nationalgrid

September 23, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4647 - 2016 Gas Cost Recovery Filing
Responses to Division Data Requests – Set 2

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's[1] responses to the second set of data requests issued by the Rhode Island Division of Public Utilities and Carriers (Division) in the above-referenced docket.

This filing also contains a Motion for Protective Treatment 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). The Company seeks protection from public disclosure of certain confidential and privileged information, which is contained in the Company's responses to Division 2-13(c), 2-14(c), 2-14(e), as well as Attachments DIV 2-13(b), 2-14(a), 2-16(a) and 2-16(b). In compliance with Rule 1.2(g), the Company has also provided the PUC with the un-redacted, confidential version of this response in a sealed envelope marked, **"Contains Privileged and Confidential Materials – Do Not Release"**, and has included a redacted copy in the filing.

Thank you for your attention to this filing. If you have any questions, please contact Jennifer Brooks Hutchinson at 401 784-7288 or Robert Humm at 401-784-7415.

Very truly yours,

Jennifer Brooks Hutchinson

Robert J. Humm

Enclosures
cc: Leo Wold, Esq.
Steve Scialabba, Division
Bruce Oliver, Division

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

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2016	)	Docket No. 4647

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 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 September 23, 2016, the Company filed with the PUC its responses to the second set of data requests from the Division of Public Utilities and Carriers (Division) in this docket. A number of the written responses and attachments contain privileged and confidential information. Division 2-13(b) and (c) seek information concerning National Grid's assessment of costs related to the Millennium Eastern System Upgrade Project (Millennium Project), including certain pricing information. National Grid is seeking protective treatment for such confidential gas-cost pricing information contained in its

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

response to Division 2-13(c) and Attachment DIV 2-13(b). Similarly, National Grid is seeking protective treatment for its confidential comparative cost analysis information contained in Attachment DIV 2-16(b) with respect to the expected cost of liquefied natural gas (LNG) from both the Northeast Energy Center LLC (Northeast Energy) project and the National Grid LNG LLC (NGLNG) facility in Providence.

Finally, National Grid is seeking protective treatment concerning certain confidential agreements it has entered into. Specifically, Attachment DIV 2-14(a) is the Precedent Agreement between National Grid and NGLNG, and Attachment DIV 2-16(a) is the Precedent Agreement between National Grid and Northeast Energy. By their terms, both agreements are entirely confidential and have not been made public. Likewise, the written responses to Division 2-14(c) and (e) contain substantive information from the Precedent Agreement between National Grid and NGLNG, which information is confidential.

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 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 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 necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *See 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 and comparative cost analyses included in National Grid's responses to the Division's second set of data requests are 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. In addition, the Precedent Agreements between National Grid and NGLNG, and National Grid and Northeast Energy, are confidential agreements that have not been made public. Public disclosure of those agreements could impair National Grid's ability to enter into similar agreements in the future, which would also cause 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.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID

By its attorneys,

____
Jennifer Brooks Hutchinson, Esq. (#6167)
Robert J. Humm, Esq. (#7920)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7415
Dated: September 23, 2016

Division 2-1

Request:

Re: Witness Arangio's Direct Testimony at page 8 of 23, lines 9-12, please:

a. Document and explain the manner in which the positioning of the Company's Rhode Island portfolio to takes advantage of opportunities presented by the development of the Marcellus basin is reflected in the development of National Grid's projected gas costs for the 2016-17 GCR year;

b. Document and explain the manner in which the positioning of the Company's Rhode Island portfolio to take advantage of opportunities presented by the development of the Marcellus basin is reflected in the Company's actual costs for the current (2015-16) GCR year to date.

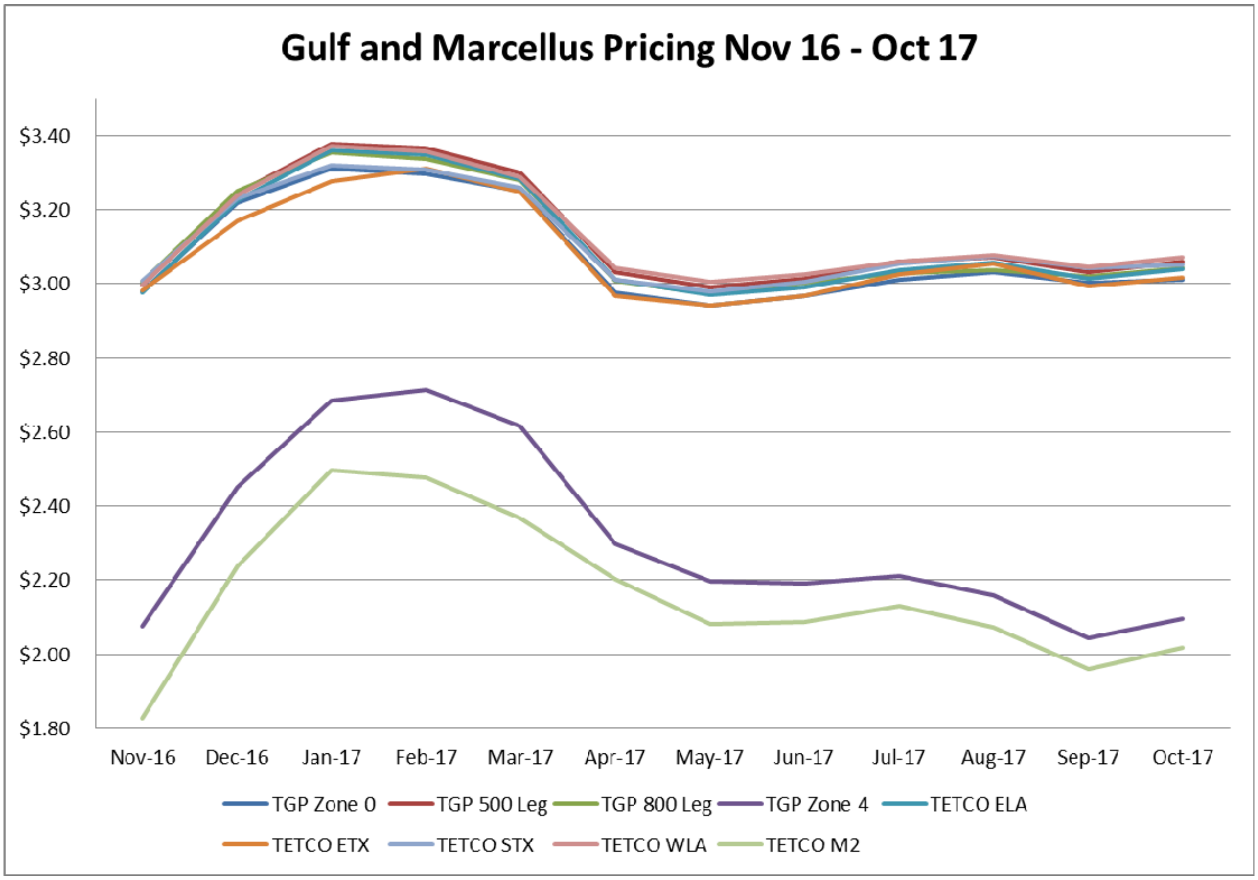
Response:

a. Please see below a snapshot from Attachment EDA-2, page 1 of 17, showing the volumes of delivered supply sourced from the Gulf of Mexico and Marcellus regions on both Tennessee Gas Pipeline (TGP) and Texas Eastern Transmission Company (Tetco).

	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	324,800	359,600	348,000	337,510	348,000	359,600	359,600	348,000	359,600	4,211,910
TENNESSEE ZONE 4	408,257	383,572	486,469	422,730	334,963	334,147	0	127,126	50,147	92,263	173,576	242,683	3,055,933
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	767,219	793,506	793,506	718,621	795,616	774,868	275,994	323,428	532,461	514,207	347,333	798,168	7,434,926

Although the Company's long-haul contracts on both TGP and Tetco are able to access supply from the Gulf of Mexico region, it is more advantageous to purchase gas along the long-haul contract paths from the Marcellus region at TGP Zone 4 and Tetco M2. The chart below illustrates this pricing dynamic, showing the projected prices for supplies in both the Gulf of Mexico and Marcellus regions that were used in the calculations for the 2016-17 projected gas costs.

