nationalgrid

Robert J. Humm
Senior Counsel

September 20, 2017

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Gas Cost Recovery
Gas Procurement Incentive Plan
Market Area Hedge Proposal
Docket No. 4647

Dear Ms. Massaro:

Enclosed for filing is National Grid's[1] request for an additional hedge to the Gas Procurement Incentive Plan (GPIP) for the upcoming November 2017 through March 2018 winter season. This filing consists of the pre-filed direct testimony and schedules of Stephen A. McCauley. In his testimony and schedules, Mr. McCauley explains the reasons for National Grid's proposal specific to the upcoming winter season, and describes National Grid's recommendations for hedge volumes and locations.

National Grid has filed a similar one-year hedging strategy with the Public Utilities Commission (PUC) in each of the three previous winter periods. This strategy, which is designed to mitigate a portion of the risk associated with market area purchases for the 2017-18 winter season, was approved by the PUC in Docket No. 4436 at the Open Meeting on September 30, 2014 and by written Order No. 21784 dated December 17, 2014; in Docket No. 4520 at the Open Meeting on September 22, 2015 and by written Order No. 22146 dated October 13, 2015; and in Docket No. 4647 at the Gas Cost Recovery (GCR) hearing on October 21, 2016 and by written Order No. 22779 dated April 27, 2017. The hedge proposal in this filing for the 2017-18 winter season is similar to the hedge strategy that National Grid executed for the 2014-15, 2015-16, and 2016-17 winter seasons. National Grid has reviewed the hedge proposal contained in this filing with the Division of Public Utilities and Carriers (Division) and its consultant, Bruce Oliver.

---

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 401-784-7415 ■ robert.humm@nationalgrid.com ■ www.nationalgrid.com

Because of the volatility evident in natural gas prices, National Grid seeks to execute the recommended hedges prior to December 1, 2017. In addition, the recommended hedges will increase National Grid's forecasted gas costs, so National Grid will be updating its GCR filing to reflect the recommended hedges proposed in this filing. Therefore, National Grid requests an expedited approval of the additional hedges submitted in this filing by or before October 11, 2017 so that National Grid can update its GCR filing before the Division's comments to the GCR are submitted on October 13. Expedited approval of the additional hedges submitted in this filing will also ensure National Grid's ability to lock in these purchases prior to the start of the winter period.

Thank you for your attention to this matter. If you have any questions, please contact Stephen McCauley at 516-545-5403 or me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosure

cc: Stephen Scialabba, Division
Bruce Oliver, Division
Leo Wold, Esq.

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

___________________________________ September 20, 2017

Joanne M. Scanlon Date

Docket No. 4647 – National Grid – 2016 Annual Gas Cost Recovery Filing (GCR) - Service List as of 9/2/16

Name/Address	E-mail	Phone
Jennifer Brooks Hutchinson, Esq. National Grid 280 Melrose St. Providence, RI 02907	Jennifer.hutchinson@nationalgrid.com; Celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com; Robert.Humm@nationalgrid.com;	401-784-7288
Ann E. Leary Elizabeth D. Arangio Stephen A. McCauley National Grid 40 Sylvan Road Waltham, MA 02541	Ann.Leary@nationalgrid.com; Elizabeth.Arangio@nationalgrid.com; Stephen.Mccauley@nationalgrid.com; Theodore.poe@nationalgrid.com;	
Leo Wold, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov; Steve.scialabba@dpuc.ri.gov; dmacrae@riag.ri.gov; Jmunoz@riag.ri.gov ;	401-222-2424
Bruce Oliver Revilo Hill Associates 7103 Laketree Drive Fairfax Station, VA 22039	Boliver.rha@verizon.net;	703-569-6480
File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Patricia.lucarelli@puc.ri.gov; Sharon.ColbyCamara@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107
Office of Energy Resources Christopher Kearns Nicholas Ucci	Christopher.Kearns@energy.ri.gov; Nicholas.ucci@energy.ri.gov;	

DIRECT TESTIMONY

OF

STEPHEN A. MCCAULEY

September 20, 2017

Table of Contents

I. <u>Introduction</u>

Q. Please state your name, place of employment and business address.

A. My name is Stephen A. McCauley. I work at National Grid, with a business address of 100 E. Old Country Road, Hicksville, NY 11801.

