The Narragansett Electric Company
d/b/a National Grid

INTERIM GAS COST RECOVERY FILING

Testimony and Attachments of:

Ann E. Leary
Nancy G. Culliford
Stephen A. McCauley

January 29, 2018

Submitted to:

Rhode Island Public Utilities Commission
RIPUC Docket No. 4719

Submitted by:

nationalgrid

Filing Letter & Motion

Robert J. Humm
Senior Counsel

January 29, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4719 – Interim Gas Cost Recovery Filing

Dear Ms. Massaro:

Enclosed please find 10 copies of the National Grid's[1] Interim Gas Cost Recovery (GCR) filing, which is being submitted pursuant to the Gas Cost Recovery Clause in National Grid's gas tariff at RIPUC NG-GAS No. 101, Section 2, Schedule A, Part 1.2. National Grid proposes an adjustment to the current GCR factors for effect March 1, 2018, which, in light of the current projected under-recovery of gas costs, is necessary for National Grid to recover by the end of October 2018 a portion of the projected gas cost deferral for the period November 1, 2017 through October 31, 2018. This filing consists of the pre-filed testimony and schedules of Ann E. Leary, Nancy G. Culliford, and Stephen A. McCauley.

National Grid's gas tariff provides that if the projected deferred gas cost balance exceeds five percent of the Company's annual gas cost revenue, the Company may request a change to its GCR factors. RIPUC NG-GAS No. 101, Section 2, Schedule A, Part 1.2. Currently, National Grid is projecting that the deferred gas cost balance as of October 31, 2018 will be approximately $34.4 million, or 24 percent of total annual gas cost revenue. As described in this filing, increases in natural gas prices, as well as the need to purchase additional natural gas during recent periods of colder than normal weather, are the major factors contributing to this projected gas cost deferral. As provided by National Grid's gas tariff, an increase in GCR factors during the GCR year ending October 31, 2018 to address the significant deferred gas costs reduces the amount of deferred gas costs to be recovered in the future, and, consequently, lessens increases in the gas cost rates that would otherwise occur in November, thus providing more rate stability for National Grid's customers. In addition, it provides National Grid recovery of costs during the same GCR year in which it has paid its suppliers for its gas supply procured to meet the needs of its customers.

To moderate the immediate customer bill impact of National Grid's proposal, the Company is proposing to recover approximately $22.8 million of the deferred gas cost balance during the period March 2018 through October 2018, and to defer recovery of approximately

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

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$11.6 million for recovery during the November 2018 through October 2019 GCR year. Based on the proposed GCR factors, an average residential heating customer using 396 therms for the period March through October 2018 will see a total bill increase related to the proposed GCR factors of $94.84, or 15.6 percent, as compared to bills based upon currently effective rates.

This filing also includes a Motion for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain pricing information contained in the pre-filed direct testimony and Attachments SAM-3, SAM-6, and SAM-7 of Stephen A. McCauley; in Attachments NGC-1 and NGC-2 to the pre-filed direct testimony of Nancy G. Culliford; and in Attachments AEL-2 and AEL-3 to the pre-filed direct testimony of Ann E. Leary. In compliance with Rule 1.2(g), National Grid has provided the PUC with one complete, un-redacted copy of the confidential materials in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release,"** and has included redacted copies of these materials for the public filing.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosures

cc: Docket 4719 Service List
Macky McCleary, Division
Jonathan Schrag, Division
John Bell, Division
Al Mancini, Division
Leo Wold, Esq.
Bruce Oliver

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

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Interim Gas Cost Recovery Filing	)	Docket No. 4719
2017-2018	)	
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MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On January 29, 2018, National Grid filed with the PUC an Interim Gas Cost Recovery (GCR) filing (the Interim GCR Filing) in the above-captioned docket. The Interim GCR Filing includes confidential gas-cost pricing information in the following documents: Attachments NGC-1 and NGC-2 to the pre-filed direct testimony of Nancy G. Culliford; Attachments AEL-2 and AEL-3 to the pre-filed direct testimony of Ann E. Leary; and pages 6, 7, and 8 and Attachments SAM-3, SAM-6, and SAM-7 to the pre-filed direct testimony of

Stephen A. McCauley. In accordance with Rule 1.2(g)(3), National Grid has provided a redacted public version of the GCR filing, as well as an unredacted, confidential version.

II. LEGAL STANDARD

Rule 1.2(g) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that the determination as to whether this exemption applies requires the application of a two-pronged test set forth in *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001). The exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain

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

necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal*, 774 A.2d 40.

The first prong of the test assesses whether the information was provided voluntarily to the governmental agency. *Providence Journal*, 774 A.2d at 47. If the answer to the first question is affirmative, then the question becomes whether the information is "of a kind that would customarily not be released to the public by the person from whom it was obtained." *Id.*

III. BASIS FOR CONFIDENTIALITY

The gas-cost pricing information – which is provided in Attachments NGC-1 and NGC-2 to the testimony of Ms. Culliford; in Attachments AEL-2 and AEL-3 to the testimony of Ms. Leary; and on pages 6, 7, and 8 and Attachments SAM-3, SAM-6, and SAM-7 to the testimony of Mr. McCauley – is confidential and privileged information of the type that National Grid would not ordinarily make public. Moreover, public disclosure of such information could impair National Grid's ability to obtain advantageous pricing in the future, thereby causing substantial competitive harm. Accordingly, National Grid seeks protection for such confidential information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

Robert J. Humm, Esq. (#7920)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7415
Dated: January 29, 2018

Testimony of
Ann E. Leary

DIRECT TESTIMONY

OF

ANN E. LEARY

January 29, 2018

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I. Introduction

Q. Please state your name and business address.

A. My name is Ann E. Leary. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Have you previously submitted testimony in this docket?

A. Yes. On September 1, 2017, I submitted pre-filed direct testimony in The Narragansett Electric Company d/b/a National Grid's (the Company) annual Gas Cost Recovery (GCR) filing (Initial GCR Filing) regarding the Company's proposed rate design, proposed GCR factors, and resulting bill impacts based on the proposed factors, pursuant to the Company's Gas Cost Recovery Clause in RIPUC NG-GAS No. 101 (the Tariff). The PUC approved the currently effective GCR factors following the conclusion of the hearing in this docket on October 30, 2017.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to introduce the Company's witnesses in this interim GCR filing and to propose revised GCR factors effective March 1, 2018 for the following services: Firm sales service customers in the Residential Non-Heating and Heating rate classes and Commercial and Industrial (C&I) firm sales customers in the Small, Medium,

Large, and Extra Large rate classes. I also discuss the reason for the Company's interim GCR filing.

Q. Who is supporting the Company's request in this filing?

A. Accompanying my testimony, which supports the calculation of the requested increase in the Company's GCR factors and the resulting bill impacts, the Company is also presenting the testimony and attachments of Company Witnesses Nancy G. Culliford, Manager of Gas Supply Planning, who presents and supports the re-forecast of gas costs for the period January 2018 through October 2018, as well as actual gas costs the Company has incurred in supplying gas to its customers since November 1, 2017, both of which are incorporated into the analysis reflected in my Attachments AEL-2 and AEL-3; and Stephen M. McCauley, Director of Energy Procurement, Wholesale Electric Supply, who presents the relationship between the Company's gas cost volatility program and the actual costs incurred by the Company since November 1, 2017 and the variability of the Company's forecasted hedged cost of gas as compared to the actual cost of gas.

Q. Are you including any attachments with your testimony?

A. Yes. I am sponsoring the following attachments:

Attachment AEL-1	Proposed Gas Cost Recovery Factors
Attachment AEL-2	Estimated Deferred Gas Cost Balance without Revised GCR
Attachment AEL-3	Estimated Deferred Gas Cost Balance with Revised GCR

Attachment AEL-4 Bill Impact Analysis

Attachment AEL-5 Derivation of Incremental Revenue Adjustment

III. GCR Factor Development

Q. What are the proposed GCR factors the Company is requesting to implement?

A. The Company is requesting approval to increase the current High Load and Low Load GCR factors by $0.225 per therm ($0.2324 per therm including the gross up for uncollectibles). Attachment AEL-1 provides a summary of the proposed GCR factors reflecting this increase, proposed to become effective March 1, 2018.

Q. Why is the Company proposing to revise its currently approved GCR factors?

A. The Company is proposing to revise its current GCR factors to recover a portion of the projected deferred gas cost balance at the end of October 2018. According to the Company's Tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A, Part 1.2, if the projected deferred gas cost balance exceeds five percent of the Company's annual gas cost revenue, the Company may request a change to its GCR factors to eliminate this deferred balance. Currently, the Company is projecting the deferred gas cost balance at October 31, 2018 to be approximately 24 percent of the total annual gas cost revenue. Because of the size of the estimated deferral balance, the Company believes it is appropriate to increase its current GCR factors at this time.

Q. What is the projected deferred gas cost balance at the end of October 2018 if the Company does not change the GCR factors?

A. If the Company does not increase its currently approved GCR factors, the Company is projecting a deferred gas cost balance of approximately $34.4 million at the end of October 2018, as detailed in Attachment AEL-2. The $34.4 million projected gas cost deferral reflects actual gas costs for the months of November and December 2017 and an updated forecast for the period January 2018 through October 2018 presented in the testimony and attachments of Ms. Culliford.

Q. What are the major factors contributing to this projected deferred gas cost balance?

A. Increases in actual and forecasted gas prices during the period November 2017 through October 2018 as compared to the forecast of gas prices presented in the Company's Initial GCR Filing is a major factor contributing to this projected deferred gas cost balance. Also a major contributor to the projected deferral balance was the need for the Company to purchase significantly more gas as a result of the extreme cold weather the New England region experienced at the end of last year and in early January 2018. As discussed in the testimonies of both Ms. Culliford and Mr. McCauley, the currently approved GCR factors were derived using a gas cost forecast for the same period that utilized a New York Mercantile Exchange (NYMEX) strip as of the close of trading on July 31, 2017. Since that time, gas prices have escalated. Actual commodity gas costs for the months of November and December 2017 were approximately $15.2 million

higher than forecasted. In addition, the updated forecast for the period January 2018 through October 2018 detailed in Ms. Culliford's Attachment NGC-1 and Attachment NGC-2 is approximately $28.4 million higher than the same months in the forecast presented in the Initial GCR Filing.

Q. In addition to updating the projected gas costs, has the Company made any other changes to the gas forecast included in the Initial GCR Filing?

A. Yes. In addition to updating the forecasted gas costs for the period January 2018 through October 2018, the Company has also updated the January 2018 sendout volume forecast by 765,782 dekatherms to reflect the incremental gas supplies purchased during the first 16 days of January 2018. As a result of this increase to January's sendout volume, the Company has also adjusted January's sales (billing) volume by the same amount.

In addition to this adjustment resulting from the Company having to purchase additional sendout for the first half of January 2018, the Company has also made a second adjustment to January's sales volume to reflect the lag in December's usage billed in January. As shown in Attachment AEL-5, the Company experienced a 28 percent increase in sendout volume as compared to forecast during the months of November and December 2017. However, volumes billed for these months were 5 percent below those forecasted in the Initial GCR Filing. Having purchased incremental gas supply in November and December 2017, the cost of which is reflected in this supplemental filing,

without acknowledging that those supplies were delivered to the Company's customers and will generate incremental GCR revenue will result, absent a discreet adjustment, in an overstatement of the projected gas cost deferral at the end of October 2018. The Company anticipates incremental revenue resulting from the additional sendout volume purchased and delivered in the latter half of December 2017 will be billed to customers in January 2018. Therefore, the Company also increased January 2018 sales volume by 1,739,589 dekatherms to reflect the billing lag of December 2017 deliveries. In total, the Company is increasing January 2018 sales volume by 2,505,371 dekatherms (1.7 million dekatherms for December 2017 deliveries estimated to be billed in January 2018 and 0.8 million dekatherms for incremental deliveries of the incremental sendout in January 2018).

The last change to the Initial GCR Filing is that the Company updated the corporate federal income tax rate to 21 percent beginning in January 2018 in the working capital and inventory finance calculations in Attachment AEL-2 and AEL-3, Pages 6 and 7.

Q. Are the proposed GCR factors designed to eliminate the projected deferred balance by October 31, 2018?

A. No, the Company is not proposing to revise its current GCR factors to eliminate the deferred balance by October 31, 2018. The Company is proposing to increase its GCR factors by a factor that is designed to recover approximately $22.8 million of the deferral during the period March 2018 through October 2018, and is proposing to delay recovery

of approximately $11.6 million of the projected deferral balance into the period November 2018 through October 2019, which is the next period the Company's GCR factors are effective based on a new full-year forecast of gas supply costs. In evaluating the recovery of the $34.4 million projected deferral during the period March 2018 through October 2018, recovering the full amount resulted in a bill impact which the Company did not believe would be reasonable to impose upon its sales customers. The bill impact of recovering the full amount of the projected deferral on a Residential Heating customer would result in a 24 percent total bill increase over the period March through October. Based on the impact not only to the Company's Residential Heating customers, but also the impact that this level of recovery would have on all of its customers coming out of a difficult winter season, the Company believes that a bill mitigation plan is appropriate to phase in recovery of the projected deferral and reaches a reasonable and acceptable balance between bill increases resulting from the rate change proposed in this filing verses the amount to defer for recovery as part of its 2018-19 GCR factors. The Company arrived at its proposal reflected in this filing, which results from limiting the total bill increase to the average residential heating customer to 15.6 percent, and further results in deferring recovery of approximately $11.6 million of the $34.4 million deferred balance to the 2018-19 GCR factors.

Q. Has the Company submitted a similar request for an interim change in its GCR factors in the past and, if so, what was the result?

A. Yes. On April 1, 2014, the Company increased its Low Load Factor and High Load GCR Factors approved for November 1, 2013 in Docket No. 4436 from $0.6626 per therm and $0.6381 per therm, respectively, to $0.9208 per therm and $0.8963 per therm, respectively. This resulted in an increase in the GCR factors of $0.2582 per therm ($0.2500 per them before the adjustment to gross up the factor for uncollectibles) and a 16.3 percent total bill increase for a Residential Heating customer during the months of April 2014 through October 2014. In addition, this proposed increase recovered approximately 50 percent of the projected deferred balance of $34.5 million, thereby deferring recovery of approximately $16.9 million to be recovered from customers during the following GCR period of November 2014 through October 2015.

Q. Is the Company's proposal consistent with the interim GCR factor approved in Docket No. 4436?

A. Yes, the Company's proposal will result in a 15.6 percent total bill increase for Residential Heating customers, which is similar to the bill increase approved in Docket No. 4436.

Q. Please provide an overview of the development of the proposed revised GCR rates.

A. The Company has calculated the proposed increase in the current GCR factors by determining a surcharge with the objectives of setting a simple value for the surcharge and limiting the total bill increase for an average Residential Heating customer to below

16 percent during the period March through October 2018. This results in a surcharge of $0.225 per therm ($0.2324 per therm after the adjustment for the gross up for uncollectibles).

Q. What is the impact of the revised GCR factors on the projected deferred balance at October 31, 2018?

A. With the implementation of the revised GCR factors proposed in this filing effective March 1, 2018, the Company projects a gas cost deferred balance of approximately $11.6 million at the end of October 2018, as detailed in Attachment AEL-3. The Company proposes it recover this deferred gas cost balance in its 2018-19 GCR factors that will be proposed by the Company in September 2018.

Q. Why can the Company not carry the deferred gas costs and recover them during the following GCR period of November 2018 through October 2019?

A. According to the Company's Gas Cost Recovery Clause in its Tariff,[1] in the event the estimate of the Deferred Gas Cost balance differs by more than five percent of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate the balance. The provision is intended to (1) not burden sales customers with

[1] *See* RIPUC NG-GAS No. 101, Section 2, Gas Charge, Schedule A, Sheet 1, Part 1.2.

significant deferred gas costs that they would need to pay for in a subsequent year, with significant defined as five percent of gas cost revenue for the year; and (2) recover the incremental gas costs from those customers who were responsible for the increase and not defer recovery to future customers. The projected deferral consists predominantly of actual costs, which the Company has and will have to pay to its suppliers. This is a significant amount for the Company to have to pay without additional funding through the GCR factors.

In addition, if the Company does not recover some of this projected deferral sales customers will eventually have to pay for the interest cost of the Company carrying the deferral at the Bank of America prime rate less 200 basis points, pursuant to the Tariff.[2]

Q. How much interest cost will customers avoid by an increase in the GCR factors on March 1, 2018?

A. The Company estimates that customers will avoid $245,000 in interest through October 31, 2018. While the Company has not estimated the benefit, customers will also benefit from avoiding interest in the following GCR period, as the beginning balance of

[2] *See* RIPUC NG-GAS No. 101, Section 2, Gas Charge, Schedule A, Part 6.3.

the deferral will be significantly less under the Company's proposal, resulting in less interest accruing on that beginning balance as of November 2018.

Q. Did the Company evaluate other options for setting the surcharge to increase the current GCR factors besides the two discussed earlier in your testimony?

A. In determining the appropriate adjustment to the current GCR factors, the Company also considered the impact on the 2018-19 GCR factors resulting from deferring $11.4 million. In the approved GCR factors, the Company is currently recovering a prior period reconciliation for the period November 2016 through October 2017 of approximately $13.5 million. Therefore, the Company's proposal to defer $11.4 million for the period November 2017 through October 2018 will maintain a similar prior period reconciliation to the amount currently included in the approved 2017-18 GCR factors.

Q. Why is the Company asking for a GCR rate change effective March 1, 2018?

A. The process for requesting a rate change requires 30 days' notice, thereby resulting in a March 1, 2018 effective date. The Company is requesting the GCR factors change effective March 1, 2018 to recover the portion of the deferral over an eight-month period. Delaying the implementation of the proposed GCR factors until April 1, 2018 would result in fewer gas deliveries over which any portion of the projected deferral could be recovered, which would result in higher GCR factors and resulting bill impacts.

Q. Are other New England gas distribution companies requesting increases in their commodity factors?

A. Yes. Seven Massachusetts gas utilities requested an increase in their currently approved Peak Gas Adjustment Factors (GAFs)[3] effective February 1, 2018[4] resulting from increases in gas supply volumes and costs during this period. The table below summarizes for each Massachusetts gas utility the increase in its Peak GAF and the associated bill impacts on residential heating customers.

	Existing Peak GAF $/therm[5]	Proposed Peak GAF $/therm	Increase in Factor	Percent Increase	Bill Impact
Columbia Gas[6]	$0.5401	$0.9676	$0.4275	79.2%	31.0%
Liberty Utilities	$0.3102	$0.8136	$0.5034	162.3%	41.4%
Berkshire Gas Company	$0.5780	$0.6630	$0.0850	14.7%	6.6%
Fitchburg Gas and Electric	$0.3499	$0.6494	$0.2995	85.6%	17.6%
Boston Gas Company	$0.6260	$0.8019	$0.1759	28.1%	11.4%
Colonial Gas Company	$0.6251	$0.8010	$0.1759	28.1%	12.2%
Blackstone Gas Company[7]	$0.6690	$0.8429	$0.1739	26.0%	10.9%

[3] Massachusetts gas utilities implement Peak (November through April) and Off-Peak (May through October) GAFs.

[4] Massachusetts gas utilities must submit for approval by the Department of Public Utilities revisions to their GAFs seven business days prior to their proposed effective date.

[5] Peak GAF and bill impact applicable to a residential heating customer.

[6] Columbia Gas proposed to defer $31.5 million for recovery during the 2018-2019 Peak season.

[7] Blackstone Gas GAF factors are billed on a $/CCF basis and not $/therm.

IV. Bill Impacts

Q. What is the bill impact of the proposed GCR factors on customer bills as compared to the rates currently in effect?

A. An average residential heating customer using 396 therms for the period March through October will experience a total bill increase of $94.84, or 15.6 percent, over their bills at currently effective rates. A summary of seasonal (March through October) bill impacts incorporating only the proposed change in the GCR factors for rate classes at various levels of usage is provided in Attachment AEL-4.

Q. Does this conclude your testimony?

A. Yes.

Attachment AEL-1

Attachment AEL-1
Interim Gas Cost Recovery Factors

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Factors Effective March 1, 2018

	Description	Source Reference	Source Line #	High Load[1]	Low Load[2]	FT-2 Mkter
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Cost Factor - $/dktherm	Approved Factor*		$1.1342	$1.5517	
(2)	Variable Cost Factor -$/dktherm	Approved Factor		$3.5711	$3.5711	
(3)	Total Gas Cost Recovery Charge- $/dktherm	Approved Factor		$4.7053	$5.1228	
(4)	Surcharge Factor	Manual Input		$2.2500	$2.2500	
(5)	Total Revised Gas Cost Recovery Charge	Line (3) +Line (4)		$6.9553	$7.3728	
(6)	Uncollectible %	Docket 4323		3.18%	3.18%	
(7)	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(5) / [1 - (6)]		$7.1837	$7.6149	
(8)	**GCR Charge on a per therm basis**	(7) / 10		$0.7183	$0.7614	
(9)	Current rate effective 11/01/17* - $/therm			$0.4859	$0.5291	
(10)	Increase- $/therm	(8) - (9)		$0.2324	$0.2323	
(11)	Percent Increase	(10) / (9)		47.8%	43.9%	

* GCR rates approved with the Rebuttal GCR filing per Docket No. 4719 filed on October 23, 2017

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load

[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load

Attachment AEL-2
REDACTED

Attachment AEL-2
Deferred Gas Cost Balances Without Interim GCR

REDACTED

National Grid
Rhode Island - Gas

Schedule 1
Page 1 of 1

Deferred Gas Cost Balances

	Description	Reference	Nov Actual	Dec Actual	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov-Oct
(1)	# of Days in Month		30	31	31	28	31	30	31	30	31	31	30	31	365
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(2)	I. Fixed Cost Deferred														
(3)	Beginning Under/(Over) Recovery		$1,106,719	$2,186,800	$518,946	($5,184,717)	($7,502,087)	($8,961,811)	($10,154,962)	($9,323,349)	($7,474,277)	($5,189,363)	($2,795,395)	($502,619)	$1,106,719
(4)	Supply Fixed Costs (net of cap rel)	Sch. 2, line (31)	$4,342,453	$4,432,787	$6,108,532	$6,106,396	$6,108,532	$4,531,059	$4,531,771	$4,531,059	$4,531,771	$4,531,771	$4,530,656	$4,531,368	$58,818,154
(5)	System Pressure to DAC	Dkt 4719	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($3,153,600)
(6)	Supply Related LNG O & M	Dkt 4323	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$575,581
(7)	NGPMP Credits		($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($10,900,000)
(8)	Working Capital	Sch. 4, line (15)	$23,513	$24,034	$29,296	$29,286	$29,296	$21,391	$21,394	$21,391	$21,394	$21,394	$21,389	$21,392	$285,170
(9)	Total Supply Fixed Costs	Sum[(4):(8)]	$3,242,798	$3,333,652	$5,014,660	$5,012,513	$5,014,660	$3,429,281	$3,429,997	$3,429,281	$3,429,997	$3,429,997	$3,428,876	$3,429,592	$45,625,304
(10)	Supply Fixed - Revenue	Sch. 3, line 13	$2,201,823	$5,004,233	$10,713,375	$7,317,730	$6,456,923	$4,602,813	$2,577,727	$1,562,969	$1,131,653	$1,027,561	$1,132,715	$1,373,589	$45,103,110
(11)	Monthly Under/(Over) Recovery	(9) - (10)	$1,040,975	($1,670,580)	($5,698,715)	($2,305,217)	($1,442,263)	($1,173,532)	$852,270	$1,866,312	$2,298,344	$2,402,436	$2,296,161	$2,056,003	$522,195
(12)	Prelim. Ending Under/(Over) Recovery	(3) + (11)	$2,147,693	$516,220	($5,179,769)	($7,489,934)	($8,944,350)	($10,135,342)	($9,302,692)	($7,457,037)	($5,175,933)	($2,786,927)	($499,234)	$1,553,384	$1,628,914
(13)	Month's Average Balance	[(3) + (12)] / 2	$1,627,206	$1,351,510	($2,330,411)	($6,337,325)	($8,223,219)	($9,548,576)	($9,728,827)	($8,390,193)	($6,325,105)	($3,988,145)	($1,647,315)	$525,383	
(14)	Interest Rate (BOA Prime minus 200 bps)		2.25%	2.38%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
(15)	Interest Applied	[(13) x (14)] / 365 x (1)	$3,009	$2,726	($4,948)	($12,154)	($17,460)	($19,620)	($20,657)	($17,240)	($13,430)	($8,468)	($3,385)	$1,116	($110,512)
(16)	Marketer Reconcilation	Dkt 4719, AEL-7, Line (50)	$36,098	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$36,098
(17)	Fixed Ending Under/(Over) Recovery	(12) + (15) + (16)	$2,186,800	$518,946	($5,184,717)	($7,502,087)	($8,961,811)	($10,154,962)	($9,323,349)	($7,474,277)	($5,189,363)	($2,795,395)	($502,619)	$1,554,499	$1,554,499
(18)	II. Variable Cost Deferred														
(19)	Beginning Under/(Over) Recovery		$13,703,849	$17,445,473	$29,443,058	$46,180,590	$45,191,882	$42,184,163	$37,455,008	$35,171,386	$34,062,004	$33,566,278	$33,195,191	$32,634,373	$13,703,849
(20)	Variable Supply Costs	Sch. 2, line (77)	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862
(21)	Supply Related LNG to DAC	Dkt 4339	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	Supply Related LNG O & M	Dkt 4323	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$572,694
(23)	Inventory Financing - LNG	Sch. 5, line (22)	$32,062	$21,879	$8,917	$3,681	$3,129	$7,665	$12,330	$16,871	$18,512	$19,401	$23,928	$24,809	$193,185
(24)	Inventory Financing - UG	Sch. 5, line (12)	$80,793	$69,463	$43,426	$30,391	$18,503	$18,804	$27,475	$35,906	$41,657	$49,189	$61,111	$71,358	$548,077
(25)	Working Capital	Sch. 4, line (30)	$51,554	$132,114	$204,200	$76,629	$56,810	$26,900	$15,715	$9,861	$7,866	$7,220	$7,431	$14,045	$610,345
(26)	Total Supply Variable Costs	Sum[(20):(25)]	$9,157,042	$23,193,618	$41,049,928	$15,448,828	$11,461,987	$5,468,717	$3,238,919	$2,078,078	$1,685,420	$1,564,106	$1,622,975	$2,960,545	$118,930,162
(27)	Supply Variable - Revenue	Sch. 3, line (30)	$5,444,194	$11,243,274	$24,392,597	$16,525,069	$14,562,370	$10,279,609	$5,599,562	$3,258,518	$2,252,867	$2,005,995	$2,251,356	$2,812,684	$100,628,096
(28)	Monthly Under/(Over) Recovery	(26) - (27)	$3,712,848	$11,950,343	$16,657,331	($1,076,241)	($3,100,383)	($4,810,892)	($2,360,643)	($1,180,440)	($567,447)	($441,889)	($628,381)	$147,861	$18,302,067
(29)	Prelim. Ending Under/(Over) Recovery	(19) + (28)	$17,416,697	$29,395,816	$46,100,390	$45,104,349	$42,091,499	$37,373,271	$35,094,365	$33,990,947	$33,494,557	$33,124,389	$32,566,810	$32,782,234	$32,005,916
(30)	Month's Average Balance	[(19) + (29)] / 2	$15,560,273	$23,420,644	$37,771,724	$45,642,469	$43,641,691	$39,778,717	$36,274,686	$34,581,166	$33,778,280	$33,345,333	$32,881,000	$32,708,304	
(31)	Interest Rate (BOA Prime minus 200 bps)		2.25%	2.38%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
(32)	Interest Applied	[(30) x (31)] / 365 x (1)	$28,776	$47,242	$80,200	$87,534	$92,664	$81,737	$77,022	$71,057	$71,721	$70,802	$67,564	$69,449	$845,767
(33)	Gas Procurement Incentive/(penalty)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(34)	Variable Ending Under/(Over) Recovery	(29) + (32) + (33)	$17,445,473	$29,443,058	$46,180,590	$45,191,882	$42,184,163	$37,455,008	$35,171,386	$34,062,004	$33,566,278	$33,195,191	$32,634,373	$32,851,683	$32,851,683
(35)	**GCR Deferred Summary**														
(36)	Beginning Under/(Over) Recovery	(3) + (19)	$14,810,568	$19,632,273	$29,962,005	$40,995,873	$37,689,795	$33,222,353	$27,300,045	$25,848,037	$26,587,727	$28,376,915	$30,399,796	$32,131,754	$14,810,568
(37)	Gas Costs	Sum[(4):(6),(16),(20):(22)]	$13,156,349	$27,188,114	$46,687,083	$21,229,687	$17,277,242	$9,731,571	$7,500,335	$6,331,664	$5,934,321	$5,805,232	$5,846,325	$7,166,864	$173,854,788
(38)	Inventory Finance	(23) + (24)	$112,855	$91,342	$52,343	$34,072	$21,632	$26,469	$39,805	$52,777	$60,169	$68,590	$85,040	$96,167	$741,261
(39)	Working Capital	(8) + (25)	$75,067	$156,147	$233,496	$105,914	$86,106	$48,291	$37,109	$31,252	$29,261	$28,614	$28,820	$35,438	$895,514
(40)	NGPMP Credits	(7)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($10,900,000)
(41)	Total Costs	Sum[(37):(40)]	$12,435,937	$26,527,270	$46,064,589	$20,461,341	$16,476,647	$8,897,998	$6,668,916	$5,507,360	$5,115,417	$4,994,103	$5,051,851	$6,390,136	$164,591,565
(42)	Revenue	(10) + (27)	$7,646,017	$16,247,507	$35,105,972	$23,842,799	$21,019,293	$14,882,422	$8,177,289	$4,821,487	$3,384,520	$3,033,556	$3,384,071	$4,186,273	$145,731,205
(43)	Monthly Under/(Over) Recovery	(41) - (42)	$4,789,920	$10,279,763	$10,958,617	($3,381,458)	($4,542,646)	($5,984,424)	($1,508,373)	$685,873	$1,730,897	$1,960,547	$1,667,780	$2,203,863	$18,860,359
(44)	Prelim. Ending Under/(Over) Recovery	(36) + (43)	$19,600,488	$29,912,036	$40,920,621	$37,614,415	$33,147,149	$27,237,928	$25,791,672	$26,533,909	$28,318,624	$30,337,462	$32,067,576	$34,335,618	
(45)	Month's Average Balance	[(36) + (44)] / 2	$17,205,528	$24,772,154	$35,441,313	$39,305,144	$35,418,472	$30,230,141	$26,545,859	$26,190,973	$27,453,175	$29,357,188	$31,233,686	$33,233,686	
(46)	Interest Rate (BOA Prime minus 200 bps)		2.25%	2.38%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
(47)	Interest Applied	(15) + (32)	$31,785	$49,968	$75,252	$75,380	$75,204	$62,117	$56,364	$53,817	$58,291	$62,334	$64,179	$70,565	$735,256
(48)	Gas Purchase Plan Incentives/(Penalties)	(33)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(49)	**Ending Under/(Over) Recovery W/ Interest**	(44) + (47) + (48)	$19,632,273	$29,962,005	$40,995,873	$37,689,795	$33,222,353	$27,300,045	$25,848,037	$26,587,727	$28,376,915	$30,399,796	$32,131,754	$34,406,182	$34,406,182