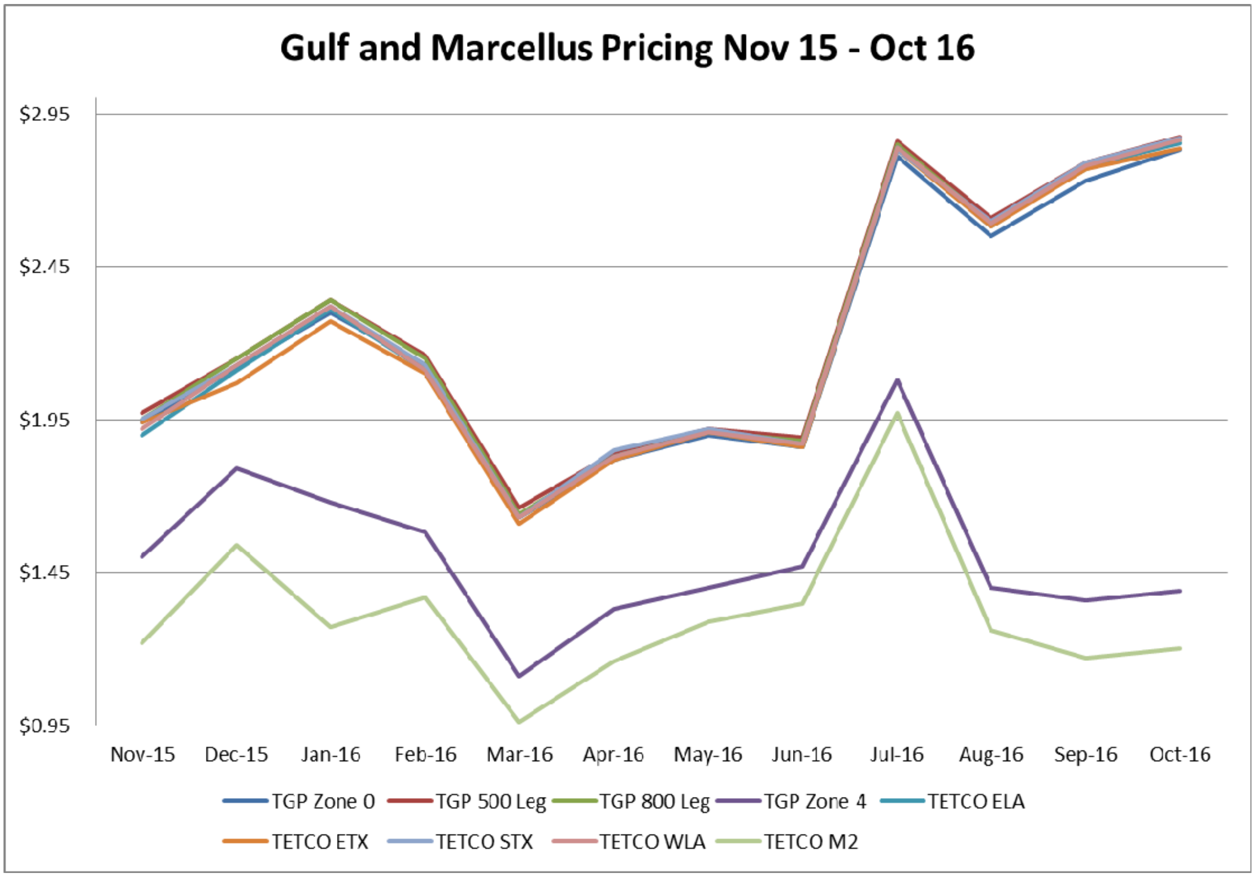
Division 2-1, page 2



b. The manner in which the positioning of the Company's Rhode Island portfolio takes advantage of opportunities presented by the development of the Marcellus basin occurs when the Company uses its existing long-haul pipeline capacity to purchase supplies at less expensive locations in the Marcellus basin as compared to the Gulf of Mexico. The less expensive purchases are included in the actual costs for the current (2015-16) GCR year-to-date. The chart below shows the actual first-of-month indices from Gas Daily for the months of November 2015 through and including September 2016. The September 9, 2016 NYMEX and forward basis pricing are used for the month of October 2016. The Marcellus purchase locations in TGP Zone 4 and Tetco M2 have been less expensive than all the Gulf of Mexico purchase locations during the entire 2015-16 GCR year.

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 2-1, page 3



Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-2

Request:

Re: Witness Arangio's Direct Testimony at page 10 of 23, line 14, please:

a. Indicate whether the Company continues to expect the AIM project to be in-service as of November 1, 2016, and if not, explain the reasons for any expected delays and the Company's best information regarding when the AIM project will be placed into service;

b. Discuss the manner in which the Company's 2016-17 GCR costs will be impacted if the in-service date for the AIM project is delayed.

Response:

a. Based on the information made available by Algonquin, it is uncertain whether the AIM Project will be in-service as of November 1, 2016. In the course of pullback operations under the Hudson River on August 27, 2016, the pullback pipe became disconnected from the drill string. Algonquin is awaiting a final decision from FERC on how to address this issue. The Company will continue to monitor construction activities and will respond accordingly.

b. The Company's existing HubLine Agreements shall continue for a term ending on and including the later of October 31, 2016 or the day prior to the service commencement date of the AIM Project. The Company would retain the HubLine contracts and continue to pay those demand charges if there should be a delay in the commencement of the AIM Project. If there is a delay in the AIM Project, the Company will have a plan in place to purchase sufficient gas supplies to meet customer demand. The Company will not commence paying the AIM demand charges until the project is in service.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-3

Request:

Re: Witness Arangio's Direct Testimony at page 12 of 23, lines 30-35, please:

a. Provide a detailed summary of the information that was provided by Texas Eastern at the meeting Scheduled for September 1, 2016;

b. Identify when Texas Eastern expects that full service will be restored to National Grid;

c. Explain and quantify the impacts, if any, that the information provided in the September 1, 2016 Texas Eastern meeting will have on the Company's estimated 2016-17 GCR costs.

Response:

a. Please see Attachment DIV 2-3(a) for the presentation provided by Texas Eastern at the September 1, 2016 meeting.

b. Texas Eastern has advised shippers that so long as Texas Eastern receives all necessary permits and approvals from PHMSA and state/local agencies, full service for Lines 12, 19 and 28 is expected by October 12, 2016 and work should be completed by November 1, 2016, for Line 27 valve sections and discharges.

c. Although Texas Eastern indicated that it remains optimistic that work should be completed by November 1, 2016, Texas Eastern further provided customers in its September 1, 2016 presentation with various capacity planning scenarios in the event full service is not restored on Lines 12, 19 and 28 and continued impairment of Line 27 occurs. Depending on the scenario, the impact on the Company's estimated 2016-17 GCR costs will vary, with the most variability being on the commodity cost of gas. If the Company is not able to source gas from the Texas Eastern M2 market area, replacement supplies will be more expensive. Given the wide range of possibilities, it is not possible to quantify the impacts at this time.

Prepared by or under the supervision of: Elizabeth D. Arangio

Operations Update: Penn-Jersey System

September 1, 2016

Agenda

Spectra Energy

- Welcome
- Penn-Jersey System Overview
- Overview of Texas Eastern Work Plan, Critical Path Items and Commitments
- Historical Flows & Illustrative Capacity Restoration Scenarios
- Q&A

Texas Eastern in Pennsylvania

Guiding Principles

- Address the needs and the safety of the immediate community
- Ensure safe operation of the pipeline system
- Provide transparency to regulatory agencies, community and customers
- Apply conservative criteria and minimize rework
- Protect the customers' needs and stabilize return to full service plan

TETLP Actions Following the Incident

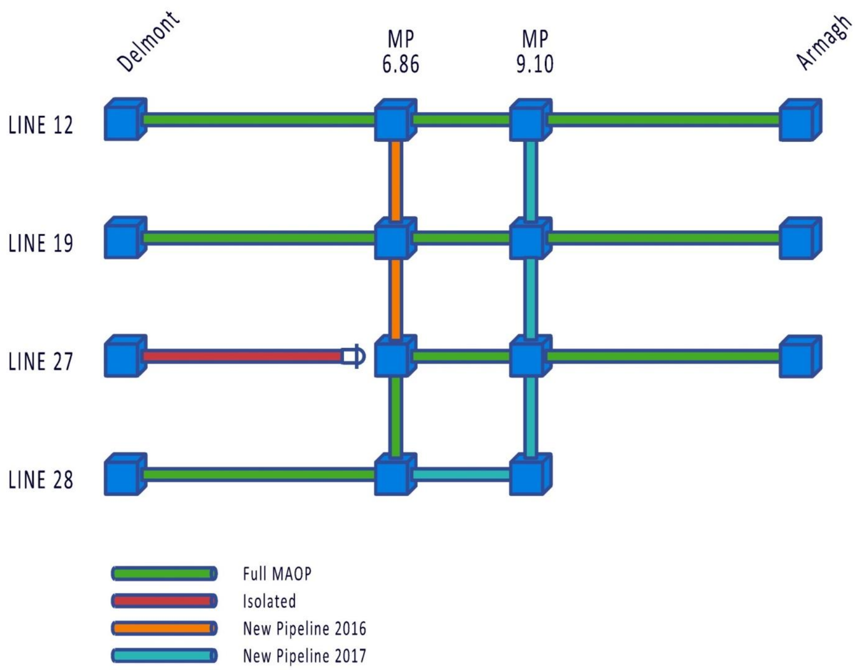
- Self-imposed temporary pressure reduction across the Penn-Jersey System(PJS)
- Records review of girth-weld coatings on all of PJS
- Developed model for evaluating circumferential anomalies
- Completed a detailed review of the most recent ILI data for PJS
- Identified anomalies for excavation and evaluation
- Re-running ILI tools for inspections more than three years old

Delmont Line 27 Incident – Work Plan

Spectra Energy

- PHMSA issued an Amended Corrective Action Order on July 19th
  - Amended CAO well-aligned with test and inspection plan and controls
  - Most significant difference required hydrostatic retest of Lines 12 (27.5 miles) and 27 (11.5 miles) from Delmont to Armagh – in progress
- Defined three primary streams of work
  - Based on review of current ILI data, identify, inspect and remediate anomalies, as necessary
  - Hydrostatic testing on Delmont Lines 12 and 27 as required by Amended CAO – including the remediation of any additional anomalies
  - Remediate, as necessary, any additional anomalies identified by the new ILI runs conducted this summer

Texas Eastern – Delmont Unplanned Outage Work Plan Overview



Work Plan - Current ILI Assessments

- Assessment of the current ILI data is complete – 626 anomalies identified for inspection
- Status thru August 30th
  - 389 have been released by environmental
  - 338 anomalies have been excavated
  - 299 have been evaluated
- Current work pace @ 40 sites/week - set based on permitted sites available for work
- Ramped up crew size and work plan in anticipation of receipt of remaining permits

Permitting Status Update

- PADEP supports emergency permits and expedited review
- Formal letter to Secretary of PADEP on Wednesday; agreement on approval process
- All sites in a county filed under one application – 9 counties
- Applications for 6 western counties in review; 3 released
- Three eastern counties have sites involving endangered species – treating separately from conventional sites
- Endangered species applications to Fish and Wildlife Services in process
- All sites associated with hydrostatic testing and new ILI runs to be addressed under PADEP emergency permit agreement

Work Plan - Hydrostatic Testing

- Hydrostatic test Line 12 Delmont Station to Armagh Station (27.5 miles)
  - 60 dig sites identified (103 small anomalies)
- Hydrostatic test Line 27 – MP 6.89 to MP 16.95 and Auxiliary Crossing (11.5 miles)
  - 24 anomalies identified