Q. What is your position and responsibilities within that position?

A. I am Director of Wholesale Electric Supply and U.S. Commodity Hedging in the Energy Procurement organization of National Grid USA Service Company, Inc. (National Grid). As Director, one of my responsibilities is for all financial hedging activity for the National Grid regulated natural gas and electric utilities, including The Narragansett Electric Company (the Company).

Q. Please describe your educational background.

A. I graduated from the United States Merchant Marine Academy in 1984 with a Bachelor of Science degree in Marine Engineering Systems.

Q. Please describe your professional experience.

A. I joined National Grid in 1992 as an engineer for the gas peak-shaving plants and the gas-regulator and telemetering stations. In 1996, I joined the gas supply group as a trader responsible for purchasing the natural gas supply requirements for both the firm gas customers and the Long Island Lighting Company generation facilities. In 1999, my responsibilities were changed to managing the emissions-allowance portfolio and the financial-hedging activities of the regulated utilities. In 2002, I was promoted to Director of Origination and Price Volatility Management. Earlier in 2017, I was promoted to my current position.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?

A. Yes, I have testified before the PUC on several occasions involving gas costs and volatility management of gas prices under the Company's Gas Procurement Incentive Plan (GPIP).

Q. Are you sponsoring any attachments to your testimony?

A. Yes. I am sponsoring the following attachments:

Attachment SAM-1	Regional Basis Point Map
Attachment SAM-2	2016-2017 Hedge Results
Attachment SAM-3	Tetco M3 Hedge Supply Cost and Mitigated Risk
Attachment SAM-4	Transco Non-NY Hedge Supply Cost and Mitigated Risk
Attachment SAM-5	TGP Hedge Supply Cost and Mitigated Risk

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the Company's proposal to hedge the market area locational basis price risk exposure for the upcoming November 2017 to March 2018 winter season. A basis hedge protects the price difference between New York Mercantile

Exchange (NYMEX) pricing and the market area where the Company purchases some of its supply in the winter. This proposal includes a plan to hedge a portion of the market area purchase price risk.

Q. Is this proposed market area hedge similar to the market area hedge the Company executed for the past three winter periods?

A. Yes, the proposed market area hedge is similar to the strategy executed for the three previous winter periods. This strategy was approved by the PUC in Docket No. 4436 at the Open Meeting on September 30, 2014 and by written Order No. 21784 dated December 17, 2014; in Docket No. 4520 at the Open Meeting on September 22, 2015 and by written Order No. 22146 dated October 13, 2015; and in Docket No. 4647 at the Gas Cost Recovery (GCR) hearing on October 21, 2016 and by written Order No. 22779 dated April 27, 2017. The changes to the strategy will be detailed later in my testimony.

Q. Where is the market area?

A. For the purposes of this filing, the market area is considered those regions where the Company is forecasted to purchase supplies outside of the producing regions of the U.S. Gulf, Canada, and the Marcellus area in West Virginia and Pennsylvania. The market areas are in New York and New Jersey, where the Company is purchasing supplies to use Algonquin Pipeline capacity and Columbia Pipeline capacity. See Attachment SAM-1 Regional Basis Point Map for the purchase point locations.