REDACTED

Supply Estimates and Actuals for Filing

Projected Gas Costs using 01/08/2018 NYMEX settled

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**SUPPLY FIXED COSTS - Pipeline Delivery**														
(2)	Algonquin (w/East to West, Hubline, AMA credits, Crary St.)		$1,619,095	$1,688,947	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$20,012,419
(3)	TETCO/Texas Eastern		$710,994	$718,333	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$8,602,057
(4)	Tennessee		$1,093,271	$1,093,271	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$13,118,696
(5)	Tennessee Dracut for Peaking		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6)	Iroquois		$6,070	$6,146	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$5,667	$5,667	$72,111
(7)	Union		$0	$0	$2,984	$2,695	$2,984	$2,887	$2,984	$2,887	$2,984	$2,984	$2,887	$2,984	$29,259
(8)	Transcanada		$0	$0	$14,077	$12,715	$14,077	$13,623	$14,077	$13,623	$14,077	$14,077	$13,623	$14,077	$138,048
(9)	Dominion		$2,295	$2,295	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$26,967
(10)	Transco		$4,854	$5,015	$5,016	$4,530	$5,016	$4,854	$5,016	$4,854	$5,016	$5,016	$4,854	$5,016	$59,055
(11)	National Fuel		$4,480	$4,549	$4,480	$4,480	$4,480	$0	$0	$0	$0	$0	$0	$0	$22,471
(12)	Columbia		$307,936	$307,936	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$3,695,226
(13)	Alberta Northeast		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(14)	Less Credits from Mkter Releases		($671,640)	($688,879)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($8,287,667)
			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(15)	**Supply Fixed - Supplier**														
(16)	Distrigas FCS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17)	**Total**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	**STORAGE FIXED COSTS - Facilities**														
(19)	Texas Eastern		$88,875	$85,450	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$1,119,670
(20)	Dominion		$83,088	$83,088	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$997,343
(21)	Tennessee		$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$580,041
(22)	Columbia		$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$116,328
(23)	National Grid LNG Tank Lease Payments		$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$1,964,880
(24)	**STORAGE FIXED COSTS - Delivery**														
(25)	Algonquin		$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$2,585,230
(26)	TETCO		$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$1,051,257
(27)	Tennessee		$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$1,059,436
(28)	Dominion		$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$369,288
(29)	Columbia		$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$192,982
(30)	**Confidential Pipelinne and Peaking Supplies**		$433,181	$466,683	$2,139,916	$2,139,916	$2,139,916	$567,635	$567,635	$567,635	$567,635	$567,635	$567,635	$567,635	$11,293,056
(31)	**TOTAL FIXED COSTS**	Sum[(2):(30)]	$4,342,453	$4,432,787	$6,108,532	$6,106,396	$6,108,532	$4,531,059	$4,531,771	$4,531,059	$4,531,771	$4,531,771	$4,530,656	$4,531,368	$58,818,154

REDACTED

Supply Estimates and Actuals for Filing

Projected Gas Costs using 01/08/2018 NYMEX settled

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(32)	**VARIABLE SUPPLY COSTS (Includes Injections)**														
(33)	Tennessee (Includes ANE and Niagara)				$2,560,567	$3,560,355	$2,048,049	$1,319,958	$887,539	$672,102	$297,940	$398,802	$715,471	$1,323,195	$13,783,977
(34)	TETCO (Includes B&W)				$158,513	$145,900	$78,559	$0	$0	$0	$0	$0	$0	$0	$382,972
(35)	M3 Delivered				$987,660	$1,076,909	$450,131	$893,074	$1,544,592	$372,743	$0	$0	$1,128,614	$827,022	$7,280,745
(36)	Maumee				$1,810,036	$1,683,842	$968,715	$124,738	$0	$0	$0	$0	$0	$0	$4,587,331
(37)	Broadrun Col				$807,323	$760,598	$701,873	$24,901	$0	$0	$0	$0	$0	$0	$2,294,694
(38)	Columbia Eagle and Downingtown				$1,048,004	$951,702	$792,272	$80,555	$96,863	$95,485	$83,327	$96,487	$56,147	$32,192	$3,333,033
(39)	TETCO M2				$1,923,197	$1,899,921	$2,016,550	$1,793,861	$610,211	$1,712,755	$1,773,418	$1,761,560	$895,627	$1,701,795	$16,088,895
(40)	Dominion to TETCO FTS				$44,940	$37,758	$40,049	$10,362	$0	$0	$0	$0	$0	$0	$133,108
(41)	Transco Leidy				$24,063,391	$90,390	$96,986	$26,935	$5,181	$4,964	$5,028	$5,014	$4,493	$4,951	$24,307,333
(42)	DistriGas FCS				$2,572,300	$2,299,114	$1,223,826	$893,164	$927,990	$25,397	$0	$0	$0	$7,270	$7,949,060
(43)	Hubline				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(44)	Total Pipeline Commodity Charges	Sum[(33):(43)]	$6,267,229	$19,836,786	$35,975,931	$12,506,488	$8,417,008	$5,167,548	$4,072,376	$2,883,446	$2,159,712	$2,261,863	$2,800,352	$3,896,424	$106,245,164
(45)	Hedging Settlements and Amortization		$1,211,420	$240,620	$799,725	$184,033	$1,140,074	$158,137	$155,032	$109,998	$83,716	$78,358	$101,322	$153,312	$4,415,747
(46)	Hedging Contracts - Commission & Other Fees		$6,189	$51,886	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$58,076
(47)	Hedging Contracts - Net Carry of Collateral		$1,141	$1,517	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,658
(48)	Refunds		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(49)	Less: Costs of Injections		$0	$0	$0	$0	$0	($148,848)	($1,167,969)	($1,099,173)	($749,700)	($977,367)	($1,496,071)	($1,326,131)	($6,965,258)
(50)	**TOTAL VARIABLE SUPPLY COSTS**	Sum[(44):(49)]	$7,485,980	$20,130,810	$36,775,656	$12,690,521	$9,557,082	$5,176,838	$3,059,439	$1,894,271	$1,493,728	$1,362,853	$1,405,603	$2,723,605	$103,756,386
(51)	Underground Storage		$769,274	$1,530,092	$1,920,448	$1,755,292	$1,603,567	$110,523	$0	$0	$0	$0	$0	$0	$7,689,197
(52)	LNG Withdrawals and Trucking		$70,178	$1,215,597	$1,934,136	$738,848	$77,949	$75,435	$76,236	$73,444	$75,932	$77,719	$77,177	$79,002	$4,571,652
(53)	Storage Delivery Costs		$0	$0	$115,421	$105,741	$97,222	$4,828	$0	$0	$0	$0	$0	$0	$323,212
(54)	**TOTAL VARIABLE STORAGE COSTS**	Sum[(51):(53)]	$839,453	$2,745,689	$3,970,005	$2,599,881	$1,778,738	$190,785	$76,236	$73,444	$75,932	$77,719	$77,177	$79,002	$12,584,060
(55)	**TOTAL VARIABLE COSTS**	(50) + (54)	$8,325,432	$22,876,499	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$116,340,447
(56)	**TOTAL SUPPLY COSTS**	(31) + (55)	$12,667,886	$27,309,286	$46,854,193	$21,396,798	$17,444,353	$9,898,682	$7,667,446	$6,498,775	$6,101,431	$5,972,343	$6,013,435	$7,333,975	$175,158,600

REDACTED

Supply Estimates and Actuals for Filing

Projected Gas Costs using 01/08/2018 NYMEX settled

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(57)	**Storage Costs for FT-2 Calculation**														
(58)	**Storage Fixed Costs - Facilities**		$393,734	$390,309	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$4,778,263
(59)	**Storage Fixed Costs - Deliveries**		$835,058	$868,336	$2,529,803	$2,529,803	$2,529,803	$957,522	$957,522	$957,522	$957,522	$957,522	$957,522	$957,522	$15,995,456
(60)	**sub-total Storage Costs**	Sum[(57):(58)]	$1,228,792	$1,258,645	$2,929,225	$2,929,225	$2,929,225	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$20,773,719
(61)	**Tennessee Dracut for Peaking.**		$0	$0	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$1,352,240
(62)	**Inventory Financing**		$112,855	$91,342	$52,343	$34,072	$21,632	$26,469	$39,805	$52,777	$60,169	$68,590	$85,040	$96,167	$741,261
(63)	**Supply related LNG O&M Costs**		$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$575,581
(64)	**Working Capital Requirement**		$3,042	$3,139	$15,368	$15,368	$15,368	$6,306	$6,306	$6,306	$6,306	$6,306	$6,306	$6,306	$96,427
(65)	**Total FT-2 Storage Fixed Costs**	Sum[(60):(64)]	$1,392,654	$1,401,090	$3,180,125	$3,161,854	$3,149,413	$1,572,908	$1,586,244	$1,599,216	$1,606,608	$1,615,029	$1,631,479	$1,642,607	$23,539,228
(66)	**System Storage MDQ (Dth)**		198,328	206,312	183,659	183,659	183,659	183,659	183,659	183,659	183,659	183,659	183,659	183,659	2,241,230
(67)	**FT-2 Storage Cost per MDQ (Dth)**	(65) / (66)	$7.0220	$6.7911	$17.3154	$17.2159	$17.1482	$8.5643	$8.6369	$8.7075	$8.7478	$8.7936	$8.8832	$8.9438	$10.5028
(68)	Pipeline Variable	(55)	$8,325,432	$22,876,499	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$116,340,447
(69)	Less Non-firm Gas Costs		($69,482)	($174,134)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($243,615)
(70)	Less Company Use		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(71)	Less Manchester St Balancing		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(72)	Plus Cashout		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(73)	Less Mkter W/drawals/Injections		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(74)	Mkter Over-takes/Undertakes		$176,006	($10,887)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$165,119
(75)	Plus Pipeline Srchg/Credit		$525,389	$234,248	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$759,637
(76)	Less Mkter FT-2 Daily weather true-up		($12,437)	($3,288)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($15,725)
(77)	**TOTAL FIRM COMMODITY COSTS**	Sum[(68):(76)]	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862

REDACTED

GCR Revenue

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**I. Fixed Cost Revenue**														
(2)	(a) Low Load dth	Sch. 6, Sum[Lines (24):(28), (30)]	1,478,464	3,055,015	6,697,312	4,549,104	3,980,376	2,797,424	1,507,174	857,523	589,461	527,941	593,153	743,076	27,376,022
(3)	Fixed Cost Factor	(4) / (2)	$1.3460	$1.5512	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	
(4)	Low Load Revenue	(2) x (3)	$1,989,994	$4,738,829	$10,392,219	$7,058,845	$6,176,349	$4,340,763	$2,338,682	$1,330,619	$914,666	$819,206	$920,396	$1,153,031	$42,173,600
(5)	(b) High Load dth	Sch. 6, Sum[lines (22), (23), (29), (31)]	54,755	67,995	133,244	78,341	97,463	81,132	60,848	54,946	41,400	33,790	37,285	44,548	785,745
(6)	Fixed Cost Factor	(7) / (5)	$1.0189	$1.1333	$1.1342	$1.1342	$1.1342	$1.1342	$1.1342	$1.1342	1.1342	1.1342	1.1342	1.1342	
(7)	High Load Revenue	(5) x (6)	$55,792	$77,058	$151,125	$88,854	$110,543	$92,019	$69,014	$62,319	$46,956	$38,324	$42,288	$50,527	$884,819
(8)	sub-total throughput Dth	(2) + (5)	1,533,220	3,123,009	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,161,767
(9)	FT-2 Storage Revenue from marketers		$154,547	$187,123	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$2,041,978
(10)	Manchester Steet Volumes (dth)	Monthly Meter Use	930	763	0	0	0	0	0	0	0	0	0	0	
(11)	Fixed cost factor (dth)	Inherent in approved GCR	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	
(12)	Manchester Street Revenue	(10) x (11)	$1,490	$1,222	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,713
(13)	**TOTAL Fixed Revenue**	(4) + (7) + (9) + (12)	$2,201,823	$5,004,233	$10,713,375	$7,317,730	$6,456,923	$4,602,813	$2,577,727	$1,562,969	$1,131,653	$1,027,561	$1,132,715	$1,373,589	$45,103,110
(14)	**II. Variable Cost Revenue**														
(15)	(a) Firm Sales dth	(8)	1,533,220	3,123,009	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,161,767
(16)	Variable Supply Cost Factor	(17) / (15)	$3.5211	$3.5698	$3.5711	$3.5711	$3.5711	$3.5711	$3.5711	$3.5711	$3.5711	$3.5711	$3.5711	$3.5711	
(17)	Variable Supply Revenue	(15) x (16)	$5,398,547	$11,148,618	$24,392,597	$16,525,069	$14,562,370	$10,279,609	$5,599,562	$3,258,518	$2,252,867	$2,005,995	$2,251,356	$2,812,684	$100,487,792
(18)	(b) TSS Sales dth	Sch. 6, line (20)	2,513	12,138	0	0	0	0	0	0	0	0	0	0	14,650
(19)	TSS Surcharge Factor	Company's website	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
(20)	TSS Surcharge Revenue	(18) x (19)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21)	(c) Default Sales dth	Sch. 6, line (60)	4,332	9,934	0	0	0	0	0	0	-	-	-	-	14,266
(22)	Variable Supply Cost Factor	(23) / (21)	$6.75	$8.23	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
(23)	Variable Supply Revenue	(21) x (22)	$29,250	$81,788	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$111,038
(24)	(d) Peaking Gas Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(25)	(e) Deferred Responsibility		$12,967	$10,056	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,024
(26)	(e) FT-1 Storage and Peaking														
(27)	Manchester Steet Volumes (dth)	Monthly Meter Use	930	763	0	0	0	0	0	0	0	0	0	0	
(28)	Variable Supply Cost Factor (dth)	Inherent in approved GCR	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	
(29)	Manchester Street Revenue	(27) x (28)	$3,430	$2,812	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,243
(30)	**TOTAL Variable Revenue**	(17)+(20)+(23)+(24)+(25)+(26)+(29)	$5,444,194	$11,243,275	$24,392,597	$16,525,069	$14,562,370	$10,279,609	$5,599,562	$3,258,518	$2,252,867	$2,005,995	$2,251,356	$2,812,684	$100,628,096
(31)	**Total Gas Cost Revenue** (w/o FT-2)	(13) + (30)	$7,646,017	$16,247,508	$35,105,972	$23,842,799	$21,019,293	$14,882,422	$8,177,289	$4,821,487	$3,384,520	$3,033,556	$3,384,071	$4,186,273	$145,731,206

Lines (12) and (29): Pursuant to the Division of Public Utilities and Carriers' approval in Docket No. D-15-04 of the Company's transportation contract for gas delivered to Manchester St. Station, beginning in July 2015, the Company is crediting imputed revenue to offset the gas costs associated with heater gas used at Manchester St. Station

REDACTED

WORKING CAPITAL

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**Supply Fixed Costs**	Sch. 1, line (4)	$4,342,453	$4,432,787	$6,108,532	$6,106,396	$6,108,532	$4,531,059	$4,531,771	$4,531,059	$4,531,771	$4,531,771	$4,530,656	$4,531,368	$58,818,154
(2)	Less: LNG Demand to DAC	Sch. 1, line (5)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($3,153,600)
(3)	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(4)	Total Adjustments	(2) + (3)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($3,153,600)
(5)	Allowable Working Capital Costs	(1) + (4)	$4,079,653	$4,169,987	$5,845,732	$5,843,596	$5,845,732	$4,268,259	$4,268,971	$4,268,259	$4,268,971	$4,268,971	$4,267,856	$4,268,568	$55,664,554
(6)	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
(7)	Working Capital Requirement	[(5) x (6)] / 365	$240,420	$245,744	$344,498	$344,372	$344,498	$251,535	$251,577	$251,535	$251,577	$251,577	$251,511	$251,553	
(8)	Cost of Capital	Dkt 4339	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(9)	Return on Working Capital Requirement	(7) x (8)	$17,454	$17,841	$25,011	$25,001	$25,011	$18,261	$18,264	$18,261	$18,264	$18,264	$18,260	$18,263	
(10)	Weighted Cost of Debt	Dkt 4339	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(11)	Interest Expense	(7) x (10)	$6,203	$6,340	$8,888	$8,885	$8,888	$6,490	$6,491	$6,490	$6,491	$6,491	$6,489	$6,490	
(12)	Taxable Income	(9) - (11)	$11,252	$11,501	$16,122	$16,117	$16,122	$11,772	$11,774	$11,772	$11,774	$11,774	$11,771	$11,773	
(13)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(14)	Return and Tax Requirement	(12) / (13)	$17,310	$17,694	$20,408	$20,401	$20,408	$14,901	$14,904	$14,901	$14,904	$14,904	$14,900	$14,902	
(15)	**Supply Fixed Working Capital Requirement**	(11) + (14)	$23,513	$24,034	$29,296	$29,286	$29,296	$21,391	$21,394	$21,391	$21,394	$21,394	$21,389	$21,392	$285,170
(16)	**Supply Variable Costs**	Sch. 1, line (20)	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862
(17)	Less: Balancing Related LNG Commodity (to DAC)	Sch. 1, line (21)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19)	Total Adjustments	(17) + (18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20)	Allowable Working Capital Costs	(16) + (19)	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862
(21)	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
(22)	Working Capital Requirement	[(20) x (21)] / 365	$527,137	$1,350,854	$2,401,203	$901,086	$668,037	$316,322	$184,790	$115,960	$92,502	$84,895	$87,382	$165,162	
(23)	Cost of Capital	Dkt 4339	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(24)	Return on Working Capital Requirement	(22) x (23)	$38,270	$98,072	$174,327	$65,419	$48,499	$22,965	$13,416	$8,419	$6,716	$6,163	$6,344	$11,991	
(25)	Weighted Cost of Debt	Dkt 4339	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(26)	Interest Expense	(22) x (25)	$13,600	$34,852	$61,951	$23,248	$17,235	$8,161	$4,768	$2,992	$2,387	$2,190	$2,254	$4,261	
(27)	Taxable Income	(24) - (26)	$24,670	$63,220	$112,376	$42,171	$31,264	$14,804	$8,648	$5,427	$4,329	$3,973	$4,089	$7,730	
(28)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(29)	Return and Tax Requirement	(27) / (28)	$37,954	$97,261	$142,248	$53,381	$39,575	$18,739	$10,947	$6,870	$5,480	$5,029	$5,177	$9,784	
(30)	**Supply Variable Working Capital Requirement**	(26) + (29)	$51,554	$132,114	$204,200	$76,629	$56,810	$26,900	$15,715	$9,861	$7,866	$7,220	$7,431	$14,045	$610,345

REDACTED

National Grid
Rhode Island - Gas

INVENTORY FINANCE

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**Storage Inventory Balance**		$9,637,833	$8,298,259	$6,127,822	$4,288,451	$2,610,887	$2,653,444	$3,877,029	$5,066,626	$5,878,226	$6,941,021	$8,623,396	$10,069,304	
(2)	Monthly Storage Deferral/Amortization		$275,404	$224,820	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(3)	**Subtotal**	(1) + (2)	$9,913,237	$8,523,079	$6,127,822	$4,288,451	$2,610,887	$2,653,444	$3,877,029	$5,066,626	$5,878,226	$6,941,021	$8,623,396	$10,069,304	
(4)	Cost of Capital	Dkt 4323	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(5)	Return on Working Capital Requirement	(3) x (4)	$719,701	$618,776	$444,880	$311,342	$189,550	$192,640	$281,472	$367,837	$426,759	$503,918	$626,059	$731,031	$5,413,965
(6)	Weighted Cost of Debt	Dkt 4323	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(7)	Interest Charges Financed	(3) x (6)	$255,762	$219,895	$158,098	$110,642	$67,361	$68,459	$100,027	$130,719	$151,658	$179,078	$222,484	$259,788	$1,923,971
(8)	Taxable Income	(5) - (7)	$463,939	$398,880	$286,782	$200,700	$122,189	$124,181	$181,445	$237,118	$275,101	$324,840	$403,575	$471,243	
(9)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(10)	Return and Tax Requirement	(8) / (9)	$713,753	$613,662	$363,015	$254,050	$154,670	$157,191	$229,677	$300,149	$348,229	$411,190	$510,854	$596,511	$4,652,952
(11)	Working Capital Requirement	(7) + (10)	$969,515	$833,557	$521,113	$364,692	$222,031	$225,650	$329,705	$430,868	$499,887	$590,268	$733,338	$856,299	$6,576,923
(12)	Monthly Average	(11) / 12	$80,793	$69,463	$43,426	$30,391	$18,503	$18,804	$27,475	$35,906	$41,657	$49,189	$61,111	$71,358	$548,077
(13)	**LNG Inventory Balance**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(14)	Cost of Capital	Dkt 4323	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(15)	Return on Working Capital Requirement	(13) x (14)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,906,990
(16)	Weighted Cost of Debt	Dkt 4323	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(17)	Interest Charges Financed	(13) x (16)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$677,691
(18)	Taxable Income	(15) - (17)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(19)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(20)	Return and Tax Requirement	(18) / (19)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,640,524
(21)	Working Capital Requirement	(17) + (20)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,318,214
(22)	Monthly Average	(21) / 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$193,185
(23)	TOTAL GCR Inventory Financing Costs	(12) + (22)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$741,261

REDACTED

Actual Dth Usage for Filing

	THROUGHPUT (Dth) Rate Class	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**SALES**													
(2)	Residential Non-Heating	25,799	36,375	78,118	46,689	63,744	50,294	32,303	22,003	16,157	14,197	15,072	17,788	418,539
(3)	Residential Non-Heating Low Income	506	908	0	0	0	0	0	0	0	0	0	0	1,414
(4)	Residential Heating	1,049,547	2,123,640	5,033,640	3,515,651	3,025,940	2,123,608	1,134,913	640,980	439,872	378,733	439,199	549,175	20,454,897
(5)	Residential Heating Low Income	85,126	174,014	0	0	0	0	0	0	0	0	0	0	259,141
(6)	Small C&I	111,854	277,727	667,862	433,958	388,594	265,063	116,832	75,482	45,315	41,777	47,836	57,800	2,530,098
(7)	Medium C&I	195,033	383,557	808,432	478,851	459,399	337,938	214,438	122,975	95,239	99,371	93,976	121,150	3,410,359
(8)	Large LLF	32,729	77,403	173,833	111,958	99,039	65,916	38,351	16,635	8,837	7,982	11,775	14,173	658,629
(9)	Large HLF	19,260	22,406	48,223	27,387	26,615	23,997	23,632	27,213	19,713	14,410	15,671	18,743	287,270
(10)	Extra Large LLF	1,662	7,001	13,545	8,686	7,404	4,898	2,641	1,452	198	78	368	778	48,712
(11)	Extra Large HLF	9,191	7,841	6,902	4,265	7,104	6,841	4,912	5,730	5,529	5,182	6,542	8,018	78,058
(12)	**Total Sales**	1,530,707	3,110,872	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,147,117
(13)	**TSS**													
(14)	Small	26	327	0	0	0	0	0	0	0	0	0	0	353
(15)	Medium	1,986	6,054	0	0	0	0	0	0	0	0	0	0	8,040
(16)	Large LLF	501	5,293	0	0	0	0	0	0	0	0	0	0	5,794
(17)	Large HLF	0	464	0	0	0	0	0	0	0	0	0	0	464
(18)	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(20)	**Total TSS**	2,513	12,138	0	0	0	0	0	0	0	0	0	0	14,650
(21)	**Sales & TSS THROUGHPUT**													
(22)	Residential Non-Heating	25,799	36,375	78,118	46,689	63,744	50,294	32,303	22,003	16,157	14,197	15,072	17,788	418,539
(23)	Residential Non-Heating Low Income	506	908	0	0	0	0	0	0	0	0	0	0	1,414
(24)	Residential Heating	1,049,547	2,123,640	5,033,640	3,515,651	3,025,940	2,123,608	1,134,913	640,980	439,872	378,733	439,199	549,175	20,454,897
(25)	Residential Heating Low Income	85,126	174,014	0	0	0	0	0	0	0	0	0	0	259,141
(26)	Small C&I	111,880	278,053	667,862	433,958	388,594	265,063	116,832	75,482	45,315	41,777	47,836	57,800	2,530,450
(27)	Medium C&I	197,019	389,610	808,432	478,851	459,399	337,938	214,438	122,975	95,239	99,371	93,976	121,150	3,418,399
(28)	Large LLF	33,230	82,697	173,833	111,958	99,039	65,916	38,351	16,635	8,837	7,982	11,775	14,173	664,423
(29)	Large HLF	19,260	22,871	48,223	27,387	26,615	23,997	23,632	27,213	19,713	14,410	15,671	18,743	287,735
(30)	Extra Large LLF	1,662	7,001	13,545	8,686	7,404	4,898	2,641	1,452	198	78	368	778	48,712
(31)	Extra Large HLF	9,191	7,841	6,902	4,265	7,104	6,841	4,912	5,730	5,529	5,182	6,542	8,018	78,058
(32)	**Total Sales & TSS Throughput**	1,533,220	3,123,009	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,161,767

