nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

August 18, 2015

VIA HAND DELIVERY & ELECTRONIC MAIL

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

**RE: Docket 4520 - Gas Cost Recovery (GCR)
Gas Procurement Incentive Plan (GPIP)
Market Area Hedge Proposal**

Dear Ms. Massaro:

Enclosed for filing in the above-referenced docket is National Grid's[1] request for an additional hedge to the GPIP for the upcoming November 2015 through March 2016 winter season. This filing consists of the pre-filed testimony and schedules of Stephen A. McCauley. In his testimony and schedules, Mr. McCauley explains the reasons for the Company's proposal specific to the upcoming winter season, and describes the Company's recommendations for hedge volumes and locations.

Last year, the Company filed a one-year hedging strategy with the Rhode Island Public Utilities Commission (PUC) in Docket No. 4436 that was designed to mitigate a portion of the risk associated with market area purchases for the November 2014 through March 2015 winter season. The PUC approved that filing at its Open Meeting on September 30, 2014 and by written Order 21784 dated December 17, 2014. The hedge proposal in this filing for the 2015-2016 winter season is similar to the hedge strategy that the Company executed for the 2014-2015 winter season. The Company has reviewed the hedge proposal contained in this filing with the Division of Public Utilities and Carriers and its consultant Bruce Oliver, and they have indicated their support of same.

Because of the volatility evident in natural gas prices, the Company seeks to execute the recommended hedges prior to November 15, 2015. Therefore, the Company requests an expedited approval of the additional hedges submitted in this filing on or before October 1, 2015 to ensure the Company's ability to lock in these purchases prior to the start of the winter period.

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

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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) 784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

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.

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.

___________________________________ August 18, 2015

Joanne M. Scanlon Date

Docket No. 4520 – National Grid – 2014 Annual Gas Cost Recovery Filing ("GCR") - Service List as of 10/6/14

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PRE-FILED TESTIMONY

OF

STEPHEN A. MCCAULEY

August 18, 2015

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I. Introduction

Q. Please state your name and business address.

A. My name is Stephen A McCauley. My business address is 100 E. Old Country Road, Hicksville, NY 11801.

Q. What is your position and responsibilities?

A. I am Director of Origination and Price Volatility Management in the Energy Procurement organization of National Grid USA Service Company, Inc. (National Grid). As Director, I am responsible for all financial hedging activity for the National Grid regulated natural gas and electric utilities, including The Narragansett Electric Company (the Company). I am also responsible for structuring and optimizing the natural gas assets to help return the most value to the regulated entities.

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 profession 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 my current position as Director.

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 its Gas Procurement Incentive Plan (GPIP).

Q. Are you sponsoring any schedules to your testimony?

A. Yes. I am sponsoring the following schedules:

SAM-1	2014-2015 Hedge Results
SAM-2	Annual Hedged Supply Costs
SAM-3	Tetco M3 Hedge Supply Cost and Mitigated Risk
SAM-4	Transco Non-NY Hedge Supply Cost and Mitigated Risk
SAM-5	AGT and 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 2015 to March 2016 winter season. A basis hedge protects the price difference between NYMEX pricing and the market area. This change 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 last year for the November 2014 through March 2015 period?

A. The proposed market area hedge is similar to the strategy executed for the November 2014 through March 2015 winter period. This strategy was approved by the PUC at the Open Meeting on September 30, 2014 in Docket No. 4436 and by written Order 21784 dated December 17, 2014.

Q. Where is the market area?

A. For the purposes of this filing, market area is considered those regions where the Company is forecasted to purchase supplies outside of the producing regions of the US Gulf, Canada, and the Marcellus area of West Virginia and Pennsylvania. These market areas are in New York and New Jersey where the Company is purchasing supplies to use Algonquin pipeline capacity and Columbia pipeline capacity. In addition it includes the New England area where the Company is purchasing supplies to use Tennessee pipeline capacity with receipt points at Dracut, MA, Algonquin capacity with receipt points at Beverly, MA, and supplies purchased directly at the city gate.

II. Gas Procurement Incentive Plan Market Area Hedge

Q. Please describe the reason for adding market area hedges to the GPIP?

A. During the winter period November 2013 through March 2014, the Northeast experienced prolonged cold temperatures. These 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 2014-2015 winter season. The Company has evaluated the market area hedge strategy executed for 2014-2015 and is making a similar recommendation for the 2015-2016 winter season in this filing.