II. Gas Procurement Incentive Plan (GPIP) Market Area Hedge

Q. Please describe the history of adding market area hedges to the GPIP.

A. During the winter period of November 2013 through March 2014, the Northeast experienced prolonged cold temperatures. The colder temperatures resulted in both overall greater demand for gas in the Northeast, as well as the Company purchasing greater-than-normal supplies in the market area. This prolonged, greater-than-normal demand resulted in much higher daily and monthly prices for natural gas delivered to the market area, which, in turn, resulted in higher cost of gas. Ultimately, the Company filed revised GCR factors on February 14, 2014. As part of the PUC's approval of the revised GCR factors that went into effect on April 1, 2014, the Company was directed to review its hedging activities with the Division of Public Utilities and Carriers (Division). As a result of the Company's discussions with the Division, the Company filed a one-year hedging strategy with the PUC to mitigate a portion of the risk associated with the market area purchases. The PUC approved the filing and the Company executed the approved hedging strategy for the 2014-15 winter season. The PUC subsequently approved, and the Company executed, a similar hedging strategy for the 2015-16 and 2016-17 winter seasons. The Company has evaluated the market area hedge strategy executed for the past three winter seasons and is making a similar recommendation for the 2017-18 winter season in this filing.

Q. Has the Company added any pipeline capacity to its portfolio that would alleviate the pricing concerns experienced in the 2013-14 winter season?

A. Although the Company has not added any pipeline capacity since last winter, it did add some capacity which came on line in the middle of the 2016-17 winter season that will alleviate some of the pricing concerns experienced in the 2013-14 winter season, but not to the extent that eliminates the need to continue to hedge the market area price risk. The Company contracted for 18,000 dekatherms (Dth) per day of capacity on Enbridge Inc.'s Algonquin Incremental Market (AIM) project. The AIM project delivers gas supply from the receipt point in Ramapo, New York to delivery points in Rhode Island and other New England delivery points. This new capacity replaces 18,000 Dth per day of capacity associated with the Algonquin Hubline capacity and the Algonquin East to West capacity. Although the new AIM capacity replaces the same quantity of capacity from the Hubline and East to West capacity, the new receipt point at Ramapo has a much lower price risk than receipt points at Algonquin delivery points in Beverly, Massachusetts.

Q. Are the pricing concerns experienced during the 2013-14 winter season still prevalent today?

A. Yes. Although the warmer-than-normal weather experienced in the northeast the past two years resulted in lower market area prices, fundamental market changes in the region can have both a positive and negative impact to prices. The net effect is not significant enough to mitigate the potential for high prices. Changes in the region to help minimize the price risk include the following: incremental capacity to the region (AIM project); low crude oil prices and high New England forward gas prices in the winter will help encourage liquefied natural gas (LNG) imports; and the ISO New England winter reliability program will encourage dual fuel generators to have on-site adequate alternative fuels for the high gas demand days. Contra factors that will have the potential to increase pricing in New England include the following: growth of demand on the local distribution companies; and nuclear power plant retirements and increased gas fired generation, which have increased demand into the region. Without significant changes to the region, the same pricing concerns that occurred in the 2013-14 winter season still exist today.

Q. Which purchase locations caused the greatest impact to the actual cost of gas in the 2013-14 winter season?

A. The greatest impact to the cost of gas resulted from purchases at Texas Eastern Transmission Corp. (Texas Eastern) market area M3 (Tetco M3), Transcontinental Gas Pipeline Corp. (Transcontinental) market area Non-NY Zone 6 (Transco Non-NY Zone 6), Algonquin Gas Transmission Co. (Algonquin) market area Algonquin city gate (AGT), and Tennessee Gas Pipeline Co. (Tennessee) market area Zone 6 (TGP Zone 6). Although the Northeast did not experience the same impact to gas prices during the 2014-

15, 2015-16, and 2016-17 winter seasons, these regions still experienced the greatest volatility.

Q. Why does the Company purchase supplies in the market area?

A. Not all of the transportation capacity within the Company's portfolio of assets have access to purchase supplies in the producing regions. Approximately 26,000 Dth per day of the total 152,705 Dth per day of Algonquin capacity delivered to the city gates has receipt points in the market area, and approximately 39,000 Dth per day of the total 92,838 Dth per day of Tennessee capacity delivered to the city gates has receipt points in the market area.