Work Plan - ILI Reassessments and Remediation

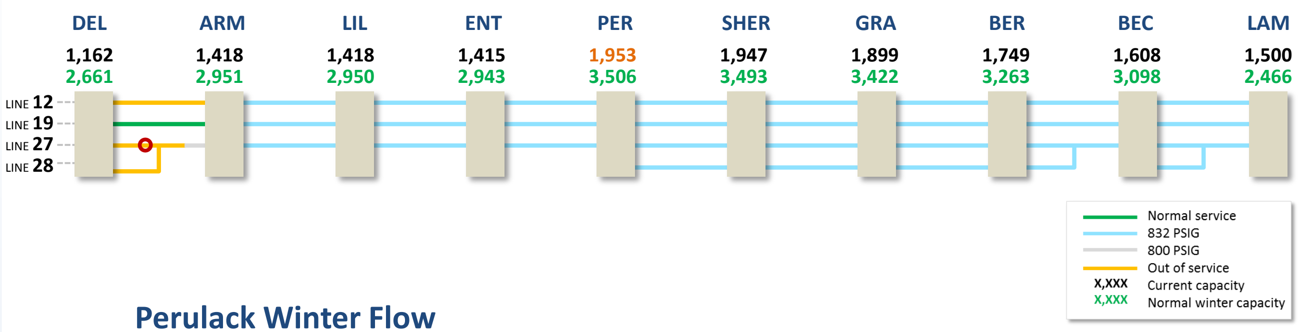
- Eight of nine re-inspection runs complete; last one to be completed on 9/8
- ILI data evaluated; identify new anomalies over next 3 weeks
- Most new information is being collected on Line 27; Line 27 remediation work to be executed after Lines 12, 19 and 28 are back in full service
- Line 27 likely isolated to support work in many locations
- Will deploy additional crews as needed for additional sites
- Permits for this work should not enter critical path given PADEP agreement

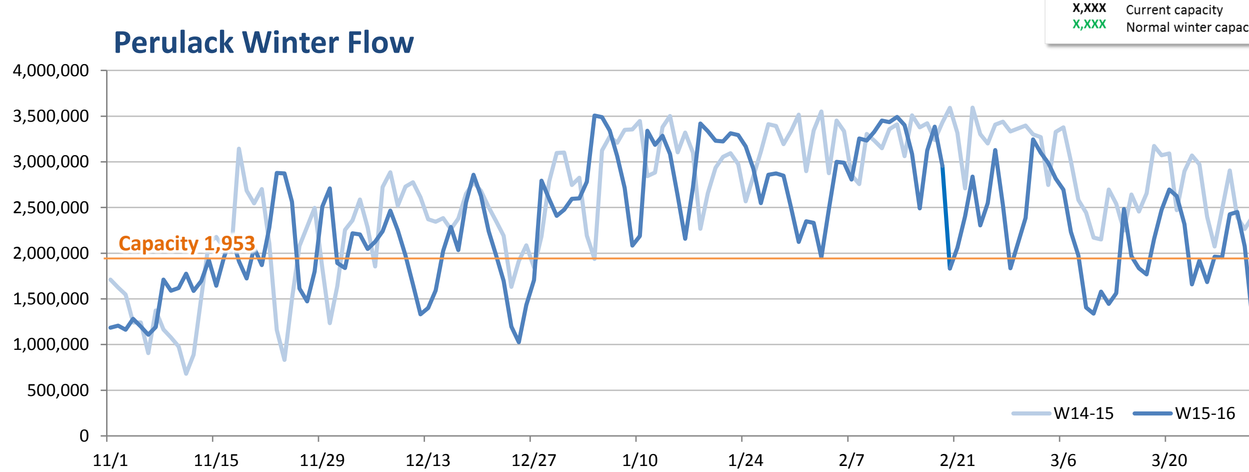
Work Plan – Return to Service

- Prioritizing work for most capacity benefit; initial focus on Lines 12 and 19
- Line 12 hydrostatic test completion expected by Oct.7th
- Return to full service for Lines 12, 19 and 28 across PJS expected by Oct. 12th
- Will allow us to remove Line 27 from service to expedite work and minimize disruption
- Line 27 valve sections and discharges will return to full service incrementally as work is completed
- As permits are received over next week, more detailed schedule on Sept. 9 for completion of work by Nov. 1

Penn-Jersey System Operating Status

Nov – Mar, Current Capacity Scenario



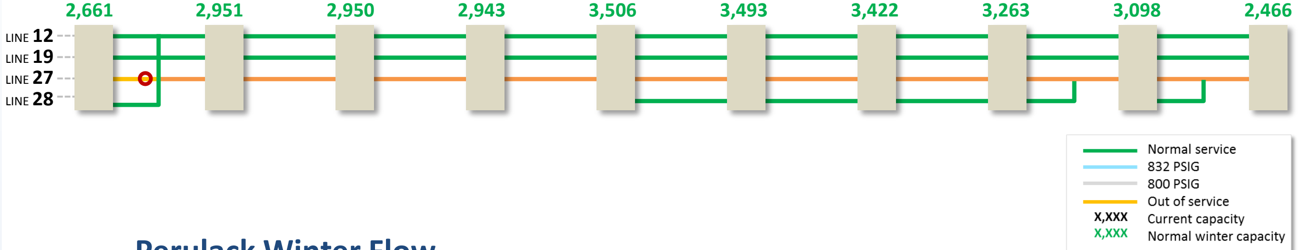


Penn-Jersey System Operating Status

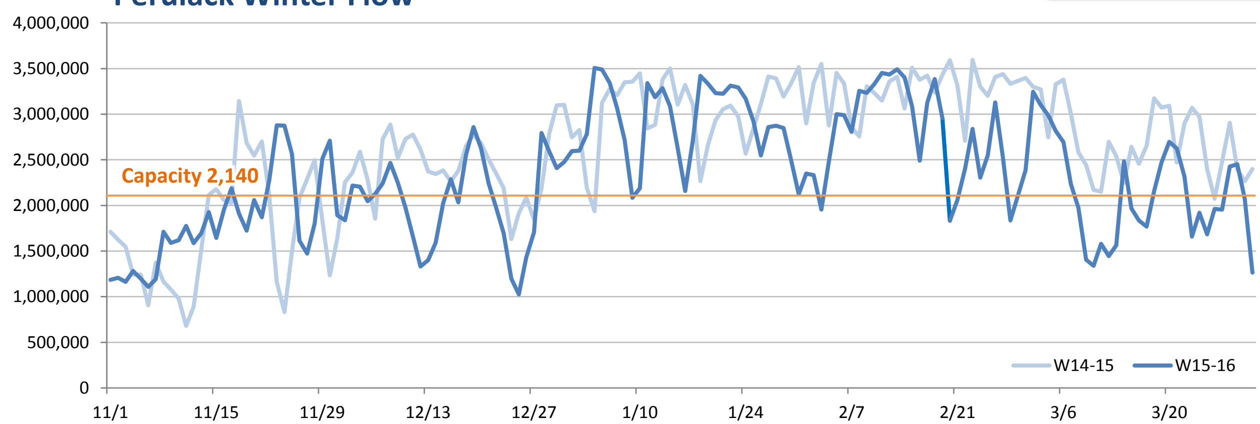
Nov – Mar, Scenario 1

Spectra Energy

DEL	ARM	LIL	ENT	PER	SHER	GRA	BER	BEC	LAM
1,395	1,689	1,734	1,730	2,140	2,133	2,060	1,908	1,748	1,353
2,661	2,951	2,950	2,943	3,506	3,493	3,422	3,263	3,098	2,466

