricted (Nov- Mar)		
	10 / 11	11 / 12	12 / 13
Station 245	96 %	99 %	100 %
Station 254*	0 %	0 %	65 %
Station 261*	0 %	0 %	80 %
Station 321	48 %	9 %	65 %
Station 325	87 %	7 %	0 %



* Constraints into New England due to: 1) decline of Atlantic Canada supplies and LNG Imports, 2) increased demand, and 3) no new infrastructure to bring supplies to New England.

"Typical" New England Market Volume Restricted: ~ 700,000 Dth/d

4

Sources: Spectra Energy, 2013 Pre-Winter Operations Meeting, November 5, 2013; and Tennessee Gas Pipeline Co, LLC, Presentation to New England Gas-Electric Focus Group, October 18, 2013

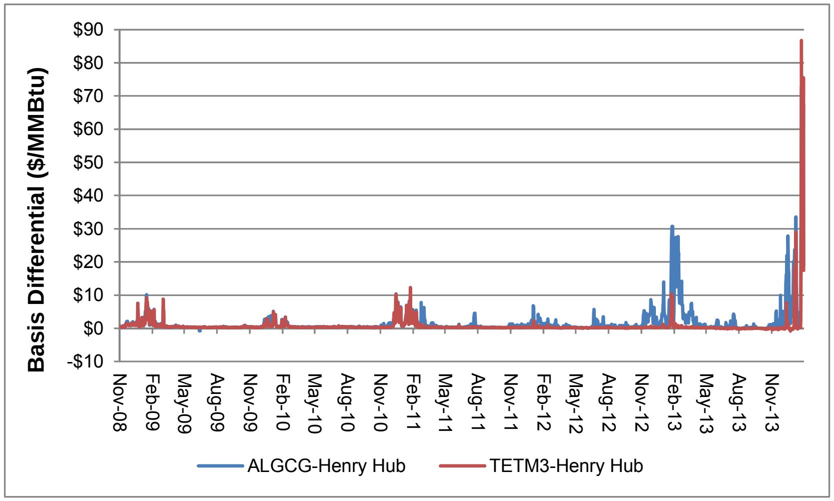
3. Natural Gas Price and Basis Analysis

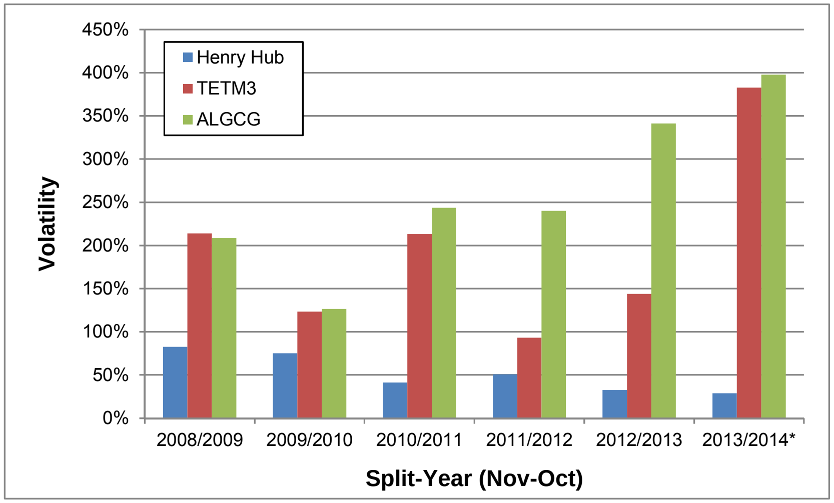
- To provide context for the evaluation of the costs and benefits associated with incremental pipeline capacity into the New England region, the regional natural gas prices and basis differentials were analyzed over the past five split-years (i.e., 2008/2009 to 2012/2013)
- The following pricing points were reviewed:
  - Algonquin Citygates ("ALGCG"): Delivery points in Connecticut, Massachusetts and Rhode Island off of Algonquin Gas Transmission
    - The ALGCG price index was utilized as a proxy for the New England region price. Other New England region price indices include Tennessee at Dracut and Tennessee Zone 6
  - Tetco M-3 ("TETM3"): Market Area 3 zone of Texas Eastern Pipeline, which runs from Westmoreland County, Pa., to Morris County, N.J.
  - Henry Hub: In Vermilion Parish in South Louisiana, the Hub has 14 interconnecting pipelines. Pipelines include Trunkline Gas, Transcontinental Gas Pipeline ("Transco"), Columbia Gulf Transmission, Texas Gas Transmission, Sabine Pipe Line, Natural Gas Pipeline Co., Southern Natural Gas and Gulf South Pipeline

Note: All historical natural gas pricing data and definitions are sourced from SNL Financial

3. Natural Gas Price and Basis Analysis (cont.)

- Mid-Atlantic natural gas prices, as represented by the TETM3 natural gas price index, have historically been priced at a premium to the Henry Hub price index
- Natural gas prices in New England, as represented by the ALGCG natural gas price index, have been at an additional premium to the Mid-Atlantic natural gas prices
- The ALGCG natural gas price index has exhibited significantly more daily volatility than the Henry Hub natural gas price index, with ALGCG prices during this current winter (i.e., winter 2013/2014) exceeding $77.00/MMBtu



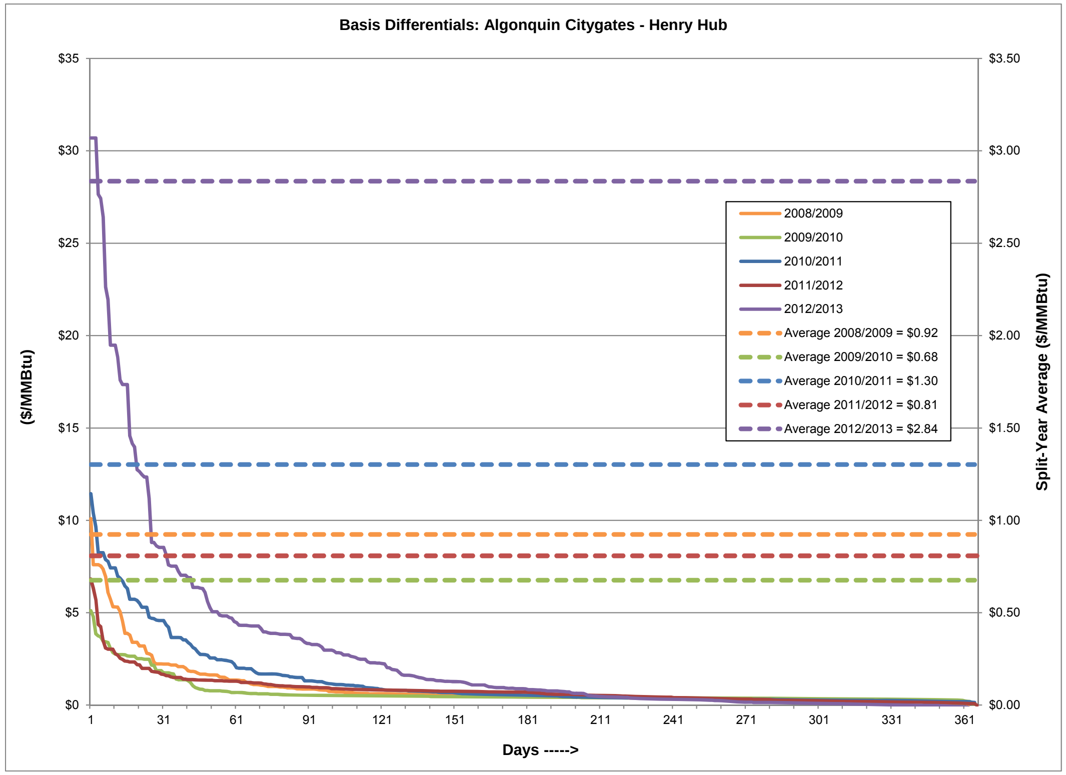


* 2013/2014 data through January 29, 2014

Note: Natural gas price volatility was calculated for each split-year by "multiplying the standard deviation of the daily logarithmic price changes, Δp, for all trading days within a certain time period by the square root of he number of trading days within the time period." See, U.S. Energy Information Administration, An Analysis of Price Volatility in Natural Gas Markets, August 2007.
Source: Historical prices through January 29, 2014 from SNL Financial

3. Natural Gas Price and Basis Analysis (cont.)

- The numbers of days in which the daily New England natural gas price premium to Henry Hub is greater than $2.00/MMBtu, or even as high as $5.00/MMBtu, has increased significantly over the past few years
- The New England natural gas price premium to Henry Hub rarely exceeded $10.00/MMBtu over the 2008/2009 to 2011/2012 time period; however, it exceeded that price level on 25 days in 2012/2013 and has already exceeded that price level on 28 days of the current 2013/2014 split-year



ALGCG-Henry Hub Basis Differential ($/MMBtu)		Number of Days					
		2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014*
Greater than or equal to	$10.00	1	0	2	0	25	28
Greater than or equal to	$5.00	13	1	24	3	53	38
Greater than or equal to	$2.00	40	27	61	21	124	56
Greater than or equal to	$1.00	78	43	113	85	164	64
Greater than or equal to	$0.50	154	118	191	218	207	79
Greater than or equal to	$0.25	339	360	323	295	257	85
Greater than	$0.00	362	365	365	365	334	86
Less than or equal to	$0.00	3	0	0	0	31	4

* 2013/2014 data through January 29, 2014

Sources: Historical prices through January 29, 2014 from SNL Financial

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3. Natural Gas Price and Basis Analysis (cont.)