REDACTED

Actual Dth Usage for Filing

		Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
	THROUGHPUT (Dth)													
	Rate Class													
(33)	**FT-1 TRANSPORTATION**													
(34)	FT-1 Medium	30,639	60,057	82,603	69,210	61,901	50,742	31,888	21,653	21,013	19,318	21,408	35,222	505,655
(35)	FT-1 Large LLF	34,759	97,785	155,618	133,244	113,703	65,130	33,765	19,154	14,104	14,041	18,967	49,248	749,517
(36)	FT-1 Large HLF	32,023	38,641	44,327	38,828	41,285	36,844	32,268	38,409	34,345	33,598	34,094	36,653	441,316
(37)	FT-1 Extra Large LLF	48,732	127,674	208,395	179,321	156,757	95,789	57,371	25,418	18,571	17,506	23,902	75,474	1,034,910
(38)	FT-1 Extra Large HLF	433,197	494,103	606,826	517,876	547,262	545,125	507,575	495,697	509,032	501,923	469,060	501,274	6,128,948
(39)	Default	4,332	9,934	0	0	0	0	0	0	0	0	0	0	14,266
(40)	**Total FT-1 Transportation**	583,682	828,194	1,097,770	938,479	920,908	793,630	662,867	600,331	597,065	586,386	567,430	697,872	8,874,612
(41)	**FT-2 TRANSPORTATION**													
(42)	FT-2 Small	6,121	14,942	24,139	25,356	22,502	17,022	10,822	5,728	3,123	2,694	3,241	6,419	142,110
(43)	FT-2 Medium	115,362	220,831	280,510	269,362	259,633	199,336	131,426	75,625	55,737	49,625	50,351	68,497	1,776,295
(44)	FT-2 Large LLF	60,802	159,214	212,126	218,045	193,970	131,076	76,859	34,677	19,007	17,387	24,596	32,879	1,180,639
(45)	FT-2 Large HLF	36,322	47,803	60,792	56,509	54,705	48,990	43,826	36,028	27,713	26,177	28,472	31,150	498,488
(46)	FT-2 Extra Large LLF	126	2,476	8,818	9,930	8,775	6,821	4,441	2,652	1,362	1,184	1,289	2,063	49,937
(47)	FT-2 Extra Large HLF	47,318	52,276	54,080	50,272	48,750	50,425	43,130	44,111	36,715	36,604	46,095	38,887	548,664
(48)	**Total FT-2 Transportation**	266,050	497,542	640,465	629,475	588,336	453,669	310,505	198,821	143,659	133,672	154,043	179,896	4,196,132
(49)	**Total THROUGHPUT**													
(50)	Residential Non-Heating	25,799	36,375	78,118	46,689	63,744	50,294	32,303	22,003	16,157	14,197	15,072	17,788	418,539
(51)	Residential Non-Heating Low Income	506	908	0	0	0	0	0	0	0	0	0	0	1,414
(52)	Residential Heating	1,049,547	2,123,640	5,033,640	3,515,651	3,025,940	2,123,608	1,134,913	640,980	439,872	378,733	439,199	549,175	20,454,897
(53)	Residential Heating Low Income	85,126	174,014	0	0	0	0	0	0	0	0	0	0	259,141
(54)	Small C&I	118,001	292,995	692,001	459,314	411,096	282,085	127,654	81,210	48,438	44,471	51,076	64,219	2,672,560
(55)	Medium C&I	343,020	670,498	1,171,545	817,424	780,934	588,016	377,752	220,253	171,990	168,314	165,735	224,869	5,700,349
(56)	Large LLF	128,791	339,695	541,577	463,247	406,712	262,122	148,974	70,466	41,947	39,409	55,337	96,300	2,594,578
(57)	Large HLF	87,605	109,315	153,343	122,724	122,605	109,831	99,726	101,650	81,771	74,186	78,236	86,545	1,227,538
(58)	Extra Large LLF	50,519	137,151	230,758	197,936	172,935	107,508	64,454	29,522	20,131	18,769	25,559	78,316	1,133,559
(59)	Extra Large HLF	489,706	554,220	667,808	572,413	603,116	602,390	555,617	545,537	551,277	543,710	521,696	548,179	6,755,670
(60)	Default	4,332	9,934	0	0	0	0	0	0	0	0	0	0	14,266
(61)	**Total Throughput**	2,382,952	4,448,745	8,568,790	6,195,399	5,587,083	4,125,854	2,541,393	1,711,620	1,371,584	1,281,789	1,351,911	1,665,391	41,232,511

Attachment AEL-3
REDACTED

Attachment AEL-3
Deferred Gas Cost Balances With Interim GCR

REDACTED

National Grid
Rhode Island - Gas

Schedule 1
Page 1 of 1

Deferred Gas Cost Balances

	Description	Reference	Nov Actual	Dec Actual	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov-Oct
(1)	# of Days in Month		30	31	31	28	31	30	31	30	31	31	30	31	365
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(2)	I. Fixed Cost Deferred														
(3)	Beginning Under/(Over) Recovery		$1,106,719	$2,186,800	$518,946	($5,184,717)	($7,502,087)	($8,961,811)	($10,154,962)	($9,323,349)	($7,474,277)	($5,189,363)	($2,795,395)	($502,619)	$1,106,719
(4)	Supply Fixed Costs (net of cap rel)	Sch. 2, line (31)	$4,342,453	$4,432,787	$6,108,532	$6,106,396	$6,108,532	$4,531,059	$4,531,771	$4,531,059	$4,531,771	$4,531,771	$4,530,656	$4,531,368	$58,818,154
(5)	System Pressure to DAC	Dkt 4719	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($3,153,600)
(6)	Supply Related LNG O & M	Dkt 4323	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$575,581
(7)	NGPMP Credits		($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($10,900,000)
(8)	Working Capital	Sch. 4, line (15)	$23,513	$24,034	$29,296	$29,286	$29,296	$21,391	$21,394	$21,391	$21,394	$21,394	$21,389	$21,392	$285,170
(9)	Total Supply Fixed Costs	Sum[(4):(8)]	$3,242,798	$3,333,652	$5,014,660	$5,012,513	$5,014,660	$3,429,281	$3,429,997	$3,429,281	$3,429,997	$3,429,997	$3,428,876	$3,429,592	$45,625,304
(10)	Supply Fixed - Revenue	Sch. 3, line 13	$2,201,823	$5,004,233	$10,713,375	$7,317,730	$6,456,923	$4,602,813	$2,577,727	$1,562,969	$1,131,653	$1,027,561	$1,132,715	$1,373,589	$45,103,110
(11)	Monthly Under/(Over) Recovery	(9) - (10)	$1,040,975	($1,670,580)	($5,698,715)	($2,305,217)	($1,442,263)	($1,173,532)	$852,270	$1,866,312	$2,298,344	$2,402,436	$2,296,161	$2,056,003	$522,195
(12)	Prelim. Ending Under/(Over) Recovery	(3) + (11)	$2,147,693	$516,220	($5,179,769)	($7,489,934)	($8,944,350)	($10,135,342)	($9,302,692)	($7,457,037)	($5,175,933)	($2,786,927)	($499,234)	$1,553,384	$1,628,914
(13)	Month's Average Balance	[(3) + (12)] / 2	$1,627,206	$1,351,510	($2,330,411)	($6,337,325)	($8,223,219)	($9,548,576)	($9,728,827)	($8,390,193)	($6,325,105)	($3,988,145)	($1,647,315)	$525,383	
(14)	Interest Rate (BOA Prime minus 200 bps)		2.25%	2.38%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
(15)	Interest Applied	[(13) x (14)] / 365 x (1)	$3,009	$2,726	($4,948)	($12,154)	($17,460)	($19,620)	($20,657)	($17,240)	($13,430)	($8,468)	($3,385)	$1,116	($110,512)
(16)	Marketer Reconcilation	Dkt 4719, AEL-7, Line (50)	$36,098	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$36,098
(17)	Fixed Ending Under/(Over) Recovery	(12) + (15) + (16)	$2,186,800	$518,946	($5,184,717)	($7,502,087)	($8,961,811)	($10,154,962)	($9,323,349)	($7,474,277)	($5,189,363)	($2,795,395)	($502,619)	$1,554,499	$1,554,499
(18)	II. Variable Cost Deferred														
(19)	Beginning Under/(Over) Recovery		$13,703,849	$17,445,473	$29,443,058	$46,180,590	$45,191,882	$37,591,724	$26,369,728	$20,530,775	$17,336,145	$15,383,962	$13,709,032	$11,688,233	$13,703,849
(20)	Variable Supply Costs	Sch. 2, line (77)	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862
(21)	Supply Related LNG to DAC	Dkt 4339	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	Supply Related LNG O & M	Dkt 4323	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$47,725	$572,694
(23)	Inventory Financing - LNG	Sch. 5, line (22)	$32,062	$21,879	$8,917	$3,681	$3,129	$7,665	$12,330	$16,871	$18,512	$19,401	$23,928	$24,809	$193,185
(24)	Inventory Financing - UG	Sch. 5, line (12)	$80,793	$69,463	$43,426	$30,391	$18,503	$18,804	$27,475	$35,906	$41,657	$49,189	$61,111	$71,358	$548,077
(25)	Working Capital	Sch. 4, line (30)	$51,554	$132,114	$204,200	$76,629	$56,810	$26,900	$15,715	$9,861	$7,866	$7,220	$7,431	$14,045	$610,345
(26)	Total Supply Variable Costs	Sum[(20):(25)]	$9,157,042	$23,193,618	$41,049,928	$15,448,828	$11,461,987	$5,468,717	$3,238,919	$2,078,078	$1,685,420	$1,564,106	$1,622,975	$2,960,545	$118,930,162
(27)	Supply Variable - Revenue	Sch. 3, line (30)	$5,444,194	$11,243,275	$24,392,597	$16,525,069	$19,149,938	$16,756,359	$9,127,611	$5,311,573	$3,672,303	$3,269,889	$3,669,841	$4,584,838	$123,147,487
(28)	Monthly Under/(Over) Recovery	(26) - (27)	$3,712,848	$11,950,343	$16,657,331	($1,076,241)	($7,687,951)	($11,287,642)	($5,888,692)	($3,233,495)	($1,986,883)	($1,705,783)	($2,046,866)	($1,624,293)	($4,217,325)
(29)	Prelim. Ending Under/(Over) Recovery	(19) + (28)	$17,416,697	$29,395,816	$46,100,389	$45,104,348	$37,503,931	$26,304,082	$20,481,036	$17,297,280	$15,349,262	$13,678,179	$11,662,167	$10,063,939	$9,486,524
(30)	Month's Average Balance	[(19) + (29)] / 2	$15,560,273	$23,420,644	$37,771,724	$45,642,469	$41,347,906	$31,947,903	$23,425,382	$18,914,027	$16,342,703	$14,531,070	$12,685,600	$10,876,086	
(31)	Interest Rate (BOA Prime minus 200 bps)		2.25%	2.38%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
(32)	Interest Applied	[(30) x (31)] / 365 x (1)	$28,776	$47,242	$80,200	$87,534	$87,793	$65,646	$49,739	$38,864	$34,700	$30,854	$26,066	$23,093	$600,508
(33)	Gas Procurement Incentive/(penalty)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(34)	Variable Ending Under/(Over) Recovery	(29) + (32) + (33)	$17,445,473	$29,443,058	$46,180,590	$45,191,882	$37,591,724	$26,369,728	$20,530,775	$17,336,145	$15,383,962	$13,709,032	$11,688,233	$10,087,032	$10,087,032
(35)	**GCR Deferred Summary**														
(36)	Beginning Under/(Over) Recovery	(3) + (19)	$14,810,568	$19,632,273	$29,962,004	$40,995,873	$37,689,794	$28,629,914	$16,214,766	$11,207,425	$9,861,867	$10,194,599	$10,913,638	$11,185,614	$14,810,568
(37)	Gas Costs	Sum[(4):(6),(16),(20):(22)]	$13,156,349	$27,188,114	$46,687,083	$21,229,687	$17,277,242	$9,731,571	$7,500,335	$6,331,664	$5,934,321	$5,805,232	$5,846,325	$7,166,864	$173,854,788
(38)	Inventory Finance	(23) + (24)	$112,855	$91,342	$52,343	$34,072	$21,632	$26,469	$39,805	$52,777	$60,169	$68,590	$85,040	$96,167	$741,261
(39)	Working Capital	(8) + (25)	$75,067	$156,147	$233,496	$105,914	$86,106	$48,291	$37,109	$31,252	$29,261	$28,614	$28,820	$35,438	$895,514
(40)	NGPMP Credits	(7)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($908,333)	($10,900,000)
(41)	Total Costs	Sum[(37):(40)]	$12,435,937	$26,527,270	$46,064,589	$20,461,341	$16,476,647	$8,897,998	$6,668,916	$5,507,360	$5,115,417	$4,994,103	$5,051,851	$6,390,136	$164,591,565
(42)	Revenue	(10) + (27)	$7,646,018	$16,247,507	$35,105,972	$23,842,799	$25,606,861	$21,359,172	$11,705,338	$6,874,542	$4,803,956	$4,297,450	$4,802,556	$5,958,427	$168,250,597
(43)	Monthly Under/(Over) Recovery	(41) - (42)	$4,789,920	$10,279,763	$10,958,617	($3,381,458)	($9,130,214)	($12,461,174)	($5,036,422)	($1,367,182)	$311,461	$696,653	$249,295	$431,709	($3,659,032)
(44)	Prelim. Ending Under/(Over) Recovery	(36) + (43)	$19,600,488	$29,912,035	$40,920,621	$37,614,415	$28,559,580	$16,168,740	$11,178,344	$9,840,243	$10,173,328	$10,891,252	$11,162,933	$11,617,323	
(45)	Month's Average Balance	[(36) + (44)] / 2	$17,205,528	$24,772,154	$35,441,312	$39,305,144	$33,124,687	$22,399,327	$13,696,555	$10,523,834	$10,017,598	$10,542,925	$11,038,285	$11,401,469	
(46)	Interest Rate (BOA Prime minus 200 bps)		2.25%	2.38%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
(47)	Interest Applied	(15) + (32)	$31,785	$49,968	$75,252	$75,380	$70,333	$46,026	$29,082	$21,624	$21,270	$22,386	$22,681	$24,209	$489,997
(48)	Gas Purchase Plan Incentives/(Penalties)	(33)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(49)	**Ending Under/(Over) Recovery W/ Interest**	(44) + (47) + (48)	$19,632,273	$29,962,004	$40,995,873	$37,689,794	$28,629,914	$16,214,766	$11,207,425	$9,861,867	$10,194,599	$10,913,638	$11,185,614	$11,641,532	$11,641,532

REDACTED

Supply Estimates and Actuals for Filing

Projected Gas Costs using 01/08/2018 NYMEX settled

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**SUPPLY FIXED COSTS - Pipeline Delivery**														
(2)	Algonquin (w/East to West, Hubline, AMA credits, Crary St.)		$1,619,095	$1,688,947	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$1,670,438	$20,012,419
(3)	TETCO/Texas Eastern		$710,994	$718,333	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$717,273	$8,602,057
(4)	Tennessee		$1,093,271	$1,093,271	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$1,093,215	$13,118,696
(5)	Tennessee Dracut for Peaking		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6)	Iroquois		$6,070	$6,146	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$5,667	$5,667	$72,111
(7)	Union		$0	$0	$2,984	$2,695	$2,984	$2,887	$2,984	$2,887	$2,984	$2,984	$2,887	$2,984	$29,259
(8)	Transcanada		$0	$0	$14,077	$12,715	$14,077	$13,623	$14,077	$13,623	$14,077	$14,077	$13,623	$14,077	$138,048
(9)	Dominion		$2,295	$2,295	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$26,967
(10)	Transco		$4,854	$5,015	$5,016	$4,530	$5,016	$4,854	$5,016	$4,854	$5,016	$5,016	$4,854	$5,016	$59,055
(11)	National Fuel		$4,480	$4,549	$4,480	$4,480	$4,480	$0	$0	$0	$0	$0	$0	$0	$22,471
(12)	Columbia		$307,936	$307,936	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$3,695,226
(13)	Alberta Northeast		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(14)	Less Credits from Mkter Releases		($671,640)	($688,879)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($692,715)	($8,287,667)
			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(15)	**Supply Fixed - Supplier**														
(16)	Distrigas FCS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17)	**Total**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	**STORAGE FIXED COSTS - Facilities**														
(19)	Texas Eastern		$88,875	$85,450	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$94,535	$1,119,670
(20)	Dominion		$83,088	$83,088	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$83,117	$997,343
(21)	Tennessee		$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$48,337	$580,041
(22)	Columbia		$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$116,328
(23)	National Grid LNG Tank Lease Payments		$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$1,964,880
(24)	**STORAGE FIXED COSTS - Delivery**														
(25)	Algonquin		$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$215,436	$2,585,230
(26)	TETCO		$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$87,605	$1,051,257
(27)	Tennessee		$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$88,286	$1,059,436
(28)	Dominion		$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$30,774	$369,288
(29)	Columbia		$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$192,982
(30)	**Confidential Pipelinne and Peaking Supplies**		$433,181	$466,683	$2,139,916	$2,139,916	$2,139,916	$567,635	$567,635	$567,635	$567,635	$567,635	$567,635	$567,635	$11,293,056
(31)	**TOTAL FIXED COSTS**	Sum[(2):(30)]	$4,342,453	$4,432,787	$6,108,532	$6,106,396	$6,108,532	$4,531,059	$4,531,771	$4,531,059	$4,531,771	$4,531,771	$4,530,656	$4,531,368	$58,818,154

REDACTED

Supply Estimates and Actuals for Filing

Projected Gas Costs using 01/08/2018 NYMEX settled

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(32)	**VARIABLE SUPPLY COSTS (Includes Injections)**														
(33)	Tennessee (Includes ANE and Niagara)				$2,560,567	$3,560,355	$2,048,049	$1,319,958	$887,539	$672,102	$297,940	$398,802	$715,471	$1,323,195	$13,783,977
(34)	TETCO (Includes B&W)				$158,513	$145,900	$78,559	$0	$0	$0	$0	$0	$0	$0	$382,972
(35)	M3 Delivered				$987,660	$1,076,909	$450,131	$893,074	$1,544,592	$372,743	$0	$0	$1,128,614	$827,022	$7,280,745
(36)	Maumee				$1,810,036	$1,683,842	$968,715	$124,738	$0	$0	$0	$0	$0	$0	$4,587,331
(37)	Broadrun Col				$807,323	$760,598	$701,873	$24,901	$0	$0	$0	$0	$0	$0	$2,294,694
(38)	Columbia Eagle and Downingtown				$1,048,004	$951,702	$792,272	$80,555	$96,863	$95,485	$83,327	$96,487	$56,147	$32,192	$3,333,033
(39)	TETCO M2				$1,923,197	$1,899,921	$2,016,550	$1,793,861	$610,211	$1,712,755	$1,773,418	$1,761,560	$895,627	$1,701,795	$16,088,895
(40)	Dominion to TETCO FTS				$44,940	$37,758	$40,049	$10,362	$0	$0	$0	$0	$0	$0	$133,108
(41)	Transco Leidy				$24,063,391	$90,390	$96,986	$26,935	$5,181	$4,964	$5,028	$5,014	$4,493	$4,951	$24,307,333
(42)	DistriGas FCS				$2,572,300	$2,299,114	$1,223,826	$893,164	$927,990	$25,397	$0	$0	$0	$7,270	$7,949,060
(43)	Hubline				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(44)	Total Pipeline Commodity Charges	Sum[(33):(43)]	$6,267,229	$19,836,786	$35,975,931	$12,506,488	$8,417,008	$5,167,548	$4,072,376	$2,883,446	$2,159,712	$2,261,863	$2,800,352	$3,896,424	$106,245,164
(45)	Hedging Settlements and Amortization		$1,211,420	$240,620	$799,725	$184,033	$1,140,074	$158,137	$155,032	$109,998	$83,716	$78,358	$101,322	$153,312	$4,415,747
(46)	Hedging Contracts - Commission & Other Fees		$6,189	$51,886	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$58,076
(47)	Hedging Contracts - Net Carry of Collateral		$1,141	$1,517	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,658
(48)	Refunds		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(49)	Less: Costs of Injections		$0	$0	$0	$0	$0	($148,848)	($1,167,969)	($1,099,173)	($749,700)	($977,367)	($1,496,071)	($1,326,131)	($6,965,258)
(50)	**TOTAL VARIABLE SUPPLY COSTS**	Sum[(44):(49)]	$7,485,980	$20,130,810	$36,775,656	$12,690,521	$9,557,082	$5,176,838	$3,059,439	$1,894,271	$1,493,728	$1,362,853	$1,405,603	$2,723,605	$103,756,386
(51)	Underground Storage		$769,274	$1,530,092	$1,920,448	$1,755,292	$1,603,567	$110,523	$0	$0	$0	$0	$0	$0	$7,689,197
(52)	LNG Withdrawals and Trucking		$70,178	$1,215,597	$1,934,136	$738,848	$77,949	$75,435	$76,236	$73,444	$75,932	$77,719	$77,177	$79,002	$4,571,652
(53)	Storage Delivery Costs		$0	$0	$115,421	$105,741	$97,222	$4,828	$0	$0	$0	$0	$0	$0	$323,212
(54)	**TOTAL VARIABLE STORAGE COSTS**	Sum[(51):(53)]	$839,453	$2,745,689	$3,970,005	$2,599,881	$1,778,738	$190,785	$76,236	$73,444	$75,932	$77,719	$77,177	$79,002	$12,584,060
(55)	**TOTAL VARIABLE COSTS**	(50) + (54)	$8,325,432	$22,876,499	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$116,340,447
(56)	**TOTAL SUPPLY COSTS**	(31) + (55)	$12,667,886	$27,309,286	$46,854,193	$21,396,798	$17,444,353	$9,898,682	$7,667,446	$6,498,775	$6,101,431	$5,972,343	$6,013,435	$7,333,975	$175,158,600

REDACTED

Supply Estimates and Actuals for Filing

Projected Gas Costs using 01/08/2018 NYMEX settled

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(57)	**Storage Costs for FT-2 Calculation**														
(58)	**Storage Fixed Costs - Facilities**		$393,734	$390,309	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$4,778,263
(59)	**Storage Fixed Costs - Deliveries**		$835,058	$868,336	$2,529,803	$2,529,803	$2,529,803	$957,522	$957,522	$957,522	$957,522	$957,522	$957,522	$957,522	$15,995,456
(60)	**sub-total Storage Costs**	Sum[(57):(58)]	$1,228,792	$1,258,645	$2,929,225	$2,929,225	$2,929,225	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$1,356,944	$20,773,719
(61)	**Tennessee Dracut for Peaking.**		$0	$0	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$1,352,240
(62)	**Inventory Financing**		$112,855	$91,342	$52,343	$34,072	$21,632	$26,469	$39,805	$52,777	$60,169	$68,590	$85,040	$96,167	$741,261
(63)	**Supply related LNG O&M Costs**		$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$47,965	$575,581
(64)	**Working Capital Requirement**		$3,042	$3,139	$15,368	$15,368	$15,368	$6,306	$6,306	$6,306	$6,306	$6,306	$6,306	$6,306	$96,427
(65)	**Total FT-2 Storage Fixed Costs**	Sum[(60):(64)]	$1,392,654	$1,401,090	$3,180,125	$3,161,854	$3,149,413	$1,572,908	$1,586,244	$1,599,216	$1,606,608	$1,615,029	$1,631,479	$1,642,607	$23,539,228
(66)	**System Storage MDQ (Dth)**		198,328	206,312	183,659	183,659	183,659	183,659	183,659	183,659	183,659	183,659	183,659	183,659	2,241,230
(67)	**FT-2 Storage Cost per MDQ (Dth)**	(65) / (66)	$7.0220	$6.7911	$17.3154	$17.2159	$17.1482	$8.5643	$8.6369	$8.7075	$8.7478	$8.7936	$8.8832	$8.9438	$10.5028
(68)	Pipeline Variable	(55)	$8,325,432	$22,876,499	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$116,340,447
(69)	Less Non-firm Gas Costs		($69,482)	($174,134)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($243,615)
(70)	Less Company Use		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(71)	Less Manchester St Balancing		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(72)	Plus Cashout		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(73)	Less Mkter W/drawals/Injections		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(74)	Mkter Over-takes/Undertakes		$176,006	($10,887)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$165,119
(75)	Plus Pipeline Srchg/Credit		$525,389	$234,248	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$759,637
(76)	Less Mkter FT-2 Daily weather true-up		($12,437)	($3,288)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($15,725)
(77)	**TOTAL FIRM COMMODITY COSTS**	Sum[(68):(76)]	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862

REDACTED

National Grid
Rhode Island - Gas

GCR Revenue

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**I. Fixed Cost Revenue**														
(2)	(a) Low Load dth	Sch. 6, Sum[Lines (24):(28), (30)]	1,478,464	3,055,015	6,697,312	4,549,104	3,980,376	2,797,424	1,507,174	857,523	589,461	527,941	593,153	743,076	27,376,022
(3)	Fixed Cost Factor	(4) / (2)	$1.3460	$1.5512	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	$1.5517	
(4)	Low Load Revenue	(2) x (3)	$1,989,994	$4,738,829	$10,392,219	$7,058,845	$6,176,349	$4,340,763	$2,338,682	$1,330,619	$914,666	$819,206	$920,396	$1,153,031	$42,173,600
(5)	(b) High Load dth	Sch. 6, Sum[lines (22), (23), (29), (31)]	54,755	67,995	133,244	78,341	97,463	81,132	60,848	54,946	41,400	33,790	37,285	44,548	785,745
(6)	Fixed Cost Factor	(7) / (5)	$1.0189	$1.1333	$1.1342	$1.1342	$1.1342	$1.1342	$1.1342	$1.1342	1.1342	1.1342	1.1342	1.1342	
(7)	High Load Revenue	(5) x (6)	$55,792	$77,058	$151,125	$88,854	$110,543	$92,019	$69,014	$62,319	$46,956	$38,324	$42,288	$50,527	$884,819
(8)	sub-total throughput Dth	(2) + (5)	1,533,220	3,123,009	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,161,767
(9)	FT-2 Storage Revenue from marketers		$154,547	$187,123	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$170,031	$2,041,978
(10)	Manchester Steet Volumes (dth)	Monthly Meter Use	930	763	0	0	0	0	0	0	0	0	0	0	
(11)	Fixed cost factor (dth)	Inherent in approved GCR	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	$1.6027	
(12)	Manchester Street Revenue	(10) x (11)	$1,490	$1,222	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,713
(13)	**TOTAL Fixed Revenue**	(4) + (7) + (9) + (12)	$2,201,823	$5,004,233	$10,713,375	$7,317,730	$6,456,923	$4,602,813	$2,577,727	$1,562,969	$1,131,653	$1,027,561	$1,132,715	$1,373,589	$45,103,110
(14)	**II. Variable Cost Revenue**														
(15)	(a) Firm Sales dth	(8)	1,533,220	3,123,009	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,161,767
(16)	Variable Supply Cost Factor	(17) / (15)	$3.5211	$3.5698	$3.5711	$3.5711	$4.6961	$5.8211	$5.8211	$5.8211	$5.8211	$5.8211	$5.8211	$5.8211	
(17)	Variable Supply Revenue	(15) x (16)	$5,398,547	$11,148,618	$24,392,597	$16,525,069	$19,149,938	$16,756,359	$9,127,611	$5,311,573	$3,672,303	$3,269,889	$3,669,841	$4,584,838	$123,007,183
(18)	(b) TSS Sales dth	Sch. 6, line (20)	2,513	12,138	0	0	0	0	0	0	0	0	0	0	14,650
(19)	TSS Surcharge Factor	Company's website	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
(20)	TSS Surcharge Revenue	(18) x (19)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21)	(c) Default Sales dth	Sch. 6, line (60)	4,332	9,934	0	0	0	0	0	0	-	-	-	-	14,266
(22)	Variable Supply Cost Factor	(23) / (21)	$6.75	$8.23	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
(23)	Variable Supply Revenue	(21) x (22)	$29,250	$81,788	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$111,038
(24)	(d) Peaking Gas Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(25)	(e) Deferred Responsibility		$12,967	$10,056	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,024
(26)	(e) FT-1 Storage and Peaking														
(27)	Manchester Steet Volumes (dth)	Monthly Meter Use	930	763	0	0	0	0	0	0	0	0	0	0	
(28)	Variable Supply Cost Factor (dth)	Inherent in approved GCR	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	$3.6884	
(29)	Manchester Street Revenue	(27) x (28)	$3,430	$2,812	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,243
(30)	**TOTAL Variable Revenue**	(17)+(20)+(23)+(24)+(25)+(26)+(2	$5,444,194	$11,243,275	$24,392,597	$16,525,069	$19,149,938	$16,756,359	$9,127,611	$5,311,573	$3,672,303	$3,269,889	$3,669,841	$4,584,838	$123,147,487
(31)	**Total Gas Cost Revenue** (w/o FT-2)	(13) + (30)	$7,646,018	$16,247,507	$35,105,972	$23,842,799	$25,606,861	$21,359,172	$11,705,338	$6,874,542	$4,803,956	$4,297,450	$4,802,556	$5,958,427	$168,250,597