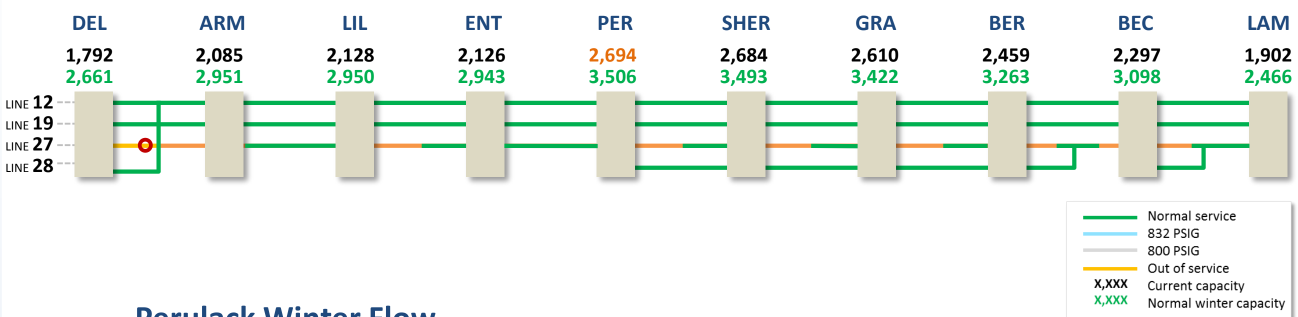


Perulack Winter Flow

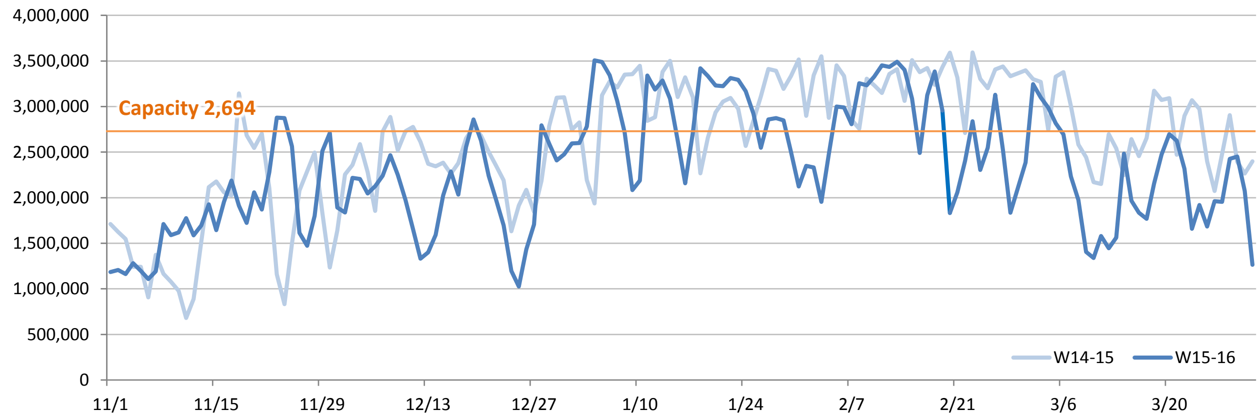


Penn-Jersey System Operating Status

Nov – Mar, Scenario 2

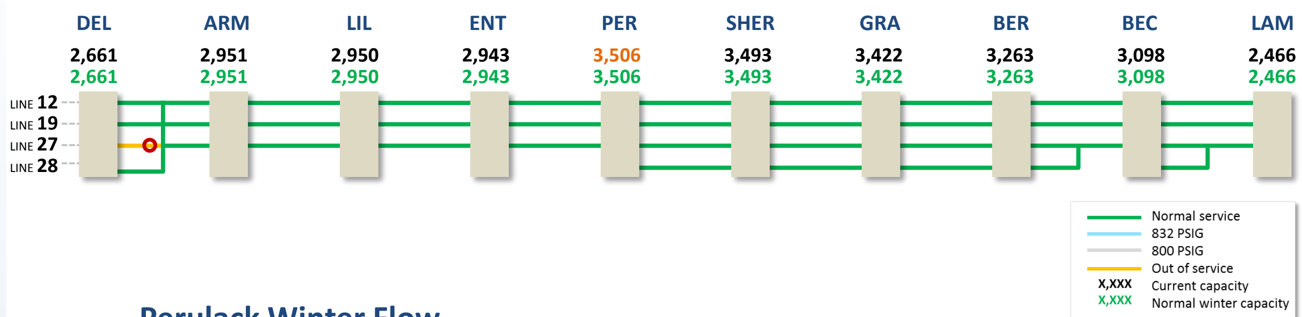


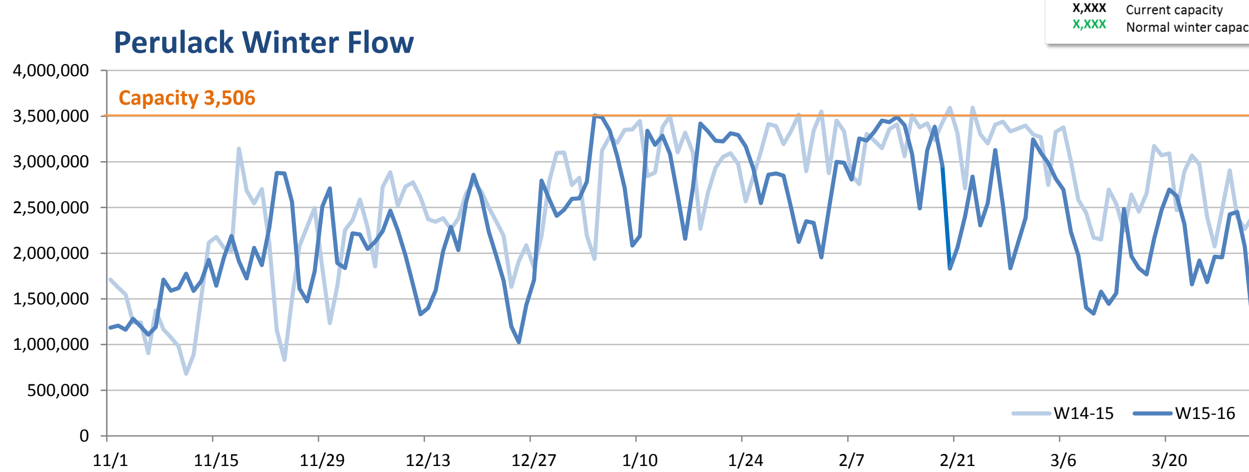
Perulack Winter Flow



Penn-Jersey System Operating Status

Nov – Mar, Final Scenario





Summary

- Three streams of work defined – scope of first two are clear and represent the majority of the work
- Work plan prioritizes Lines 12, 19 and 28 – fewest anomalies
- Mid-October return to full service of Lines 12, 19, and 28 represents capacity needs historically not seen until Mid-November
- Incremental return of Line 27 segments will provide capacity increase to meet needs historically not seen until end of November
- Permitting process is in alignment with accelerated schedule
- Meeting at least weekly with PHMSA on work plan, findings and schedule – in agreement on approach and work plan
- Our work plan is designed to provide full service of the PJS by November 1st

Q&A

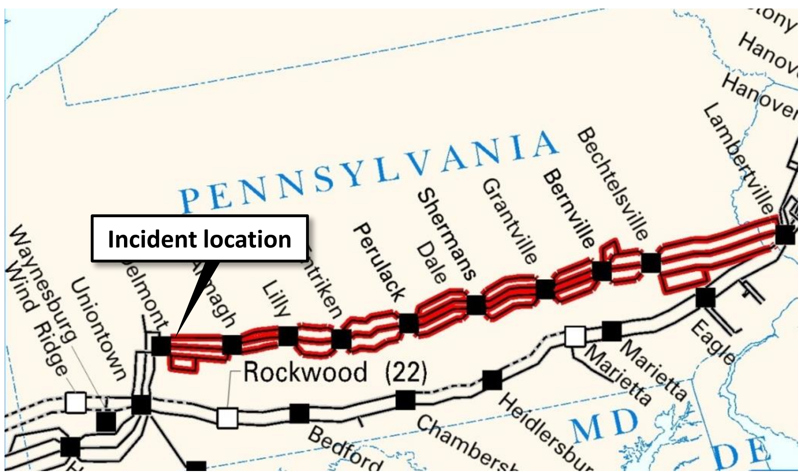
APPENDIX

Spectra Energy:
U.S. Gas Transmission

SE US Gas
12,660 miles in 26 states

Texas Eastern
9,075 miles in 17 states

Penn-Jersey System



Original Construction

Line 12
1954

Line 19
1958 through 1968

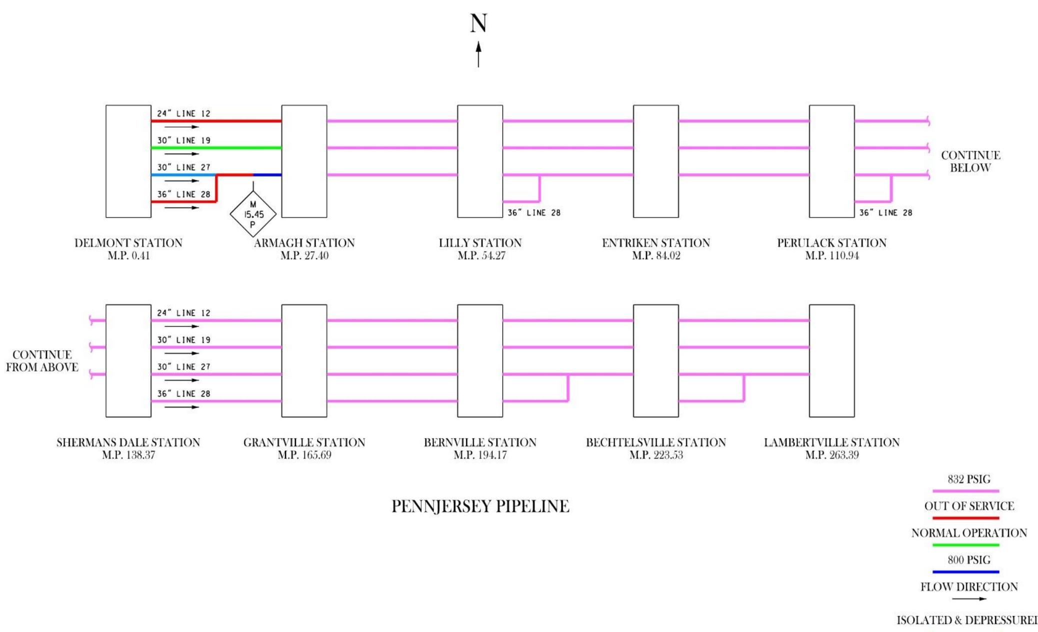
Line 27
1965 through 1988

Line 28
1968 and 1986 through 2015

Pipeline Integrity

- All lines were hydrostatically tested during construction
- Pipelines have been in-line inspected, except a few short sections

Penn-Jersey System Operating Status

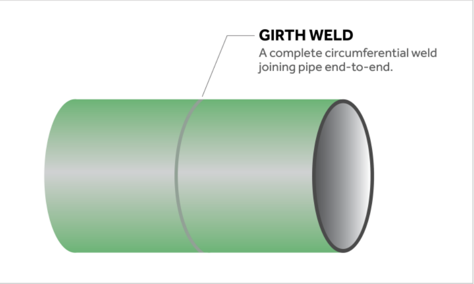


Delmont Line 27 Incident Summary

- Pipeline rupture and fire occurred on April 29, 2016
  - Four parallel pipelines located in the ROW at failure site
  - Isolation valves for all four lines shut in within one hour
  - Community impacts (9 homes evacuated; 1 home destroyed; 1 injured resident)
- PHMSA issued Corrective Action Order on May 3rd
  - PHMSA's preliminary investigation identified evidence of corrosion along two circumferential girth welds.
  - The pattern of corrosion indicated a possible flaw related to tape coating used on the girth welds applied during construction of the line.

Delmont Line 27 Incident Details

- Installed in 1981
- Class 1 location
- 30-inch x 0.404-inch wall thickness, X-65
- 1,050 psig MAOP – 60% SMYS
- Fusion-bonded epoxy pipe coating
- Tape coating on girth welds
- In-line inspected in 2005 and 2012
  - 2012 ILI identified 33% wall loss at failure location
  - Did not meet criteria for investigation



Division 2-4

Request:

Re: Witness Arangio's Direct Testimony at page 13 of 23, lines 3-12, please document and quantify the impact the Texas Eastern force majeure has had on the Company's Rhode Island actual and expected gas costs for the current (2015-16) GCR year, including but not limited to, identification and quantification of any fixed payments that the Company is not obligated to make during the period of that its service from Texas Eastern is affected.