- The 2012/2013 winter price differential between the New England and Gulf of Mexico pricing indices averaged over $6.00/MMBtu, which is the highest level observed over the five-year historical period from 2008/2009 to 2012/2013
- The current 2013/2014 ALGCG to Henry Hub basis averaged $9.86/MMBtu, which is nearly four times higher than the five-year historical average of $2.50/MMBtu
- New England forward prices are expected to continue to be at a premium to Henry Hub and Mid-Atlantic natural gas prices
- The high natural gas premium (i.e., basis differential) between the New England and Mid-Atlantic markets reflects the existing pipeline constraint between the Mid-Atlantic market, which has significant access to natural gas production from Marcellus Shale, and the New England market

Split-Year (Nov-Oct)	Winter (Nov-Mar)			Summer (Apr-Oct)			Annual (Nov-Oct)		
	TETM3-Henry Hub	ALGCG-Henry Hub	ALGCG-TETM3	TETM3-Henry Hub	ALGCG-Henry Hub	ALGCG-TETM3	TETM3-Henry Hub	ALGCG-Henry Hub	ALGCG-TETM3
2008/2009	1.51	1.70	0.19	0.34	0.37	0.04	0.82	0.92	0.10
2009/2010	0.79	1.06	0.27	0.34	0.40	0.07	0.52	0.68	0.15
2010/2011	1.88	2.47	0.59	0.26	0.48	0.21	0.93	1.30	0.37
2011/2012	0.28	1.09	0.81	0.17	0.61	0.44	0.22	0.81	0.59
2012/2013	0.67	6.17	5.50	0.03	0.48	0.45	0.29	2.84	2.54
2013/2014 [1]	5.29	9.86	4.56	n/a	n/a	n/a	n/a	n/a	n/a
Historical Average (2008/09-2012/13)	**1.02**	**2.50**	**1.47**	**0.23**	**0.47**	**0.24**	**0.56**	**1.31**	**0.75**
2013/2014 [2]	5.16	12.34	7.17	(0.70)	0.46	1.16	1.74	5.41	3.67
2014/2015	1.42	8.50	7.08	(0.91)	0.25	1.16	0.06	3.69	3.63
2015/2016	1.20	7.95	6.75	(0.92)	0.14	1.05	(0.08)	3.29	3.37
Forward Average (2013/14-2015/16) [2]	**2.59**	**9.59**	**7.00**	**(0.84)**	**0.28**	**1.12**	**(0.57)**	**4.13**	**3.55**

[1] Historical split-year 2013/2014 includes data through January 29, 2014
[2] Winter 2013/2014 based on historical monthly averages for November 2013-January 2014, and forward settlement prices for February-March 2014

Sources: Historical prices through January 29, 2014 from SNL Financial; and forward settlement prices as of January 28, 2014 from Bloomberg Professional

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Contents

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4. Northeast Pipeline Infrastructure Activity

- There have been significant natural gas pipeline expansions in the Northeast U.S. associated with the development of the Marcellus Shale and Utica Shale natural gas plays
- In 2013, approximately 3.2 Bcf/day of natural gas pipeline expansion projects in the Northeast U.S. have come on-line

Status	Capacity	Estimated CapEx
On-Line (since 2010)	Approx. 8.6 Bcf/day	$5.8 billion
Under Construction	Approx. 0.5 Bcf/day	$0.5 billion
Under Regulatory Review	Approx. 5.2 Bcf/day	$3.9 billion
Announced	Approx. 8.0 Bcf/day	$4.5 billion [1]

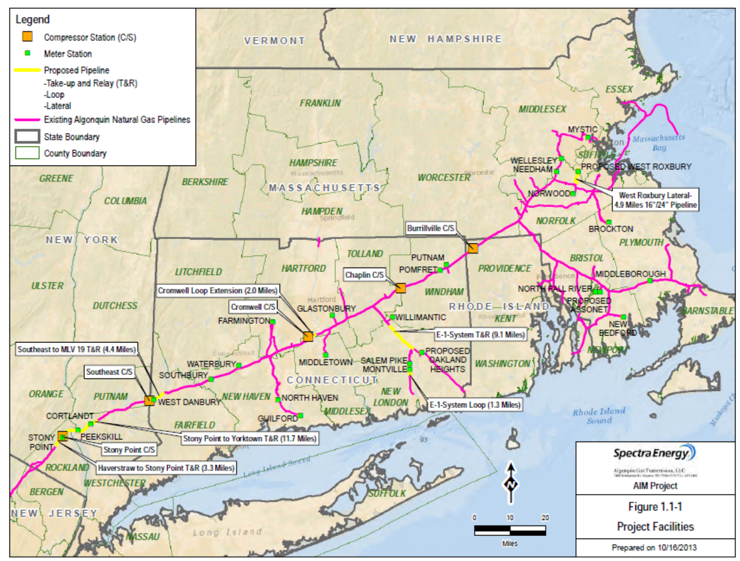
[1] Note: Estimates for capital expenditures ("CapEx") were not available for certain of the projects; therefore, the CapEx estimates reflect the data that is available

- Several key projects are targeted to alleviate the current capacity constraints into New England, or will have a direct impact on the New England and Atlantic Canada regions:
  - Spectra Energy – AIM Project
  - Spectra Energy and M&NP – Atlantic Bridge
  - Kinder Morgan – Northeast Expansion
  - TCPL – Mainline System Open Season / PNGTS – C2C Expansion Project

Source: Based on Sussex review and analysis of public documents

4. Spectra Energy – AIM Project

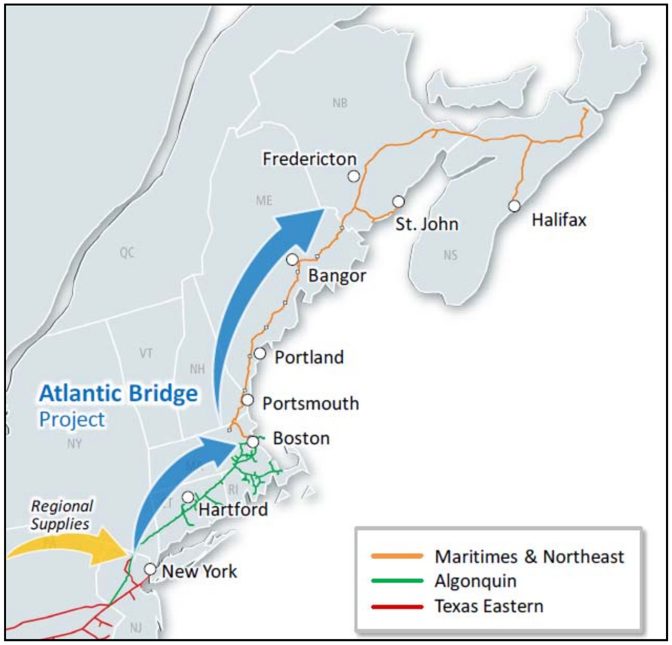
- Owner: Spectra Energy / Algonquin Gas Transmission
- Proposed Facilities:
  - Approximately 36.7 miles of take-up and relay, loop and lateral pipeline facilities, modifications to five compressor stations, modifications to 24 existing M&R stations, and construction of three new M&R stations
  - Receipt points: Millennium at Ramapo, NY and TGP at Mahwah, NJ
  - Delivery points: Multiple delivery points
- Shippers: 10 LDCs in CT, MA and RI (i.e., Yankee Gas, NSTAR Gas, Connecticut Natural Gas, Southern Connecticut Gas, The Narragansett Electric Company, Colonial Gas, Boston Gas, Columbia Gas of Massachusetts, Norwich Public Utilities and Middleborough Gas & Electric)
- Capacity: 342,000 Dth/day
- Estimated CapEx: $1 billion
- Anticipated In-Service Date: November 2016
- Regulatory Status:
  - Prefiled with FERC: June 2013
  - CT PURA pre-approved CT LDC PAs on Nov. 22, 2013
  - Massachusetts DPU approved MA LDC PAs on Jan. 31, 2014
  - File major permit applications: Q1/2014
  - Receive FERC certificate: Q1/2015
  - Begin construction:Q2/2015



Source: Based on Sussex review and analysis of public documents

4. Spectra Energy and M&NP – Atlantic Bridge

- Owners: Spectra Energy / Algonquin Gas Transmission and Maritimes & Northeast Pipeline
- Proposed Facilities:
  - Receipt points: Millennium at Ramapo, NY and Texas Eastern at Lambertville, NJ
  - Delivery points: Existing and new delivery points on AGT and M&NP
- Shippers:
  - Anchor shipper – Unitil Corporation
  - Other shippers – TBD (reliant on open season)
- Capacity: 100,000 – 600,000 Dth/day (Scalable)
- Estimated CapEx: TBD
- Anticipated In-Service Date: November 2017
- Regulatory Status:
  - Open season from February 5, 2014 to March 31, 2014
- Target Markets:
  - New England and Atlantic Canada