Q. Why were the market area prices not initially hedged in the GPIP?

A. Market area purchases are typically the highest costs supplies. These supplies are "swing" supplies needed on colder-than-normal and sometimes normal winter days. On warmer-than-normal days, these supplies are not needed and, therefore, customer requirements are met with less expensive supplies purchased in the producing region. Since market area supplies are needed on some, but not all, winter days, they cannot be purchased in advance of a particular month and are typically purchased one day in advance when the forecast for colder temperatures is more certain. In order to hedge supplies in advance of the month of delivery, it must be known that supplies will be needed each and every day of the month in equal volumes per day. Since it is not known whether the market area supplies will be needed each and every day, such supplies are not typically hedged.

Q. What market area hedges did the Company execute for the 2016-17 winter season?

A. The Company hedged the receipt points of Tetco M3 (16,907 Dth per day) and Transco Non-NY Zone 6, (3,735 Dth per day) for the months of January, February, and March 2017.

Q. What was the outcome of the market area hedges for the 2016-17 winter season?

A. The Tetco M3 basis hedges resulted in an incremental cost of $2,309,365 for the hedged period of January, February and March 2017. The Transco Non-NY Zone 6 basis hedges resulted in an incremental cost of $707,764 for January, February, and March 2017. The Algonquin basis was hedged using Tetco M3 to Ramapo. The net result was a cost of $3,017,128, which is shown in more detail in Attachment SAM-2. The incremental cost is in relation to what the customers would have otherwise have paid if the hedges were not executed and the gas supplies were purchased at market prices.

Q. Does the Company recommend to hedge market area basis again for the coming winter season?

A. Yes. Similar to the past few years, the Company recommends that a portion of the market area price risk be hedged for the coming winter season. Although the same uncertainty of market area supply requirements exists, the benefits to hedge a portion of the market area price risk continues to outweigh the potential incremental cost to baseloading a higher cost supply. "Baseloading" means to purchase a fixed volume of supply for delivery each and every day of the month regardless of the weather or customer demand.

Q. What is the Company recommending for hedge volumes and locations for the 2017-18 winter season?

A. The Company recommends hedging purchases at receipt point locations Eagle and Downingtown on the Columbia Pipeline, and Lambertville and Ramapo on the Algonquin Pipeline. This is similar to the receipt points hedged in the 2016-17 winter season, in which supplies at the Algonquin city gate have been replaced with Ramapo purchases. As of January 7, 2017, the new AIM capacity has moved the forecasted purchases from Beverly, MA, an Algonquin city gate-based price, to the Algonquin receipt point at Ramapo, which is a Tetco M3-based price.

The Company is recommending hedging the maximum receipt point volumes at Downingtown (approximately 3,600 Dth per day of delivered supplies) using Transco Non-NY Zone 6 as the hedge location. The Tetco M3 hedge location will be used to hedge the maximum receipt point volumes at Eagle (approximately 3,600 Dth per day of delivered supplies) and approximately 4,000 Dth per day of delivered supplies from

Lambertville. The new AIM capacity can deliver 18,000 Dth per day from Ramapo to the Company's city gates, and the Company is recommending hedging 9,000 Dth per day using the Tetco M3 hedge location. The Company is recommending hedging the volumes and locations listed above for the months of January, February, and March 2018.