Response:

The impact of the Texas Eastern force majeure on the Company's gas costs for the current (2015-16) GCR year total an incremental cost of $82,112.00. These incremental charges were incurred during the April 29, 2016 through May 11, 2016 period, when supplies had to be purchased downstream of the Delmont Compressor Station outage. The Company is obligated to continue to pay all demand charges on Texas Eastern.

Division 2-5

Request:

Re: Witness Arangio's Direct Testimony at page 13 of 23, line 14, through page 14 of 23, line 10, please:

a. Indicate when the Company expects to finalize contracts with suppliers for the up to 20,000 Dth per day of firm capacity entitlements for the months of December 2016 through February 2017;

b. Provide the Company's current best estimates of the costs of the contracts for up to 20,000 Dth per day of firm capacity entitlements that will be offset by reductions in Texas Eastern charges;

c. Provide an explanation that the use of replacement capacity would be expected to have on the Company's sourcing of gas and variable costs of gas supply for the 2016-17 GCR year;

Response:

a. The Company is in the process of finalizing contract negotiations with selected suppliers that participated in the Company's RFP process for firm supplies through the Delmont Compressor Station (Delmont) and expects to finalize these contracts prior to November 1, 2016.

b. Reservation Charge Adjustment for Force Majeure Events and Certain Orders Issued by PHMSA and the calculation of such credits are governed by Section 31 (Reservation Charge Adjustment) of Texas Eastern Transmission, LP's (Texas Eastern) tariff on file with the Federal Energy Regulatory Commission. Because the Company expects to fully utilize its maximum daily quantity on the pipeline as needed by exercising its call options under these agreements for supplies downstream of Delmont and into the Company's contracts with the pipeline, the Company does not anticipate receipt of reservation charge credits.

c. The Company did not seek replacement capacity, but instead requested the option for supply downstream of the restriction through Delmont using existing capacity. If the Company is unable to access supplies upstream of Delmont due to restrictions, which are normally purchased and priced at Market Area M2 on Texas Eastern, it would then use its call option for supply downstream of Delmont which will be purchased and priced at Market Area M3 on Texas Eastern.

Prepared by or under the supervision of: Elizabeth D. Arangio

Division 2-6

Request:

Re: Witness Arangio's Direct Testimony at page 13 of 23, line 14, through page 14 of 23, line 10, please:

a. Provide a comparison of the Company's available capacity resources for the winter of 2016-17, with and without the referenced replacement capacity contracts for up to 20,000 Dth per day of firm capacity, and the Company's estimated design day peak demands for the winter of 2016-17;

b. Provide data, analyses, workpapers, studies and other documents that constitute the Company's assessment of alternative to contracting for up to 20,000 Dth per day of firm capacity.

Response:

a.

Available Capacity Resources 2016-17 *With* Texas Eastern M3 Supply Call	
	MMBtus
Total Transportation	245,543
LNG Vapor	113,000
Total Capacity	358,543
Peak Day Demand 2016-17	357,153

Available Capacity Resources 2016-17 *Without* Texas Eastern M3 Supply Call	
	MMBtus
Total Transportation	245,543
LNG Vapor	113,000
Total Capacity	358,543
Peak Day Demand 2016-17	357,153

The Company's contingency plan was not to contract for replacement capacity, but to use its existing capacity and seek the option for a supply call downstream of the restriction through the Delmont Compressor Station. Therefore, the Company's available capacity resources for the winter of 2016-17 are the same with and without the supply call.

b. See the Company's response to (a) above.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-7

Request:

Re: Witness Arangio's Direct Testimony at page 13 of 23, line 14, through page 14 of 23, line 10, please indicate:

a. Whether a restoration of full Texas Eastern service prior to the December 1, 2016 would enable the Company to avoid capacity costs under the contracts for replacement capacity;

b. Whether a restoration of Texas Eastern service at any time during the period between December 1, 2016 and February 28, 2017 could result in the result in the Company's ability to avoid capacity cost payments under the replacement capacity contracts;

c. Whether Texas Eastern's restoration of service on or before November 1, 2016 will result in the Company paying demand charges for both the restored Texas Eastern capacity and capacity obtained under the referenced replacement capacity contracts for the months of December 2016 through February 2017.

Response:

a. The Company's contingency plan was not to contract for replacement capacity, but to use its existing capacity and seek the option for a supply call downstream of the restriction through the Delmont Compressor Station. Therefore, restoration of full Texas Eastern service prior to December 1, 2016 would not enable the Company to avoid the fixed costs associated with the supply calls at Texas Eastern M3.

b. The Company's contingency plan was not to contract for replacement capacity, but to use its existing capacity and seek the option for a supply call downstream of the restriction through the Delmont Compressor Station. Therefore, restoration of Texas Eastern service at any time during the period between December 1, 2016 and February 28, 2017 would not enable the Company to avoid the fixed costs associated with the supply calls at Texas Eastern M3.

c. The Company did not seek replacement capacity, but instead requested the option for supply downstream of the restriction through the Delmont Compressor Station using existing capacity. The Company is continuing to pay demand charges for all Texas Eastern capacity. So, whether or not Texas Eastern restores service on or before November 1, 2016, the Company will continue to pay demand charges for its Texas Eastern capacity and the fixed costs associated with the supply calls at Texas Eastern M3 for the months of December 2016 through February 2017.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-8

Request:

Re: Witness Arangio's Direct Testimony at page 15 of 23, lines 6-7, please:

a. Identify and discuss the alternatives available to the Company, if any, to the extension of the referenced of the Tennessee Pipeline agreement for an incremental 24,000 Dth per day of capacity from Dracut.

b. Identify and explain the criteria the Company will use to make its decision regarding the exercise of its "right of first refusal."

c. Provide the workpapers, data, analyses (including SENDOUT® model scenarios and their results), and other documents and studies upon which the Company relies to evaluate alternatives to exercising is its "right of first refusal" for the referenced Tennessee Pipeline capacity.

Response:

a. There are no practical alternatives available to the Company due to the location of the Cumberland LNG tank as well as the configuration of the Company's distribution system. This agreement provides primary firm delivery to the Lincoln gate station. Gas is delivered to this gate station by Tennessee Pipeline and serves an isolated portion of the Company's distribution system. The loss of this source of supply cannot be replaced by deliveries to any of the other Tennessee Pipeline gate stations, nor can it be replaced by additional deliveries to any of the Company's Algonquin Pipeline gate stations. Therefore, the Company anticipates an extension of this incremental Tennessee capacity.

b. Please see the Company's response to (a), above.

c. Please see the Company's response to (a), above.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-9

Request:

Re: Witness Arangio's Direct Testimony at page 15 of 23, lines 7-0, please:

a. Provide the referenced "forecasted peak day and Peak hour customer requirements" the Company has used to assess its need for utilization of "portable LNG" on the peak day;

b. Provided the computations relied upon to assess the number of truckloads that could be required on the peak day and the amount of gas in Dth that the Company expects to obtain from each truckload;

c. Document the Company's historic experience with respect to the actual amounts of gas derived from a truckload of LNG at the point of delivery when portable LNG gasification equipment is employed;

d. Explain what use is made with that balance of a truckload of LNG if actual requirements on a peak day do not require the full contents of a truckload of LNG that arrives at the site where the portable gasifier is deployed.

Response:

a. The forecasted peak day requirement is 415,374 dekatherms (Dth). The peak hour customer requirements are 5 percent of the peak day, or approximately 20,769 Dth per hour.

b. The amount of gas required on the peak hour of the peak day was calculated to be 760 Dth for approximately 9 hours. This made the peak day requirement 6,840 Dth.

c. A typical delivery of gas via portable operations yields approximately 1,000 mcf of volume, dependent upon the size of the tanker truck providing the liquid.

d. If product remains on the truck following the peak vaporization period, the remaining LNG is delivered to a National Grid LNG plant capable of receiving the LNG.

Prepared by or under the supervision of: Elizabeth D. Arangio and Adnan Malik

Division 2-10

Request:

Re: Witness Arangio's Direct Testimony at page 15 of 23, line 11, through page 16 of 23, line 2, please:

a. Provide the analyses upon which the Company has relied to determine that a "term of four months" is necessary and appropriate for the new Dracut capacity;

b. Verify that the new Dracut capacity has only been contracted for the specified four month period in the winter of 2016-17, and if not, explain the nature and duration of any longer term commitments the Company has made to purchase or have options to continue to purchase the "new Dracut capacity;"

c. Identify and explain any and all potential variability in the charges that National Grid will pay for the referenced "new Dracut capacity" over the full term of the agreement for that service including any possible extension(s) of the initial agreement;

d. Identify the "appropriate resource mix" that was determined using the SENDOUT® model;

e. Please provide a load duration curve, or equivalent information regarding the frequency and duration of load, for sendout from the Cumberland LNG tank during each of the last three winter seasons.

Response:

a. The table below provides the output from the SENDOUT® model run used to determine the total supply requirements at Dracut for the term of four months (volumes = MDth).