Lines (12) and (29): Pursuant to the Division of Public Utilities and Carriers' approval in Docket No. D-15-04 of the Company's transportation contract for gas delivered to Manchester St. Station, beginning in July 2015, the Company is crediting imputed revenue to offset the gas costs associated with heater gas used at Manchester St. Station

REDACTED

WORKING CAPITAL

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**Supply Fixed Costs**	Sch. 1, line (4)	$4,342,453	$4,432,787	$6,108,532	$6,106,396	$6,108,532	$4,531,059	$4,531,771	$4,531,059	$4,531,771	$4,531,771	$4,530,656	$4,531,368	$58,818,154
(2)	Less: LNG Demand to DAC	Sch. 1, line (5)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($3,153,600)
(3)	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(4)	Total Adjustments	(2) + (3)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($3,153,600)
(5)	Allowable Working Capital Costs	(1) + (4)	$4,079,653	$4,169,987	$5,845,732	$5,843,596	$5,845,732	$4,268,259	$4,268,971	$4,268,259	$4,268,971	$4,268,971	$4,267,856	$4,268,568	$55,664,554
(6)	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
(7)	Working Capital Requirement	[(5) x (6)] / 365	$240,420	$245,744	$344,498	$344,372	$344,498	$251,535	$251,577	$251,535	$251,577	$251,577	$251,511	$251,553	
(8)	Cost of Capital	Dkt 4339	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(9)	Return on Working Capital Requirement	(7) x (8)	$17,454	$17,841	$25,011	$25,001	$25,011	$18,261	$18,264	$18,261	$18,264	$18,264	$18,260	$18,263	
(10)	Weighted Cost of Debt	Dkt 4339	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(11)	Interest Expense	(7) x (10)	$6,203	$6,340	$8,888	$8,885	$8,888	$6,490	$6,491	$6,490	$6,491	$6,491	$6,489	$6,490	
(12)	Taxable Income	(9) - (11)	$11,252	$11,501	$16,122	$16,117	$16,122	$11,772	$11,774	$11,772	$11,774	$11,774	$11,771	$11,773	
(13)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(14)	Return and Tax Requirement	(12) / (13)	$17,310	$17,694	$20,408	$20,401	$20,408	$14,901	$14,904	$14,901	$14,904	$14,904	$14,900	$14,902	
(15)	**Supply Fixed Working Capital Requirement**	(11) + (14)	$23,513	$24,034	$29,296	$29,286	$29,296	$21,391	$21,394	$21,391	$21,394	$21,394	$21,389	$21,392	$285,170
(16)	**Supply Variable Costs**	Sch. 1, line (20)	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862
(17)	Less: Balancing Related LNG Commodity (to DAC)	Sch. 1, line (21)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	Plus: Supply Related LNG O&M Costs	Dkt 4323	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19)	Total Adjustments	(17) + (18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20)	Allowable Working Capital Costs	(16) + (19)	$8,944,909	$22,922,438	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$117,005,862
(21)	Number of Days Lag	Dkt 4323	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	21.51	
(22)	Working Capital Requirement	[(20) x (21)] / 365	$527,137	$1,350,854	$2,401,203	$901,086	$668,037	$316,322	$184,790	$115,960	$92,502	$84,895	$87,382	$165,162	
(23)	Cost of Capital	Dkt 4339	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(24)	Return on Working Capital Requirement	(22) x (23)	$38,270	$98,072	$174,327	$65,419	$48,499	$22,965	$13,416	$8,419	$6,716	$6,163	$6,344	$11,991	
(25)	Weighted Cost of Debt	Dkt 4339	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(26)	Interest Expense	(22) x (25)	$13,600	$34,852	$61,951	$23,248	$17,235	$8,161	$4,768	$2,992	$2,387	$2,190	$2,254	$4,261	
(27)	Taxable Income	(24) - (26)	$24,670	$63,220	$112,376	$42,171	$31,264	$14,804	$8,648	$5,427	$4,329	$3,973	$4,089	$7,730	
(28)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(29)	Return and Tax Requirement	(27) / (28)	$37,954	$97,261	$142,248	$53,381	$39,575	$18,739	$10,947	$6,870	$5,480	$5,029	$5,177	$9,784	
(30)	**Supply Variable Working Capital Requirement**	(26) + (29)	$51,554	$132,114	$204,200	$76,629	$56,810	$26,900	$15,715	$9,861	$7,866	$7,220	$7,431	$14,045	$610,345

REDACTED

National Grid
Rhode Island - Gas

Schedule 5
Page 1 of 1

INVENTORY FINANCE

	Description	Reference	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
(1)	**Storage Inventory Balance**		$9,637,833	$8,298,259	$6,127,822	$4,288,451	$2,610,887	$2,653,444	$3,877,029	$5,066,626	$5,878,226	$6,941,021	$8,623,396	$10,069,304	
(2)	Monthly Storage Deferral/Amortization		$275,404	$224,820	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(3)	**Subtotal**	(1) + (2)	$9,913,237	$8,523,079	$6,127,822	$4,288,451	$2,610,887	$2,653,444	$3,877,029	$5,066,626	$5,878,226	$6,941,021	$8,623,396	$10,069,304	
(4)	Cost of Capital	Dkt 4323	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(5)	Return on Working Capital Requirement	(3) x (4)	$719,701	$618,776	$444,880	$311,342	$189,550	$192,640	$281,472	$367,837	$426,759	$503,918	$626,059	$731,031	$5,413,965
(6)	Weighted Cost of Debt	Dkt 4323	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(7)	Interest Charges Financed	(3) x (6)	$255,762	$219,895	$158,098	$110,642	$67,361	$68,459	$100,027	$130,719	$151,658	$179,078	$222,484	$259,788	$1,923,971
(8)	Taxable Income	(5) - (7)	$463,939	$398,880	$286,782	$200,700	$122,189	$124,181	$181,445	$237,118	$275,101	$324,840	$403,575	$471,243	
(9)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(10)	Return and Tax Requirement	(8) / (9)	$713,753	$613,662	$363,015	$254,050	$154,670	$157,191	$229,677	$300,149	$348,229	$411,190	$510,854	$596,511	$4,652,952
(11)	Working Capital Requirement	(7) + (10)	$969,515	$833,557	$521,113	$364,692	$222,031	$225,650	$329,705	$430,868	$499,887	$590,268	$733,338	$856,299	$6,576,923
(12)	Monthly Average	(11) / 12	$80,793	$69,463	$43,426	$30,391	$18,503	$18,804	$27,475	$35,906	$41,657	$49,189	$61,111	$71,358	$548,077
(13)	**LNG Inventory Balance**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(14)	Cost of Capital	Dkt 4323	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	7.26%	
(15)	Return on Working Capital Requirement	(13) x (14)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,906,990
(16)	Weighted Cost of Debt	Dkt 4323	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	2.58%	
(17)	Interest Charges Financed	(13) x (16)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$677,691
(18)	Taxable Income	(15) - (17)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(19)	1 - Combined Tax Rate	Dkt 4323	0.65	0.65	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79	
(20)	Return and Tax Requirement	(18) / (19)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,640,524
(21)	Working Capital Requirement	(17) + (20)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,318,214
(22)	Monthly Average	(21) / 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$193,185
(23)	TOTAL GCR Inventory Financing Costs	(12) + (22)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$741,261

REDACTED

Actual Dth Usage for Filing

	THROUGHPUT (Dth)	Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
	Rate Class													
(1)	**SALES**													
(2)	Residential Non-Heating	25,799	36,375	78,118	46,689	63,744	50,294	32,303	22,003	16,157	14,197	15,072	17,788	418,539
(3)	Residential Non-Heating Low Income	506	908	0	0	0	0	0	0	0	0	0	0	1,414
(4)	Residential Heating	1,049,547	2,123,640	5,033,640	3,515,651	3,025,940	2,123,608	1,134,913	640,980	439,872	378,733	439,199	549,175	20,454,897
(5)	Residential Heating Low Income	85,126	174,014	0	0	0	0	0	0	0	0	0	0	259,141
(6)	Small C&I	111,854	277,727	667,862	433,958	388,594	265,063	116,832	75,482	45,315	41,777	47,836	57,800	2,530,098
(7)	Medium C&I	195,033	383,557	808,432	478,851	459,399	337,938	214,438	122,975	95,239	99,371	93,976	121,150	3,410,359
(8)	Large LLF	32,729	77,403	173,833	111,958	99,039	65,916	38,351	16,635	8,837	7,982	11,775	14,173	658,629
(9)	Large HLF	19,260	22,406	48,223	27,387	26,615	23,997	23,632	27,213	19,713	14,410	15,671	18,743	287,270
(10)	Extra Large LLF	1,662	7,001	13,545	8,686	7,404	4,898	2,641	1,452	198	78	368	778	48,712
(11)	Extra Large HLF	9,191	7,841	6,902	4,265	7,104	6,841	4,912	5,730	5,529	5,182	6,542	8,018	78,058
(12)	**Total Sales**	1,530,707	3,110,872	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,147,117
(13)	**TSS**													
(14)	Small	26	327	0	0	0	0	0	0	0	0	0	0	353
(15)	Medium	1,986	6,054	0	0	0	0	0	0	0	0	0	0	8,040
(16)	Large LLF	501	5,293	0	0	0	0	0	0	0	0	0	0	5,794
(17)	Large HLF	0	464	0	0	0	0	0	0	0	0	0	0	464
(18)	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(20)	**Total TSS**	2,513	12,138	0	0	0	0	0	0	0	0	0	0	14,650
(21)	**Sales & TSS THROUGHPUT**													
(22)	Residential Non-Heating	25,799	36,375	78,118	46,689	63,744	50,294	32,303	22,003	16,157	14,197	15,072	17,788	418,539
(23)	Residential Non-Heating Low Income	506	908	0	0	0	0	0	0	0	0	0	0	1,414
(24)	Residential Heating	1,049,547	2,123,640	5,033,640	3,515,651	3,025,940	2,123,608	1,134,913	640,980	439,872	378,733	439,199	549,175	20,454,897
(25)	Residential Heating Low Income	85,126	174,014	0	0	0	0	0	0	0	0	0	0	259,141
(26)	Small C&I	111,880	278,053	667,862	433,958	388,594	265,063	116,832	75,482	45,315	41,777	47,836	57,800	2,530,450
(27)	Medium C&I	197,019	389,610	808,432	478,851	459,399	337,938	214,438	122,975	95,239	99,371	93,976	121,150	3,418,399
(28)	Large LLF	33,230	82,697	173,833	111,958	99,039	65,916	38,351	16,635	8,837	7,982	11,775	14,173	664,423
(29)	Large HLF	19,260	22,871	48,223	27,387	26,615	23,997	23,632	27,213	19,713	14,410	15,671	18,743	287,735
(30)	Extra Large LLF	1,662	7,001	13,545	8,686	7,404	4,898	2,641	1,452	198	78	368	778	48,712
(31)	Extra Large HLF	9,191	7,841	6,902	4,265	7,104	6,841	4,912	5,730	5,529	5,182	6,542	8,018	78,058
(32)	**Total Sales & TSS Throughput**	1,533,220	3,123,009	6,830,556	4,627,445	4,077,839	2,878,555	1,568,022	912,469	630,861	561,730	630,438	787,624	28,161,767

REDACTED

Actual Dth Usage for Filing

		Nov Actual (a)	Dec Actual (b)	Jan Forecast (c)	Feb Forecast (d)	Mar Forecast (e)	Apr Forecast (f)	May Forecast (g)	Jun Forecast (h)	Jul Forecast (i)	Aug Forecast (j)	Sep Forecast (k)	Oct Forecast (l)	Nov-Oct (m)
	THROUGHPUT (Dth)													
	Rate Class													
(33)	**FT-1 TRANSPORTATION**													
(34)	FT-1 Medium	30,639	60,057	82,603	69,210	61,901	50,742	31,888	21,653	21,013	19,318	21,408	35,222	505,655
(35)	FT-1 Large LLF	34,759	97,785	155,618	133,244	113,703	65,130	33,765	19,154	14,104	14,041	18,967	49,248	749,517
(36)	FT-1 Large HLF	32,023	38,641	44,327	38,828	41,285	36,844	32,268	38,409	34,345	33,598	34,094	36,653	441,316
(37)	FT-1 Extra Large LLF	48,732	127,674	208,395	179,321	156,757	95,789	57,371	25,418	18,571	17,506	23,902	75,474	1,034,910
(38)	FT-1 Extra Large HLF	433,197	494,103	606,826	517,876	547,262	545,125	507,575	495,697	509,032	501,923	469,060	501,274	6,128,948
(39)	Default	4,332	9,934	0	0	0	0	0	0	0	0	0	0	14,266
(40)	**Total FT-1 Transportation**	583,682	828,194	1,097,770	938,479	920,908	793,630	662,867	600,331	597,065	586,386	567,430	697,872	8,874,612
(41)	**FT-2 TRANSPORTATION**													
(42)	FT-2 Small	6,121	14,942	24,139	25,356	22,502	17,022	10,822	5,728	3,123	2,694	3,241	6,419	142,110
(43)	FT-2 Medium	115,362	220,831	280,510	269,362	259,633	199,336	131,426	75,625	55,737	49,625	50,351	68,497	1,776,295
(44)	FT-2 Large LLF	60,802	159,214	212,126	218,045	193,970	131,076	76,859	34,677	19,007	17,387	24,596	32,879	1,180,639
(45)	FT-2 Large HLF	36,322	47,803	60,792	56,509	54,705	48,990	43,826	36,028	27,713	26,177	28,472	31,150	498,488
(46)	FT-2 Extra Large LLF	126	2,476	8,818	9,930	8,775	6,821	4,441	2,652	1,362	1,184	1,289	2,063	49,937
(47)	FT-2 Extra Large HLF	47,318	52,276	54,080	50,272	48,750	50,425	43,130	44,111	36,715	36,604	46,095	38,887	548,664
(48)	**Total FT-2 Transportation**	266,050	497,542	640,465	629,475	588,336	453,669	310,505	198,821	143,659	133,672	154,043	179,896	4,196,132
(49)	**Total THROUGHPUT**													
(50)	Residential Non-Heating	25,799	36,375	78,118	46,689	63,744	50,294	32,303	22,003	16,157	14,197	15,072	17,788	418,539
(51)	Residential Non-Heating Low Income	506	908	0	0	0	0	0	0	0	0	0	0	1,414
(52)	Residential Heating	1,049,547	2,123,640	5,033,640	3,515,651	3,025,940	2,123,608	1,134,913	640,980	439,872	378,733	439,199	549,175	20,454,897
(53)	Residential Heating Low Income	85,126	174,014	0	0	0	0	0	0	0	0	0	0	259,141
(54)	Small C&I	118,001	292,995	692,001	459,314	411,096	282,085	127,654	81,210	48,438	44,471	51,076	64,219	2,672,560
(55)	Medium C&I	343,020	670,498	1,171,545	817,424	780,934	588,016	377,752	220,253	171,990	168,314	165,735	224,869	5,700,349
(56)	Large LLF	128,791	339,695	541,577	463,247	406,712	262,122	148,974	70,466	41,947	39,409	55,337	96,300	2,594,578
(57)	Large HLF	87,605	109,315	153,343	122,724	122,605	109,831	99,726	101,650	81,771	74,186	78,236	86,545	1,227,538
(58)	Extra Large LLF	50,519	137,151	230,758	197,936	172,935	107,508	64,454	29,522	20,131	18,769	25,559	78,316	1,133,559
(59)	Extra Large HLF	489,706	554,220	667,808	572,413	603,116	602,390	555,617	545,537	551,277	543,710	521,696	548,179	6,755,670
(60)	Default	4,332	9,934	0	0	0	0	0	0	0	0	0	0	14,266
(61)	**Total Throughput**	2,382,952	4,448,745	8,568,790	6,195,399	5,587,083	4,125,854	2,541,393	1,711,620	1,371,584	1,281,789	1,351,911	1,665,391	41,232,511

Attachment AEL-4
Bill Impact Analysis

National Grid - RI Gas
Interim Gas Cost Recovery Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	258	$501.16	$439.35	$61.80	14.1%	$0.00	$59.95	$0.00	$0.00	$0.00	$0.00	$1.85
	285	$541.23	$472.98	$68.25	14.4%	$0.00	$66.20	$0.00	$0.00	$0.00	$0.00	$2.05
	313	$582.67	$507.70	$74.97	14.8%	$0.00	$72.72	$0.00	$0.00	$0.00	$0.00	$2.25
	340	$622.70	$541.28	$81.42	15.0%	$0.00	$78.98	$0.00	$0.00	$0.00	$0.00	$2.44
	369	$664.98	$576.60	$88.38	15.3%	$0.00	$85.73	$0.00	$0.00	$0.00	$0.00	$2.65
Average Customer	**396**	**$703.35**	**$608.52**	**$94.84**	**15.6%**	$0.00	$91.99	$0.00	$0.00	$0.00	$0.00	$2.85
	422	$740.04	$638.96	$101.07	15.8%	$0.00	$98.04	$0.00	$0.00	$0.00	$0.00	$3.03
	452	$782.39	$674.16	$108.24	16.1%	$0.00	$104.99	$0.00	$0.00	$0.00	$0.00	$3.25
	479	$820.39	$705.68	$114.71	16.3%	$0.00	$111.27	$0.00	$0.00	$0.00	$0.00	$3.44
	505	$856.95	$736.02	$120.93	16.4%	$0.00	$117.30	$0.00	$0.00	$0.00	$0.00	$3.63
	537	$901.29	$772.67	$128.62	16.6%	$0.00	$124.76	$0.00	$0.00	$0.00	$0.00	$3.86

Residential Heating Low Income:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	258	$478.08	$416.28	$61.80	14.8%	$0.00	$59.95	$0.00	$0.00	$0.00	$0.00	$1.85
	285	$516.90	$448.65	$68.25	15.2%	$0.00	$66.20	$0.00	$0.00	$0.00	$0.00	$2.05
	313	$557.06	$482.09	$74.97	15.6%	$0.00	$72.72	$0.00	$0.00	$0.00	$0.00	$2.25
	340	$595.85	$514.43	$81.42	15.8%	$0.00	$78.98	$0.00	$0.00	$0.00	$0.00	$2.44
	369	$636.87	$548.49	$88.38	16.1%	$0.00	$85.73	$0.00	$0.00	$0.00	$0.00	$2.65
Average Customer	**396**	**$674.16**	**$579.32**	**$94.84**	**16.4%**	$0.00	$91.99	$0.00	$0.00	$0.00	$0.00	$2.85
	422	$709.84	$608.76	$101.07	16.6%	$0.00	$98.04	$0.00	$0.00	$0.00	$0.00	$3.03
	452	$751.02	$642.79	$108.24	16.8%	$0.00	$104.99	$0.00	$0.00	$0.00	$0.00	$3.25
	479	$787.98	$673.27	$114.71	17.0%	$0.00	$111.27	$0.00	$0.00	$0.00	$0.00	$3.44
	505	$823.54	$702.61	$120.93	17.2%	$0.00	$117.30	$0.00	$0.00	$0.00	$0.00	$3.63
	537	$866.72	$738.10	$128.62	17.4%	$0.00	$124.76	$0.00	$0.00	$0.00	$0.00	$3.86

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National Grid - RI Gas
Interim Gas Cost Recovery Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Non-Heating:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	77	$231.60	$213.17	$18.43	8.6%	$0.00	$17.88	$0.00	$0.00	$0.00	$0.00	$0.55
	86	$245.37	$224.76	$20.61	9.2%	$0.00	$19.99	$0.00	$0.00	$0.00	$0.00	$0.62
	95	$259.13	$236.38	$22.75	9.6%	$0.00	$22.07	$0.00	$0.00	$0.00	$0.00	$0.68
	102	$269.82	$245.37	$24.45	10.0%	$0.00	$23.72	$0.00	$0.00	$0.00	$0.00	$0.73
	109	$280.49	$254.39	$26.10	10.3%	$0.00	$25.32	$0.00	$0.00	$0.00	$0.00	$0.78
Average Customer	119	**$295.37**	**$266.89**	**$28.48**	**10.7%**	$0.00	$27.63	$0.00	$0.00	$0.00	$0.00	$0.85
	126	$306.50	$276.31	$30.19	10.9%	$0.00	$29.28	$0.00	$0.00	$0.00	$0.00	$0.91
	135	$320.26	$287.90	$32.36	11.2%	$0.00	$31.39	$0.00	$0.00	$0.00	$0.00	$0.97
	143	$332.49	$298.24	$34.26	11.5%	$0.00	$33.23	$0.00	$0.00	$0.00	$0.00	$1.03
	153	$347.75	$311.08	$36.67	11.8%	$0.00	$35.57	$0.00	$0.00	$0.00	$0.00	$1.10
	160	$358.47	$320.14	$38.33	12.0%	$0.00	$37.18	$0.00	$0.00	$0.00	$0.00	$1.15

Residential Non-Heating Low Income:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	77	$217.39	$198.96	$18.43	9.3%	$0.00	$17.88	$0.00	$0.00	$0.00	$0.00	$0.55
	86	$230.76	$210.15	$20.61	9.8%	$0.00	$19.99	$0.00	$0.00	$0.00	$0.00	$0.62
	95	$244.11	$221.36	$22.75	10.3%	$0.00	$22.07	$0.00	$0.00	$0.00	$0.00	$0.68
	102	$254.48	$230.03	$24.45	10.6%	$0.00	$23.72	$0.00	$0.00	$0.00	$0.00	$0.73
	109	$264.84	$238.73	$26.10	10.9%	$0.00	$25.32	$0.00	$0.00	$0.00	$0.00	$0.78
Average Customer	**119**	**$279.28**	**$250.79**	**$28.48**	**11.4%**	$0.00	$27.63	$0.00	$0.00	$0.00	$0.00	$0.85
	126	$290.07	$259.89	$30.19	11.6%	$0.00	$29.28	$0.00	$0.00	$0.00	$0.00	$0.91
	135	$303.43	$271.07	$32.36	11.9%	$0.00	$31.39	$0.00	$0.00	$0.00	$0.00	$0.97
	143	$315.30	$281.04	$34.26	12.2%	$0.00	$33.23	$0.00	$0.00	$0.00	$0.00	$1.03
	153	$330.10	$293.43	$36.67	12.5%	$0.00	$35.57	$0.00	$0.00	$0.00	$0.00	$1.10
	160	$340.51	$302.18	$38.33	12.7%	$0.00	$37.18	$0.00	$0.00	$0.00	$0.00	$1.15

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Bill Impact Analysis with Various Levels of Consumption:

C & I Small:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	402	$805.02	$708.75	$96.27	13.6%	$0.00	$93.38	$0.00	$0.00	$0.00	$0.00	$2.89
	444	$862.30	$755.95	$106.35	14.1%	$0.00	$103.16	$0.00	$0.00	$0.00	$0.00	$3.19
	486	$918.88	$802.50	$116.38	14.5%	$0.00	$112.89	$0.00	$0.00	$0.00	$0.00	$3.49
	530	$977.73	$850.79	$126.94	14.9%	$0.00	$123.13	$0.00	$0.00	$0.00	$0.00	$3.81
	574	$1,036.14	$898.69	$137.44	15.3%	$0.00	$133.32	$0.00	$0.00	$0.00	$0.00	$4.12
Average Customer	**617**	**$1,089.81**	**$942.11**	**$147.70**	**15.7%**	$0.00	$143.27	$0.00	$0.00	$0.00	$0.00	$4.43
	660	$1,144.03	$985.97	$158.06	16.0%	$0.00	$153.32	$0.00	$0.00	$0.00	$0.00	$4.74
	703	$1,197.94	$1,029.58	$168.36	16.4%	$0.00	$163.31	$0.00	$0.00	$0.00	$0.00	$5.05
	746	$1,251.85	$1,073.18	$178.67	16.6%	$0.00	$173.31	$0.00	$0.00	$0.00	$0.00	$5.36
	789	$1,305.76	$1,116.80	$188.96	16.9%	$0.00	$183.29	$0.00	$0.00	$0.00	$0.00	$5.67
	832	$1,359.69	$1,160.44	$199.25	17.2%	$0.00	$193.27	$0.00	$0.00	$0.00	$0.00	$5.98

C & I Medium:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	3,953	$5,657.46	$4,710.78	$946.68	20.1%	$0.00	$918.28	$0.00	$0.00	$0.00	$0.00	$28.40
	4,378	$6,203.25	$5,154.77	$1,048.47	20.3%	$0.00	$1,017.02	$0.00	$0.00	$0.00	$0.00	$31.45
	4,803	$6,748.68	$5,598.42	$1,150.26	20.5%	$0.00	$1,115.75	$0.00	$0.00	$0.00	$0.00	$34.51
	5,228	$7,294.46	$6,042.42	$1,252.03	20.7%	$0.00	$1,214.47	$0.00	$0.00	$0.00	$0.00	$37.56
	5,654	$7,841.01	$6,486.96	$1,354.05	20.9%	$0.00	$1,313.43	$0.00	$0.00	$0.00	$0.00	$40.62
Average Customer	**6,080**	**$8,387.94**	**$6,931.84**	**$1,456.09**	**21.0%**	$0.00	$1,412.41	$0.00	$0.00	$0.00	$0.00	$43.68
	6,506	$8,934.53	$7,376.43	$1,558.09	21.1%	$0.00	$1,511.35	$0.00	$0.00	$0.00	$0.00	$46.74
	6,932	$9,481.10	$7,820.99	$1,660.11	21.2%	$0.00	$1,610.31	$0.00	$0.00	$0.00	$0.00	$49.80
	7,357	$10,026.84	$8,264.96	$1,761.89	21.3%	$0.00	$1,709.03	$0.00	$0.00	$0.00	$0.00	$52.86
	7,783	$10,573.46	$8,709.55	$1,863.91	21.4%	$0.00	$1,807.99	$0.00	$0.00	$0.00	$0.00	$55.92
	8,208	$11,119.20	$9,153.51	$1,965.69	21.5%	$0.00	$1,906.72	$0.00	$0.00	$0.00	$0.00	$58.97

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National Grid - RI Gas
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Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Large:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	18,225	$24,894.48	$20,529.86	$4,364.62	21.3%	$0.00	$4,233.68	$0.00	$0.00	$0.00	$0.00	$130.94
	20,186	$27,417.35	$22,583.13	$4,834.23	21.4%	$0.00	$4,689.20	$0.00	$0.00	$0.00	$0.00	$145.03
	22,149	$29,942.44	$24,638.10	$5,304.34	21.5%	$0.00	$5,145.21	$0.00	$0.00	$0.00	$0.00	$159.13
	24,112	$32,467.60	$26,693.15	$5,774.44	21.6%	$0.00	$5,601.21	$0.00	$0.00	$0.00	$0.00	$173.23
	26,076	$34,993.80	$28,749.01	$6,244.79	21.7%	$0.00	$6,057.45	$0.00	$0.00	$0.00	$0.00	$187.34
Average Customer	**28,037**	**$37,516.80**	**$30,802.36**	**$6,714.44**	**21.8%**	$0.00	$6,513.01	$0.00	$0.00	$0.00	$0.00	$201.43
	29,999	$40,040.64	$32,856.36	$7,184.29	21.9%	$0.00	$6,968.76	$0.00	$0.00	$0.00	$0.00	$215.53
	31,962	$42,565.75	$34,911.35	$7,654.40	21.9%	$0.00	$7,424.77	$0.00	$0.00	$0.00	$0.00	$229.63
	33,925	$45,091.30	$36,966.78	$8,124.52	22.0%	$0.00	$7,880.78	$0.00	$0.00	$0.00	$0.00	$243.74
	35,888	$47,616.42	$39,021.77	$8,594.65	22.0%	$0.00	$8,336.81	$0.00	$0.00	$0.00	$0.00	$257.84
	37,850	$50,140.38	$41,075.90	$9,064.48	22.1%	$0.00	$8,792.55	$0.00	$0.00	$0.00	$0.00	$271.93