Q. Why is the Company recommending hedging the Tetco M3 and Transco Non-NY Zone 6 priced supplies?

A. The Tetco M3 and Transco Non-NY Zone 6 supplies are not forecasted to be baseloaded for the months of January, February, and March 2018 and, therefore, hedging these supplies may result in potentially higher costs. Hedging these supplies requires the Company to take delivery each and every day of the month. On normal and colder-than-normal days, the baseloaded Tetco M3 and Transco Non-NY Zone 6 supplies will be needed and the Company will avoid having to pay the daily prices on the Tetco M3 and Transco Non-NY Zone 6 capacity. On warmer-than-normal days, the Tetco M3 and Transco Non-NY Zone 6 supplies will displace less expensive supplies from the producing region, resulting in higher gas costs. The Company did an analysis to compare the potential incremental costs of baseloading the Tetco and Transco supplies under normal weather conditions versus the potential high price scenario under much colder weather conditions. Under normal monthly weather conditions, the Company estimates the increased cost of baseloading the Tetco M3 and Transco Non-NY Zone 6 supplies for the months of January, February, and March 2018 at $1.1 million (this compares with approximately $1.5 million from the 2016-17 hedge recommendation). The potential savings of baseloading the Tetco M3 and Transco Non-NY Zone 6 supplies for the months of January, February, and March 2018 in a high price, cold winter scenario is approximately $11 million (this compares with approximately $16 million from the 2016-17 hedge recommendation). The results of this analysis is shown, by month, in Attachments SAM-3 and SAM-4 for the cost of baseloading Tetco and Transco supplies under normal weather conditions for the months of January through March 2018 compared to the risk mitigated by hedging these same supplies under colder-than-normal weather conditions. For the recommended hedged months, the risk mitigated is 9.6 times greater than the cost to baseloading these supplies.

Q. Will the Millennium Pipeline Company LLC (Millennium) Eastern System Upgrade Project (Millennium Project) affect the Company's current strategy?

A. No. The Company previously entered into a precedent agreement for 9,000 Dth per day as part of the Millennium Project for an initial term of 15 years with service expected to commence September 1, 2018. The Company's 9,000 Dth per day of Millennium capacity represents half the Company's AIM Project volume. The Millennium Project will provide the Company with the opportunity to directly secure a cost effective domestically produced source of supply. The Millennium Project was originally intended to be in service for the 2017-18 winter. However, opposition at both the state and federal levels, as well as a lack of quorum at the Federal Energy Regulatory Commission during the first seven months of 2017, resulted in the Millennium Project not yet having the necessary authorizations and permits to commence construction and service. Pending receipt of all outstanding permits and authorizations, the Millennium Project expects to go in service in winter 2018-19.

Q. Does the Company recommend hedging any of the Tennessee (TGP) Zone 6 supplies?

A. No, the Company does not recommend hedging the TGP Zone 6 supplies. Using the same criteria of comparing the potential incremental cost of baseloading the TGP Zone 6 supplies under a normal weather scenario versus the risk mitigated under a high priced, cold winter scenario, the Company does not believe hedging TGP Zone 6 supplies is in the best interest of the customers. In Attachment SAM-5, the Company compares the cost of hedging the New England priced supplies assuming baseloading for normal weather and the potential risk of purchasing TGP Zone 6 supplies at daily market prices under a high price, design load forecast. The Company believes it is not in the best interest of the customers to baseload and hedge the TGP Zone 6 supplies because the incremental cost of baseloading TGP Zone 6 supplies is high relative to the potential risk mitigated under a design load scenario. In all months, the risk mitigated was only 0.32 to 1.00 times the cost to baseload the supplies. For example, in January 2018, the incremental cost of baseloading TGP Zone 6 supplies based on the normal forecast would result in an incremental cost of $7.09 million with a potential mitigated risk of $7.08

million. Here, the potential risk mitigated is less than the expected actual cost to baseload and hedge the TGP Zone 6 capacity.

Q. Does the Company recommend hedging market area purchases for December 2017?

A. No, the Company does not recommend hedging in December 2017. The load factor for all four locations is very low and, therefore, the risk to purchase supplies is small. The load factor in December 2017 is 1% for TGP Zone 6 priced supplies, 10% for Transco Non-NY Zone 6 priced supplies, and 32% for Tetco M3 priced supplies. Load factors are based on normal conditions.

Q. How much risk does the Company's recommended strategy mitigate?

A. The Company's recommended market area hedging strategy mitigates approximately 35% of the market area price risk under design weather conditions, assuming prices in the highest 5% probability. The remaining 65% of the price risk will remain unhedged because the incremental costs to hedge this risk would not outweigh the potential benefit to customers over a multi-year period.