Division 2-10, page 2

Day	NOV 2016 MDth	DEC 2016 MDth	JAN 2017 MDth	FEB 2017 MDth	MAR 2017 MDth	APR 2017 MDth
1			26.7		35.53	
2		21.36	1.54			
3		39.02		26.96	16.59	
4		3.75		32.31	11.86	
5		26.93		39.02		23.44
6		8.21		39.02		
7		12.66	19.81	39.02		
8		12.56	8.11	9.26	7.09	
9		31.22	3.97	18.4	30.68	
10		0.66		4.45	35.67	
11			6.59	13.8		
12			39.02			
13		16.87	4.13	9.33		
14		12.5	29.25	28.29		
15			4.1			
16		0.63				
17						
18			0.56			
19			39.02	0.67		
20		0.64	32.57			
21		12.44	2.46	4.53		
22			39.02	18.57		
23	0.93					
24	20.02		27.39			
25	24.55			28.04		
26			3.15	14.27		
27			33.02	1.63	2.36	
28				0.73	11.85	
29			32.08			
30			33.02			
31			5.84			
Total	45.49	199.46	391.36	328.3	151.62	23.44
Average	1.52	6.43	12.62	11.73	4.89	0.78
Minimum						
Maximum	24.55	39.02	39.02	39.02	35.67	23.44

Prepared by or under the supervision of: Elizabeth D. Arangio

b. As referenced in Elizabeth D. Arangio's Direct Testimony at page 15 of 23, line 1, through 9, the Company has secured an incremental 24,000 Dth of pipeline capacity on the Tennessee Pipeline for a 12 month period (November 1, 2016 through October 31, 2017) from Dracut, MA to the Company's citygate in Lincoln, RI. The Company has secured a supply arrangement to be transported on this capacity for a four month period (December 2016 through March 2017).

c. The Company will pay the Tennessee Pipeline Firm Transportation Tariff (FT-A) Maximum Reservation Rate of Zone 6 to Zone 6, which is currently $4.7435 per month. If the Company renews the capacity agreement it expects to pay the same Tennessee Pipeline Firm Transportation Tariff (FT-A) Maximum Reservation Rate of Zone 6 to Zone 6. The annual reservation charge totals $1,366,128 at the current Tennessee Pipeline FT-A Tariff Rate.

d. The SENDOUT® model utilizes all assets in the portfolio including the existing Dracut capacity of 15,000 Dth per day as well as the new Dracut capacity of 24,000 Dth per day in order to determine the appropriate MDQ and ACQ for RFPs to meet design day and design year requirements. The Company sought proposals and awarded bids for a maximum daily quantity of 39,000 Dth per day of supply (15,000 Dth per day of existing Dracut capacity plus 24,000 Dth per day of new Dracut capacity) for a maximum seasonal quantity of 1,092,000 Dth for a term of four months (December 2016, January 2017, February 2017 and March 2017).

e. Please see the Company's response to Division 1-4, filed in this docket on September 16, 2016, for the sendout volumes from the Cumberland LNG tank during each of the last three winter seasons.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-11

Request:

Re: Witness Arangio's Direct Testimony at page 16 of 23, line 17, through page 17 of 23, line 3, please identify and explain the importance of the key features of the "*changing gas supply landscape*" and the impacts of such a changing landscape on the Company's gas supply planning and gas supply procurement activities.

Response:

The Company's Rhode Island portfolio continues to be situated to take advantage of opportunities across various supply sources in order to purchase economically-priced supplies. However, the portfolio planning process must consider the ability to access gas supply in a way that enhances the overall portfolio. Some supply sourcing options have proved to be vulnerable to severe price spikes during peak demand periods over the last few years. The Company has taken steps to mitigate this exposure through its commitments to Algonquin's AIM Project and Millennium's Expansion project.

Although price factors are the primary driver for contract portfolio decisions, the non-price factors of supply reliability cannot be understated. A diverse portfolio with supply sourcing options helps to mitigate both price and reliability issues. As discussed, the Company found itself needing to re-evaluate the long-term reliability of gas supply portfolio, with particular focus on LNG, and the need for a long-term solution. To that end, the Company has taken steps to mitigate this exposure through its commitments to long-term LNG supply and liquefaction services.

Lastly, with the suspension of the Tennessee Gas Pipeline's Northeast Energy Direct Project , the Company is in the process of identifying alternative pipeline capacity paths from supply sources and interconnections to the Company's citygates. At this time, these pipeline capacity paths include the following:

1) Dawn supply via TransCanada to the Portland Natural Gas Transmission System to the Tennessee Pipeline to the Company's citygates;
2) ENGIE supply from the Everett terminal to the Company's citygates via the Tennessee Pipeline;
3) Repsol supply from Dracut to the Company's citygates via the Tennessee Pipeline; and
4) Spectra's Access Northeast Project to Dracut to the Company's citygates via the Tennessee Pipeline.

The Company is engaged in ongoing discussions with all parties.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-12

Request:

Re: Witness Arangio's Direct Testimony at page 17 of 23, lines 5-16, please:

a. Indicate the amount of daily deliverability in terms of Dth/day that is provided for in the referenced "*Precedent Agreement with Algonquin*" and identify the months of each year that the identified deliverability will be available to National Grid;

b. Provide a copy of the referenced AFT-CL Rate Schedule;

c. Provide the data, analyses, and studies upon which the Company relied to determine the sizing of the referenced "new meter station;"

d. Discuss the supply alternatives available to the Company for the winter of 2017-18 if the project is not completed and in-service by November 1, 2017.

Response:

a. The daily deliverability provided in Precedent Agreement with Algonquin is 96,000 Dth/day. The contract is available to the Company 365 days a year.

b. Please see Attachment DIV 2-12(b) for a copy of Algonquin's AFT-CL Rate Schedule.

c. The 96,000 Dth per day was derived from a peak hour requirement of 4,000 Dth translated to a 24 hour day. The volume was derived utilizing the SynerGi model for Rhode Island loaded with the 2013 five-year peak day forecast. The approximately 4,000 Dth per hour from the Crary Street meter was required in order to offset the need for Providence LNG, maintain maximum operating pressure on the 99 psig system, and maintain pressures above minimum design pressure during peak day conditions. The 96,000 Dth per day allows the flexibility of utilizing higher flows during peak-demand hours with future forecast increases. For instance, the 2015 peak-day model requires 4,580 Dth per hour for peak hour, which, with a 5 percent peak hour would equate to 91,600 Dth per day, is still within the peak day limits. While the new meter station's purpose is to limit dependency on LNG usage, it also provides reliability where LNG is limited or not available on peak-day.

d. The purchase of incremental LNG would be required to support system distribution pressures.

Prepared by or under the supervision of: Elizabeth D. Arangio and Adnan Malik

Rate Schedule AFT-CL
Firm Transportation Service

	Base Tariff Rate 1/ 2/ $/Dth
CANAL LATERAL	
Reservation Charge:	
Maximum	$2.0858
Minimum	$0.0000
Commodity Charge:	
Maximum	$0.0000
Minimum	$0.0000
Authorized Overrun Commodity Charge	
Maximum	$0.0686
Minimum	$0.0000
MIDDLETOWN LATERAL	
Reservation Charge:	
Maximum	$3.2764
Minimum	$0.0000
Commodity Charge:	
Maximum	$0.0000
Minimum	$0.0000
Authorized Overrun Commodity Charge	
Maximum	$0.1077
Minimum	$0.0000
CLEARY LATERAL	
Reservation Charge:	
Maximum	$1.4529
Minimum	$0.0000
Commodity Charge:	
Maximum	$0.0000
Minimum	$0.0000
Authorized Overrun Commodity Charge	
Maximum	$0.0478
Minimum	$0.0000
LAKE ROAD LATERAL	
Reservation Charge:	
Maximum	$0.6476
Minimum	$0.0000
Commodity Charge:	
Maximum	$0.0000
Minimum	$0.0000
Authorized Overrun Commodity Charge	
Maximum	$0.0213
Minimum	$0.0000

1/ The Base Tariff is the effective rate on file with the Commission excluding adjustments approved by the Commission.

2/ Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions. The ACA Surcharge will only apply if the AFT-CL Customer has not paid an ACA Surcharge for the same gas volumes transported under another rate schedule.

Rate Schedule AFT-CL
Firm Transportation Service

	Base Tariff Rate 1/ 2/ ($/Dth)	GRI Adj.	Total Rate
BRAYTON POINT LATERAL			
Reservation Charge:			
Maximum	$1.2700		$1.2700
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000		$0.0018
Minimum	$0.0000		$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.0418		$0.0436
Minimum	$0.0000		$0.0018
BELLINGHAM LATERAL			
Reservation Charge:			
Maximum	$0.9714		$0.9714
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000		$0.0018
Minimum	$0.0000		$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.0319		$0.0337
Minimum	$0.0000		$0.0018
PHELPS DODGE LATERAL			
Reservation Charge:			
Maximum	$0.0000		$0.0000
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0166		$0.0184
Minimum	$0.0000		$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.0166		$0.0184
Minimum	$0.0000		$0.0018
MANCHESTER STREET LATERAL			
Reservation Charge:			
Maximum	$2.4500		$2.4500
Minimum	$0.0000		$0.0000
Commodity Charge:			
Maximum	$0.0000		$0.0018
Minimum	$0.0000		$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.0805		$0.0823
Minimum	$0.0000		$0.0018

1/ The Base Tariff is the effective rate on file with the Commission excluding adjustments approved by the Commission.

2/ Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions. The ACA Surcharge will only apply if the AFT-CL Customer has not paid an ACA Surcharge for the same gas volumes transported under another rate schedule.

Rate Schedule AFT-CL
Firm Transportation Service

	Base------------$/Dth -------- Tariff Rate 1/ 2/	GRI Adj.	Total Rate
CAPE COD LATERAL			
Reservation Charge:			
Maximum	$9.0501	-	$9.0501
Minimum	$0.0000	-	$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0000	$0.0018
Minimum	$0.0000	$0.0000	$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.2975	$0.0000	$0.2993
Minimum	$0.0000	$0.0000	$0.0018
NORTHEAST GATEWAY LATERAL			
Reservation Charge:			
Maximum	$4.3449	-	$4.3449
Minimum	$0.0000	-	$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0000	$0.0018
Minimum	$0.0000	$0.0000	$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.1428	$0.0000	$0.1446
Minimum	$0.0000	$0.0000	$0.0018
J-2 FACILITY			
Reservation Charge:			
Maximum	$4.6346	-	$4.6346
Minimum	$0.0000	-	$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0000	$0.0018
Minimum	$0.0000	$0.0000	$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.1524	$0.0000	$0.1542
Minimum	$0.0000	$0.0000	$0.0018
KLEEN ENERGY LATERAL			
Reservation Charge:			
Maximum	$1.2247	-	$1.2247
Minimum	$0.0000	-	$0.0000
Commodity Charge:			
Maximum	$0.0000	$0.0000	$0.0018
Minimum	$0.0000	$0.0000	$0.0018
Authorized Overrun Commodity Charge			
Maximum	$0.0403	$0.0000	$0.0421
Minimum	$0.0000	$0.0000	$0.0018

1/ The Base Tariff is the effective rate on file with the Commission excluding adjustments approved by the Commission.