Source: Based on Sussex review and analysis of public documents

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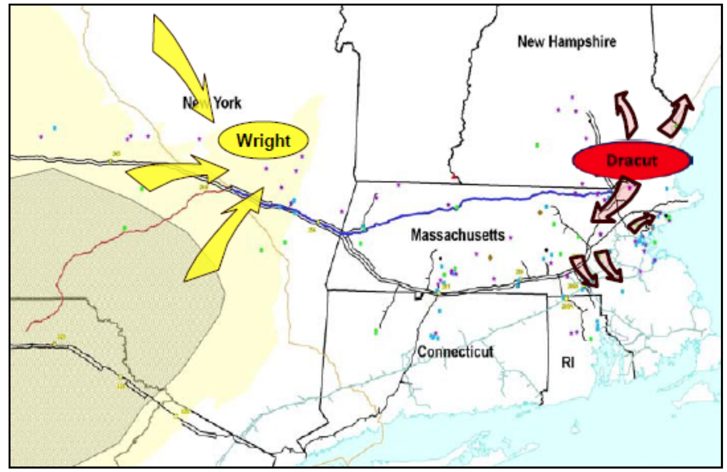
4. Kinder Morgan – Northeast Expansion



- Owner: Kinder Morgan / Tennessee Gas Pipeline
- Proposed Facilities:
  - Approx. 179 miles of pipeline, laterals as necessary, additional meter stations, and modifications to existing facilities
  - Receipt point: IGT and Constitution at Wright, NY
  - Delivery point: M&NP at Dracut, MA
- Capacity: 600,000 – 2,200,000 Dth/day
- Estimated CapEx: $1.75 - $2.75 billion
- Estimated Rates: Negotiated rates
- Anticipated In-Service Date: November 2018
- Regulatory Status:
  - Non-binding open season from February 13, 2014 to March 28, 2014
  - File major permit applications: Q3/2014
  - Begin construction: Q2/2017
- Upstream/Downstream Issues: Constitution Pipeline will provide a source of gas supply at Wright, NY
  - Shippers: Cabot Oil & Gas and Southwestern Energy Services Company
  - FERC final environmental assessment to be issued by mid-June 2014
  - Anticipated In-Service Date: March 2015

Source: Based on Sussex review and analysis of public documents

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4. TCPL – Mainline System Open Season

- Owner: TransCanada PipeLines Limited
- Proposed Facilities:
  - Receipt points: Empress, St. Clair, Dawn, Kirkwall, Niagara Falls, Chippawa, Parkway and Iroquois
  - Delivery point: Any delivery point on system
- Estimated Rates: Service is offered under the following toll schedules (15 year term):
  - Through December 31, 2014 – Current tolls will remain in effect (“RH-003-2011 Compliance Tolls”)
  - January 1, 2015 to December 31, 2020 – Tolls to be fixed, one time reset, and bridging contribution charge
  - January 1, 2021 to December 31, 2030 – Cost of service for TCPL segments utilized
- Anticipated In-Service Date: November 2016
- Regulatory Status:
  - Binding open season from November 29, 2013 to January 15, 2014
  - Open Season is premised on NEB approval of the Mainline Settlement Agreement dated October 31, 2013, as amended on November 15, 2013 and December 13, 2013 among Union Gas Limited, Enbridge Gas Distribution Inc., Gaz Metro Limited Partnership and TCPL, and implementation by TCPL of tariff changes, including TCPL’s Transportation Access Procedures, necessary to give effect to the Mainline Settlement Agreement as approved

Source: Based on Sussex review and analysis of public documents

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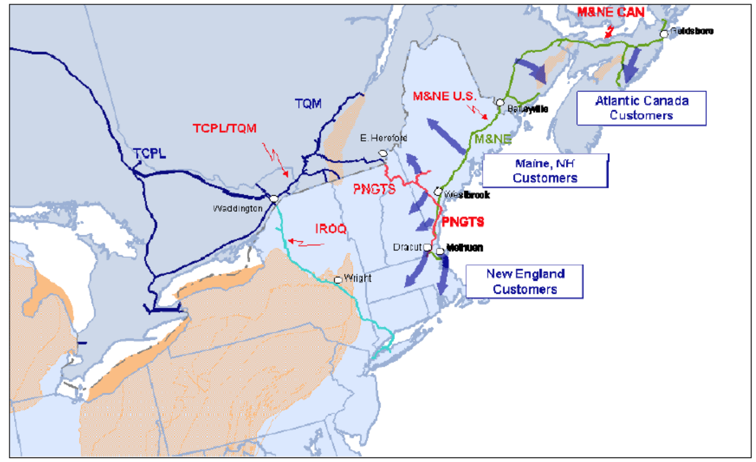
4. PNGTS – C2C Expansion Project

- Owner: Portland Natural Gas Transmission System
- Proposed Facilities:
  - Receipt point: Pittsburg, NH
  - Delivery point: Westbrook, ME
  - No incremental capacity to Dracut, MA
- Capacity: 120,000 – 150,000 Dth/day
- Estimated Rates: $0.60/Dth
- Anticipated In-Service Date: November 2016
- Regulatory Status:
  - Binding open season from December 3, 2013 to January 24, 2014
- Upstream/Downstream Issues:
  - Bidders will be responsible for making their own upstream arrangements either directly with TCPL/TQM, or through contractual arrangements with other upstream shippers to East Hereford (Pittsburg)
- Minimum term of 15 years



Source: Based on Sussex review and analysis of public documents

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Contents

5. Cost / Benefit Analysis: Overview

- Sussex reviewed the benefit of new pipeline capacity into New England relative to the associated cost of such capacity
- Incremental pipeline capacity into the New England region would place downward pressure on the regional natural gas price indices and, therefore, benefit customers who use those price signals in transactions
- Given that the power generation segment is most likely the largest consumer of natural gas purchased at the New England natural gas price index, this segment was the focus of the analysis
- Based on the historical relationship between natural gas prices and electricity LMPs in ISO-NE, Sussex calculated the potential reduction in LMPs as a result of a reduction in wholesale natural gas prices to estimate the potential energy cost savings to electricity customers using actual data for the 2012/2013 split-year
- The benefit (i.e., reduced natural gas costs) associated with any incremental pipeline expansion was compared to various cost estimates (i.e., cost of pipeline capacity)

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5. Benefits Estimation: Overview

- The first step in the analysis (i.e., the benefits of incremental pipeline capacity into the New England region) consisted of:
  - Natural Gas Basis / Capacity Utilization Analysis: An estimate of the potential reduction in the New England natural gas basis differentials should new infrastructure be developed
  - Reduction in Natural Gas Prices: The assumed New England natural gas basis reduction was used to estimate the reduction in the New England wholesale price of natural gas
  - Reduction in LMPs: The resulting estimated New England natural gas wholesale price reduction would likely result in lower LMPs in the ISO-NE power market, which would benefit electricity customers in the region, including customers in Maine
    - Since natural gas-fired generation is setting the ISO-NE LMPs for the majority of the hours, this reduction in LMPs would provide a benefit to electricity customers
    - Please note, the hours when natural gas fueled generation set the LMP was based on information available from ISO-NE and certain dispatch order assumptions

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5. Benefits Estimation: Natural Gas Basis / Capacity Utilization Analysis

- In order to estimate the potential reduction in the New England natural gas basis differentials as a result of incremental pipeline capacity into the region, Sussex analyzed the historical daily New England natural gas basis differentials and pipeline capacity utilization from January 1, 2011 to December 17, 2013, specifically:
  - Sussex calculated the historical daily natural gas basis differentials between the New England natural gas price index, as represented by ALGCG, and Henry Hub
    - Analysis excluded weekends, holidays, and days when the ALGCG to Henry Hub basis differential was zero or negative
  - For each analysis day, Sussex reviewed the pipeline flows on AGT and estimated the AGT west-to-east flows (i.e., AGT West-end Utilization)
  - Please note, the analysis of AGT capacity utilization is assumed to be a proxy for the current New England pipeline capacity utilization from the South and West (i.e., AGT and TGP)