Q. Does the Company recommend hedging market area supplies beyond March 2018?

A. No, the Company is not making a recommendation in this filing regarding hedging market area supplies beyond March 2018. The Company's recommendation in this filing is to protect against the price increases experienced during the 2013-14 winter season, while balancing the incremental costs of achieving a certain amount of price certainty for customers. The Company would not want to preclude the opportunity to protect more or less of that risk in the future. Therefore, the Company will perform a similar analysis after the 2018 winter season and make a recommendation for the November 2018 through March 2019 period.

Q. If approved, when does the Company plan to execute the recommended hedge volumes?

A. If approved, the Company will execute the recommended hedge volumes prior to December 1, 2017.

Q. Will any of the market area basis hedges impact the total hedge percentage of the forecasted purchases under the GPIP?

A. No, the market area basis hedges will not impact the portfolio hedge percentage in the current GPIP. Market area basis is one of two components that make up the total commodity price. Commodity price is made up of a producing region price component and a transportation price component. The Company hedges the producing region price component using the existing NYMEX Henry Hub fixed price hedges and Dominion

South Point[1] locational basis hedges. The Company is proposing to hedge the transportation component using the market area basis hedges proposed in this filing. One dekatherm of NYMEX Henry Hub fixed price hedges and one dekatherm of market area basis hedges equals one dekatherm of delivered supply.

Q. Will the market area basis hedges impact the GPIP incentive?

A. No, market area basis hedges will be excluded from the incentive calculation.

Q. Will the market area basis hedges impact the GCR filing submitted on September 1, 2017 in Docket No. 4719?

A. Yes, the recommended hedges will increase the forecasted gas costs by approximately $1.1 million. The Company will be updating its GCR filing to reflect the recommended hedges proposed in this filing. If approved by the PUC, the revised GCR factors will go into effect November 1, 2017.

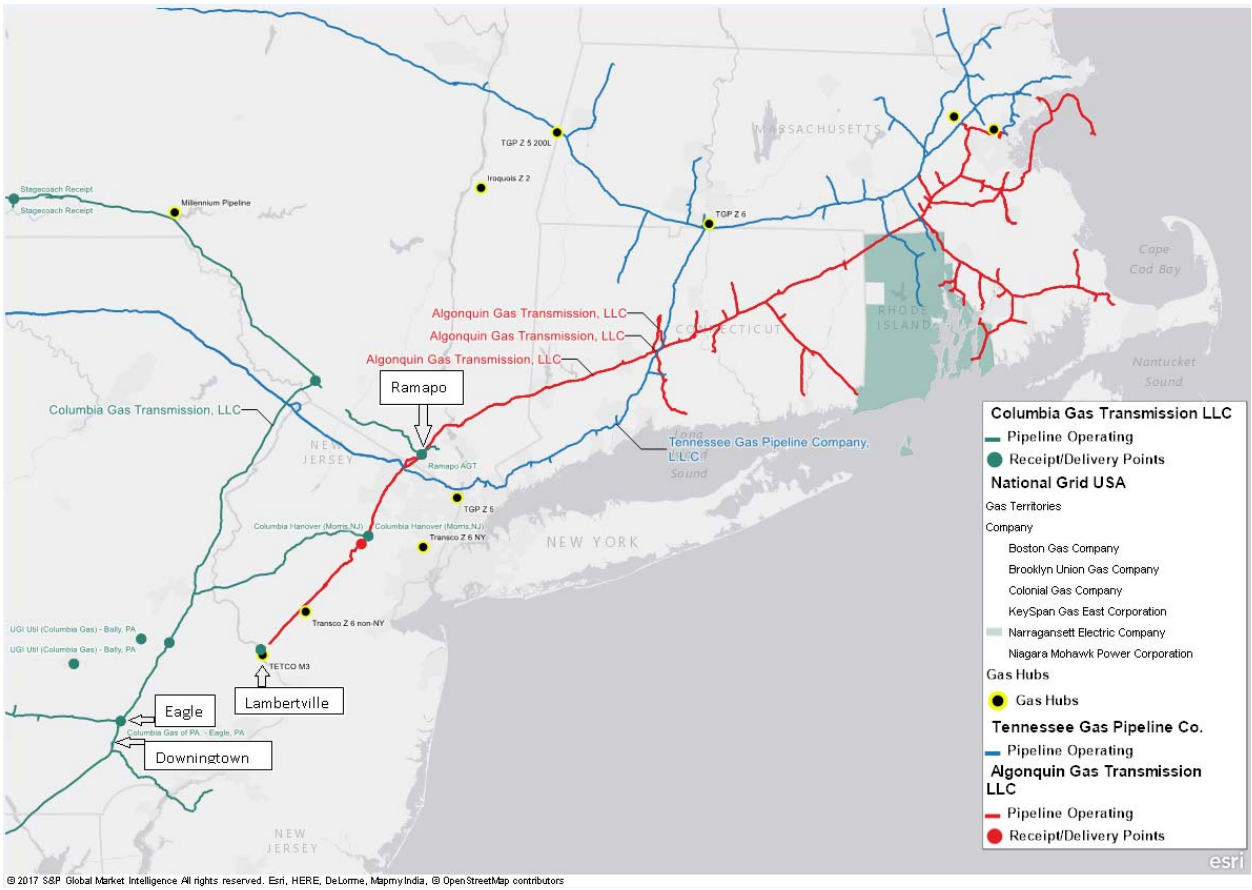
Q. Does this conclude your testimony?