2/ Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions. The ACA Surcharge will only apply if the AFT-CL Customer has not paid an ACA Surcharge for the same gas volumes transported under another rate schedule.

Rate Schedule AFT-CL
Capacity Release

	Base Tariff Rate 1/ (a)	----- $/Dth ----------Volumetric---- 2/ Base Rate (b)	Total Rate (c)=(b)
CANAL LATERAL			
Reservation Charge:			
Maximum	$2.0858	$0.0686	$0.0686
Minimum	$0.0000	$0.0000	$0.0000
MIDDLETOWN LATERAL			
Reservation Charge:			
Maximum	$3.2764	$0.1077	$0.1077
Minimum	$0.0000	$0.0000	$0.0000
CLEARY LATERAL			
Reservation Charge:			
Maximum	$1.4529	$0.0478	$0.0478
Minimum	$0.0000	$0.0000	$0.0000
LAKE ROAD LATERAL			
Reservation Charge:			
Maximum	$0.6476	$0.0213	$0.0213
Minimum	$0.0000	$0.0000	$0.0000
BRAYTON POINT LATERAL			
Reservation Charge:			
Maximum	$1.2700	$0.0418	$0.0418
Minimum	$0.0000	$0.0000	$0.0000
BELLINGHAM LATERAL			
Reservation Charge:			
Maximum	$0.9714	$0.0319	$0.0319
Minimum	$0.0000	$0.0000	$0.0000
PHELPS DODGE LATERAL			
Reservation Charge:			
Maximum	$0.0000	$0.0000	$0.0000
Minimum	$0.0000	$0.0000	$0.0000
MANCHESTER STREET LATERAL			
Reservation Charge:			
Maximum	$2.4500	$0.0805	$0.0805
Minimum	$0.0000	$0.0000	$0.0000
CAPE COD LATERAL			
Reservation Charge:			
Maximum	$9.0501	$0.2975	$0.2975
Minimum	$0.0000	$0.0000	$0.0000
NORTHEAST GATEWAY LATERAL			
Reservation Charge:			
Maximum	$4.3449	$0.1428	$0.1428
Minimum	$0.0000	$0.0000	$0.0000

1/ The Base Tariff is the effective rate on file with the Commission, excluding adjustments approved by the Commission.

2/ The volumetric reservation charges are applicable to capacity releases where Releasing Customer's Notice provides for bids on a volumetric basis, and are exclusive of surcharges and commodity.

Rate Schedule AFT-CL
Capacity Release

	Base Tariff Rate 1/ (a)	----- $/Dth ----------Volumetric---- 2/ Base Rate (b)	Total Rate (c) = (b)
J-2 FACILITY			
Reservation Charge:			
Maximum	$4.6346	$0.1524	$0.1524
Minimum	$0.0000	$0.0000	$0.0000
KLEEN ENERGY LATERAL			
Reservation Charge:			
Maximum	$1.2247	$0.0403	$0.0403
Minimum	$0.0000	$0.0000	$0.0000

1/ The Base Tariff is the effective rate on file with the Commission, excluding adjustments approved by the Commission.

2/ The volumetric reservation charges are applicable to capacity releases where Releasing Customer's Notice provides for bids on a volumetric basis, and are exclusive of surcharges and commodity.

Rate Schedule AIT-1
Interruptible Transportation Service

	Base $/Dth Tariff Rate 1/ 2/
Commodity Charge:	
Maximum	$0.2421
Minimum	$0.0076
Authorized Overrun	
Maximum	$0.2421
Minimum	$0.0076

HUBLINE SURCHARGE APPLICABLE TO ALL CUSTOMERS UTILIZING RECEIPT POINTS BETWEEN AND INCLUDING BEVERLY AND WEYMOUTH AND/OR UTILIZING DELIVERY POINTS BETWEEN BEVERLY AND WEYMOUTH, INCLUDING BEVERLY AND EXCLUDING WEYMOUTH, AND IN ADDITION TO OTHER APPLICABLE CHARGES:

Commodity Charge: 3/				
Maximum	$0.0612	$0.0000	$0.0000	$0.0612
Minimum	$0.0000	$0.0000	$0.0000	$0.0000

1/ The Base Tariff is the effective rate on file with the Commission, excluding adjustments approved by the Commission.

2/ Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions.

3/ HubLine surcharges applicable to both the Commodity and Authorized Overrun Charges.

Redacted

Division 2-13

Request:

Re: Witness Arangio's Direct Testimony at page 17 of 23, line 18, through page 18 of 23, line 19, please:

a. Provide the data, analyses, studies and rationale on which the Company has relied on to determine the size of its commitment to the "Millennium Project;"

b. Provide the data, analyses, studies, and other documents upon which the Company relies to assess the cost-effectiveness of the supplies it will be able to access through the Millennium Project;

c. Provide the Company's available information regarding the costs of the Millennium Project capacity addressed by the referenced Millennium Project Precedent Agreement for each year that agreement will be in effect, and specify any and all adjustments to the initial pricing under that agreement that are permissible or required during the term of the Millennium Project Precedent Agreement.

Response:

a. Millennium conducted a binding Open Season for parties interested in signing up for incremental capacity between Millennium's interconnection with Empire Pipeline in Corning, New York through and including Millennium's interconnection with Algonquin Pipeline in Ramapo, New York. The Open Season ran from March 11, 2015 through March 31, 2015. The Company nominated 9,000 MMBtus, which represents 50 percent of the total 18,000 MMBtus of the Company's capacity on Algonquin's AIM Project. When the Company entered into its AIM Project precedent agreement, Ramapo represented a fairly liquid point to purchase supply; however, the record breaking sendouts experienced during the winters of 2013-14 and 2014-15 resulted in dramatic fluctuations in supply availability – particularly in the Northeast and, more specifically, at Ramapo. Therefore, the Company determined it was necessary to secure access to supplies upstream of Ramapo for a portion of its AIM capacity in order to maintain liquidity at Ramapo. The Millennium Project provides access to multiple supply points and provides enhanced reliability as well as substantial flexibility and supply diversity.

Redacted

Division 2-13, page 2

b. Please see Attachment DIV 2-13(b) for an analysis of estimated purchases at Ramapo compared to Millennium East Pool for the period of November 2017 through October 2018. The attached table shows an annual savings of $630,648 (using the September 20, 2016 NYMEX).

c. On July 29, 2016, Millennium submitted its application to the Federal Energy Regulatory Commission for the Eastern System Upgrade, having a total project capacity of 223,000 Dth per day, for a total project cost of $275,000,000, and proposing to the existing Rate Schedule FT-1 rate set as the recourse rate for service on the expansion capacity created by the Millennium Project [CP16-486]. The existing rate under Rate Schedule FT-1 offered by the pipeline is $0.6499 per Dth per day. The Company's Millennium Project Precedent Agreement (Agreement) is a precedent agreement for a 15-year firm transportation upstream of the Company's AIM capacity. The Proposed Agreement includes an executed Negotiated Rate Agreement, which sets forth a reservation rate of $[redacted] per Dth per day for the first six months of the transportation service agreement; after the first six months of the transportation service agreement, the reservation rate will be adjusted using the methodology set forth in Attachment C of the proposed Agreement, with an upward limit of $[redacted] per Dth per day that is based on the actual cost of the project.

9/20/16 NYMEX

	Purchases at Ramapo			Purchases on Millennium		
	NYMEX	TET M3 Basis	Price at Ramapo	NYMEX	MPL East Pool	
Nov-17	$ 3.160	$ (0.665)	$ 2.495	$ 3.160	$ (1.150)	$ 2.010
Dec-17	$ 3.280	$ 0.190	$ 3.470	$ 3.280	$ (1.110)	$ 2.170
Jan-18	$ 3.376	$ 2.080	$ 5.456	$ 3.376	$ (0.920)	$ 2.456
Feb-18	$ 3.336	$ 2.050	$ 5.386	$ 3.336	$ (0.900)	$ 2.436
Mar-18	$ 3.252	$ (0.048)	$ 3.204	$ 3.252	$ (0.950)	$ 2.302
Apr-18	$ 2.847	$ (0.525)	$ 2.322	$ 2.847	$ (0.729)	$ 2.118
May-18	$ 2.807	$ (0.705)	$ 2.102	$ 2.807	$ (0.803)	$ 2.004
Jun-18	$ 2.828	$ (0.692)	$ 2.136	$ 2.828	$ (0.866)	$ 1.962
Jul-18	$ 2.856	$ (0.458)	$ 2.398	$ 2.856	$ (0.866)	$ 1.990
Aug-18	$ 2.863	$ (0.535)	$ 2.328	$ 2.863	$ (0.946)	$ 1.917
Sep-18	$ 2.846	$ (0.965)	$ 1.881	$ 2.846	$ (1.029)	$ 1.817
Oct-18	$ 2.873	$ (0.895)	$ 1.978	$ 2.873	$ (0.985)	$ 1.888