Note: All natural gas pricing and pipeline flows data from SNL Financial

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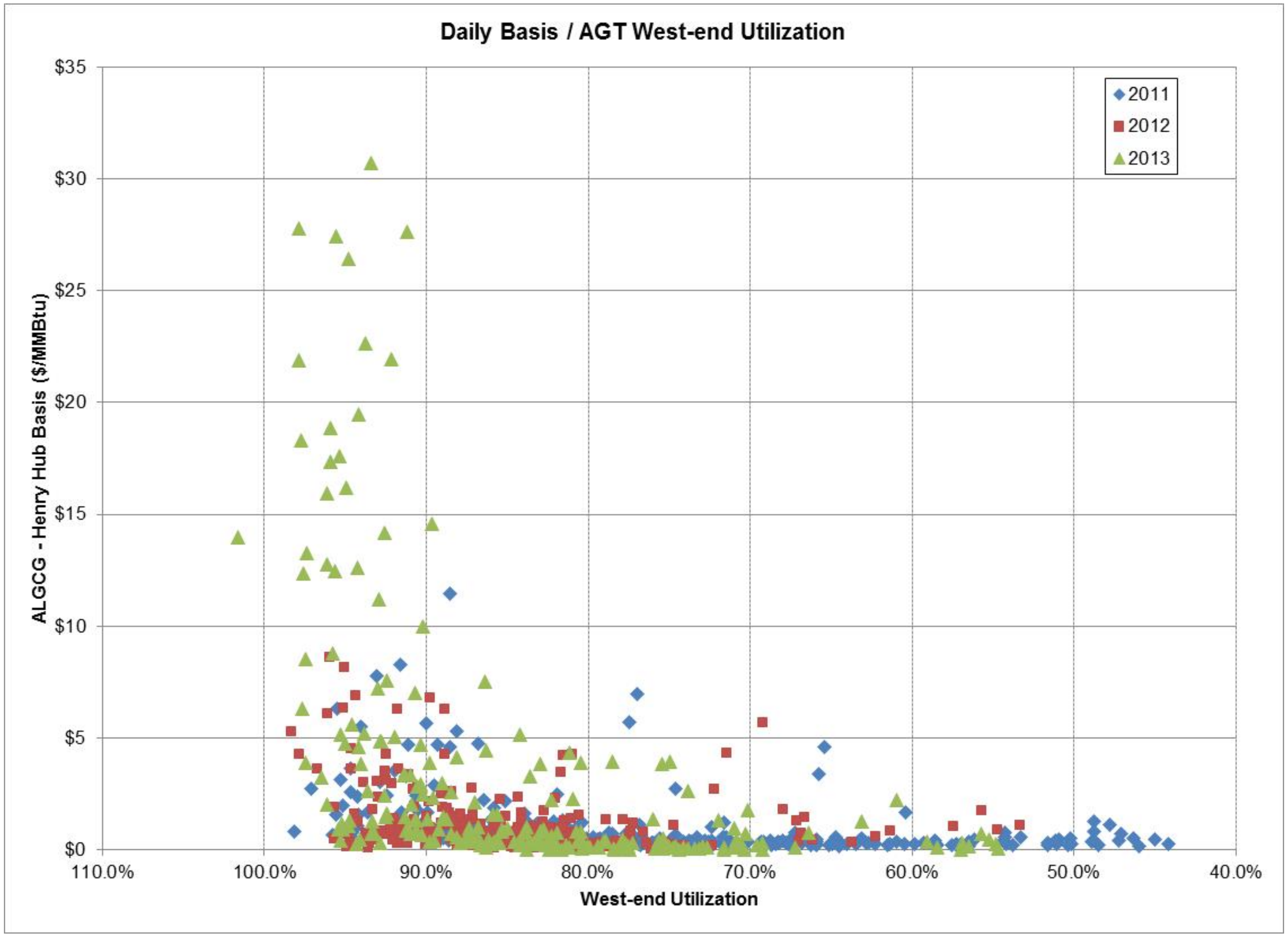
5. Benefits Estimation: Natural Gas Basis / Capacity Utilization Analysis (cont.)

- As the AGT West-end Utilization reaches 80% or higher, the chances of significant basis premiums greatly increases



Source: Historical prices through December 17, 2013 from SNL Financial

5. Benefits Estimation: Natural Gas Basis / Capacity Utilization Analysis (cont.)

ALGCG-Henry Hub ($/MMBtu) Basis Differential (January 1, 2011 – December 17, 2013)

AGT West-end Utilization	# of Obs.	Avg.	Median	Min.	Max.	Std. Dev.
Greater than or equal to 95%	41	8.25	6.09	0.41	27.81	7.37
Between 90% and 95%	125	3.77	1.76	0.09	30.70	5.54
Between 85% and 90%	141	1.46	0.80	0.12	14.57	1.98
Between 80% and 85%	155	0.81	0.54	0.00	5.13	0.91
Between 75% and 80%	80	0.62	0.33	0.00	6.97	1.11
Between 70% and 75%	61	0.62	0.30	0.00	4.36	0.89
Between 65% and 70%	42	0.73	0.34	0.02	5.69	1.14
Between 60% and 65%	25	0.52	0.33	0.15	2.25	0.49

- At a utilization greater than or equal to 95%, the average basis differential between ALGCG and Henry Hub is approximately $8.25, which is more than double the basis differential from the 90% to 95% utilization segment of $3.77
- The standard deviation at the utilization segments greater than 90% indicates a high degree of volatility
- The average basis differential approximately doubles as utilization increases through the highest three utilization segments

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5. Benefits Estimation: Reduction in Natural Gas Prices

- To estimate the effect of incremental pipeline capacity on New England wholesale natural gas prices, Sussex reviewed a range of basis differential reductions based on the results of the Natural Gas Basis / Capacity Utilization Analysis discussed above, as well as a review of the following case studies:
  - Forward natural gas basis differentials for the New England region
  - Forward natural gas basis differentials for the New York City region

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5. Benefits Estimation: ALGCG Forward Prices

- The Spectra Energy AIM and TGP Connecticut Expansion projects are expected to come on-line on November 1, 2016
  - Provides incremental capacity of 342,000 Dth/day (Spectra Energy) and 72,100 Dth/day (TGP) to serve the New England LDCs
  - Spectra AIM Shippers: 10 LDCs in MA, RI and CT (i.e., NSTAR Gas, Colonial Gas, Boston Gas, Columbia Gas of Massachusetts, Middleborough Gas & Electric, The Narragansett Electric Company, Norwich Public Utilities, Yankee Gas, Connecticut Natural Gas, and Southern Connecticut Gas); and TGP Connecticut Expansion shippers: Connecticut Natural Gas and Yankee Gas
  - Since the capacity associated with the Spectra Energy AIM and TGP Connecticut Expansion projects are supported by natural gas utilities (i.e., LDC forecasted growth will require the AIM and Connecticut Expansion capacity), the availability of the AIM and Connecticut Expansion capacity for use by other market segments (e.g., power generation) will likely decrease over time
- As shown in the table below, the ALGCG to Henry Hub forward basis for 2016/2017 is approximately 30% to 32% lower than the forward basis for 2014/2015. While there may be several market and commercial issues associated with this reduction in forward prices, the expected incremental capacity associated with the Spectra Energy AIM and TGP Connecticut Expansion projects in 2016/2017 are likely key contributors to this basis reduction

Split-Year (Nov-Oct)	Forward ALGCG-Henry Hub Basis ($/MMBtu)			
	November	December	January	November to January
2014/2015	3.68	8.16	12.06	7.97
2015/2016	3.44	7.52	11.34	7.43
2016/2017	2.55	5.52	8.19	5.42
Percent Change 2014/2015 to 2016/2017	**(30.7%)**	**(32.4%)**	**(32.1%)**	**(32.0%)**

Source: Forward settlement prices as of January 2, 2014 from Bloomberg Professional

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5. Benefits Estimation: NYC Case Study

- The Spectra Energy NJ-NY Expansion and Transco Northeast Supply Link[1] projects were placed in service on November 1, 2013:
  - Provided incremental capacity of 800,000 Dth/day (Spectra Energy) and 250,000 Dth/day (Transco) to serve the New Jersey and New York City metropolitan areas
- As shown in the table below, which reflects the market expectations before this winter, the Transco Zone 6 New York ("TRZ6NY") to Henry Hub forward winter 2013/2014 basis of $0.68/MMBtu is an approximately 64% reduction from the historical winter 2008/2009 to 2012/2013 average of $1.88/MMBtu and a 78% reduction from the 2012/2013 winter basis of $3.04/MMBtu
- While there may be several market and commercial issues associated with this reduction in forward prices, the incremental pipeline capacity associated with the Spectra Energy NJ-NY Expansion and Transco Northeast Supply Link projects were likely key contributors to this price reduction

Split-Year (Nov-Oct)	TRZ6NY-Henry Hub Basis ($/MMBtu)		
	Winter (Nov-Mar)	Summer (Apr-Oct)	Annual (Nov-Oct)
2008/2009	1.81	0.38	0.97
2009/2010	1.22	0.35	0.71
2010/2011	2.75	0.49	1.43
2011/2012	0.59	0.19	0.36
2012/2013	3.04	0.20	1.37
Historical Average (2008/2009-2012/2013)	**1.88**	**0.32**	**0.97**
2013/2014	0.68	(0.52)	(0.02)
2014/2015	0.42	(0.53)	(0.13)
2015/2016	0.39	(0.45)	(0.10)
Forward Average (2013/2014-2015/2016)	**0.50**	**(0.50)**	**(0.09)**

Note: [1] Half of the Transco Northeast Supply Link capacity was placed in service in August 2013, with the remainder placed in service on November 1, 2013
Source: Historical prices from SNL Financial; and forward settlement prices as of October 31, 2013 from Bloomberg Professional