C & I HLF Large:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	30,067	$34,722.36	$27,518.66	$7,203.70	26.2%	$0.00	$6,987.59	$0.00	$0.00	$0.00	$0.00	$216.11
	33,306	$38,306.63	$30,326.93	$7,979.70	26.3%	$0.00	$7,740.31	$0.00	$0.00	$0.00	$0.00	$239.39
	36,546	$41,891.89	$33,135.91	$8,755.98	26.4%	$0.00	$8,493.30	$0.00	$0.00	$0.00	$0.00	$262.68
	39,782	$45,473.11	$35,941.84	$9,531.27	26.5%	$0.00	$9,245.33	$0.00	$0.00	$0.00	$0.00	$285.94
	43,021	$49,057.40	$38,750.08	$10,307.32	26.6%	$0.00	$9,998.10	$0.00	$0.00	$0.00	$0.00	$309.22
Average Customer	**46,260**	**$52,641.03**	**$41,557.80**	**$11,083.24**	**26.7%**	$0.00	$10,750.74	$0.00	$0.00	$0.00	$0.00	$332.50
	49,499	$56,225.36	$44,366.03	$11,859.33	26.7%	$0.00	$11,503.55	$0.00	$0.00	$0.00	$0.00	$355.78
	52,736	$59,807.61	$47,172.71	$12,634.90	26.8%	$0.00	$12,255.85	$0.00	$0.00	$0.00	$0.00	$379.05
	55,975	$63,391.88	$49,980.95	$13,410.93	26.8%	$0.00	$13,008.60	$0.00	$0.00	$0.00	$0.00	$402.33
	59,213	$66,975.12	$52,788.43	$14,186.69	26.9%	$0.00	$13,761.09	$0.00	$0.00	$0.00	$0.00	$425.60
	62,452	$70,559.40	$55,596.67	$14,962.72	26.9%	$0.00	$14,513.84	$0.00	$0.00	$0.00	$0.00	$448.88

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National Grid - RI Gas
Interim Gas Cost Recovery Filing
Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Extra-Large:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	72,940	$81,114.89	$63,646.87	$17,468.02	27.4%	$0.00	$16,943.98	$0.00	$0.00	$0.00	$0.00	$524.04
	80,797	$89,473.78	$70,124.13	$19,349.65	27.6%	$0.00	$18,769.16	$0.00	$0.00	$0.00	$0.00	$580.49
	88,652	$97,830.85	$76,600.08	$21,230.77	27.7%	$0.00	$20,593.85	$0.00	$0.00	$0.00	$0.00	$636.92
	96,505	$106,186.46	$83,075.02	$23,111.44	27.8%	$0.00	$22,418.10	$0.00	$0.00	$0.00	$0.00	$693.34
	104,363	$114,546.29	$89,552.95	$24,993.34	27.9%	$0.00	$24,243.54	$0.00	$0.00	$0.00	$0.00	$749.80
Average Customer	**112,217**	**$122,902.64**	**$96,028.36**	**$26,874.28**	**28.0%**	$0.00	$26,068.05	$0.00	$0.00	$0.00	$0.00	$806.23
	120,072	$131,259.53	$102,504.15	$28,755.38	28.1%	$0.00	$27,892.72	$0.00	$0.00	$0.00	$0.00	$862.66
	127,927	$139,616.98	$108,980.44	$30,636.54	28.1%	$0.00	$29,717.44	$0.00	$0.00	$0.00	$0.00	$919.10
	135,782	$147,974.07	$115,456.38	$32,517.69	28.2%	$0.00	$31,542.16	$0.00	$0.00	$0.00	$0.00	$975.53
	143,638	$156,332.04	$121,932.96	$34,399.08	28.2%	$0.00	$33,367.11	$0.00	$0.00	$0.00	$0.00	$1,031.97
	151,493	$164,689.12	$128,408.88	$36,280.24	28.3%	$0.00	$35,191.83	$0.00	$0.00	$0.00	$0.00	$1,088.41

C & I HLF Extra-Large:

	Annual Consumption (Therms)	Mar- Oct Proposed Rates	Mar- Oct Current Rates	Mar- Oct Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
	276,118	$263,265.67	$197,111.21	$66,154.46	33.6%	$0.00	$64,169.83	$0.00	$0.00	$0.00	$0.00	$1,984.63
	305,854	$291,239.14	$217,960.30	$73,278.84	33.6%	$0.00	$71,080.47	$0.00	$0.00	$0.00	$0.00	$2,198.37
	335,589	$319,212.29	$238,809.33	$80,402.97	33.7%	$0.00	$77,990.88	$0.00	$0.00	$0.00	$0.00	$2,412.09
	365,325	$347,185.74	$259,658.38	$87,527.36	33.7%	$0.00	$84,901.54	$0.00	$0.00	$0.00	$0.00	$2,625.82
	395,060	$375,158.38	$280,506.86	$94,651.52	33.7%	$0.00	$91,811.97	$0.00	$0.00	$0.00	$0.00	$2,839.55
Average Customer	**424,797**	**$403,132.72**	**$301,356.71**	**$101,776.01**	**33.8%**	$0.00	$98,722.73	$0.00	$0.00	$0.00	$0.00	$3,053.28
	454,532	$431,105.83	$322,205.58	$108,900.25	33.8%	$0.00	$105,633.24	$0.00	$0.00	$0.00	$0.00	$3,267.01
	484,269	$459,080.17	$343,055.32	$116,024.85	33.8%	$0.00	$112,544.10	$0.00	$0.00	$0.00	$0.00	$3,480.75
	514,004	$487,053.31	$363,904.32	$123,148.99	33.8%	$0.00	$119,454.52	$0.00	$0.00	$0.00	$0.00	$3,694.47
	543,739	$515,025.92	$384,752.83	$130,273.09	33.9%	$0.00	$126,364.90	$0.00	$0.00	$0.00	$0.00	$3,908.19
	573,476	$543,000.79	$405,603.05	$137,397.74	33.9%	$0.00	$133,275.81	$0.00	$0.00	$0.00	$0.00	$4,121.93

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Attachment AEL-5

Attachment AEL-5
Derivation of Incremental Revenue

Derivation of Incremental Revenue

		Nov Actual	Dec Actual	Total	Nov FCST	Dec FCST	Total	Nov Difference	Dec Difference	Total	Percent Difference
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Billing Data										
	Sales & TSS THROUGHPUT										
(1)	Residential Non-Heating	26,304	37,283	63,588	26,718	39,278	65,996	(414)	(1,995)	(2,408)	-3.6%
(2)	Residential Heating	1,134,674	2,297,654	3,432,328	1,304,358	2,321,462	3,625,820	(169,684)	(23,808)	(193,492)	-5.3%
(3)	Small C&I	111,880	278,053	389,933	126,421	299,220	425,641	(14,541)	(21,167)	(35,707)	-8.4%
(4)	Medium C&I	197,019	389,610	586,629	214,633	381,004	595,638	(17,614)	8,606	(9,008)	-1.5%
(5)	Large LLF	33,230	82,697	115,926	40,481	84,267	124,748	(7,251)	(1,571)	(8,822)	-7.1%
(6)	Large HLF	19,260	22,871	42,130	21,195	26,978	48,173	(1,935)	(4,108)	(6,043)	-12.5%
(7)	Extra Large LLF	1,662	7,001	8,663	2,782	7,288	10,070	(1,120)	(287)	(1,407)	-14.0%
(8)	Extra Large HLF	9,191	7,841	17,032	10,343	7,847	18,191	(1,152)	(6)	(1,158)	-6.4%
(9)	**Total Sales & TSS Throughput**	1,533,220	3,123,009	4,656,229	1,746,930	3,167,346	4,914,276	(213,711)	(44,336)	(258,047)	-5.3%

		Nov Actual	Dec Actual	Jan Rev FCST	Nov-Jan Total	Nov-Dec Total
(10)	**Sendout- Act/Rev Fcst Dktherm**	2,857,768	5,113,414	5,709,026	13,680,208	7,971,182
		Forecast	Forecast	Initial FCST	Total	Total
(11)	**Sendout- Original Fcst Dktherm**	2,286,401	3,945,192	4,943,244	11,174,837	6,231,593
(12)	**Difference**	571,367	1,168,222	765,782	2,505,371	1,739,589
(13)	**Percent Difference**	25%	30%	15%	22%	28%

	Revised Jan 2018 Billing Forecast	Initial Filing	Incremental	Revised Filing
	Sales & TSS THROUGHPUT			
(14)	Residential Non-Heating	49,465		78,118
(15)	Residential Heating	3,187,357		5,033,640
(16)	Small C&I	422,898		667,862
(17)	Medium C&I	511,908		808,432
(18)	Large LLF	110,073		173,833
(19)	Large HLF	30,535		48,223
(20)	Extra Large LLF	8,577		13,545
(21)	Extra Large HLF	4,370		6,902
(22)	**Total Sales & TSS Throughput**	4,325,184	2,505,371	6,830,556

Testimony of
Nancy G. Culliford

DIRECT TESTIMONY

OF

NANCY G. CULLIFORD

January 29, 2018

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I. Introduction

Q. Please state your name and business address.

A. My name is Nancy G. Culliford. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Have you previously submitted testimony in this docket?

A. Yes. On September 1, 2017, I submitted pre-filed direct testimony providing support for the estimated gas costs, assignments of pipeline capacity to marketers, and other issues relating to The Narragansett Electric Company d/b/a National Grid's (the Company) proposed Gas Cost Recovery (GCR) factors. In addition, my testimony discusses modifications that the Company had made to its portfolio for the 2017-18 GCR year ending October 31, 2018.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports the updated gas costs and other issues relating to the Company's proposed GCR factors.

Q. Are you sponsoring attachments to your testimony?

A. Yes. I am sponsoring the following attachments:

Attachment NGC-1	Updated Summary of Projected Gas Costs - **CONFIDENTIAL Information Redacted**
Attachment NGC-2	Updated Gas Cost Details - **CONFIDENTIAL Information Redacted**

II. <u>Projected Gas Costs</u>

Q. Why is it necessary to request an increase in the GCR factors at this time?

A. The extreme cold weather from mid-December 2017 through early-January 2018 caused the Company to purchase additional gas supplies to meet increased customer demand. The cost of these supplies exceeded the Company's projected costs from its initial September 1, 2017 GCR filing (Initial GCR Filing). As a result, the current estimate of deferred gas cost recovery through October 31, 2018 as a percentage of total gas cost revenue for the November 2017 through October 2018 GCR year exceeds the five percent trigger for adjusting the gas cost factors provided for in the Company's tariff. RIPUC NG-GAS No. 101, Section 2, Schedule A, Sheet 2.

The table below shows the actual Heating Degree Days (HDDs) as measured at T.F. Green Airport compared to forecasted normal and design weather HDDs for the six week period.

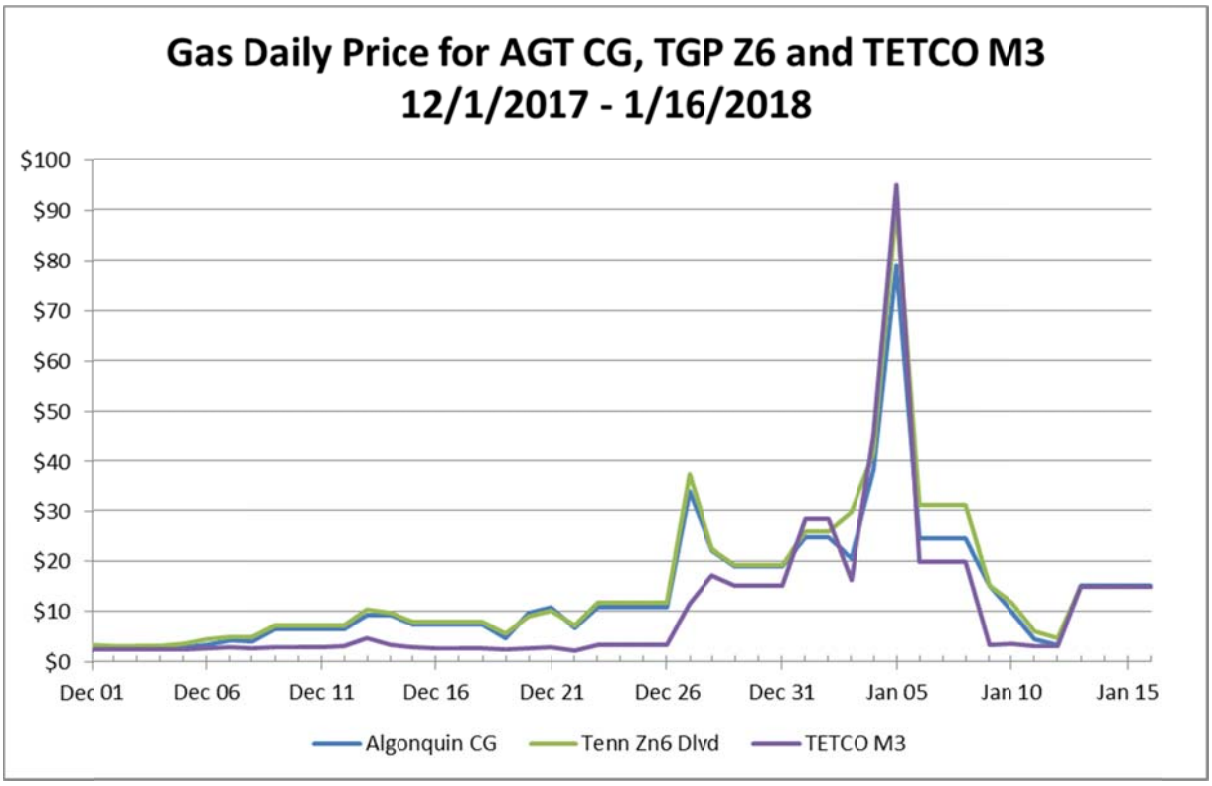
Heating Degree Day Summary (T.F. Green Aiport)					
	ACTUAL	NORMAL	DESIGN	Actual vs. Normal	Actual vs. Design
Week Ending 12/17	263	212	238	124%	111%
Week Ending 12/24	200	191	214	105%	93%
Week Ending 12/31	348	171	193	204%	180%
Week Ending 1/7	351	219	238	160%	147%
Week Ending 1/14	205	264	286	78%	72%
Total	1,367	1,057	1,169	129%	117%

Beginning December 11, 2017 through and including January 7, 2018, actual weather was colder than forecasted normal weather for all four weeks, and colder than forecasted design weather in three of the four weeks.

From mid-December into January, the Northeast markets posted large increases in demand because of this colder than normal and design weather. In December 2017 and January 2018, the Company experienced 6 of the top 10 highest sendout volumes in Company history within its service territory. The table below shows the top 10 highest sendouts in Company history.

Rank	Date	Sendout	HDD
1	January 6, 2018	387,584	60
2	January 5, 2018	372,048	56
3	February 14, 2016	368,126	59
4	January 1, 2018	365,370	56
5	February 13, 2016	363,535	62
6	December 31, 2017	360,872	58
7	December 28, 2017	360,058	56
8	February 15, 2015	353,402	57
9	January 15, 2004	351,459	64
10	December 29, 2017	345,152	56

This extreme weather caused increased customer usage and required the Company to purchase market area-priced supplies, including supplies over and above those in the Company's existing portfolio. During this period, these supplies were largely priced at Gas Daily Indices at one of the following locations: Algonquin city-gates, Tennessee Zone 6 delivered, or Texas Eastern M-3. The chart below shows the respective daily indices for December 2017 and January 2018, demonstrating the sharp price escalation as the cold stretch continued. The bulk of the Company's incremental purchases were made from late December through mid-January. As demonstrated by the graph below, the cost of these incremental supplies during the extreme cold was as expensive as $94 per million British thermal units (MMBtu).



When pipeline supplies were exhausted, the Company had to use liquefied natural gas (LNG) to meet customer requirements. At the end of December 2017, the Company's LNG storage inventory balance was 67 percent full, below the design season rule curve level of 95 percent.[1] The LNG inventory levels continued to decrease, and by January 8, the Company's available LNG supplies were at 36 percent. Because of this decreased LNG inventory, the Company had to both purchase market area gas supplies and incremental LNG supplies to replenish the LNG inventory.

From January 1 through January 16, 2018, the Company continued to purchase incremental market area supply. The chart below shows a summary of these supplies. During the first 16 days of January, the Company purchased 0.765 billion cubic feet (Bcf) of market area supply at an average price of $31. This included 0.494 Bcf of supply purchased using the Company's Tennessee capacity originating at Dracut, Massachusetts. For comparison, the Company's design winter season forecast for firm customers calls for 1.124 Bcf of supply from Dracut, and, in less than a month and a half, from December 9 through January 16, the Company purchased 0.858 Bcf of Dracut supply – which is 76 percent of the design forecast for firm customers for the entire 2017-18 winter. Compared to a normal winter season forecast of 0.303 Bcf of supply from Dracut, the December 9, 2017 through January 16, 2018 purchased are 283 percent of the forecast.

[1] Design rule curve levels indicate the level of inventory that is needed in order to meet design season requirements for each day remaining in the winter period.

	Market Area Volumes
Jan 1, 2018	66,271
Jan 2, 2018	66,271
Jan 3, 2018	42,000
Jan 4, 2018	56,271
Jan 5, 2018	81,565
Jan 6, 2018	81,071
Jan 7, 2018	81,771
Jan 8, 2018	55,271
Jan 9, 2018	30,500
Jan 10, 2018	13,000
Jan 11, 2018	0
Jan 12, 2018	0
Jan 13, 2018	45,271
Jan 14, 2018	45,978
Jan 15, 2018	55,271
Jan 16, 2018	45,271
	765,782

Q. Have there been any notable changes to the Company's portfolio since the 2017 GCR proceeding?

A. Yes. The following two changes to the Company's gas supply portfolio have occurred since the Initial GCR Filing: (1) the Company has entered into a LNG Liquid Agreement with ENGIE Gas & LNG LLC (ENGIE), which went into service effective January 10, 2018; and (2) the Company has also entered into a Firm Combination Contract with ENGIE to be used as either liquid or vapor, and was also placed into service effective January 10, 2018.

Q. Please provide the details for the changes to the Company's resource portfolio.

A. Each of the changes to the Company's resource portfolio is further described below.

ENGIE LNG Liquid Agreement

The Company's LNG liquid supply contract with ENGIE commenced on January 10, 2018 and will terminate on October 1, 2018. The Company retained the right to purchase a quantity of LNG up to the maximum daily quantity (MDQ) of 5,000 MMBtu per day with a total quantity during the term of up to 100,000 MMBtus. The Company entered into this LNG Liquid Agreement during the extended cold period in order to refill its LNG facilities. As mentioned above, the Company's LNG storage balance fell well below the design season rule curve and the purchase of the liquid contract was necessary in order to put the Company back on the LNG rule curve and ensure LNG would be available for the remainder of the winter season.

ENGIE Firm Combination Agreement

The Company's Firm Combination Agreement with ENGIE for both vapor and liquid commenced on January 10, 2018 and will terminate on October 1, 2018. During the term, the Company retained the right to purchase a quantity of LNG up to the MDQ of 10,000 MMBtu per day with a total quantity during the term of up to 150,000 MMBtus. Prior to April 1, 2018, the Company has the option to call on the MDQ as either vapor or LNG. The vapor component of the Firm Combination Agreement has a delivery point of

Dey Street in Providence, Rhode Island. The Company entered into this Firm Combination Agreement for the following two reasons: (1) during the extreme cold period, few counterparties were able to deliver pipeline gas to the National Grid citygates due to restrictions on the interstate pipelines; and (2) the addition of the 10,000 MMBtu per day supply provides for deliveries to the Company's citygates and provided an opportunity for the Company to bring its LNG supply back in line with its LNG rule curve.

The costs for these two ENGIE contracts are included in Attachment NGC-2, Page 14, under the rows titled "ENGIE Gas Demand Payment Winter Vapor" and "ENGIE Gas Demand Payment Winter Combination."

Q. How has the Company updated commodity prices in this filing?

A. The attachments to my testimony include the original forecasted gas costs for November 2017 and December 2017 and the re-calculated forecasted gas costs for the January 2018 through October 2018 period using actual first-of-month pricing for January 2018, and the January 8, 2018 New York Mercantile Exchange (NYMEX) strip for the February 2018 through October 2018 period.

Q. How were forecasted gas costs re-calculated?

A. The Company re-calculated projected gas costs using the SENDOUT model results as shown in the Initial GCR Filing and updated prices as described above. When the Company purchases supply at locations other than Henry Hub, which is the pricing point for NYMEX contracts, the Company uses indicative market differentials to the Henry Hub to determine the expected difference, or "basis." Applying the basis differential to the NYMEX pricing creates a reasonable estimate of the expected cost of the supply. Up to date pricing will estimate expected normal costs for the remainder of the GCR year, but in order to capture the incremental costs for January as a result of the design-like weather, the Company reflected the actual market area purchases executed January 1 through 16 and included them in the projected January 2018 estimate. These costs are included in Attachment NGC-2, Page 9, under the rows titled "Estimated Incremental Costs."

Q. How did the Company categorize the projected gas cost components?

A. The Company disaggregated gas costs into the following two components: (1) Supply Fixed Cost Component, and (2) Supply Variable Cost Component, just as it did in the Initial GCR Filing. An updated summary, disaggregating these same cost components by month for the period November 2017 through October 2018, is shown in Attachment NGC-1.

Q. Please describe Attachment NGC-2, pages 1 through 17.

A. Attachment NGC-2 shows the supporting detail for gas costs included in this filing for the period November 2017 through October 2018. The first two pages show the forecasted sendout by supply source under normal weather from the SENDOUT model, as well as the detailed makeup of supply by pipeline source, storage contract, and peaking facility. The forecasted sendout volumes remain unchanged from the Initial GCR Filing, with the exception of the incremental volumes purchased in January 2018. The next section, pages 3 through 6, shows the calculation of the per unit delivered cost for each pipeline path, including both pipeline variable charges and pipeline fuel losses. Pages 7 through 9 show the calculation of the delivered cost for each path (the price multiplied by the quantity). Pages 10 through 14 show the detailed calculation of total fixed costs. The cost details for gas injected into and withdrawn from underground storage are shown on pages 15 and 16, and all costs associated with LNG injected into and withdrawn from storage are detailed on page 17.

Q. Does this conclude your testimony?

A. Yes.

Attachment NGC-1
(REDACTED)

REDACTED

SUMMARY OF ESTIMATED GAS COSTS FOR 2017-2018 GCR

01/08/2018 NYMEX UPDATE

Variable Costs	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	GCR TOTAL
Total Pipeline Supply Costs	$5,452,587	$9,587,626	$36,775,656	$12,690,521	$9,557,082	$5,176,838	$3,059,439	$1,894,271	$1,493,728	$1,362,853	$1,405,603	$2,723,605	$91,179,811
Total Storage Product Costs	$113,091	$1,262,219	$1,920,448	$1,755,292	$1,603,567	$110,523	$0	$0	$0	$0	$0	$0	$6,765,141
Total Storage Delivery Costs	$4,801	$70,340	$115,421	$105,741	$97,222	$4,828	$0	$0	$0	$0	$0	$0	$398,353
Total LNG Costs	$75,435	$77,949	$1,934,136	$738,848	$77,949	$75,435	$76,236	$73,444	$75,932	$77,719	$77,177	$79,002	$3,439,260
Total All Variable Gas Costs	$5,645,914	$10,998,135	$40,745,661	$15,290,402	$11,335,821	$5,367,623	$3,135,675	$1,967,716	$1,569,660	$1,440,572	$1,482,780	$2,802,607	$101,782,564
Fixed Costs													
Total Pipeline Demands	[redacted]												
Total Storage Facilities	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$399,422	$4,793,063
Total Storage Delivery	$438,183	$438,183	$438,183	$438,183	$438,183	$438,183	$438,183	$438,183	$438,183	$438,183	$438,183	$438,183	$5,258,193
Total Supplier Demands	[redacted]												
Total All Fixed Costs	$5,107,123	$5,141,113	$6,801,247	$6,799,110	$6,801,247	$5,223,774	$5,224,486	$5,223,774	$5,224,486	$5,224,486	$5,223,370	$5,224,082	$67,218,297
Capacity Release Credits	$692,715	$692,715	$692,715	$692,715	$692,715	$692,715	$692,715	$692,715	$692,715	$692,715	$692,715	$692,715	$8,312,577
NGPMP Credit	$908,333	$908,333	$908,333	$908,333	$908,333	$908,333	$908,333	$908,333	$908,333	$908,333	$908,333	$908,333	$10,900,000
Net Fixed Costs	$3,506,075	$3,540,065	$5,200,199	$5,198,062	$5,200,199	$3,622,725	$3,623,438	$3,622,725	$3,623,438	$3,623,438	$3,622,322	$3,623,034	$48,005,720
Total All Gas Costs	[redacted]												$149,788,284

Attachment NGC-2
(REDACTED)

National Grid
2017 Estimated GCR
Normal Weather Scenario

Natural Gas Supply VS. Requirements

Units: DTH

	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	OCT 2018	TOTAL
Forecast Demand													
RI Sales GCR	2,286,401	3,945,192	4,943,244	4,417,284	3,736,115	2,175,893	1,268,260	808,643	647,353	593,008	639,818	1,177,517	26,638,728
Total Demand	2,286,401	3,945,192	4,943,244	4,417,284	3,736,115	2,175,893	1,268,260	808,643	647,353	593,008	639,818	1,177,517	26,638,728
Storage Injections													
TENNESSEE FSMA 501	0	0	0	0	0	0	122,389	118,441	0	15,409	118,441	122,389	497,067
DOMINION GSS 300170	0	0	0	0	0	0	0	0	0	0	67,306	36,578	103,884
DOMINION GSS 300168	0	0	0	0	0	0	26,019	25,179	11,663	21,856	21,151	21,856	127,723
DOMINION GSS 300171	0	0	0	0	0	11,012	31,885	30,856	29,910	26,783	25,919	26,783	183,150
DOMINION GSSTE 600045	0	0	0	0	0	0	0	0	21,580	63,172	188,947	100,490	374,188
TETCO FSS-1 400515	0	0	0	0	0	1,734	8,964	8,675	8,964	8,964	8,675	8,964	54,941
TETCO SS-1 400221	0	0	0	0	0	35,783	188,124	182,056	188,124	188,124	182,056	188,124	1,152,392
TETCO SS-1 400185	0	0	0	0	0	1,612	8,225	7,960	8,225	8,225	7,960	8,225	50,430
DOMINION GSS 300169	0	0	0	0	0	8,626	34,803	33,680	32,647	29,234	28,291	29,234	196,516
COLUMBIA FSS 9630	0	0	0	0	0	3,818	40,791	40,791	34,673	40,791	26,514	14,277	201,656
TENNESSEE 62918	0	0	0	0	0	0	42,454	41,084	0	36,623	41,084	42,454	203,700
Total Storage Injections	0	0	0	0	0	62,585	503,653	488,722	335,786	439,182	716,344	599,374	3,145,647
LNG PROVIDENCE	0	0	0	0	0	58,815	147,562	141,626	49,504	21,620	141,028	22,964	583,119
LNG EXETER	0	0	0	0	0	87,891	4,034	5,080	2,092	5,976	5,677	4,631	115,381
Total LNG Injections	0	0	0	0	0	146,706	151,596	146,706	51,596	27,596	146,706	27,596	698,500
Total Injections	0	0	0	0	0	209,291	655,249	635,428	387,382	466,778	863,049	626,970	3,844,147