A. Yes.

---

[1] The Dominion South Point locational basis hedges were incorporated into the GPIP Supplemental Marcellus Hedge Proposal and approved by the PUC in Docket No. 4520 at the Open Meeting on June 29, 2015 and by written Order No. 22024 dated August 6, 2015.

Attachment SAM-1: Regional Basis Point Map (source: SNL/Platts)



Attachment SAM-2: Hedge Results 2016-2017

	Transco Non-NY				Tetco M3			
Month	Volume (dt)	Hedge Price	Unhedged (GD Avg Index)	Dollar Savings	Volume (dt)	Hedge Price	Unhedged (GD Avg Index)	Dollar Savings
Dec-2016	-	$ -	$ 3.69	$ -	-	$ -	$ 3.50	
Jan-2017	115,785	$ 5.88	$ 3.56	$ (268,303.73)	524,117	$ 5.63	$ 3.48	$ (1,130,393.57)
Feb-2017	104,580	$ 5.34	$ 2.72	$ (273,768.03)	473,396	$ 5.23	$ 2.62	$ (1,236,241.34)
Mar-2017	115,785	$ 4.58	$ 3.15	$ (165,692.07)	524,117	$ 2.85	$ 2.96	$ 57,270.37
Total				$ (707,763.83)				$ (2,309,364.54)

Attachment SAM-3: Tetco M3 Hedge Supply Cost and Mitigated Risk

		Tetco M3 (TCO Eagle, Lambertville, Ramapo)				
		Dec	Jan	Feb	Mar	Total
Max Volume Daily	a	25,612	25,612	25,612	25,612	
Max volume monthly	b	793,972	793,972	717,136	793,972	3,099,052
Delivered Cost M3	c	$3.42	$5.33	$5.22	$3.28	
Delivered Cost TCO	d	$2.98	$3.06	$3.07	$3.02	
M3 Normal Forecast (dt/month)	e	254,116	534,504	513,968	229,341	1,531,928
M3 Normal Forecast (dt/day)		8,197	17,242	18,356	7,398	
M3 Forecast Excess (dt/month)	f = (b - e)	539,856	259,468	203,168	564,631	
M3 Design Forecast (dt/month)	g	425,510	595,169	563,502	344,965	
M3 Design Forecast (dt/day)		13,726	19,199	20,125	11,128	
M3 Design Excess (dt/month)	h = (b - g)	368,462	198,803	153,634	449,007	
Incremental Cost of Baseload Hedge vs Normal	i = (c - d) * f	$ 237,599	$ 588,919	$ 437,309	$ 151,286	$ 1,415,112
Price Simulation 95th percentile	j	$ 6.73	$ 12.87	$ 13.78	$ 8.46	
Unhedged Risk Design Volume	k = (g * j)	$ 1,593,937	$ 5,838,228	$ 6,036,769	$ 1,877,306	$ 15,346,240
Cost to Risk Mitigation Ratio Design	k/i	6.71	9.91	13.80	12.41	