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5. Benefits Estimation: Maine Energy Costs

- Since the benefit analysis is based on actual data for 2012/2013, a comparison to the previous two years was developed to provide context. Energy costs in Maine were approximately 15.6% higher in 2012/2013 relative to 2010/2011 and 56.8% higher than 2011/2012. Winter (i.e., Nov-Mar) energy costs in Maine represented over 50% of total annual energy costs in 2010/2011 and 2012/2013

	Energy Costs – Maine			Difference between Years	
Month	**2010/2011**	**2011/2012**	**2012/2013**	**2012/13 – 2010/11**	**2012/13 – 2011/12**
November	$40,609,614	$31,878,374	$50,829,241	$10,219,626	$18,950,867
December	$66,302,025	$34,717,061	$46,639,723	$(19,662,301)	$11,922,663
January	$77,371,637	$41,052,686	$89,985,239	$12,613,603	$48,932,553
February	$51,272,664	$27,651,593	$109,298,930	$58,026,266	$81,647,337
March	$44,311,891	$25,866,951	$49,261,297	$4,949,407	$23,394,347
April	$37,615,878	$22,507,599	$41,167,547	$3,551,669	$18,659,948
May	$37,463,657	$24,766,656	$36,080,804	$(1,382,853)	$11,314,147
June	$38,410,421	$32,416,880	$33,078,194	$(5,332,227)	$661,314
July	$58,901,699	$44,421,662	$55,987,099	$(2,914,600)	$11,565,437
August	$43,461,972	$42,047,943	$35,004,816	$(8,457,157)	$(7,043,128)
September	$36,222,451	$31,307,683	$33,025,659	$(3,196,792)	$1,717,976
October	$38,474,402	$31,973,143	$32,291,424	$(6,182,979)	$318,281
Total Split-Year	$570,418,311	$390,608,231	$612,649,973	$42,231,662	$222,041,741
Nov – Mar	$279,867,830	$161,166,664	$346,014,431	$66,146,600	$184,847,766
Dec – Feb	$194,946,325	$103,421,340	$245,923,892	$50,977,568	$142,502,553

Difference between Normal Year HDD (in winter months) or CDD (in summer months) and Actual HDD and CDD

<(75%)	(50%) - (75%)	(25%) – (50%)	(10%) – (25%)	(10%) – 10%	10% - 25%	25% - 50%	50% - 75%	>75%

	Weather – Actuals		Difference from Normal Year		Energy Costs
Split-Year	**HDD**	**CDD**	**HDD**	**CDD**	**Maine**
2010/2011	5,593	981	-74	240	$570,418,311
2011/2012	4,524	880	-1,174	139	$390,608,231
2012/2013	5,448	896	-219	155	$612,649,973

Note: Normal Year = 30-Year Average from 1981-2010

Source: ISO New England, 2010-2013 SMD Hourly Data

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5. Benefits Estimation: ISO-NE Energy Costs

- Similar to the Maine market, a review of the last three years of ISO-NE energy costs was developed for context. Energy costs in ISO-NE were approximately 15.9% higher in 2012/2013 relative to 2010/2011 and 59.5% higher than 2011/2012. Winter (i.e., Nov-Mar) energy costs in ISO-NE represented approximately 50% of annual energy costs in 2010/2011 and 2012/2013

	Energy Costs – ISO-NE			Difference between Years	
Month	2010/2011	2011/2012	2012/2013	2012/13 – 2010/11	2012/13 – 2011/12
November	$447,642,370	$361,138,517	$566,747,947	$119,105,577	$205,609,430
December	$770,261,650	$395,102,819	$515,445,646	$(254,816,004)	$120,342,827
January	$852,384,171	$464,624,530	$1,037,786,716	$185,402,545	$573,162,186
February	$581,344,475	$312,778,190	$1,272,847,870	$691,503,395	$960,069,679
March	$492,623,849	$267,773,347	$567,605,026	$74,981,177	$299,831,679
April	$417,254,084	$243,522,969	$406,528,240	$(10,725,844)	$163,005,272
May	$428,755,135	$265,368,061	$406,414,752	$(22,340,383)	$141,046,691
June	$491,282,092	$421,659,561	$421,726,419	$(69,555,673)	$66,858
July	$771,946,293	$569,821,544	$773,114,488	$1,168,195	$203,292,944
August	$537,252,420	$515,217,693	$414,658,718	$(122,593,702)	$(100,558,976)
September	$441,427,969	$328,396,660	$441,204,360	$(223,609)	$112,807,701
October	$413,989,864	$348,054,634	$340,802,781	$(73,187,083)	$(7,251,853)
Total	$6,646,164,372	$4,493,458,526	$7,164,882,963	$518,718,591	$2,671,424,438
Nov – Mar	$3,144,256,515	$1,801,417,403	$3,960,433,205	$816,176,690	$2,159,015,802
Dec – Feb	$2,203,990,295	$1,172,505,539	$2,826,080,231	$622,089,936	$1,653,574,692

Difference between Normal Year HDD (in winter months) or CDD (in summer months) and Actual HDD and CDD

<(75%)	(50%) - (75%)	(25%) – (50%)	(10%) – (25%)	(10%) – 10%	10% - 25%	25% - 50%	50% - 75%	>75%

	Weather – Actuals		Difference from Normal Year		Energy Costs
Split-Year	HDD	CDD	HDD	CDD	ISO-NE
2010/2011	5,593	981	-74	240	$6,646,164,372
2011/2012	4,524	880	-1,174	139	$4,493,458,526
2012/2013	5,448	896	-219	155	$7,164,882,963

Note: Normal Year = 30-Year Average from 1981-2010

Source: ISO New England, 2010-2013 SMD Hourly Data

5. Benefits Estimation: Reduction in LMPs

- For the 2012/2013 split-year, Sussex estimated the potential pro forma benefits to electricity customers associated with a reduction in LMP for hours when natural gas-fired generation was the marginal fuel [1]
  - First, Sussex estimated the number of hours the LMP in New England was set by natural gas-fired generators using weekly marginal fuel type data from ISO-NE
    - Assumed marginal fuel type data for ISO-NE as a whole was representative of the marginal fuel for the individual zones (e.g., Maine)
    - Converted the reported weekly percentages by fuel type to number of hours in each week
    - Assumed ISO-NE followed a dispatch curve where oil-fired generation set the LMP for the hours in the week with the highest electricity demand, followed by natural gas-fired generation
    - Using this approach, Sussex assigned a marginal fuel type for each hour of each day in split-year 2012/2013

Note: [1] Please note that the analysis is based on historical data; results represent the pro forma effect reduction in basis differentials and LMPs
Source: ISO New England, Weekly Market Report Data for the Week Ending December 8, 2013

5. Benefits Estimation: Reduction in LMPs (cont.)

- Next, Sussex estimated the reduction in the New England wholesale price of natural gas (as represented by the ALGCG price index) associated with a reduction in the New England natural gas price premium (i.e., basis differential)
  - Based on the results of the Natural Gas Basis / Capacity Utilization Analysis, and a review of the ALGCG forward prices and NYC Case Study, Sussex analyzed a range of basis differential reductions from 25% to 75%
  - The daily natural gas price reduction was estimated based on the estimated New England basis reduction range of 25% to 75%. For example, if the New England basis differential was reduced by 50% from $2/MMBtu to $1/MMBtu, then the New England natural gas price (as represented by the ALGCG price index) would be reduced from $4/MMBtu (for example) to $3/MMBtu, which is equal to a natural gas price reduction of 25%
  - Based on the Natural Gas Basis / Capacity Utilization Analysis, Sussex assumed that a reduction in natural gas prices occurred only when AGT West-end Utilization was greater than 80% and the New England basis differential was greater than $0.25/MMBtu
    - At AGT West-end Utilization levels below 80% and basis differentials lower than $0.25/MMBtu, there was a minimal effect on the total energy cost savings
- Sussex assumed that the reduction in LMP would be equal to the calculated reduction in the New England natural gas wholesale price
- For each hour that natural gas was the marginal fuel, Sussex estimated the energy cost savings for that hour by multiplying the reduction in LMP by the hourly demand
- The annual energy cost savings to electricity customers was the sum of the energy cost savings over all hours that natural gas-fired generation was setting the marginal price of electricity for the split-year 2012/2013

Sources: SNL Financial; and ISO New England, 2012-2013 SMD Hourly Data

5. Benefits Estimation: Reduction in LMPs – Scenario Results

❖ Scenario Results Detail – Basis Reduction of 30% – Maine:

							Reduction in Natural Gas Price Premium			
Month	% of Hours Oil is on Margin	% of Hours Gas is on Margin	% of Hours Other Fuels are on Margin	Total Monthly Demand in Maine (MW)	Average Maine LMP ($/MWh)	Total Maine Costs ($)	Average Reduction in LMP (%)	Average Reduction in Maine LMP ($/MWh)	Total Maine Costs after Reduction in LMP ($)	Energy Cost Savings for Maine Customers ($)
Nov-12	14%	58%	28%	917,815	$ 53.53	$ 50,829,241	-13%	$ (4.42)	$ 46,488,144	$ (4,341,097)
Dec-12	0%	65%	35%	992,020	$ 45.80	$ 46,639,723	-12%	$ (4.07)	$ 42,204,231	$ (4,435,492)
Jan-13	3%	61%	36%	1,028,165	$ 83.63	$ 89,985,239	-17%	$ (11.62)	$ 76,886,680	$ (13,098,559)
Feb-13	4%	54%	43%	907,240	$ 116.19	$ 109,298,930	-23%	$ (17.12)	$ 92,377,291	$ (16,921,639)
Mar-13	0%	59%	41%	944,908	$ 50.93	$ 49,261,297	-11%	$ (3.66)	$ 45,434,252	$ (3,827,046)
Apr-13	1%	71%	28%	893,327	$ 45.09	$ 41,167,547	-4%	$ (1.43)	$ 39,771,127	$ (1,396,420)
May-13	1%	72%	27%	898,030	$ 39.12	$ 36,080,804	-2%	$ (0.84)	$ 35,237,659	$ (843,145)
Jun-13	0%	63%	37%	916,942	$ 34.77	$ 33,078,194	0%	$ (0.04)	$ 33,027,506	$ (50,688)
Jul-13	2%	75%	22%	1,069,844	$ 48.87	$ 55,987,099	-4%	$ (1.99)	$ 53,565,653	$ (2,421,446)
Aug-13	0%	80%	20%	1,009,849	$ 33.32	$ 34,994,438	0%	$ (0.17)	$ 34,791,547	$ (202,890)
Sep-13	0%	80%	20%	905,220	$ 34.97	$ 33,025,659	0%	$ -	$ 33,025,659	$ -
Oct-13	0%	80%	20%	934,297	$ 33.53	$ 32,291,424	-2%	$ (0.51)	$ 31,772,719	$ (518,704)
2012/2013	2%	68%	30%	11,417,657	$ 51.64	$ 612,639,595	-7%	$ (3.82)	$ 564,582,468	$ (48,057,127)

❖ Scenario Results Detail – Basis Reduction of 30% – ISO-NE:

							Reduction in Natural Gas Price Premium			
Month	% of Hours Oil is on Margin	% of Hours Gas is on Margin	% of Hours Other Fuels are on Margin	Total Monthly Demand in ISO-NE (MW)	Average ISO-NE LMP ($/MWh)	Total ISO-NE Costs ($)	Average Reduction in LMP (%)	Average Reduction in ISO-NE LMP ($/MWh)	Total ISO-NE Costs after Reduction in LMP ($)	Energy Cost Savings for ISO-NE Customers ($)
Nov-12	14%	58%	28%	9,929,622	$ 55.04	$ 566,747,947	-13%	$ (4.51)	$ 518,449,198	$ (48,298,749)
Dec-12	0%	65%	35%	10,825,697	$ 46.30	$ 515,445,646	-12%	$ (4.11)	$ 466,115,746	$ (49,329,900)
Jan-13	3%	61%	36%	11,330,245	$ 86.53	$ 1,037,786,716	-17%	$ (12.10)	$ 885,214,820	$ (152,571,895)
Feb-13	4%	54%	43%	10,057,171	$ 122.31	$ 1,272,847,870	-23%	$ (18.00)	$ 1,074,539,871	$ (198,307,998)
Mar-13	0%	59%	41%	10,420,336	$ 53.09	$ 567,605,026	-11%	$ (3.81)	$ 523,150,231	$ (44,454,795)
Apr-13	1%	71%	28%	9,282,373	$ 42.89	$ 406,528,240	-4%	$ (1.36)	$ 392,373,467	$ (14,154,773)
May-13	1%	72%	27%	9,668,418	$ 40.31	$ 406,414,752	-2%	$ (0.88)	$ 395,975,425	$ (10,439,327)
Jun-13	0%	63%	37%	10,752,306	$ 37.09	$ 421,726,419	0%	$ (0.05)	$ 420,981,758	$ (744,660)
Jul-13	2%	75%	22%	13,420,675	$ 52.07	$ 773,114,488	-4%	$ (2.16)	$ 737,948,865	$ (35,165,623)
Aug-13	0%	80%	20%	11,367,359	$ 34.72	$ 414,655,828	0%	$ (0.18)	$ 412,166,301	$ (2,489,527)
Sep-13	0%	80%	20%	9,930,388	$ 40.43	$ 441,204,360	0%	$ -	$ 441,204,360	$ -
Oct-13	0%	80%	20%	9,709,008	$ 33.94	$ 340,802,781	-2%	$ (0.50)	$ 335,558,393	$ (5,244,388)
2012/2013	2%	68%	30%	126,693,598	$ 53.72	$ 7,164,880,073	-7%	$ (3.97)	$ 6,603,678,436	$ (561,201,637)

5. Benefits Estimation: Reduction in LMPs – Scenario Results (cont.)

❖ Scenario Results Detail – Basis Reduction of 50% – Maine:

Reduction in Natural Gas Price Premium

Month	% of Hours Oil is on Margin	% of Hours Gas is on Margin	% of Hours Other Fuels are on Margin	Total Monthly Demand in Maine (MW)	Average Maine LMP ($/MWh)	Total Maine Costs ($)	Average Reduction in LMP (%)	Average Reduction in Maine LMP ($/MWh)	Total Maine Costs after Reduction in LMP ($)	Energy Cost Savings for Maine Customers ($)
Nov-12	14%	58%	28%	917,815	$ 53.53	$ 50,829,241	-22%	$ (7.37)	$ 43,594,080	$ (7,235,161)
Dec-12	0%	65%	35%	992,020	$ 45.80	$ 46,639,723	-19%	$ (6.79)	$ 39,247,237	$ (7,392,487)
Jan-13	3%	61%	36%	1,028,165	$ 83.63	$ 89,985,239	-29%	$ (19.37)	$ 68,154,308	$ (21,830,932)
Feb-13	4%	54%	43%	907,240	$ 116.19	$ 109,298,930	-38%	$ (28.53)	$ 81,096,198	$ (28,202,731)
Mar-13	0%	59%	41%	944,908	$ 50.93	$ 49,261,297	-18%	$ (6.10)	$ 42,882,888	$ (6,378,409)
Apr-13	1%	71%	28%	893,327	$ 45.09	$ 41,167,547	-7%	$ (2.39)	$ 38,840,180	$ (2,327,367)
May-13	1%	72%	27%	898,030	$ 39.12	$ 36,080,804	-4%	$ (1.40)	$ 34,675,563	$ (1,405,241)
Jun-13	0%	63%	37%	916,942	$ 34.77	$ 33,078,194	0%	$ (0.07)	$ 32,993,714	$ (84,480)
Jul-13	2%	75%	22%	1,069,844	$ 48.87	$ 55,987,099	-7%	$ (3.32)	$ 51,951,355	$ (4,035,744)
Aug-13	0%	80%	20%	1,009,849	$ 33.32	$ 34,994,438	-1%	$ (0.28)	$ 34,656,287	$ (338,151)
Sep-13	0%	80%	20%	905,220	$ 34.97	$ 33,025,659	0%	$ -	$ 33,025,659	$ -
Oct-13	0%	80%	20%	934,297	$ 33.53	$ 32,291,424	-3%	$ (0.85)	$ 31,426,916	$ (864,507)
2012/2013	2%	68%	30%	11,417,657	$ 51.64	$ 612,639,595	-12%	$ (6.37)	$ 532,544,384	$ (80,095,211)

❖ Scenario Results Detail – Basis Reduction of 50% – ISO-NE:

Reduction in Natural Gas Price Premium

Month	% of Hours Oil is on Margin	% of Hours Gas is on Margin	% of Hours Other Fuels are on Margin	Total Monthly Demand in ISO-NE (MW)	Average ISO-NE LMP ($/MWh)	Total ISO-NE Costs ($)	Average Reduction in LMP (%)	Average Reduction in ISO-NE LMP ($/MWh)	Total ISO-NE Costs after Reduction in LMP ($)	Energy Cost Savings for ISO-NE Customers ($)
Nov-12	14%	58%	28%	9,929,622	$ 55.04	$ 566,747,947	-22%	$ (7.52)	$ 486,250,032	$ (80,497,915)
Dec-12	0%	65%	35%	10,825,697	$ 46.30	$ 515,445,646	-19%	$ (6.86)	$ 433,229,145	$ (82,216,501)
Jan-13	3%	61%	36%	11,330,245	$ 86.53	$ 1,037,786,716	-29%	$ (20.16)	$ 783,500,223	$ (254,286,492)
Feb-13	4%	54%	43%	10,057,171	$ 122.31	$ 1,272,847,870	-38%	$ (30.00)	$ 942,334,539	$ (330,513,330)
Mar-13	0%	59%	41%	10,420,336	$ 53.09	$ 567,605,026	-18%	$ (6.35)	$ 493,513,701	$ (74,091,325)
Apr-13	1%	71%	28%	9,282,373	$ 42.89	$ 406,528,240	-7%	$ (2.27)	$ 382,936,952	$ (23,591,289)
May-13	1%	72%	27%	9,668,418	$ 40.31	$ 406,414,752	-4%	$ (1.47)	$ 389,015,874	$ (17,398,878)
Jun-13	0%	63%	37%	10,752,306	$ 37.09	$ 421,726,419	0%	$ (0.08)	$ 420,485,318	$ (1,241,101)
Jul-13	2%	75%	22%	13,420,675	$ 52.07	$ 773,114,488	-7%	$ (3.60)	$ 714,505,116	$ (58,609,372)
Aug-13	0%	80%	20%	11,367,359	$ 34.72	$ 414,655,828	-1%	$ (0.29)	$ 410,506,616	$ (4,149,211)
Sep-13	0%	80%	20%	9,930,388	$ 40.43	$ 441,204,360	0%	$ -	$ 441,204,360	$ -
Oct-13	0%	80%	20%	9,709,008	$ 33.94	$ 340,802,781	-3%	$ (0.83)	$ 332,062,135	$ (8,740,647)
2012/2013	2%	68%	30%	126,693,598	$ 53.72	$ 7,164,880,073	-12%	$ (6.62)	$ 6,229,544,011	$ (935,336,062)

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5. Benefits Estimation: Reduction in LMPs – Scenario Results (cont.)