Delivered Firm Sales Supply

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	GCR Total
Sources of Supply													
TENNESSEE ZONE 0 CXN	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 0	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 1	0	0	0	0	0	0	0	0	0	0	0	0	0
TENNESSEE ZONE 4 CXN	348,000	359,600	359,600	336,400	359,600	348,000	333,804	256,881	95,795	138,861	291,827	359,600	3,587,968
TENNESSEE ZONE 4	372,136	561,797	456,709	408,980	326,648	153,627	0	0	0	0	0	171,448	2,451,346
TENNESSEE NIAGARA	2,134	0	5,335	3,201	0	32,010	33,077	32,010	33,077	33,077	32,010	33,077	239,008
TENNESSEE DRACUT	0	14,431	23,557	144,527	38,778	0	0	0	0	0	0	0	221,294
TETCO ELA	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO ETX	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO STX	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO WLA	0	0	0	0	0	0	0	0	0	0	0	0	0
TETCO M2	774,107	798,268	798,167	720,958	798,475	776,776	272,001	775,935	801,546	801,412	441,848	801,270	8,560,762
TETCO M3 DELIVERED	477,660	104,703	188,368	205,193	149,868	376,031	666,208	163,113	0	0	546,497	375,849	3,253,490
COLUMBIA MAUMEE	72,184	878,862	691,706	616,913	367,033	49,885	0	0	0	0	0	0	2,676,583
COLUMBIA BROADRUN	0	308,519	308,519	278,662	265,930	9,958	0	0	0	0	0	0	1,171,588
COLUMBIA EAGLE	14,378	29,290	94,579	84,510	78,468	30,887	40,791	40,791	34,673	40,791	26,514	14,277	529,950
COLUMBIA DOWNINGTOWN	0	10,643	111,019	100,198	111,987	2,063	0	0	0	0	0	0	335,911
TRANSCO LEIDY	36,470	38,067	38,067	34,383	38,067	11,414	2,232	2,160	2,232	2,232	2,160	2,232	209,716
TETCO LEIDY	7,164	16,486	16,486	14,890	16,486	4,257	0	0	0	0	0	0	75,767
TETCO to B&W SCT	0	49,945	60,372	51,168	28,654	0	0	0	0	0	0	0	190,140
ALGONQUIN - AIM	116,496	165,795	491,644	439,006	408,990	377,851	402,200	11,169	0	0	0	3,321	2,416,471
ANE II-DAWN-TENN-WADDY	0	30,824	30,806	27,835	0	0	5,784	0	0	0	0	0	95,249
GAZ METRO LNG Refill	0	0	0	0	0	26,706	27,596	26,706	27,596	27,596	26,706	27,596	190,500
GDF SUEZ LNG Refill	0	0	0	0	0	120,000	124,000	120,000	24,000	0	120,000	0	508,000
PORTABLE LNG	0	0	0	0	0	0	0	0	0	0	0	0	0

National Grid
2017 Estimated GCR
Normal Weather Scenario

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
Non LNG Liquid take	2,220,728	3,367,230	3,674,933	3,466,825	2,988,984	2,172,760	1,756,097	1,282,059	967,322	1,016,374	1,340,855	1,761,074	26,015,241
LNG Liquid take	0	0	0	0	0	146,706	151,596	146,706	51,596	27,596	146,706	27,596	698,500
Total take	2,220,728	3,367,230	3,674,933	3,466,825	2,988,984	2,319,466	1,907,693	1,428,765	1,018,918	1,043,969	1,487,561	1,788,670	26,713,741
Storage Withdrawals													
TENNESSEE FSMA 501	0	16,077	162,881	157,995	151,063	3,435	0	0	0	0	0	0	491,450
DOMINION GSS 300170	0	16,034	43,945	36,771	3,958	0	0	0	0	0	0	0	100,707
DOMINION GSS 300168	738	22,597	30,387	36,554	36,003	0	0	0	0	0	0	0	126,279
DOMINION GSS 300171	0	30,764	68,291	57,610	22,368	0	0	0	0	0	0	0	179,033
DOMINION GSSTE 600045	49,628	69,626	69,626	62,888	69,626	43,248	0	0	0	0	0	0	364,642
TETCO FSS-1 400515	0	13,651	13,651	13,651	12,013	0	0	0	0	0	0	0	52,968
TETCO SS-1 400221	0	283,662	288,039	288,039	257,851	0	0	0	0	0	0	0	1,117,591
TETCO SS-1 400185	0	12,605	12,605	12,605	11,092	0	0	0	0	0	0	0	48,907
DOMINION GSS 300169	0	44,009	54,033	49,328	43,446	0	0	0	0	0	0	0	190,815
COLUMBIA FSS 9630	0	44,787	71,211	52,666	24,450	3,729	0	0	0	0	0	0	196,842
TENNESSEE 62918	0	8,334	61,187	32,433	99,444	0	0	0	0	0	0	0	201,398
LNG PROVIDENCE	10,824	11,185	362,848	109,863	11,185	10,824	11,185	10,824	11,185	11,185	10,824	11,185	583,119
LNG EXETER	4,482	4,631	29,607	40,057	4,631	4,482	4,631	4,482	4,631	4,631	4,482	4,631	115,381
Total Withdrawal Delivered	65,673	577,962	1,268,312	950,459	747,131	65,718	15,817	15,306	15,817	15,817	15,306	15,817	3,769,133
Total Storage Withdrawal	50,366	562,145	875,857	800,540	731,314	50,411	0	0	0	0	0	0	3,070,633
Total Peaking Withdrawal	15,306	15,817	392,455	149,919	15,817	15,306	15,817	15,306	15,817	15,817	15,306	15,817	698,500
Total Supply	**2,286,401**	**3,945,192**	**4,943,244**	**4,417,284**	**3,736,115**	**2,238,478**	**1,771,913**	**1,297,365**	**983,139**	**1,032,190**	**1,356,162**	**1,776,891**	**29,784,374**
Storage Withdrawals at Storage Facilty													
TENNESSEE FSMA 501	0	16,261	164,743	159,800	152,789	3,474	0	0	0	0	0	0	497,067
DOMINION GSS 300170	0	16,540	45,331	37,931	4,082	0	0	0	0	0	0	0	103,884
DOMINION GSS 300168	746	22,855	30,735	36,972	36,415	0	0	0	0	0	0	0	127,723
DOMINION GSS 300171	0	31,471	69,861	58,935	22,883	0	0	0	0	0	0	0	183,150
DOMINION GSSTE 600045	50,934	71,465	71,465	64,549	71,465	44,310	0	0	0	0	0	0	374,188
TETCO FSS-1 400515	0	14,160	14,160	14,160	12,461	0	0	0	0	0	0	0	54,941
TETCO SS-1 400221	0	292,495	297,008	297,008	265,881	0	0	0	0	0	0	0	1,152,392
TETCO SS-1 400185	0	12,998	12,998	12,998	11,438	0	0	0	0	0	0	0	50,430
DOMINION GSS 300169	0	45,324	55,647	50,802	44,744	0	0	0	0	0	0	0	196,516
COLUMBIA FSS 9630	0	45,883	72,953	53,954	25,048	3,818	0	0	0	0	0	0	201,656
TENNESSEE 62918	0	8,429	61,887	32,804	100,580	0	0	0	0	0	0	0	203,700
	51,680	577,880	896,787	819,912	747,786	51,601	0	0	0	0	0	0	3,145,646

National Grid
2017 Estimated GCR
Normal Weather Scenario

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
01/08/2018 NYMEX UPDATE	**$2.920**	**$3.079**	**$2.738**	**$2.835**	**$2.772**	**$2.676**	**$2.680**	**$2.720**	**$2.758**	**$2.761**	**$2.742**	**$2.766**	
TENNESSEE ZONE 0 CONNEXION													
Basis	($0.198)	($0.183)	($0.118)	($0.107)	($0.120)	($0.188)	($0.172)	($0.175)	($0.162)	($0.167)	($0.170)	($0.182)	
Usage to Zn 6	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	$0.0425	
Fuel to Zn 6	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
Total Delivered	$2.8853	$3.0670	$2.7788	$2.8916	$2.8122	$2.6409	$2.6618	$2.7005	$2.7537	$2.7516	$2.7287	$2.7412	
TENNESSEE ZONE 0													
Basis	($0.198)	($0.183)	($0.118)	($0.107)	($0.120)	($0.188)	($0.172)	($0.175)	($0.162)	($0.167)	($0.170)	($0.182)	
Usage to Zn 6	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	$0.3464	
Fuel to Zn 6	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
Total Delivered	$3.1892	$3.3709	$3.0827	$3.1955	$3.1161	$2.9448	$2.9657	$3.0044	$3.0576	$3.0555	$3.0326	$3.0451	
TENNESSEE ZONE 1													
Basis	($0.142)	($0.095)	($0.078)	($0.045)	($0.090)	($0.110)	($0.125)	($0.128)	($0.107)	($0.086)	($0.098)	($0.100)	
Usage to Zn 6	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	$0.3019	
Fuel to Zn 6	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
Total Delivered	$3.1866	$3.4006	$3.0641	$3.1991	$3.0869	$2.9665	$2.9551	$2.9935	$3.0548	$3.0797	$3.0475	$3.0703	
TENNESSEE ZONE 4 CONNEXION													
Basis	($0.789)	($0.637)	($0.198)	($0.206)	($0.216)	($0.254)	($0.296)	($0.392)	($0.379)	($0.409)	($0.546)	($0.472)	
Usage to Zn 6	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	$0.0115	
Fuel to Zn 6	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	
Total Delivered	$2.1669	$2.4814	$2.5805	$2.6705	$2.5967	$2.4612	$2.4227	$2.3661	$2.4177	$2.3904	$2.2326	$2.3317	
TENNESSEE ZONE 4													
Basis	($0.789)	($0.637)	($0.198)	($0.206)	($0.216)	($0.254)	($0.296)	($0.392)	($0.379)	($0.409)	($0.546)	($0.472)	
Usage to Zn 6	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	
Fuel to Zn 6	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	1.13%	
Total Delivered	$2.2719	$2.5864	$2.6855	$2.7755	$2.7017	$2.5662	$2.5277	$2.4711	$2.5227	$2.4954	$2.3376	$2.4367	
TENNESSEE NIAGARA													
Basis	($0.416)	($0.397)	$0.592	$0.009	($0.128)	($0.618)	($0.789)	($0.815)	($0.856)	($0.843)	($0.848)	($0.846)	
Tenn usage	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	
Tenn Fuel	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	
Total Delivered	$2.6124	$2.7919	$3.4452	$2.9552	$2.7536	$2.1628	$1.9944	$2.0086	$2.0055	$2.0217	$1.9975	$2.0237	
TENNESSEE DRACUT													
Basis	$0.390	$3.177	$9.502	$6.930	$3.168	$0.320	-$0.052	-$0.122	$0.185	$0.233	-$0.355	-$0.215	
Usage	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	$0.0360	
Fuel	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	
Total Delivered	$3.3463	$6.2926	$12.2772	$9.8020	$5.9766	$3.0323	$2.6643	$2.6343	$2.9793	$3.0303	$2.4232	$2.5873	
TETCO ELA													
Basis	($0.100)	($0.097)	($0.088)	($0.073)	($0.082)	($0.095)	($0.098)	($0.105)	($0.108)	($0.107)	($0.105)	($0.102)	
Usage to M3	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel to M3	3.63%	4.33%	4.33%	4.33%	4.33%	3.63%	3.63%	3.63%	3.63%	3.63%	3.63%	3.63%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$3.0289	$3.2233	$2.8729	$2.9911	$2.9151	$2.7786	$2.7796	$2.8142	$2.8508	$2.8550	$2.8372	$2.8655	

National Grid
2017 Estimated GCR
Normal Weather Scenario

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TETCO ETX													
Basis	($0.135)	($0.197)	($0.108)	($0.099)	($0.137)	($0.108)	($0.097)	($0.098)	($0.107)	($0.081)	($0.078)	($0.098)	
Usage to M3	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	$0.0627	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel to M3	3.63%	4.33%	4.33%	4.33%	4.33%	3.63%	3.63%	3.63%	3.63%	3.63%	3.63%	3.63%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.9922	$3.1178	$2.8518	$2.9637	$2.8571	$2.7650	$2.7807	$2.8215	$2.8519	$2.8823	$2.8655	$2.8697	
TETCO STX													
Basis	($0.095)	($0.147)	($0.078)	($0.083)	($0.110)	($0.078)	($0.060)	($0.055)	($0.060)	($0.057)	($0.048)	($0.078)	
Usage to M3	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	$0.0677	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel to M3	3.73%	4.47%	4.47%	4.47%	4.47%	3.73%	3.73%	3.73%	3.73%	3.73%	3.73%	3.73%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$3.0422	$3.1801	$2.8926	$2.9899	$2.8947	$2.8043	$2.8273	$2.8745	$2.9091	$2.9154	$2.9049	$2.8986	
TETCO WLA													
Basis	($0.088)	($0.097)	($0.078)	($0.093)	($0.092)	($0.072)	($0.075)	($0.082)	($0.085)	($0.085)	($0.082)	($0.080)	
Usage to M3	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	$0.0645	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel to M3	3.59%	4.29%	4.29%	4.29%	4.29%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$3.0420	$3.2238	$2.8841	$2.9706	$2.9052	$2.8034	$2.8044	$2.8390	$2.8756	$2.8787	$2.8620	$2.8892	
TETCO M2													
Basis	($0.715)	($0.535)	($0.468)	($0.347)	($0.390)	($0.492)	($0.560)	($0.635)	($0.668)	($0.685)	($0.832)	($0.762)	
Usage on Tetco	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel on Tetco	2.07%	2.49%	2.49%	2.49%	2.49%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.3310	$2.6933	$2.4095	$2.6353	$2.5255	$2.3094	$2.2434	$2.2073	$2.2125	$2.1981	$2.0270	$2.1239	
TETCO M3 DELIVERED													
Basis	($0.430)	$0.295	$2.442	$2.350	$0.190	($0.335)	($0.395)	($0.468)	($0.445)	($0.485)	($0.708)	($0.598)	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.5254	$3.4195	$5.2432	$5.2483	$3.0035	$2.3750	$2.3185	$2.2852	$2.3467	$2.3094	$2.0652	$2.2004	
COLUMBIA MAUMEE													
Basis	($0.201)	($0.205)	($0.218)	($0.205)	($0.230)	($0.268)	($0.255)	($0.258)	($0.282)	($0.327)	($0.352)	($0.342)	
Usage on Columbia	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel on Columbia	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.8189	$2.9794	$2.6168	$2.7295	$2.6393	$2.5005	$2.5179	$2.5558	$2.5701	$2.5271	$2.4821	$2.5169	

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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
COLUMBIA BROADRUN													
Basis	($0.201)	($0.205)	($0.218)	($0.205)	($0.230)	($0.268)	($0.255)	($0.258)	($0.282)	($0.327)	($0.352)	($0.342)	
Usage on Columbia	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel on Columbia	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.8189	$2.9794	$2.6168	$2.7295	$2.6393	$2.5005	$2.5179	$2.5558	$2.5701	$2.5271	$2.4821	$2.5169	
COLUMBIA EAGLE													
Basis	($0.430)	$0.295	$2.442	$2.350	$0.190	($0.335)	($0.395)	($0.468)	($0.445)	($0.485)	($0.708)	($0.598)	
Usage on Columbia	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel on Columbia	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.5845	$3.4917	$5.3418	$5.3470	$3.0696	$2.4319	$2.3746	$2.3408	$2.4033	$2.3654	$2.1176	$2.2548	
COLUMBIA DOWNINGTOWN													
Basis	$0.100	$0.670	$2.000	$2.000	$2.000	($0.135)	($0.230)	($0.255)	($0.148)	($0.193)	($0.480)	($0.360)	
Usage on Columbia	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	$0.0224	
Usage on AGT	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
Fuel on Columbia	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	1.432%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$3.1271	$3.8758	$4.8890	$4.9884	$4.9239	$2.6367	$2.5435	$2.5589	$2.7073	$2.6643	$2.3510	$2.4985	
TRANSCO LEIDY													
Basis	($0.808)	($0.693)	($0.498)	($0.475)	($0.492)	($0.580)	($0.622)	($0.685)	($0.768)	($0.777)	($0.922)	($0.810)	
Usage on Transco	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	$0.0073	
Usage on AGT	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	
Fuel on Transco	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	0.41%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Delivered to Algonquin	$2.1280	$2.4031	$2.2565	$2.3770	$2.2967	$2.1119	$2.0738	$2.0507	$2.0055	$1.9995	$1.8348	$1.9713	
Total Delivered	$2.3761	$2.6553	$2.5072	$2.6289	$2.5478	$2.3599	$2.3214	$2.2981	$2.2525	$2.2464	$2.0802	$2.2180	

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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TETCO LEIDY													
Basis	($0.680)	($0.684)	($0.298)	($0.581)	($0.622)	($0.520)	($0.572)	($0.549)	($0.575)	($0.545)	($0.795)	($0.667)	
Usage on Tetco	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	
Usage on AGT	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	
Fuel on Tetco	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.5200	$2.6800	$2.7260	$2.5357	$2.4293	$2.4341	$2.3851	$2.4495	$2.4618	$2.4955	$2.2205	$2.3759	
TETCO to B&W SCT													
Basis	($0.715)	($0.535)	($0.468)	($0.347)	($0.390)	($0.492)	($0.560)	($0.635)	($0.668)	($0.685)	($0.832)	($0.762)	
Usage on Tetco	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	$0.0458	
Usage on AGT	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	$0.2286	
Fuel to M3	2.07%	2.49%	2.49%	2.49%	2.49%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	2.07%	
Fuel on AGT	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.5471	$2.9094	$2.6256	$2.8514	$2.7416	$2.5255	$2.4595	$2.4234	$2.4286	$2.4142	$2.2431	$2.3400	
ALGONQUIN - AIM													
Basis	($0.430)	$0.295	$2.442	$2.350	$0.190	($0.335)	($0.395)	($0.468)	($0.445)	($0.485)	($0.708)	($0.598)	
AGT Usage	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	
AGT Fuel	0.91%	0.97%	0.97%	0.97%	0.97%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	
Total Delivered	$2.5142	$3.4083	$5.2320	$5.2371	$2.9923	$2.3638	$2.3073	$2.2740	$2.3355	$2.2982	$2.0540	$2.1892	
DAWN TO TENNESSEE - WADDY													
Basis	$0.135	$0.155	$0.262	$0.600	$0.500	($0.521)	($0.571)	($0.472)	($0.471)	($0.497)	($0.621)	($0.499)	
Union usage	$0.0075	$0.0075	$0.0075	$0.0075	$0.0075	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Iroquois usage	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	
Tenn usage	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	$0.0880	
Fuel on Union	0.88%	1.00%	1.15%	1.09%	1.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on TransCanada	0.93%	0.55%	1.12%	0.39%	0.71%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Fuel on Iroquois	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	
Fuel on Tenn	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	
Total Delivered	$3.2400	$3.4151	$3.1977	$3.6187	$3.4602	$2.2675	$2.2211	$2.3614	$2.4007	$2.3775	$2.2332	$2.3805	

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Natural Gas Supply VS. Requirements

Units: DTH

Total Delivered to the City Gate Gas Supply Costs

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TENNESSEE ZONE 0 CONNEXION													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$2.885	$3.067	$2.779	$2.892	$2.812	$2.641	$2.662	$2.700	$2.754	$2.752	$2.729	$2.741	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 0													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.189	$3.371	$3.083	$3.195	$3.116	$2.945	$2.966	$3.004	$3.058	$3.056	$3.033	$3.045	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 1													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.187	$3.401	$3.064	$3.199	$3.087	$2.966	$2.955	$2.993	$3.055	$3.080	$3.047	$3.070	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE ZONE 4 CONNEXION													
Delivered MMBtu	348,000	359,600	359,600	336,400	359,600	348,000	333,804	256,881	95,795	138,861	291,827	359,600	
Delivered Price	$2.1669	$2.4814	$2.5805	$2.6705	$2.5967	$2.4612	$2.4227	$2.3661	$2.4177	$2.3904	$2.2326	$2.3317	
Total Delivered Cost	$754,066	$892,315	$927,959	$898,372	$933,778	$856,491	$808,722	$607,808	$231,603	$331,931	$651,532	$838,486	
TENNESSEE ZONE 4													
Delivered MMBtu	372,136	561,797	456,709	408,980	326,648	153,627	0	0	0	0	0	171,448	
Delivered Price	$2.2719	$2.5864	$2.6855	$2.7755	$2.7017	$2.5662	$2.5277	$2.4711	$2.5227	$2.4954	$2.3376	$2.4367	
Total Delivered Cost	$845,439	$1,453,037	$1,226,505	$1,135,144	$882,509	$394,236	$0	$0	$0	$0	$0	$417,771	
TENNESSEE NIAGARA													
Delivered MMBtu	2,134	0	5,335	3,201	0	32,010	33,077	32,010	33,077	33,077	32,010	33,077	
Delivered Price	$2.6124	$2.7919	$3.4452	$2.9552	$2.7536	$2.1628	$1.9944	$2.0086	$2.0055	$2.0217	$1.9975	$2.0237	
Total Delivered Cost	$5,575	$0	$18,380	$9,460	$0	$69,231	$65,970	$64,294	$66,337	$66,871	$63,939	$66,937	
TENNESSEE DRACUT													
Delivered MMBtu	0	14,431	23,557	144,527	38,778	0	0	0	0	0	0	0	
Delivered Price	$3.35	$6.29	$12.28	$9.80	$5.98	$3.03	$2.66	$2.63	$2.98	$3.03	$2.42	$2.59	
Total Delivered Cost	$0	$90,810	$289,215	$1,416,652	$231,762	$0	$0	$0	$0	$0	$0	$0	
TETCO ELA													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.0289	$3.2233	$2.8729	$2.9911	$2.9151	$2.7786	$2.7796	$2.8142	$2.8508	$2.8550	$2.8372	$2.8655	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO ETX													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$2.9922	$3.1178	$2.8518	$2.9637	$2.8571	$2.7650	$2.7807	$2.8215	$2.8519	$2.8823	$2.8655	$2.8697	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

National Grid
2017 Estimated GCR
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Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TETCO STX													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.042	$3.180	$2.893	$2.990	$2.895	$2.804	$2.827	$2.875	$2.909	$2.915	$2.905	$2.899	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO WLA													
Delivered MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	
Delivered Price	$3.0420	$3.2238	$2.8841	$2.9706	$2.9052	$2.8034	$2.8044	$2.8390	$2.8756	$2.8787	$2.8620	$2.8892	
Total Delivered Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
TETCO M2													
Delivered MMBtu	774,107	798,268	798,167	720,958	798,475	776,776	272,001	775,935	801,546	801,412	441,848	801,270	
Delivered Price	$2.3310	$2.6933	$2.4095	$2.6353	$2.5255	$2.3094	$2.2434	$2.2073	$2.2125	$2.1981	$2.0270	$2.1239	
Total Delivered Cost	$1,804,450	$2,149,949	$1,923,197	$1,899,921	$2,016,550	$1,793,861	$610,211	$1,712,755	$1,773,418	$1,761,560	$895,627	$1,701,795	
TETCO M3 DELIVERED													
Delivered MMBtu	477,660	104,703	188,368	205,193	149,868	376,031	666,208	163,113	0	0	546,497	375,849	
Delivered Price	$2.5254	$3.4195	$5.2432	$5.2483	$3.0035	$2.3750	$2.3185	$2.2852	$2.3467	$2.3094	$2.0652	$2.2004	
Total Delivered Cost	$1,206,267	$358,037	$987,660	$1,076,909	$450,131	$893,074	$1,544,592	$372,743	$0	$0	$1,128,614	$827,022	
COLUMBIA MAUMEE													
Delivered MMBtu	72,184	878,862	691,706	616,913	367,033	49,885	0	0	0	0	0	0	
Delivered Price	$2.8189	$2.9794	$2.6168	$2.7295	$2.6393	$2.5005	$2.5179	$2.5558	$2.5701	$2.5271	$2.4821	$2.5169	
Total Delivered Cost	$203,482	$2,618,510	$1,810,036	$1,683,842	$968,715	$124,738	$0	$0	$0	$0	$0	$0	
COLUMBIA BROADRUN													
Delivered MMBtu	0	308,519	308,519	278,662	265,930	9,958	0	0	0	0	0	0	
Delivered Price	$2.8189	$2.9794	$2.6168	$2.7295	$2.6393	$2.5005	$2.5179	$2.5558	$2.5701	$2.5271	$2.4821	$2.5169	
Total Delivered Cost	$0	$919,211	$807,323	$760,598	$701,873	$24,901	$0	$0	$0	$0	$0	$0	
COLUMBIA EAGLE													
Delivered MMBtu	14,378	29,290	94,579	84,510	78,468	30,887	40,791	40,791	34,673	40,791	26,514	14,277	
Delivered Price	$2.5845	$3.4917	$5.3418	$5.3470	$3.0696	$2.4319	$2.3746	$2.3408	$2.4033	$2.3654	$2.1176	$2.2548	
Total Delivered Cost	$37,160	$102,271	$505,227	$451,873	$240,863	$75,114	$96,863	$95,485	$83,327	$96,487	$56,147	$32,192	
COLUMBIA DOWNINGTOWN													
Delivered MMBtu	0	10,643	111,019	100,198	111,987	2,063	0	0	0	0	0	0	
Delivered Price	$3.1271	$3.8758	$4.8890	$4.9884	$4.9239	$2.6367	$2.5435	$2.5589	$2.7073	$2.6643	$2.3510	$2.4985	
Total Delivered Cost	$0	$41,251	$542,777	$499,829	$551,409	$5,440	$0	$0	$0	$0	$0	$0	

National Grid
2017 Estimated GCR
Normal Weather Scenario

Natural Gas Supply VS. Requirements

Units: DTH

	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	TOTAL
TRANSCO LEIDY													
Delivered MMBtu	36,470	38,067	38,067	34,383	38,067	11,414	2,232	2,160	2,232	2,232	2,160	2,232	
Delivered Price	$2.3761	$2.6553	$2.5072	$2.6289	$2.5478	$2.3599	$2.3214	$2.2981	$2.2525	$2.2464	$2.0802	$2.2180	
Total Delivered Cost	$86,657	$101,078	$95,442	$90,390	$96,986	$26,935	$5,181	$4,964	$5,028	$5,014	$4,493	$4,951	
TETCO LEIDY													
Delivered MMBtu	7,164	16,486	16,486	14,890	16,486	4,257	0	0	0	0	0	0	
Delivered Price	$2.5200	$2.6800	$2.7260	$2.5357	$2.4293	$2.4341	$2.3851	$2.4495	$2.4618	$2.4955	$2.2205	$2.3759	
Total Delivered Cost	$18,052	$44,181	$44,940	$37,758	$40,049	$10,362	$0	$0	$0	$0	$0	$0	
TETCO to B&W SCT													
Delivered MMBtu	0	49,945	60,372	51,168	28,654	0	0	0	0	0	0	0	
Delivered Price	$2.5471	$2.9094	$2.6256	$2.8514	$2.7416	$2.5255	$2.4595	$2.4234	$2.4286	$2.4142	$2.2431	$2.3400	
Total Delivered Cost	$0	$145,309	$158,513	$145,900	$78,559	$0	$0	$0	$0	$0	$0	$0	
ALGONQUIN - AIM													
Delivered MMBtu	116,496	165,795	491,644	439,006	408,990	377,851	402,200	11,169	0	0	0	3,321	
Delivered Price	$2.5142	$3.4083	$5.2320	$5.2371	$2.9923	$2.3638	$2.3073	$2.2740	$2.3355	$2.2982	$2.0540	$2.1892	
Total Delivered Cost	$292,889	$565,086	$2,572,300	$2,299,114	$1,223,826	$893,164	$927,990	$25,397	$0	$0	$0	$7,270	
DAWN TO TENNESSEE - WADDY													
Delivered MMBtu	0	30,824	30,806	27,835	0	0	5,784	0	0	0	0	0	
Delivered Price	$3.2400	$3.4151	$3.1977	$3.6187	$3.4602	$2.2675	$2.2211	$2.3614	$2.4007	$2.3775	$2.2332	$2.3805	
Total Delivered Cost	$0	$105,267	$98,509	$100,727	$0	$0	$12,847	$0	$0	$0	$0	$0	
ESTIMATED INCREMENTAL COSTS													
Tennessee Dracut MMBtu	0	0	494,481	0	0	0	0	0	0	0	0	0	
Tennessee Dracut Cost	$0	$0	$14,442,066	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Tennessee City Gate MMBtu	0	0	125,794	0	0	0	0	0	0	0	0	0	
Tennessee City Gate Costs	$0	$0	$5,008,903	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Algonquin City Gate MMBtu	0	0	49,007	0	0	0	0	0	0	0	0	0	
Algonquin City Gate Costs	$0	$0	$2,000,889	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Texas Eastern M3 MMBtu	0	0	96,500	0	0	0	0	0	0	0	0	0	
Texas Eastern M3 Costs	$0	$0	$2,516,090	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total Incremental MMBtu	0	0	765,782	0	0	0	0	0	0	0	0	0	
Total Incremental Costs	$0	$0	$23,967,949	$0	$0	$0	$0	$0	$0	$0	$0	$0	