Q. Has the Company added any pipeline capacity to the portfolio that would alleviate the pricing concerns experienced in the 2013-2014 winter season?

A. No incremental capacity will be available for the 2015-2016 winter season. The Company expects the first new capacity into the New England region to be Spectra's Algonquin AIM expansion with an expected in-service date of November 2016. As a result, the Company expects a similar supply/demand imbalance to affect the region if the weather is colder than normal, resulting in potentially higher gas costs during the 2015-2016 winter season.

Q. Which purchase locations caused the greatest impact to the actual cost of gas in the 2013-2014 winter season?

A. The greatest impact to the cost of gas resulted from purchases at Texas Eastern Transmission market area M3 (Tetco M3), Transcontinental Pipeline market area Non-NY Zone 6 (Transco Non-NY Zone 6), Algonquin Gas Transmission market area Algonquin Citygate (AGT), and Tennessee Gas Pipeline market area Zone 6 (TGP Zone 6). Although, the Northeast did not experience the same impact to gas prices during the 2014-2015 winter season, 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 has access to purchase supplies in the producing regions. Approximately 35,600 dt/day of the total 152,705 dt/day of Algonquin capacity delivered to the city gates has receipt points in the market area, and approximately 15,000 dt/day of the total 68,838 dt/day of Tennessee capacity delivered to the city gates has receipt points in the market area.

Q. Why weren't the market area prices initially hedged in the GPIP?

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 the 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, these supplies are not typically hedged.

Q. What market area hedges did the Company execute for the 2014-2015 winter season?

A. The Company hedged the receipt points of Tetco M3 (approximately 13,800 dt/day) and Transco Non-NY Zone 6 (approximately 3,800 dt/day) for the months of January 2015, February 2015, and March 2015, and 3,000 dt/day of baseload supplies purchased at

Beverly, MA into Algonquin for the months of December 2014, January 2015, and February 2015.

Q. What was the outcome of the market area hedges for the 2014-2015 winter season?

A. The Tetco M3 basis hedges resulted in a benefit of $385,430 for the hedged period of January, February and March of 2015. The Transco Non-NY Zone 6 basis hedges resulted in a benefit of $951,358 for January, February and March of 2015. The Algonquin basis hedges resulted in an incremental cost of $1,517,157 for December 2014, January and February 2015. The net result was a cost of $180,368 and is shown in more detail on SAM-1. The benefit/cost is in relation to what the customers would have otherwise have paid if the hedges were not executed. The hedged price for 2014-2015 was lower than the actual costs for similar purchases in the 2013-2014 winter season.

Q. Does the Company recommend to hedge market area basis again for the coming November 2015 through March 2016 winter season?

A. Yes, similar to last year 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 2015-2016 winter season, and why did the Company select these?

A. The Company recommends hedging the same locations and monthly volumes for the 2015-2016 winter season: Tetco M3 (approximately 13,800 dt/day) and Transco Non-NY Zone 6 (approximately 3,800 dt/day) for the months of January 2015, February 2015, and March 2015; and 3,000 dt/day of baseload supplies purchased at Beverly into the Algonquin Hubline capacity for the months of December 2014, January 2015, and February 2015.

Q. Why is the Company recommending hedging 3,000 dt/day of Algonquin supplies if the hedge resulted in incremental costs of $1,517,157 during the 2014-2015 winter season?

A. The Company recommends hedging 3,000 dt/day of Algonquin supplies for the months of December 2015, January 2016, and February 2016 for a few reasons. First, the Company will be baseloading this same volume as a result of the Sendout model forecast and, therefore, the hedge will match exactly to the physical volume that will be purchased. Although the hedge price in 2014-2015 was higher than the eventual unhedged price it guaranteed, costs were $1.7 million lower than the 2013-2014 winter costs. As of the filing date, a similar Algonquin hedge for the 2015-2016 winter season is expected to be $1.2 million lower than actual costs for the 2014-2015 winter season and $2.9 million less than the 2013-2014 actual costs. See SAM-2.