❖ Scenario Results Detail – Basis Reduction of 70% – Maine:

Reduction in Natural Gas Price Premium

Month	% of Hours Oil is on Margin	% of Hours Gas is on Margin	% of Hours Other Fuels are on Margin	Total Monthly Demand in Maine (MW)	Average Maine LMP ($/MWh)	Total Maine Costs ($)	Average Reduction in LMP (%)	Average Reduction in Maine LMP ($/MWh)	Total Maine Costs after Reduction in LMP ($)	Energy Cost Savings for Maine Customers ($)
Nov-12	14%	58%	28%	917,815	$ 53.53	$ 50,829,241	-30%	$ (10.32)	$ 40,700,015	$ (10,129,226)
Dec-12	0%	65%	35%	992,020	$ 45.80	$ 46,639,723	-27%	$ (9.50)	$ 36,290,242	$ (10,349,481)
Jan-13	3%	61%	36%	1,028,165	$ 83.63	$ 89,985,239	-40%	$ (27.12)	$ 59,421,935	$ (30,563,304)
Feb-13	4%	54%	43%	907,240	$ 116.19	$ 109,298,930	-53%	$ (39.94)	$ 69,815,106	$ (39,483,824)
Mar-13	0%	59%	41%	944,908	$ 50.93	$ 49,261,297	-25%	$ (8.54)	$ 40,331,524	$ (8,929,773)
Apr-13	1%	71%	28%	893,327	$ 45.09	$ 41,167,547	-9%	$ (3.35)	$ 37,909,233	$ (3,258,314)
May-13	1%	72%	27%	898,030	$ 39.12	$ 36,080,804	-5%	$ (1.97)	$ 34,113,466	$ (1,967,337)
Jun-13	0%	63%	37%	916,942	$ 34.77	$ 33,078,194	0%	$ (0.10)	$ 32,959,922	$ (118,272)
Jul-13	2%	75%	22%	1,069,844	$ 48.87	$ 55,987,099	-10%	$ (4.65)	$ 50,337,057	$ (5,650,042)
Aug-13	0%	80%	20%	1,009,849	$ 33.32	$ 34,994,438	-1%	$ (0.39)	$ 34,521,027	$ (473,411)
Sep-13	0%	80%	20%	905,220	$ 34.97	$ 33,025,659	0%	$ -	$ 33,025,659	$ -
Oct-13	0%	80%	20%	934,297	$ 33.53	$ 32,291,424	-4%	$ (1.20)	$ 31,081,113	$ (1,210,310)
2012/2013	2%	68%	30%	11,417,657	$ 51.64	$ 612,639,595	-17%	$ (8.92)	$ 500,506,300	$ (112,133,295)

❖ Scenario Results Detail – Basis Reduction of 70% – ISO-NE:

Reduction in Natural Gas Price Premium

Month	% of Hours Oil is on Margin	% of Hours Gas is on Margin	% of Hours Other Fuels are on Margin	Total Monthly Demand in ISO-NE (MW)	Average ISO-NE LMP ($/MWh)	Total ISO-NE Costs ($)	Average Reduction in LMP (%)	Average Reduction in ISO-NE LMP ($/MWh)	Total ISO-NE Costs after Reduction in LMP ($)	Energy Cost Savings for ISO-NE Customers ($)
Nov-12	14%	58%	28%	9,929,622	$ 55.04	$ 566,747,947	-30%	$ (10.52)	$ 454,050,866	$ (112,697,081)
Dec-12	0%	65%	35%	10,825,697	$ 46.30	$ 515,445,646	-27%	$ (9.60)	$ 400,342,545	$ (115,103,101)
Jan-13	3%	61%	36%	11,330,245	$ 86.53	$ 1,037,786,716	-40%	$ (28.22)	$ 681,785,626	$ (356,001,089)
Feb-13	4%	54%	43%	10,057,171	$ 122.31	$ 1,272,847,870	-53%	$ (42.00)	$ 810,129,207	$ (462,718,662)
Mar-13	0%	59%	41%	10,420,336	$ 53.09	$ 567,605,026	-25%	$ (8.89)	$ 463,877,170	$ (103,727,856)
Apr-13	1%	71%	28%	9,282,373	$ 42.89	$ 406,528,240	-9%	$ (3.18)	$ 373,500,436	$ (33,027,804)
May-13	1%	72%	27%	9,668,418	$ 40.31	$ 406,414,752	-5%	$ (2.06)	$ 382,056,322	$ (24,358,430)
Jun-13	0%	63%	37%	10,752,306	$ 37.09	$ 421,726,419	0%	$ (0.11)	$ 419,988,878	$ (1,737,541)
Jul-13	2%	75%	22%	13,420,675	$ 52.07	$ 773,114,488	-10%	$ (5.04)	$ 691,061,367	$ (82,053,121)
Aug-13	0%	80%	20%	11,367,359	$ 34.72	$ 414,655,828	-1%	$ (0.41)	$ 408,846,932	$ (5,808,896)
Sep-13	0%	80%	20%	9,930,388	$ 40.43	$ 441,204,360	0%	$ -	$ 441,204,360	$ -
Oct-13	0%	80%	20%	9,709,008	$ 33.94	$ 340,802,781	-4%	$ (1.16)	$ 328,565,876	$ (12,236,905)
2012/2013	2%	68%	30%	126,693,598	$ 53.72	$ 7,164,880,073	-17%	$ (9.27)	$ 5,855,409,587	$ (1,309,470,486)

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5. Estimated Cost Range: Pipeline Capacity

- Sussex developed Cost Assumptions for a range of incremental pipeline capacity (i.e., 350,000 Dth/day, 700,000 Dth/day and 1,000,000 Dth/day) based on rates ranging from $1.00 to $2.00 per daily MDQ

Cost Assumptions (350,000 Dth)			Cost Assumptions (700,000 Dth)			Cost Assumptions (1,000,000 Dth)		
Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)	Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)	Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)
$1.00	350,000	$127,750,000	$1.00	700,000	$255,500,000	$1.00	1,000,000	$365,000,000
$1.10	350,000	$140,525,000	$1.10	700,000	$281,050,000	$1.10	1,000,000	$401,500,000
$1.20	350,000	$153,300,000	$1.20	700,000	$306,600,000	$1.20	1,000,000	$438,000,000
$1.30	350,000	$166,075,000	$1.30	700,000	$332,150,000	$1.30	1,000,000	$474,500,000
$1.40	350,000	$178,850,000	$1.40	700,000	$357,700,000	$1.40	1,000,000	$511,000,000
$1.50	350,000	$191,625,000	$1.50	700,000	$383,250,000	$1.50	1,000,000	$547,500,000
$1.60	350,000	$204,400,000	$1.60	700,000	$408,800,000	$1.60	1,000,000	$584,000,000
$1.70	350,000	$217,175,000	$1.70	700,000	$434,350,000	$1.70	1,000,000	$620,500,000
$1.80	350,000	$229,950,000	$1.80	700,000	$459,900,000	$1.80	1,000,000	$657,000,000
$1.90	350,000	$242,725,000	$1.90	700,000	$485,450,000	$1.90	1,000,000	$693,500,000
$2.00	350,000	$255,500,000	$2.00	700,000	$511,000,000	$2.00	1,000,000	$730,000,000

5. Cost / Benefit Analysis: Analytical Estimates – New England

- Using the estimated basis reduction associated with potential pipeline infrastructure additions, as discussed on previous slides, Sussex developed a basis reduction table ranging from 25% to 75% (i.e., Estimated Benefits); similarly, Sussex used the cost of pipeline capacity table previously discussed, which included rates ranging from $1.00 to $2.00 per daily MDQ (i.e., Cost Assumptions)
  - As shown below, a 40% basis reduction would offset a 1,000,000 Dth/day of incremental pipeline capacity at a $2.00/Dth daily rate
  - At a $1.50/Dth daily rate, the estimated benefit over annual cost is approximately $200,000,000