	NOV 2017	**DEC** 2017	**JAN** 2018	**FEB** 2018	**MAR** 2018	**APR** 2018	**MAY** 2018	**JUN** 2018	**JUL** 2018	**AUG** 2018	**SEP** 2018	**OCT** 2018	**TOTAL**
Financial Hedges as of January 08, 2018													
Quantity	1,500,000	1,995,000	3,020,000	2,850,000	2,310,000	1,709,304	983,499	652,214	460,274	414,562	405,208	689,339	16,989,399
Average Price	$2.924	$3.043	$3.201	$3.113	$3.032	$2.788	$2.835	$2.841	$2.871	$2.865	$2.853	$2.921	
01/08/2018 NYMEX UPDATE	$2.920	$3.079	$2.738	$2.835	$2.772	$2.676	$2.680	$2.720	$2.758	$2.761	$2.742	$2.766	
NYMEX Hedges	$5,925	-$71,035	$1,399,180	$792,463	$600,874	$191,267	$152,282	$79,098	$52,176	$43,058	$44,922	$106,752	$3,396,962
Basis Hedges	$192,625	$72,350	-$599,455	-$608,430	$539,200	-$33,130	$2,750	$30,900	$31,540	$35,300	$56,400	$46,560	-$233,390
Impact of Financial Hedges	**$198,550**	**$1,315**	**$799,725**	**$184,033**	**$1,140,074**	**$158,137**	**$155,032**	**$109,998**	**$83,716**	**$78,358**	**$101,322**	**$153,312**	**$3,163,572**
Total Pipeline Costs (Incl Inj)	**$5,452,587**	**$9,587,626**	**$36,775,656**	**$12,690,521**	**$9,557,082**	**$5,325,685**	**$4,227,408**	**$2,993,444**	**$2,243,428**	**$2,340,220**	**$2,901,674**	**$4,049,736**	**$98,145,069**
Total Delivered Pipeline Vol	**2,220,728**	**3,367,230**	**4,440,715**	**3,466,825**	**2,988,984**	**2,172,760**	**1,756,097**	**1,282,059**	**967,322**	**1,016,374**	**1,340,855**	**1,761,074**	**26,781,023**
WACOG (Cost/Volume)	$2.455	$2.847	$8.281	$3.661	$3.197	$2.451	$2.407	$2.335	$2.319	$2.303	$2.164	$2.300	$3.665
Injections	0	0	0	0	0	62,585	503,653	488,722	335,786	439,182	716,344	599,374	3,145,647
Cost of Injections	$0	$0	$0	$0	$0	$148,848	$1,167,969	$1,099,173	$749,700	$977,367	$1,496,071	$1,326,131	**$6,965,258**
Total GCR Cost Including Financial Hedges, Excluding Injections													
Total Pipeline Costs	**$5,452,587**	**$9,587,626**	**$36,775,656**	**$12,690,521**	**$9,557,082**	**$5,176,838**	**$3,059,439**	**$1,894,271**	**$1,493,728**	**$1,362,853**	**$1,405,603**	**$2,723,605**	**$91,179,811**
Total Pipeline Purchase Volumes	**2,220,728**	**3,367,230**	**4,440,715**	**3,466,825**	**2,988,984**	**2,110,175**	**1,252,443**	**793,337**	**631,536**	**577,191**	**624,512**	**1,161,700**	**23,635,376**

2017 GCR Estimate
Fixed Cost Estimates
Nov 2017 - Oct 2018

2017-2018 Gas Supply Fixed Costs
UNIT PRICES

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
PIPELINE FIXED COST UNIT PRICES													
ALGONQUIN AFT-E/AFT-1 DEMAND	$/Dth	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734
ALGONQUIN AFT-3 DEMAND	$/Dth	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734
ALGONQUIN AFT-ES/1S DEMAND	$/Dth	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294
ALGONQUIN AIM DEMAND	$/Dth	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862	$41.7862
ALGONQUIN AFT-CLMS DEMAND (Crary St)	$/Dth	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375	$2.7375
COLUMBIA FTS DEMAND	$/Dth	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890	$6.4890
DOMINION FTNN DEMAND	$/Dth	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671
IROQUOIS DEMAND	$/Dth	$5.9982	$5.9982	$5.9982	$5.9982	$5.9982	$5.9982	$5.9982	$5.9982	$5.9982	$5.9982	$5.5997	$5.5997
NATIONAL FUEL DEMAND	$/Dth	$3.8067	$3.8067	$3.8067	$3.8067	$3.8067	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216	$21.5216
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$/Dth	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$/Dth	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211	$21.4211
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$/Dth	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575	$22.7575
TENNESSEE FT-A DEMAND DRACUT	$/Dth	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447	$4.7447
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$/Dth	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563	$7.1563
TEXAS EASTERN CDS STX DEMAND M3	$/Dth	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060	$6.8060
TEXAS EASTERN CDS WLA DEMAND M3	$/Dth	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260	$2.8260
TEXAS EASTERN CDS ELA DEMAND M3	$/Dth	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750	$2.3750
TEXAS EASTERN CDS ETX DEMAND M3	$/Dth	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890	$2.1890
TEXAS EASTERN CDS 1-3 DEMAND M3	$/Dth	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500	$10.6500
TEXAS EASTERN FTS DEMAND	$/Dth	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500
TEXAS EASTERN SCT STX DEMAND M3	$/Dth	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220	$2.7220
TEXAS EASTERN SCT WLA DEMAND M3	$/Dth	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310	$1.1310
TEXAS EASTERN SCT ELA DEMAND M3	$/Dth	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500	$0.9500
TEXAS EASTERN SCT ETX DEMAND M3	$/Dth	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760	$0.8760
TEXAS EASTERN SCT 1-3 DEMAND M3	$/Dth	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600	$4.2600
TRANSCANADA DEMAND	$/Dth	$13.4616	$13.9103	$13.9103	$12.5642	$13.9103	$13.4616	$13.9103	$13.4616	$13.9103	$13.9103	$13.4616	$13.9103
TRANSCO DEMAND ZONE 6 TO 6	$/Dth	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305	$0.1305
UNION DEMAND	$/Dth	$2.8170	$2.9109	$2.9109	$2.6292	$2.9109	$2.8170	$2.9109	$2.8170	$2.9109	$2.9109	$2.8170	$2.9109
STORAGE FIXED COST UNIT PRICES													
COLUMBIA FSS DEMAND	$/Dth	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010	$1.5010
COLUMBIA FSS CAPACITY	$/Dth	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288	$0.0288
DOMINION GSS DEMAND	$/Dth	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683
DOMINION GSS CAPACITY	$/Dth	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145
DOMINION GSS-TE DEMAND	$/Dth	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683	$1.8683
DOMINION GSS-TE CAPACITY	$/Dth	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145	$0.0145
TENNESSEE FSMA DEMAND	$/Dth	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938	$1.4938
TENNESSEE FSMA CAPACITY	$/Dth	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205	$0.0205
TEXAS EASTERN SS-1 DEMAND	$/Dth	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370	$5.4370
TEXAS EASTERN SS-1 CAPACITY	$/Dth	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293
TEXAS EASTERN FSS-1 DEMAND	$/Dth	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894	$0.0894
TEXAS EASTERN FSS-1 CAPACITY	$/Dth	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293	$0.1293

REDACTED

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
STORAGE DELIVERY FIXED UNIT PRICES													
ALGONQUIN FOR TETCO SS-1	$/Dth	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734
ALGONQUIN DELIVERY FOR FSS-1	$/Dth	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734
ALGONQUIN SCT FOR SS-1	$/Dth	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$/Dth	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734
ALGONQUIN SCT DELIVERY FOR GSS-TE	$/Dth	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294	$2.6294
ALGONQUIN DELIVERY FOR GSS	$/Dth	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854	$9.7854
ALGONQUIN DELIVERY FOR FSS	$/Dth	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734	$6.5734
COLUMBIA DELIVERY FOR FSS	$/Dth	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190	$6.3190
DOMINION DELIVERY FOR GSS	$/Dth	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671
DOMINION DELIVERY FOR GSS	$/Dth	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671	$4.1671
TENNESSEE DELIVERY FOR GSS	$/Dth	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475
TENNESSEE DELIVERY FOR FSMA	$/Dth	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475	$8.1475
TETCO DELIVERY FOR FSS-1	$/Dth	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700	$5.1700
TETCO DELIVERY FOR GSS/GSS-TE	$/Dth	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500	$5.3500
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760	$6.5760
TETCO DELIVERY FOR GSS-TE	$/Dth	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640	$6.8640
TETCO DELIVERY FOR GSS	$/Dth	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790	$5.1790
SUPPLIER FIXED COST UNIT PRICES													
GAZ METRO DEMAND PAYMENT Summer	$/Dth	[redacted]											
ENGIE GAS DEMAND PAYMENT Summer	$/Dth												
ENGIE GAS DEMAND PAYMENT Winter Port Vapo	$/Dth												
ENGIE GAS DEMAND PAYMENT Winter Vapor	$/Dth												
ENGIE GAS DEMAND PAYMENT Winter Combinati	$/Dth												
PEAKING SUPPLY AT DRACUT	$/Dth												
							BILLING UNITS						
PIPELINE FIXED COST BILLING UNITS													
ALGONQUIN AFT-E/AFT-1 DEMAND	Dth	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285	87,285
ALGONQUIN AFT-3 DEMAND	Dth	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063	11,063
ALGONQUIN AFT-ES/1S DEMAND	Dth	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079	4,079
ALGONQUIN AIM DEMAND	Dth	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
ALGONQUIN AFT-CLMS DEMAND (Crary St)	Dth	96,000	96,000	96,000	96,000	96,000	96,000	96,000	96,000	96,000	96,000	96,000	96,000
COLUMBIA FTS DEMAND	Dth	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455
DOMINION FTNN DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
IROQUOIS DEMAND	Dth	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
NATIONAL FUEL DEMAND	Dth	1,177	1,177	1,177	1,177	1,177	0	0	0	0	0	0	0
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
TENNESSEE FT-A DEMAND ZONE 1 TO 6	Dth	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500
TENNESSEE FT-A DEMAND ZONE 0 TO 6	Dth	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
TENNESSEE FT-A DEMAND ZONE 1 TO 6	Dth	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313	13,313
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	Dth	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600
TENNESSEE FT-A DEMAND DRACUT	Dth	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500	10,500
TENNESSEE FT-A DEMAND DRACUT FOR PEAK	Dth	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500	28,500
TENNESSEE FT-A DEMAND ZONE 5 TO 6	Dth	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067
TEXAS EASTERN CDS STX DEMAND M3	Dth	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844	13,844
TEXAS EASTERN CDS WLA DEMAND M3	Dth	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716	15,716
TEXAS EASTERN CDS ELA DEMAND M3	Dth	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758	23,758
TEXAS EASTERN CDS ETX DEMAND M3	Dth	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995	7,995
TEXAS EASTERN CDS 1-3 DEMAND M3	Dth	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934	45,934
TEXAS EASTERN FTS DEMAND	Dth	537	537	537	537	537	537	537	537	537	537	537	537
TEXAS EASTERN SCT STX DEMAND M3	Dth	571	571	571	571	571	571	571	571	571	571	571	571
TEXAS EASTERN SCT WLA DEMAND M3	Dth	648	648	648	648	648	648	648	648	648	648	648	648
TEXAS EASTERN SCT ELA DEMAND M3	Dth	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183	1,183
TEXAS EASTERN SCT ETX DEMAND M3	Dth	329	329	329	329	329	329	329	329	329	329	329	329
TEXAS EASTERN SCT 1-3 DEMAND M3	Dth	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099	2,099
TRANSCANADA DEMAND	Dth	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
TRANSCO DEMAND ZONE 6 TO 6	Dth	37,200	38,440	38,440	34,720	38,440	37,200	38,440	37,200	38,440	38,440	37,200	38,440
UNION DEMAND	Dth	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025

REDACTED

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
STORAGE FIXED COST BILLING UNITS													
COLUMBIA FSS DEMAND	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA FSS CAPACITY	Dth	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957	203,957
DOMINION GSS DEMAND	Dth	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403	11,403
DOMINION GSS CAPACITY	Dth	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304	1,039,304
DOMINION GSS-TE DEMAND	Dth	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337	14,337
DOMINION GSS-TE CAPACITY	Dth	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324	1,376,324
TENNESSEE FSMA DEMAND	Dth	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169
TENNESSEE FSMA CAPACITY	Dth	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343	815,343
TEXAS EASTERN SS-1 DEMAND	Dth	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802	14,802
TEXAS EASTERN SS-1 CAPACITY	Dth	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336	103,336
TEXAS EASTERN FSS-1 DEMAND	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TEXAS EASTERN FSS-1 CAPACITY	Dth	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720	4,720
STORAGE DELIVERY BILLING UNITS													
ALGONQUIN FOR TETCO SS-1	Dth	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137
ALGONQUIN DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
ALGONQUIN SCT FOR SS-1	Dth	665	665	665	665	665	665	665	665	665	665	665	665
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	Dth	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739	11,739
ALGONQUIN SCT DELIVERY FOR GSS-TE	Dth	187	187	187	187	187	187	187	187	187	187	187	187
ALGONQUIN DELIVERY FOR GSS	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
ALGONQUIN DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
COLUMBIA DELIVERY FOR FSS	Dth	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545	2,545
DOMINION DELIVERY FOR GSS	Dth	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324	5,324
DOMINION DELIVERY FOR GSS	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
TENNESSEE DELIVERY FOR GSS	Dth	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725	6,725
TENNESSEE DELIVERY FOR FSMA	Dth	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111	4,111
TETCO DELIVERY FOR FSS-1	Dth	944	944	944	944	944	944	944	944	944	944	944	944
TETCO DELIVERY FOR GSS/GSS-TE	Dth	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377
TETCO DELIVERY FOR GSS-TE	Dth	538	538	538	538	538	538	538	538	538	538	538	538
TETCO DELIVERY FOR GSS-TE	Dth	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011	5,011
TETCO DELIVERY FOR GSS	Dth	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061
SUPPLIER FIXED COST BILLING UNITS													
GAZ METRO DEMAND PAYMENT Summer	Dth	[redacted]											
ENGIE GAS DEMAND PAYMENT Summer	Dth												
ENGIE GAS DEMAND PAYMENT Winter Port Vapo	Dth												
ENGIE GAS DEMAND PAYMENT Winter Vapor	Dth												
ENGIE GAS DEMAND PAYMENT Winter Combinati	Dth												
PEAKING SUPPLY AT DRACUT	Dth												

REDACTED

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	
PIPELINE FIXED COST DOLLARS							**TOTAL COST**							
ALGONQUIN AFT-E/AFT-1 DEMAND	$	$573,759	$573,759	$573,759	$573,759	$573,759	$573,759	$573,759	$573,759	$573,759	$573,759	$573,759	$573,759	
ALGONQUIN AFT-3 DEMAND	$	$72,722	$72,722	$72,722	$72,722	$72,722	$72,722	$72,722	$72,722	$72,722	$72,722	$72,722	$72,722	
ALGONQUIN AFT-ES/1S DEMAND	$	$10,725	$10,725	$10,725	$10,725	$10,725	$10,725	$10,725	$10,725	$10,725	$10,725	$10,725	$10,725	
ALGONQUIN AIM DEMAND	$	$752,152	$752,152	$752,152	$752,152	$752,152	$752,152	$752,152	$752,152	$752,152	$752,152	$752,152	$752,152	
ALGONQUIN AFT-CLMS DEMAND (Crary St)	$	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	
CANADIAN CAPACITY AMA FEE	$	[redacted]												
COLUMBIA FTS DEMAND	$	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	$307,935	
DOMINION FTNN DEMAND	$	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	$2,238	
IROQUOIS DEMAND	$	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$6,070	$5,667	$5,667	
NATIONAL FUEL DEMAND	$	$4,480	$4,480	$4,480	$4,480	$4,480	$0	$0	$0	$0	$0	$0	$0	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$75,326	$75,326	$75,326	$75,326	$75,326	$75,326	$75,326	$75,326	$75,326	$75,326	$75,326	$75,326	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$139,890	$139,890	$139,890	$139,890	$139,890	$139,890	$139,890	$139,890	$139,890	$139,890	$139,890	$139,890	
TENNESSEE FT-A DEMAND ZONE 0 TO 6	$	$128,998	$128,998	$128,998	$128,998	$128,998	$128,998	$128,998	$128,998	$128,998	$128,998	$128,998	$128,998	
TENNESSEE FT-A DEMAND ZONE 1 TO 6	$	$285,179	$285,179	$285,179	$285,179	$285,179	$285,179	$285,179	$285,179	$285,179	$285,179	$285,179	$285,179	
TENNESSEE FT-A DEMAND ZONE 0 TO 6 CXN	$	$263,987	$263,987	$263,987	$263,987	$263,987	$263,987	$263,987	$263,987	$263,987	$263,987	$263,987	$263,987	
TENNESSEE FT-A DEMAND DRACUT	$	$49,819	$49,819	$49,819	$49,819	$49,819	$49,819	$49,819	$49,819	$49,819	$49,819	$49,819	$49,819	
TENNESSEE FT-A DEMAND DRACUT FOR PEAK	$	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	$135,224	
TENNESSEE FT-A DEMAND ZONE 5 TO 6	$	$14,792	$14,792	$14,792	$14,792	$14,792	$14,792	$14,792	$14,792	$14,792	$14,792	$14,792	$14,792	
TEXAS EASTERN CDS STX DEMAND M3	$	$94,222	$94,222	$94,222	$94,222	$94,222	$94,222	$94,222	$94,222	$94,222	$94,222	$94,222	$94,222	
TEXAS EASTERN CDS WLA DEMAND M3	$	$44,413	$44,413	$44,413	$44,413	$44,413	$44,413	$44,413	$44,413	$44,413	$44,413	$44,413	$44,413	
TEXAS EASTERN CDS ELA DEMAND M3	$	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	$56,425	
TEXAS EASTERN CDS ETX DEMAND M3	$	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501	
TEXAS EASTERN CDS 1-3 DEMAND M3	$	$489,197	$489,197	$489,197	$489,197	$489,197	$489,197	$489,197	$489,197	$489,197	$489,197	$489,197	$489,197	
TEXAS EASTERN FTS DEMAND	$	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	$2,873	
TEXAS EASTERN SCT STX DEMAND M3	$	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	$1,554	
TEXAS EASTERN SCT WLA DEMAND M3	$	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	$733	
TEXAS EASTERN SCT ELA DEMAND M3	$	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	$1,124	
TEXAS EASTERN SCT ETX DEMAND M3	$	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	
TEXAS EASTERN SCT 1-3 DEMAND M3	$	$8,942	$8,942	$8,942	$8,942	$8,942	$8,942	$8,942	$8,942	$8,942	$8,942	$8,942	$8,942	
TRANSCANADA DEMAND	$	$13,623	$14,077	$14,077	$12,715	$14,077	$13,623	$14,077	$13,623	$14,077	$14,077	$13,623	$14,077	
TRANSCO DEMAND ZONE 6 TO 6	$	$4,854	$5,016	$5,016	$4,530	$5,016	$4,854	$5,016	$4,854	$5,016	$5,016	$4,854	$5,016	
UNION DEMAND	$	$2,887	$2,984	$2,984	$2,695	$2,984	$2,887	$2,984	$2,887	$2,984	$2,984	$2,887	$2,984	
WESTERLY LATERAL (Yankee Gas)	$	[redacted]												
TOTAL PIPELINE DEMAND COSTS		[redacted]												
STORAGE FIXED COST DOLLARS														
COLUMBIA FSS DEMAND	$	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	$3,820	
COLUMBIA FSS CAPACITY	$	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	$5,874	
DOMINION GSS DEMAND	$	$21,304	$21,304	$21,304	$21,304	$21,304	$21,304	$21,304	$21,304	$21,304	$21,304	$21,304	$21,304	
DOMINION GSS CAPACITY	$	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	$15,070	
DOMINION GSS-TE DEMAND	$	$26,786	$26,786	$26,786	$26,786	$26,786	$26,786	$26,786	$26,786	$26,786	$26,786	$26,786	$26,786	
DOMINION GSS-TE CAPACITY	$	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	$19,957	
TENNESSEE FSMA DEMAND	$	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	$31,622	
TENNESSEE FSMA CAPACITY	$	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	$16,715	
TEXAS EASTERN SS-1 DEMAND	$	$80,478	$80,478	$80,478	$80,478	$80,478	$80,478	$80,478	$80,478	$80,478	$80,478	$80,478	$80,478	
TEXAS EASTERN SS-1 CAPACITY	$	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	$13,361	
TEXAS EASTERN FSS-1 DEMAND	$	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	$84	
TEXAS EASTERN FSS-1 CAPACITY	$	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	$610	
NATIONAL GRID LNG TANK LEASE PAYMENTS	$	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	**$1,964,880**
TOTAL STORAGE DEMAND COSTS	$	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$4,793,063**
STORAGE DELIVERY FIXED COSTS														
ALGONQUIN FOR TETCO SS-1	$	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	$92,928	
ALGONQUIN DELIVERY FOR FSS-1	$	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	$6,205	
ALGONQUIN SCT FOR SS-1	$	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	$1,749	
ALGONQUIN DELIVERY FOR GSS, GSS-TE,	$	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	$77,165	
ALGONQUIN SCT DELIVERY FOR GSS-TE	$	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	$492	
ALGONQUIN DELIVERY FOR GSS CONV	$	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	$20,168	
ALGONQUIN DELIVERY FOR FSS	$	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	$16,729	
COLUMBIA DELIVERY FOR FSS	$	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	$16,082	
DOMINION DELIVERY FOR GSS	$	$22,186	$22,186	$22,186	$22,186	$22,186	$22,186	$22,186	$22,186	$22,186	$22,186	$22,186	$22,186	
DOMINION DELIVERY FOR GSS CONV	$	$8,588	$8,588	$8,588	$8,588	$8,588	$8,588	$8,588	$8,588	$8,588	$8,588	$8,588	$8,588	
TENNESSEE DELIVERY FOR GSS	$	$54,792	$54,792	$54,792	$54,792	$54,792	$54,792	$54,792	$54,792	$54,792	$54,792	$54,792	$54,792	
TENNESSEE DELIVERY FOR FSMA	$	$33,494	$33,494	$33,494	$33,494	$33,494	$33,494	$33,494	$33,494	$33,494	$33,494	$33,494	$33,494	
TETCO DELIVERY FOR FSS-1	$	$4,880	$4,880	$4,880	$4,880	$4,880	$4,880	$4,880	$4,880	$4,880	$4,880	$4,880	$4,880	
TETCO DELIVERY FOR GSS/GSS-TE	$	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	$34,117	
TETCO DELIVERY FOR GSS-TE	$	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	$3,538	
TETCO DELIVERY FOR GSS-TE	$	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	$34,396	
TETCO DELIVERY FOR GSS CONV	$	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	$10,674	
TOTAL STORAGE DELIVERY DEMAND COSTS		**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$5,258,193**

REDACTED

GAZ METRO DEMAND PAYMENT Summer	$	[redacted]												
ENGIE GAS DEMAND PAYMENT Summer	$													
ENGIE GAS DEMAND PAYMENT Winter Port Vapo	$													
ENGIE GAS DEMAND PAYMENT Winter Vapor	$													
ENGIE GAS DEMAND PAYMENT Winter Combinati	$													
PEAKING SUPPLY AT DRACUT	$													
TOTAL SUPPLIER DEMAND COSTS														
TOTAL ALL DEMAND COSTS	$	**$5,107,123**	**$5,141,113**	**$6,801,247**	**$6,799,110**	**$6,801,247**	**$5,223,774**	**$5,224,486**	**$5,223,774**	**$5,224,486**	**$5,224,486**	**$5,223,370**	**$5,224,082**	**$67,218,297**
		Nov-17	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Total**
Marketer Demand Charge Credits														
Capacity Release Volumes as of August 1, 2017														
Tennessee Zone 1	Dth	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	
Tennessee Dracut	Dth	8	8	8	8	8	8	8	8	8	8	8	8	
Algonquin	Dth	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	2,714	
Tetco STX/AGT	Dth	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	
Tetco WLA/AGT	Dth	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	
Tetco ELA/AGT	Dth	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	
Columbia/AGT	Dth	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	
Total		**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	**33,547**	
System Weighted Average cost per MMBtu		**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	**$20.6491**	
Total Demand Charge Credit		**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$8,312,577**
Demand Costs Net of Releases to Marketers	$	**$4,414,408**	**$4,448,398**	**$6,108,532**	**$6,106,396**	**$6,108,532**	**$4,531,059**	**$4,531,771**	**$4,531,059**	**$4,531,771**	**$4,531,771**	**$4,530,656**	**$4,531,368**	**$58,905,720**
TOTAL PIPELINE DEMANDS	$	[redacted]												
TOTAL STORAGE FACILITIES DEMANDS	$	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$399,422**	**$4,793,063**
TOTAL STORAGE DELIVERY DEMANDS	$	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$438,183**	**$5,258,193**
TOTAL SUPPLIER DEMANDS	$	[redacted]												
Total All Demands	$	**$5,107,123**	**$5,141,113**	**$6,801,247**	**$6,799,110**	**$6,801,247**	**$5,223,774**	**$5,224,486**	**$5,223,774**	**$5,224,486**	**$5,224,486**	**$5,223,370**	**$5,224,082**	**$67,218,297**
Marketer Release Credits	$	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$692,715**	**$8,312,577**
NGPMP Credit	$	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$908,333**	**$10,900,000**
Demand Net of Releases	$	**$3,506,075**	**$3,540,065**	**$5,200,199**	**$5,198,062**	**$5,200,199**	**$3,622,725**	**$3,623,438**	**$3,622,725**	**$3,623,438**	**$3,623,438**	**$3,622,322**	**$3,623,034**	**$48,005,720**

Storage Product Cost

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
WACOG Injections	$2.366	$2.847	$8.101	$3.607	$2.816	$2.378	$2.319	$2.249	$2.233	$2.225	$2.088	$2.213	
Injection Charge	$0.024	$0.024	$0.024	$0.024	$0.024	$0.024	$0.024	$0.024	$0.024	$0.024	$0.024	$0.024	
Total Injection Cost	$2.390	$2.871	$8.125	$3.631	$2.840	$2.402	$2.343	$2.273	$2.256	$2.249	$2.112	$2.236	
Combined Storage	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	
Beginning Inventory	4,257,865	4,206,185	3,628,305	2,731,518	1,911,606	1,163,820	1,174,804	1,678,457	2,167,179	2,502,966	2,942,148	3,658,492	
Volume Withdrawn	51,680	577,880	896,787	819,912	747,786	51,601	0	0	0	0	0	0	3,145,646
Volume Injected	0	0	0	0	0	62,585	503,653	488,722	335,786	439,182	716,344	599,374	3,145,647
Begining Inventory $	$9,552,094	$9,436,055	$8,139,654	$6,127,822	$4,288,451	$2,610,887	$2,648,018	$3,827,962	$4,938,756	$5,696,440	$6,684,250	$8,197,354	
Volume Withdrawn $ (1)	$116,040	$1,297,517	$1,967,404	$1,798,752	$1,640,519	$113,205	$0	$0	$0	$0	$0	$0	$6,933,436
Volume Injected $	$0	$0	$0	$0	$0	$150,336	$1,179,944	$1,110,794	$757,684	$987,810	$1,513,104	$1,340,383	$7,040,055
Ending Inventory	4,206,185	3,628,305	2,731,518	1,911,606	1,163,820	1,174,804	1,678,457	2,167,179	2,502,966	2,942,148	3,658,492	4,257,865	
Ending Inventory $	$9,436,055	$8,139,654	$6,127,822	$4,288,451	$2,610,887	$2,648,018	$3,827,962	$4,938,756	$5,696,440	$6,684,250	$8,197,354	$9,537,737	
Average $/MMBtu	$2.2434	$2.2434	$2.2434	$2.2434	$2.2434	$2.2540	$2.2806	$2.2789	$2.2759	$2.2719	$2.2406	$2.2400	
Withdrawal Costs	**$1,082**	**$18,811**	**$22,565**	**$21,560**	**$19,001**	**$1,019**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$84,038**
Transportation Costs	**$771**	**$16,231**	**$45,901**	**$40,721**	**$41,270**	**$1,126**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$146,020**
Costs Allocated to Fuel	**$2,948**	**$35,298**	**$46,955**	**$43,460**	**$36,951**	**$2,682**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$168,295**
Storage Value Less Fuel	**$113,091**	**$1,262,219**	**$1,920,448**	**$1,755,292**	**$1,603,567**	**$110,523**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$6,765,141**
Delivered Volumes	50,366	562,145	875,857	800,540	731,314	50,411	0	0	0	0	0	0	3,070,633
Hedge Amortization	$100	$1,116	-$44,428	-$40,619	-$37,046	-$2,556	$0	$0	$0	$0	$0	$0	-$123,433