Attachment SAM-4: Transco Non-NY Zone 6 Hedge Supply Cost and Mitigated Risk

		Transco Non-NY (Downingtown)				
		Dec	Jan	Feb	Mar	Total
Max Volume Daily		3,628	3,628	3,628	3,628	
Max volume monthly		112,468	112,468	101,584	112,468	438,988
Delivered Cost Transco Non-NY		$3.88	$6.09	$6.06	$3.71	
Delivered Cost TCO		$2.98	$3.06	$3.07	$3.02	
Non-NY Normal Forecast (dt/month)		10,903	60,669	58,032	20,142	149,747
Non-NY Normal Forecast (dt/day)		352	1,957	2,073	650	
Non-NY Forecast Excess (dt/month)		101,565	51,799	43,552	92,326	
Non-NY Design Forecast (dt/month)		39,126	74,887	73,305	31,047	
Non-NY Design Forecast (dt/day)		1,262	2,416	2,618	1,002	
Non-NY Design Excess (dt/month)		73,342	37,581	28,279	81,421	
Incremental Cost of Baseload Hedge						
	vs Normal	$ 91,043	$ 156,916	$ 130,372	$ 64,318	$ 442,649
Price Simulation 95th percentile		$ 7.87	$ 13.57	$ 13.87	$ 8.25	
Unhedged Risk Design Volume		$ 191,253	$ 786,749	$ 791,528	$ 162,563	$ 1,932,093
Risk Mitigation to Cost Ratio Design		2.10	5.01	6.07	2.53	

Attachment SAM-5: TGP Hedge Supply Cost and Mitigated Risk

		Tenn Zone 6 Dracut				
		Dec	Jan	Feb	Mar	Total
Max Volume Daily		38,950	38,950	38,950	38,950	
Max volume monthly		1,207,450	1,207,450	1,090,600	1,207,450	4,712,950
Delivered Cost Dracut		$6.29	$8.78	$8.78	$5.42	
Delivered Cost Tenn Zone 4		$2.59	$2.80	$2.83	$2.76	
TGP Z6 Normal Forecast (dt/month)		14,433	23,559	144,542	38,782	221,316
TGP Z6 Normal Forecast (dt/day)		466	760	5,162	1,251	
TGP Z6 Forecast Excess (dt/month)		1,193,018	1,183,891	946,058	1,168,668	
TGP Z6 Design Forecast (dt/month)		104,162	451,530	187,523	164,782	
TGP Z6 Design Forecast (dt/day)		3,360	14,565	6,697	5,316	
TGP Z6 Design Excess (dt/month)		1,103,288	755,921	903,077	1,042,668	
Incremental Cost of Baseload Hedge						
	vs warm winter	4,475,070	7,230,316	6,490,972	3,215,650	21,412,009
	vs Normal	$ 4,421,580	$ 7,089,241	$ 5,630,697	$ 3,112,366	$ 20,253,884
Price Simulation 95th percentile		$ 16.29	$ 18.49	$ 19.33	$ 14.26	
Unhedged Risk Design Volume		$ 1,427,558	$ 7,084,544	$ 3,095,397	$ 1,895,012	$ 13,502,511
Risk Mitigation to Cost Ratio Design		0.32	1.00	0.55	0.61	