Estimated Benefits		
Basis Reduction of:	Annual Energy Cost Savings for Maine Customers ($)	Annual Energy Cost Savings for ISO-NE Customers ($)
25%	$40,047,605	$467,668,031
30%	$48,057,127	$561,201,637
35%	$56,066,648	$654,735,243
40%	**$64,076,169**	**$748,268,849**
45%	$72,085,690	$841,802,455
50%	$80,095,211	$935,336,062
55%	$88,104,732	$1,028,869,668
60%	$96,114,253	$1,122,403,274
65%	$104,123,774	$1,215,936,880
70%	$112,133,295	$1,309,470,486
75%	$120,142,816	$1,403,004,092

Cost Assumptions (1,000,000 Dth)		
Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)
$1.00	1,000,000	$365,000,000
$1.10	1,000,000	$401,500,000
$1.20	1,000,000	$438,000,000
$1.30	1,000,000	$474,500,000
$1.40	1,000,000	$511,000,000
$1.50	**1,000,000**	**$547,500,000**
$1.60	1,000,000	$584,000,000
$1.70	1,000,000	$620,500,000
$1.80	1,000,000	$657,000,000
$1.90	1,000,000	$693,500,000
$2.00	**1,000,000**	**$730,000,000**

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5. Cost / Benefit Analysis: Analytical Estimates – Maine

- Maine could act independently to contract for incremental capacity to Maine, or upstream of Maine
  - Sussex reviewed two scenarios: (i) 50,000 Dth/day; and (ii) 200,000 Dth/day
  - Please note that the capacity amounts (e.g., 50,000 Dth/day and 200,000 Dth/day) may be part of a larger capacity addition

Estimated Benefits		Cost Assumptions (50,000 Dth)			Cost Assumptions (200,000 Dth)		
Basis Reduction of:	Annual Energy Cost Savings for Maine Customers ($)	Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)	Rate ($/Dth)	Capacity (Dth)	Annual Cost ($)
25%	$40,047,605	$1.00	50,000	$18,250,000	**$1.00**	**200,000**	**$73,000,000**
30%	$48,057,127	$1.10	50,000	$20,075,000	$1.10	200,000	$80,300,000
35%	$56,066,648	$1.20	50,000	$21,900,000	$1.20	200,000	$87,600,000
40%	**$64,076,169**	$1.30	50,000	$23,725,000	$1.30	200,000	$94,900,000
45%	$72,085,690	$1.40	50,000	$25,550,000	$1.40	200,000	$102,200,000
50%	$80,095,211	$1.50	50,000	$27,375,000	$1.50	200,000	$109,500,000
55%	$88,104,732	$1.60	50,000	$29,200,000	$1.60	200,000	$116,800,000
60%	$96,114,253	$1.70	50,000	$31,025,000	$1.70	200,000	$124,100,000
65%	$104,123,774	$1.80	50,000	$32,850,000	$1.80	200,000	$131,400,000
70%	$112,133,295	$1.90	50,000	$34,675,000	$1.90	200,000	$138,700,000
75%	$120,142,816	**$2.00**	**50,000**	**$36,500,000**	$2.00	200,000	$146,000,000

- At a 40% basis reduction scenario (i.e., Estimated Benefits), the State of Maine would need to pay less than $1.00/Dth per day for pipeline capacity (i.e., Cost Assumptions for 200,000 Dth/day of capacity); conversely, at the lower volume level (i.e., Cost Assumptions for 50,000 Dth) the State of Maine could pay above $2.00/Dth for capacity

5. Cost / Benefit Analysis: Summary

- The introduction of new pipeline capacity into a constrained region will reduce the basis differential between that region and the Henry Hub natural gas price index
- Sussex considered two cases to estimate the potential basis reduction associated with incremental pipeline capacity into the New England region:
  1. The expected addition of the Spectra Energy AIM Project (342,000 Dth/day) and the TGP Connecticut Expansion (72,000 Dth/day) to the New England region in November 2016 corresponded with a forward natural gas price reduction of approximately 35%
  2. The addition of over 1,000,000 Dth/day of pipeline capacity into the New York City region corresponded with a 65% to 70% reduction in forward natural gas prices
- While other variables may affect the basis, incremental pipeline capacity is the principal factor
- Because it is difficult to identify all variables affecting the basis and given that quantifying the relationship between those variables and the basis would require substantial judgment and likely be subject to estimation, Sussex believes that the case study method is a reasonable approach
- The application of the two cases to the New England region therefore assumes that all variables affecting the basis reduction, but for incremental pipeline capacity, remain constant, and that both cases can be applied to the New England region

5. Cost / Benefit Analysis: Summary – Regional Capacity Addition

- Using the two cases to inform a cost (new pipeline infrastructure) / benefit (lower electricity costs) analysis provides the following:
  - If the focus is the New England region:
    - A 400,000 Dth/day pipeline capacity addition into the New England region at a daily cost of $1.50/Dth (the mid-point of the cost range reviewed) results in an annual cost of $219 million; assuming the new capacity addition reduces the natural gas price index by 35% and therefore, the ISO-NE LMPs when natural gas-fired generation is on the margin, may reduce electricity costs by $655 million, which yields an overall annual benefit of $436 million (i.e., $655 million - $219 million)
    - A 1,000,000 Dth/day pipeline capacity addition into the New England region at a daily rate of $1.50/Dth (the mid-point of the cost estimate range reviewed) results in an annual cost of $548 million; assuming the new capacity addition reduces the natural gas price index by 65% and therefore the LMPs, electricity costs may be reduced by $1.2 billion, which yields an overall annual benefit of $652 million (i.e., $1.2 billion - $548 million)
  - If the focus is the Maine region, assuming Maine's capacity additions are part of a larger, regional capacity addition:
    - A 50,000 Dth/day capacity addition at a daily rate of $1.50/Dth would result in an annual cost of approximately $27 million; assuming a 35% reduction in Maine LMPs would result in a $56 million electricity cost savings – an overall benefit of $29 million
    - A 200,000 Dth/day capacity addition at a daily rate of $1.50/Dth would result in an annual cost of $110 million; assuming a 65% reduction in Maine LMPs would result in a $104 million electricity cost savings – an overall <u>cost</u> of $6 million

5. Cost / Benefit Analysis: Summary – Maine Capacity Addition

- The State of Maine could act independently and contract for additional capacity to Maine, on a standalone basis (i.e., not part of a larger pipeline project)
  - Assuming the State of Maine contracts for additional capacity:
    - A 50,000 Dth/day capacity addition at a daily rate of $1.50/Dth would result in an annual cost of approximately $27 million
      - To achieve $27 million in electricity cost savings for the State of Maine, a basis reduction of 15% to 20% is required
      - 50,000 Dth/day represents an incremental capacity addition of approximately 1% of peak day demand for New England. A capacity addition of that magnitude is not likely to have a substantial effect on the basis premium for the New England region
    - A 200,000 Dth/day capacity addition at a daily rate of $1.50/Dth would result in an annual cost of approximately $110 million
      - To achieve $110 million in electricity cost savings for the State of Maine, a basis reduction of 65% to 70% is required
      - By comparison, the capacity addition of over 1,000,000 Dth/day of pipeline capacity into the New York City region corresponded with a 65% to 70% reduction in forward natural gas prices.
        - 1,000,000 Dth/day represents an incremental addition of approximately 23% of peak day demand for the New York City region. However, 200,000 Dth/day represents an incremental addition of approximately 4% to 5% of peak day demand for the New England region

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Contents

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6. Summary and Conclusions

- There is potential for significant growth in natural gas demand in the New England region – particularly given the various state/provincial natural gas initiatives
- Several natural gas infrastructure projects have been proposed by various entities to alleviate the current capacity constraints into the New England region
- Incremental natural gas pipeline capacity into the New England region would place downward pressure on the regional natural gas price indices and, therefore, benefit customers who use those price signals in transactions (e.g., electricity generation segment)
- Based on the historical relationship between natural gas prices and electricity LMPs in ISO-NE, Sussex calculated the potential reduction in LMPs as a result of an expected reduction in wholesale natural gas prices (associated with incremental pipeline capacity) to estimate the potential energy cost savings to electricity customers for the 2012/2013 split-year
- The benefit (i.e., reduced natural gas costs and, therefore, lower LMPs) associated with incremental pipeline expansion was compared to various cost estimates (i.e., cost of pipeline capacity)
  - For the New England region, the estimated annual benefits under a 40% basis reduction scenario would offset the annual costs of a 1,000,000 Dth/day of incremental pipeline capacity at a daily pipeline charge of $2.00/Dth
  - At a 40% basis reduction scenario, the estimated annual benefits to the State of Maine would more than offset the annual costs of a 50,000 Dth/day contract assuming a daily rate as high as $2.00/Dth; however, the estimated benefits would not offset the annual costs of a 200,000 Dth/day contract at a daily rate of a $1.00/Dth