- amortization of hedges on injection gas
$6,075
($129,508) Update
($123,433)

(1) Includes Hedge Amortization
3,145,646 Withdrawal

Storage Withdrawal Variable Costs
2017-2018 GCR Storage Estimate

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
Storage Withdrawals at Facility (Dth)													
TENNESSEE FSMA 501	0	16,261	164,743	159,800	152,789	3,474	0	0	0	0	0	0	497,067
DOMINION GSS 300170	0	16,540	45,331	37,931	4,082	0	0	0	0	0	0	0	103,884
DOMINION GSS 300168	746	22,855	30,735	36,972	36,415	0	0	0	0	0	0	0	127,723
DOMINION GSS 300171	0	31,471	69,861	58,935	22,883	0	0	0	0	0	0	0	183,150
DOMINION GSSTE 600045	50,934	71,465	71,465	64,549	71,465	44,310	0	0	0	0	0	0	374,188
TETCO FSS-1 400515	0	14,071	14,071	14,071	12,382	0	0	0	0	0	0	0	54,595
TETCO SS-1 400221	0	286,440	290,860	290,860	260,377	0	0	0	0	0	0	0	1,128,537
TETCO SS-1 400185	0	12,728	12,728	12,728	11,201	0	0	0	0	0	0	0	49,386
DOMINION GSS 300169	0	45,324	55,647	50,802	44,744	0	0	0	0	0	0	0	196,516
COLUMBIA FSS 9630	0	45,883	72,953	53,954	25,048	3,818	0	0	0	0	0	0	201,656
TENNESSEE 62918	0	8,429	61,887	32,804	100,580	0	0	0	0	0	0	0	203,700
TOTAL WITHDRAWALS	51,680	571,467	890,281	813,406	741,967	51,601	0	0	0	0	0	0	3,120,402
Storage Withdrawal Charges													
Tennessee Withdrawal	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	$0.0087	
Dominion GSS Withdrawal	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	$0.0161	
Dominion GSS-TE Withdrawal	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	$0.0210	
TETCO SS-1 Withdrawal	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	$0.0471	
TETCO FSS-1 Withdrawal	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	$0.0307	
Columbia Withdrawal	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153	
Storage Withdrawal Costs													
Tennessee Withdrawal	$0	$215	$1,972	$1,676	$2,204	$30	$0	$0	$0	$0	$0	$0	$6,097
Dominion GSS Withdrawal	$12	$1,871	$3,245	$2,973	$1,741	$0	$0	$0	$0	$0	$0	$0	$9,841
Dominion GSS-TE Withdrawal	$1,070	$1,501	$1,501	$1,356	$1,501	$931	$0	$0	$0	$0	$0	$0	$7,858
TETCO SS-1 Withdrawal	$0	$14,091	$14,299	$14,299	$12,791	$0	$0	$0	$0	$0	$0	$0	$55,480
TETCO FSS-1 Withdrawal	$0	$432	$432	$432	$380	$0	$0	$0	$0	$0	$0	$0	$1,676
Columbia Withdrawal	$0	$702	$1,116	$825	$383	$58	$0	$0	$0	$0	$0	$0	$3,085
Total Storage Withdrawal Costs	$1,082	$18,811	$22,565	$21,560	$19,001	$1,019	$0	$0	$0	$0	$0	$0	$84,038

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
Storage Withdrawals at Gate (Dth)													
TENNESSEE FSMA 501	0	16,077	162,881	157,995	151,063	3,435	0	0	0	0	0	0	491,450
DOMINION GSS 300170	0	16,034	43,945	36,771	3,958	0	0	0	0	0	0	0	100,707
DOMINION GSS 300168	738	22,597	30,387	36,554	36,003	0	0	0	0	0	0	0	126,279
DOMINION GSS 300171	0	30,764	68,291	57,610	22,368	0	0	0	0	0	0	0	179,033
DOMINION GSSTE 600045	49,628	69,626	69,626	62,888	69,626	43,248	0	0	0	0	0	0	364,642
TETCO FSS-1 400515	0	13,651	13,651	13,651	12,013	0	0	0	0	0	0	0	52,968
TETCO SS-1 400221	0	283,662	288,039	288,039	257,851	0	0	0	0	0	0	0	1,117,591
TETCO SS-1 400185	0	12,605	12,605	12,605	11,092	0	0	0	0	0	0	0	48,907
DOMINION GSS 300169	0	44,009	54,033	49,328	43,446	0	0	0	0	0	0	0	190,815
COLUMBIA FSS 9630	0	44,787	71,211	52,666	24,450	3,729	0	0	0	0	0	0	196,842
TENNESSEE 62918	0	8,334	61,187	32,433	99,444	0	0	0	0	0	0	0	201,398
TOTAL WITHDRAWALS	50,366	562,145	875,857	800,540	731,314	50,411	0	0	0	0	0	0	3,070,633
Storage Transportation Charges													
Tennessee Transport	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	
Dominion Transport on TETCO/AGT	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	$0.0138	
Dominion Transport on DTI/TETCO/AGT	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	$0.0302	
Dominion Transport on Tennessee	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	$0.1165	
Dominion Transport on DTI/Tennessee	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	$0.1329	
TETCO SS-1 Transport	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	$0.0125	
TETCO FSS-1 Transport	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	$0.0478	
Columbia Transport	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	$0.0347	
Storage Transportation Costs													
Tennessee Transport	$0	$2,844	$26,104	$22,185	$29,184	$400	$0	$0	$0	$0	$0	$0	$80,717
Dominion Transport on TETCO/AGT	$685	$1,385	$1,903	$1,663	$1,270	$597	$0	$0	$0	$0	$0	$0	$7,503
Dominion Transport on DTI/TETCO/AGT	$0	$1,329	$1,632	$1,490	$1,312	$0	$0	$0	$0	$0	$0	$0	$5,763
Dominion Transport on Tennessee	$86	$2,633	$3,540	$4,259	$4,194	$0	$0	$0	$0	$0	$0	$0	$14,712
Dominion Transport on DTI/Tennessee	$0	$2,131	$5,840	$4,887	$526	$0	$0	$0	$0	$0	$0	$0	$13,384
TETCO SS-1 Transport	$0	$3,703	$3,758	$3,758	$3,362	$0	$0	$0	$0	$0	$0	$0	$14,581
TETCO FSS-1 Transport	$0	$652	$652	$652	$574	$0	$0	$0	$0	$0	$0	$0	$2,531
Columbia Transport	$0	$1,554	$2,471	$1,827	$848	$129	$0	$0	$0	$0	$0	$0	$6,830
Total Storage Transportation Costs	$771	$16,231	$45,901	$40,721	$41,270	$1,126	$0	$0	$0	$0	$0	$0	$146,020
Total Storage Variable Costs	$1,852	$35,043	$68,466	$62,281	$60,271	$2,146	$0	$0	$0	$0	$0	$0	$230,058

REDACTED

LNG Estimate for 2017 - 2018

NATIONAL GRID - RI SERVICE AREA
NOVEMBER 2017 - OCTOBER 2018

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
LNG Supply Costs													
01/08/2018 NYMEX UPDATE	$2.920	$3.079	$2.738	$2.835	$2.772	$2.676	$2.680	$2.720	$2.758	$2.761	$2.742	$2.766	
Trucking GDF Suez	[redacted]												
Basis ENGIE Gas Contract													
Delivered Cost ENGIE Gas													
Trucking Gaz Metro	[redacted]												
Gaz Metro Contract Commodity													
Delivered Cost Gaz Metro													
	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	
Combined LNG Inventory													
Beginning Inventory Volume	[redacted]												
Engie Gas Injections													
Gaz Metro Injections													
Volume Withdrawn	15,306	15,817	392,455	149,919	15,817	15,306	15,817	15,306	15,817	15,817	15,306	15,817	698,500
Begining Inventory	[redacted]												
Injection Costs													
Withdrawal Costs	$75,434.53	$77,949	$1,934,136	$738,848	$77,949	$75,435	$76,236	$73,444	$75,932	$77,719	$77,177	$79,002	$3,439,260
Ending Volume	[redacted]												
Ending Inventory													
Average Cost Per Dth	$4.928	$4.928	$4.928	$4.928	$4.928	$4.820	$4.798	$4.801	$4.914	$5.042	$4.995	$5.093	
Portable Vapor													
Portable Vapor Volume	0	0	0	0	0	0	0	0	0	0	0	0	
Average Cost Per Dth	[redacted]												
Total Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total All LNG Costs	**$75,435**	**$77,949**	**$1,934,136**	**$738,848**	**$77,949**	**$75,435**	**$76,236**	**$73,444**	**$75,932**	**$77,719**	**$77,177**	**$79,002**	**$3,439,260**

Testimony of
Stephen A. McCauley

DIRECT TESTIMONY

OF

STEPHEN A. MCCAULEY

January 29, 2018

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I. Introduction 1

II. Market Area Hedge Strategy Impact for the Period January 1-16, 2018 4

I. Introduction

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, New York 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. As Director, one of my responsibilities is for all financial hedging activity for the National Grid USA 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. 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 2017 Market Area Hedge Proposal
Attachment SAM-2 Regional Basis Point Map
Attachment SAM-3 Forecasted and Actual January 2018 Market Area Purchases
Attachment SAM-4 January 2018 Market Area Hedged Volumes
Attachment SAM-5 Hedge Benefits
Attachment SAM-6 Market Area Purchased Costs January 1-16
Attachment SAM-7 Hypothetical Market Area Hedge

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain (1) the effectiveness of the Company's market area hedge strategy and (2) the cost of gas as a result of the cold snap experienced in late-December 2017 and early-January 2018.

Q. What is the market area hedge strategy?

A. On September 19, 2017, the Company proposed a market area hedge strategy to mitigate approximately 35 percent of the expected price risk associated with forecasted supply purchases made in the market area in the 2017-18 winter period. On October 5, 2017, the PUC approved the proposed structure and the Company executed the proposed transactions prior to the winter season. Please see Attachment SAM-1 for a copy of the Company's approved 2017 Market Area Hedge Proposal.

Q. Was the approved 2017-18 market area hedge strategy similar to strategies executed in previous winter seasons?

A. Yes, the market area hedge strategy approved for the 2017-18 winter season was similar to the strategy executed by the Company for the three previous winter periods. The PUC had approved this strategy 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. Please see Attachment SAM-2 for the Regional Basis Point Map for the purchase point locations.

II. <u>Market Area Hedge Strategy Impact for the Period January 1-16, 2018</u>

Q. What was the Company's forecasted and actual market area purchases for January 2018?

A. Please see Attachment SAM -3 for the Forecasted and Actual Market Area Purchases from January 1, 2018 through January 16, 2018. The table lists the following information regarding the Market Area: (1) forecasted normal weather purchases; (2) forecasted design weather purchases; (3) actual purchases; (4) maximum daily purchases; and (5) minimum daily purchases at Tennessee Zone 6, Texas Eastern M3 (Tetco M3), Algonquin, and Transcontinental Non-NY Zone 6 (Transco Non-NY). The forecasted

normal weather and design weather estimates were used to develop the strategy proposed in the Company's market area hedge strategy. At each of the four locations, the actual daily average purchases for the first 16 days of the month exceeded the forecasted design weather average daily purchases. For example, at Tennessee Zone 6, the actual daily average was 38,767 dekatherms (dt) per day compared to the design weather forecast of 14,565 dt per day, and the Algonquin actual daily average was 3,063 dt per day compared to a design weather forecast of zero. The actual total volume purchased at Tennessee Zone 6, Tetco M3, and Algonquin for the first 16 days of the month exceeded the total design weather forecast for the whole month.

Q. What did the Company hedge for January 2018?

A. Please see Attachment SAM-4 for the January 2018 Market Area Hedged Purchases. The Company hedged 17,500 dt per day, or 542,500 dt per month, of the maximum 26,000 dt per day at Tetco M3. It also hedged 100 percent – 3,489 dt per day, or 108,159 dt per month – of the available capacity at Transco Non-NY. The 542,500 dt per month of Tetco M3 purchases is approximately equal to the forecasted normal weather purchases of 534,504 dt per month.

Q. What benefit did customers realize as a result of the market area hedges the Company did execute for January 2018?

A. Please see Attachment SAM-5 for the Hedge Benefits. Customers received a net benefit of approximately $7.5 million as a result of the hedged purchases at Tetco M3 and Transco Non-NY from the first 16 days of January. The hedges provided a unit cost of $4.03 per dt for the purchases at Tetco M3 and $4.74 per dt for the purchases at Transco Non-NY. The actual cost of the Tetco M3 purchases was $1.1 million, whereas if the Tetco M3 purchases were not hedged, the cost would have been $7.3 million. The actual cost of the Transco Non-NY purchases was $264,494, whereas if the Transco Non-NY purchases were not hedged, the cost would have been $1.6 million.

Q. What were the actual costs for the market area purchases not hedged from January 1, 2018 through January 16, 2018?

A. Please see Attachment SAM-6 for the Market Area Purchased Costs from January 1-16, 2018 (excluding hedged volumes). The Company purchased a total of [redacted] dt at Tennessee Zone 6 at a cost of $19.5 million, [redacted] dt at Algonquin at a cost of $2.0 million, and an incremental [redacted] dt at Tetco M3 at a cost of $2.5 million.

Q. Why did the Company not hedge the Tennessee Zone 6 and Algonquin market area purchases?

A. In Attachment SAM-1, Market Area Hedge Proposal, Page 12 of 15, the Company described the cost to hedge the forecasted purchases and the potential risk of having to purchase the needed Tennessee Zone 6 supplies under design weather conditions. The

Company's analysis showed that the cost to hedge the supply was equal to or greater than the cost to purchase supplies forecasted at design weather condition pricing. This can be seen in Attachment 5 of the Market Area Hedge Proposal. The Company did not hedge any supplies at Algonquin because the normal or design weather conditions did not forecast the need to purchase supplies at Algonquin.

Q. Based on the higher than design weather conditions in early January 2018, what would have been the cost to hedge the incremental market area supplies?

A. If the Company knew before the winter it would have needed a maximum of [redacted] dt per day at Tennessee Zone 6 and [redacted] dt per day at Algonquin, the cost to hedge would have been much higher than the current incremental costs realized to date. In order to hedge for the maximum risk, a hedging strategy would need to use the highest one day requirement at each location. Using the data available to the Company from January 1-16, 2018, the Company would have been required to hedge [redacted] dt per day for Tennessee Zone 6, which occurred on January 1, 2, 6, and 7; and [redacted] dt per day for Algonquin on January 5 and 7. Since the cold experienced during these days could happen anytime between mid-December and mid-February, the Company would need to hedge [redacted] dt per day of Tennessee Zone 6 and [redacted] dt per day at Algonquin for January 1 through February 28. Hedging supplies require the volume to be equal for each day of a month and for the whole month. In Attachment SAM-7, showing a Hypothetical Market Area Hedge, the table demonstrates what the costs would have been if the

Company had hedged [redacted] dt per day at Tennessee Zone 6 and [redacted] dt per day at Algonquin for January and February 2018 based on a hedge executed on September 1, 2017. The table demonstrates that the Tennessee Zone 6 costs would have been approximately $30.7 million and Algonquin costs would have been approximately $7.7 million. The total cost of supplies purchased between January 1-16 at Tennessee Zone 6 and Algonquin is approximately $21.4 million. At this point in the winter, hedging those two locations would have cost more than what the Company has spent through January 16, 2018.

Q. Does the Company believe the current market area hedge strategy is in the best interest of its customers?

A. Yes. The Company believes the current market area hedge strategy balances the risks and costs under different weather conditions over multiple years. The hedges provide some protection under more severe conditions, but do not burden customers with incremental costs in normal and warmer than normal winters.

Q. Does this conclude your testimony?

A. Yes.

Attachment SAM-1

Attachment SAM-1: 2017 Market Area Hedge Proposal

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

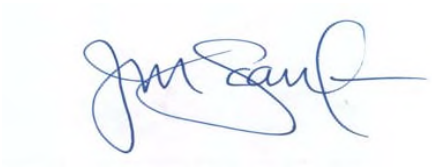
Enclosure

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

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Bruce Oliver Revilo Hill Associates 7103 Laketree Drive Fairfax Station, VA 22039	Boliver.rha@verizon.net;	703-569-6480
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THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC DOCKET NO. 4647
GAS PROCUREMENT INCENTIVE PLAN (GPIP)
MARKET AREA HEDGE PROPOSAL
WITNESS: STEPHEN A. MCCAULEY
SEPTEMBER 20, 2017

DIRECT TESTIMONY

OF

STEPHEN A. MCCAULEY

September 20, 2017

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC DOCKET NO. 4647
GAS PROCUREMENT INCENTIVE PLAN (GPIP)
MARKET AREA HEDGE PROPOSAL
WITNESS: STEPHEN A. MCCAULEY
SEPTEMBER 20, 2017

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I. Introduction 1

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I. Introduction

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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).

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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.

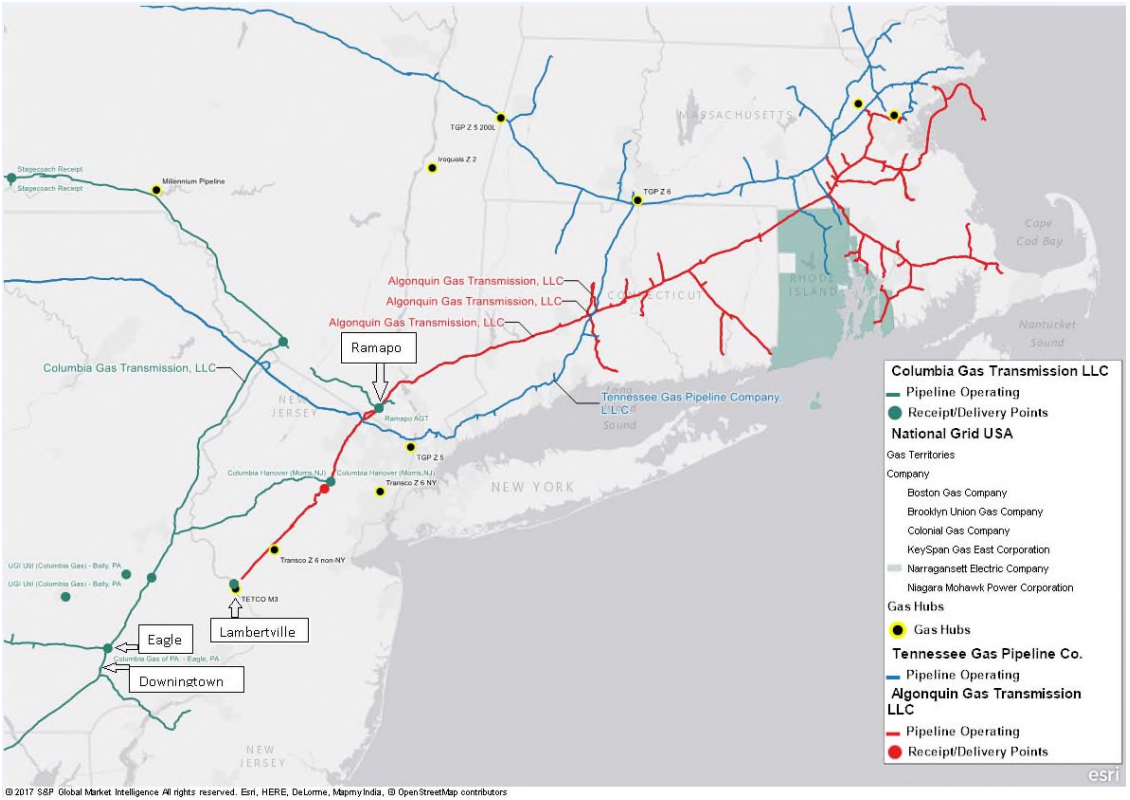
Q. Does this conclude your testimony?

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.

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC DOCKET NO. ____
GAS PROCUREMENT INCENTIVE PLAN (GPIP)
MARKET AREA HEDGE PROPOSAL
WITNESS: STEPHEN A. MCCAULEY
SEPTEMBER 20, 2017
ATTACHMENT SAM-1

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



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ATTACHMENT SAM-2

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)

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ATTACHMENT SAM-3

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	

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ATTACHMENT SAM-4

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	

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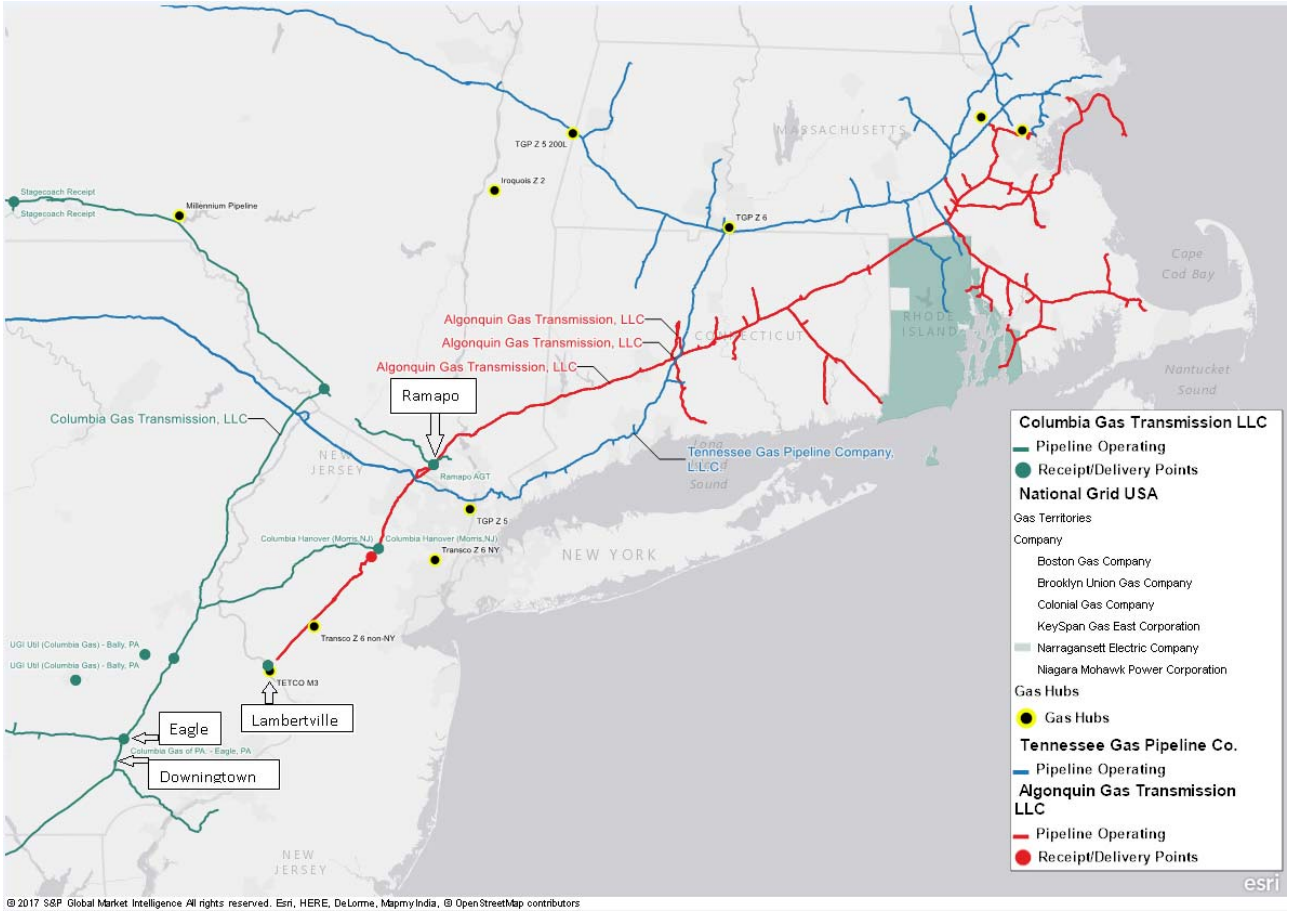
ATTACHMENT SAM-5

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	

Attachment SAM-2

Attachment SAM-2: Regional Basis Point Map (source: SNL/Platts)



Attachment SAM-3

REDACTED

Attachment SAM-3: Forecasted and Actual January 2018 Market Area Purchases

	Tennessee Zone 6 (Dth)	Tetco M3 (Dth)	Algonquin (Dth)	Transco Non-NY Zone 6 (Dth)	Total
Forecast - Monthly volume (Normal Weather)	23,559	534,504	0	60,669	618,733
Forecast - Daily Avg volume (Normal Weather)	760	17,242	0	1,957	19,959
Forecast - Monthly volume (Design Weather)	451,530	595,169	0	74,887	1,121,586
Forecast - Daily Avg volume (Design Weather)	14,565	19,199	0	2,416	36,180
Actual - Monthly volume (Jan 1-16)	[redacted]	[redacted]	[redacted]	55,824	[redacted]
Actual - Daily Avg volume (Jan 1-16)	[redacted]	[redacted]	[redacted]	3,489	[redacted]
Actual - Daily Max volume (Jan 1-16)	[redacted]	[redacted]	[redacted]	3,489	[redacted]
Actual - Daily Min volume (Jan 1-16)	0	17,500	0	3,489	20,989

Attachment SAM-4

Attachment SAM-4 January 2018 Market Area Hedged Volumes

	Tennessee Zone 6 (Dth)	Tetco M3 (Dth)	Algonquin (Dth)	Transco Non-NY Zone 6 (Dth)	Total
Monthly volumes (January 1 to 31)	0	542,500	0	108,159	650,659
January 1 to 16 volume	0	280,000	0	55,824	335,824
Daily Volumes	0	17,500	0	3,489	20,989

Attachment SAM-5

Attachment SAM-5 Hedge Benefit

	Tennessee Zone 6 (Dth)	Tetco M3 (Dth)	Algonquin (Dth)	Transco Non-NY Zone 6 (Dth)	Total
Hedge Volume Price		$4.03		$4.74	
Actual Hedge Volume Costs (January 1 - 16)		$1,127,840		$264,494	$1,392,334
Hedged Volume Cost if not hedged		$7,300,572		$1,548,872	$8,849,444
Net Hedge Benefit Customers Received	$0	$6,172,732	$0	$1,284,378	$7,457,110

Attachment SAM-6

REDACTED

Attachment SAM-6 Market Area Purchased Costs January 1-16

	Tennessee Zone 6 (Dth)	Tetco M3 (Dth)	Algonquin (Dth)	Transco Non-NY Zone 6 (Dth)	Total
Unhedged Purchase Volumes	[redacted]				
Total Costs	$19,450,970	$2,516,090	$2,000,889	0	$23,967,949
Unit Costs	[redacted]				

Attachment SAM-7

REDACTED

Attachment SAM-7 Hypothetical Market Area Hedge

	Tennessee Zone 6 (Dth)	Tetco M3 (Dth)	Algonquin (Dth)	Transco Non-NY Zone 6 (Dth)	Total
Hyporthetical Monthly Hedge Volume	[redacted]				
Hypothetical Daily Hedge Volume					
Hypothetical Hedge Cost (Jan and Feb)	$30,743,868	$2,187,118	$7,749,300		$40,680,286