Q. Why is the Company recommending hedging the Tetco M3 and Transco Non-NY 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 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 capacity 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 2016 is at $1.1 million. The potential savings of baseloading the Tetco M3 and Transco Non-NY Zone 6 supplies for the months of January, February and March 2016 in a high price cold winter scenario is $14.1 million. The results of this analysis is shown in SAM-3 and SAM-4 for the cost of baseloading Tetco and Transco supplies under normal weather conditions 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 more than 8 times greater than the cost to baseloading these supplies. In addition, the forecasted 2015-2016 hedge price for the Tetco M3 and Transco Non-NY Zone 6 supplies is approximately the same as the hedge price for the 2014-2015 winter season and approximately $10.6 million less than the actual costs experienced in 2013-2014. Hedging the same forecasted supplies at approximately the same price helps maintain stable prices year-on-year. See SAM-2 for the year-on-year comparison.

Q. Does the Company recommend hedging any additional Algonquin (AGT) or Tennessee (TGP) Zone 6 supplies?

A. The Company does not recommend hedging additional AGT and TGP Zone 6 supplies. Using the same criteria of comparing the potential incremental cost of baseloading the AGT and 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 is in the best interest of the customers. In SAM-5 the Company compares the cost of hedging the New England priced supplies assuming baseloading for normal and the actual 2014-2015 volume scenarios. In both of the cases it was not in the best interest of the customers to baseload and hedge the supplies. The Company determined this by calculating the incremental cost of baseloading the supplies at the forward price versus the marginal cost of supply under a least cost dispatch. This cost was compared to the risk mitigated under a colder than normal winter at the potential high price scenario where the Company would purchase the incremental supplies at the going market price. In both scenarios the risk mitigated was only 2.5 to 3.5 times the cost to baseload the supplies. For example, in January 2016 the incremental cost of baseloading the New England price supplies based on the normal forecast would result in an incremental cost of $1,891,678 (note 1) with a potential mitigated risk of $4,700,633 (note 2). In order for the hedge to be beneficial to the Narragansett Customers Rhode Island would have to experience an extreme weather and price scenario once every two to three years.

Q. Does the Company recommend hedging additional market area swing purchases for the months of November 2015 and December 2015?

A. The Company does not recommend hedging the months of November 2015 and December 2015. The load factor for all four locations is very low and therefore the risk to purchase supplies is small. The load factor for AGT and TGP Zone 6 is 5% for November and December and 16% in November for Tetco M3 and Transco Non-NY Zone 6 and 55% in December. 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 85% of the market area requirements under normal weather conditions. Under colder than normal weather conditions, with prices in the highest 5% probability, the market area hedging strategy will mitigate approximately 57% of the market area requirements and 34% of the price exposure. The remaining 66% of the price risk will remain unhedged because the incremental costs to hedge this risk (as discussed above and shown in SAM-5) would not outweigh the potential benefit to customers over a multi-year 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 November 15, 2015.

Q. Does the Company recommend hedging market area supplies beyond March 2015?

A. The Company is not making a recommendation regarding hedging market area supplies beyond March 2016 in this filing. The Company's recommendation in this filing is to protect against the price increases experienced during the 2013-2014 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 2016 winter season and make a recommendation for the November 2016 through March 2017 period.

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. Does this conclude your testimony?

A. Yes.

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[1] The Dominion South Point locational basis hedges was incorporated to the Gas Procurement Incentive Plan Supplemental Marcellus Hedge Proposal and approved by the Commission in the June 29, 2015 open meeting in Docket 4520.

Schedule SAM-1

2014-2015 Hedge Results

	Algonquin				Transco Non-NY				Tetco M3			
	Volume	Hedge Price	Unhedged (FOM Index)	Dollar Savings	Volume	Hedge Price	Unhedged (GD Avg Index)	Dollar Savings	Volume	Hedge Price	Unhedged (GD Avg Index)	Dollar Savings
Dec 2014	93,000	$ 15.63	$ 13.88	$ (162,936.00)								
Jan 2015	93,000	$ 18.56	$ 10.12	$ (784,827.00)	117,800	$ 9.02	$ 5.12	$ (459,302.20)	427,800	$ 7.53	$ 4.59	$ (1,257,304.20)
Feb 2015	84,000	$ 17.18	$ 10.40	$ (569,394.00)	106,400	$ 6.82	$ 14.04	$ 768,633.60	386,400	$ 5.50	$ 10.84	$ 2,064,921.60
Mar 2015					117,800	$ 2.88	$ 3.53	$ 76,098.80	427,800	$ 2.52	$ 2.86	$ 143,740.80
Total				$ (1,517,157.00)				$ 385,430.20				$ 951,358.20

Schedule SAM-2

Annual Hedged Supply Costs

Market Area Hedge Summary

Market Area	Daily Volume	Hedge Term	2013/14 Cost	2014/15 Hedge Price	2015/16 Forecast*
Algonquin	3,000	Dec-Feb	$ 6,343,350	$ 4,623,747	$ 3,361,500
Tetco M3	13,800	Jan-Mar	$ 14,469,291	$ 6,440,971	$ 6,309,360
Transco Non-NY	3,800	Jan-Mar	$ 4,417,792	$ 2,136,121	$ 1,940,760
Total			$ 25,230,432	$ 13,200,838	$ 11,611,620

*assumes same NYMEX price as 2014/15

Schedule SAM-3

Tetco M3 Hedge Supply Cost and Mitigated Risk

		Tetco M3		
		Jan	Feb	Mar
Max Volume Daily		13,800	13,800	13,800
Max volume monthly		427,800	400,200	427,800
Delivered Cost M3		$8.11	$6.72	$3.29
Delivered Cost TCO		$3.32	$3.34	$3.24
M3 Forecast (dt/day)		10,194	10,804	4,861
M3 Forecast Excess (dt/day)		3,606	2,996	8,939
M3 2013-14 Actual (dt/day)		11,660	12,565	12,770
Incremental Cost of Baseload Hedge				
	vs Forecast	$ 535,083	$ 293,642	$ 11,663
Potential High Market Price		$ 20.04	$ 17.90	$ 8.65
Cost at Risk		$ 4,481,301	$ 4,216,759	$ 2,211,473
Cost to Risk Mitigation Ratio		8.37	14.36	189.61

Schedule SAM-4

Transco Non-NY Hedge Supply Cost and Mitigated Risk

		Transco Non-NY		
		Jan	Feb	Mar
Max Volume Daily		3,800	3,800	3,800
Max volume monthly		117,800	110,200	117,800
Delivered Cost Transco Non-NY		$8.97	$7.59	$3.39
Delivered Cost TCO		$3.32	$3.34	$3.24
Non-NY Forecast (dt/day)		3,413	2,450	890
Non-NY Forecast Excess (dt/day)		387	1,350	2,910
Non-NY 2013-14 Actual (dt/day)		3,161	3,252	2,570
Incremental Cost of Baseload Hedge				
	vs Forecast	$ 67,792	$ 166,364	$ 12,994
Potential High Market Price		$ 22.99	$ 21.47	$ 8.76
Cost at Risk		$ 1,401,183	$ 1,331,365	$ 437,831
Cost to Risk Mitigation Ratio		12.52	19.71	79.72

Schedule SAM-5

AGT and TGP Hedge Supply Cost and Mitigated Risk

		New England Region		
		Jan	Feb	Mar
Delivered Cost M2		$2.94	$2.88	$2.69
Delivered Cost TCO		$3.32	$3.34	$3.24
New England Market Prices		$14.08	$13.78	$8.16
Narragansett Costs 2013-14		$30.12	$25.08	$26.05
Daily Avg Requirement (dt/day)				
	Normal Forecast	5,671	9,521	2,294
	Actual 2013-14	9,610	8,665	1,033
	Actual 2013-15	20,856	45,453	2,935
95% Probability Market Price		$ 40.82	$ 41.43	$ 24.19
Incremental Cost to Baseload Hedge				
	Baseload normal (note 1)	$ 1,891,678	$ 2,881,530	$ 349,388
	Baseload Actual 2014-15	$ 6,956,986	$ 13,755,600	$ 447,178
Actual 2014-15 volume (dt/month)		646,536	1,318,125	91,000
Mitigated Risk				
	Baseload Normal (note 2)	$ 4,700,633	$ 7,633,945	$ 1,139,639
	Daily volume hedged with E	159,774	312,053	5,481
	Daily volume above Normal	486,762	1,006,072	85,519
	Still at risk	$ 13,015,293	$ 27,814,929	$ 1,370,762
Mitigated Risk				
	Actual 2014-15	$ 17,287,420	$ 36,442,264	$ 1,458,610
	Daily volume hedged with E	485,408	1,091,889	14,677
	Daily volume above Actual I	161,128	226,236	76,323
	Still at risk	$ 4,308,325	$ 6,254,751	$ 1,223,350