REDACTED

MPL Fuel	MPL Commod	Price at Ramapo	Base Design DTH 88% Load Factor	# of Days	TET M3 TOTAL	MPL
$ 0.0121	$ 0.003	$ 2.025	269,200	30	**$ 671,654**	$ 545,236
$ 0.0131	$ 0.003	$ 2.186	278,900	31	**$ 967,783**	$ 609,774
$ 0.0148	$ 0.003	$ 2.474	278,900	31	**$ 1,521,678**	$ 690,020
$ 0.0147	$ 0.003	$ 2.454	251,900	28	**$ 1,356,733**	$ 618,151
$ 0.0138	$ 0.003	$ 2.319	278,900	31	**$ 893,596**	$ 646,811
$ 0.0127	$ 0.003	$ 2.134	269,900	30	**$ 626,708**	$ 575,978
$ 0.0121	$ 0.003	$ 2.019	-	31	**$ -**	$ -
$ 0.0118	$ 0.003	$ 1.977	247,000	30	**$ 527,592**	$ 488,345
$ 0.0120	$ 0.003	$ 2.005	247,800	31	**$ 594,224**	$ 496,906
$ 0.0115	$ 0.003	$ 1.932	248,900	31	**$ 579,439**	$ 480,833
$ 0.0109	$ 0.003	$ 1.831	250,300	30	**$ 470,814**	$ 458,357
$ 0.0114	$ 0.003	$ 1.903	273,600	31	**$ 541,181**	$ 520,567
			2,895,300		**$ 8,751,403**	$ 6,130,978

REDACTED

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MPL Demand Charge	MPL TOTAL	Savings / (Costs)
[redacted]		
		$ 630,648

Redacted

Division 2-14

Request:

Re: Witness Arangio's Direct Testimony at page 19 of 23, lines 2-12, please:

a. Provide a complete copy of the referenced Precedent Agreement for liquefaction services at NGLNG's facilities in Providence.

b. Provide the information available to the Company regarding the anticipated construction, operating, and maintenance costs for the liquefaction facility.

c. Provide the charges for liquefaction capacity and services, that the Company is committed to pay under the referenced Precedent Agreement for liquefaction services at the NGLNG facility in Providence, RI, as well as specification of any and all adjustments to the initial pricing under that agreement that are permissible or required during the term of the referenced NGLNG Precedent Agreement.

d. Provide the data, analyses, studies and other document upon which the Company has relied to assess the types and quantities of products (or by-products) that the liquefaction process is expected to produce based on the gas supplied that National Grid expects to deliver to the NGLNG Providence liquefaction facility.

e. Indicate the Company's rights under the reference Precedent Agreement for liquefaction services to revenue derived from the sale of hydrocarbon products extracted from gas its delivers to the liquefaction facility. If no such rights are provided under the agreement, explain the manner in which the value of such products was considered in negotiation of the pricing of services provided under the Precedent Agreement.

Response:

a. See Attachment DIV 2-14(a). The Precedent Agreement between the Company and NGLNG (Precedent Agreement) is confidential. Accordingly, the Company is providing a confidential version of Attachment DIV 2-14(a) subject to a Motion for Protective Treatment. Because the entirety of the Precedent Agreement is deemed confidential, a redacted version of Attachment DIV 2-14(a) is not being provided.

Prepared by or under the supervision of: Elizabeth D. Arangio

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b. See Attachment DIV 2-14(b). On April 1, 2016, NGLNG submitted an application to the Federal Energy Regulatory Commission (FERC) for a certificate of public convenience and necessity and related authorizations to construct, own and operate facilities to provide a liquefaction service (FERC Docket No. CP 16-121). The FERC application includes all information available regarding the anticipated construction, operating and maintenance costs for the liquefaction facility.

c. See Attachment DIV 2-14(b) for the expected rates for liquefaction and capacity services. Pursuant to the Precedent Agreement, [redacted]. Further, pursuant to the Precedent Agreement, [redacted]

d. The Company did not rely on data, analyses, studies or documents to assess the types and quantities of products (or by-products) that the liquefaction process is expected to produce.

e. Under the Precedent Agreement [redacted]

Prepared by or under the supervision of: Elizabeth D. Arangio

Redacted

Precedent Agreement

The Precedent Agreement between the Company and NGLNG (Precedent Agreement) is confidential.

Due to the voluminous nature of this Attachment DIV 2-14(b), the Company is providing this document on CD-ROM.

Division 2-15

Request:

Re: Witness Arangio's Direct Testimony at page 19 of 23, lines 2-12, please:

a. Provide the data, analyses, workpapers, studies and other documents relied upon to assess the amount of capacity (i.e., Dth/day) and the annual volumes that will be available to National Grid's Rhode Island operations under the terms of the Precedent Agreement.

b. Document the portion of the total capacity of the liquefaction facility that is represented by the Company's commitments under the referenced Precedent Agreement that are intended to serve the needs of National Grid's Rhode Island gas distribution utility customers;

c. Identify the number of other entities with which NGLNG has contracted to provide liquefaction services at its Providence facilities and the amounts of capacity and winter season Dth that have been committed to those entities. Also, indicate the amounts of capacity and annual Dth that have been committed to unaffiliated entities.

d. Clarify from where the volumes need to fill the Exeter facilities will be trucked.

Response:

a. The calculation below shows how the amount of capacity and annual volumes were calculated between the entities contracting with NGLNG for liquefaction services. The calculation was based on the LNG maximum storage quantity (MSQ) of the Company divided by the total LNG MSQ of both parties contracting for liquefaction services.

Division 2-15, page 2

		MSQ (MMBtu)
Boston Gas:	Commercial Point	1,192,345
	Lynn	1,045,000
	Salem	1,045,000
	Tewksbury	1,045,000
	South Yarmouth	179,740
	Wareham	9,234
	Haverhill	418,000
	NGLNG	1,159,664
		6,093,983
Narragansett:	Cumberland	86,000
	Exeter	202,000
	NGLNG	600,000
		888,000

Boston Gas % =	87.3%
Narragansett % =	12.7%

NGLNG Liquefaction Project:
MDQ = 20,600 per day (17,984 for Boston Gas and 2,616 for Narragansett)
MSQ = 4,000,000 (3,492,000 for Boston Gas and 508,000 for Narragansett)

b. As shown in the Company's response to (a), above, the Company's commitments represent approximately 12.7% of the total capacity of the liquefaction facility.

c. NGNLG's LNG storage facility is presently fully subscribed by three firm storage customers for peak-shaving. Those three storage customers are the Company, Boston Gas Company (Boston) and an unaffiliated third party, Con Edison. NGLNG's project was undertaken at the request of the Company and Boston to add liquefaction capability so that NGLNG's firm storage customers could deliver gas for storage in vapor form as an alternative to delivering LNG for storage by tanker trucks. On May 13, 2016, the Massachusetts Department of Public Utilities (DPU) issued an Order in DPU 15-129 approving Boston's precedent agreement with NGLNG for annual liquefaction capacity of 3.5 Bcf, or up to 17,984 Dth per day, for a term of 20 years.

There will be no change to the LNG storage tanks resulting from the project. As explained in its application for a Certificate of Public Convenience and Necessity filed with the Federal Energy Regulatory Commission (FERC) (FERC Docket No. CP 16-121), NGLNG's unaffiliated third party customer is currently considering whether it wants to contract for firm liquefaction service as well. Should that unaffiliated third party decide to take liquefaction service, the precedent agreement provides that the liquefaction service commitments of the Company and Boston will be reduced correspondingly.

d. When possible, volumes needed to fill the Exeter facility will come from NGLNG, since the trucking distance from NGLNG to Exeter is much less than the trucking distance from the Northeast Energy project to Exeter. However, if the Company has reached its capacity of the NGLNG liquefaction by filling its NGLNG storage, then the remaining volumes will be trucked from Northeast Energy.

Prepared by or under the supervision of: Elizabeth D. Arangio

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Division 2-16

Request:

Re: Witness Arangio's Direct Testimony at page 19 of 23, line 14, through page 18 of 23, line 19, please:

a. Provide a complete copy of the Precedent Agreement for Northeast Energy Center LLC liquefaction services;

b. Provide the Company's assessment of the comparative costs for LNG obtained from the Northeast Energy project (including trucking costs) and costs of LNG obtained from the NGLNG facilities in Providence;

c. Document and explain the basis for the Company's decisions to enter into a 15-year commitment for the Northeast Energy project capacity and services while entering into a 20-year agreement for similar services from NGLNG.

Response:

a. Please see Attachment DIV 2-16 (a). The Precedent Agreement for Northeast Energy Center LLC liquefaction services is a confidential agreement. Accordingly, the Company is providing a confidential version of Attachment DIV 2-16(a) subject to a Motion for Protective Treatment. Because the entirety of the agreement is deemed confidential, a redacted version of Attachment DIV 2-16(a) is not being provided.

b. See Attachment DIV 2-16 (b) for the comparative cost analysis per Dth for expected cost of LNG from both the Northeast Energy Project and the NGLNG facility.

c. The Company considered a term of less than 20 years. The advantage of a 20-year term compared to a 5, 10 or 15-year term is that the unit rate under a 15 to 20-year commitment is typically lower than the rate for a shorter term agreement. In the Company's experience, a term of 15 to 20 years is common in connection with infrastructure projects like this that require the construction of facilities. Project developers are unwilling to commit the required capital without some assurance of cost recovery and therefore will typically require a higher unit rate for a shorter term agreement. In instances like this where the Company expects to utilize the facilities for 20 years or more, a 20-year agreement is less expensive than a shorter term agreement. The 15 and 20 year terms with Northeast and NGLNG, respectively, were the result of negotiations between the parties with respect to these and other significant provisions contained in the agreements.

Prepared by or under the supervision of: Elizabeth D. Arangio

Redacted

Precedent Agreement

The Precedent Agreement for Northeast Energy Center LLC liquefaction services is a confidential agreement.

REDACTED

			Expected Rate	Negotiated Cap
		LIBERTY / NORTHSTAR	**NG LNG**	**NG LNG**
	Summer NYMEX (Assumed)	$4.00	$4.00	$4.00
		[TGP Z4 219]	*[TETCO M2]*	*[TETCO M2]*
	Summer Basis	-$1.15	-$1.36	-$1.36
	Pipeline Transport	$0.15	$0.19	$0.19
	Summer Pre-Liquefaction Commodity	$3.00	$2.83	$2.83
(1)	Summer Liquefaction Fuel	[redacted]	[redacted]	[redacted]
	Estimated Trucking Rate	[redacted]	[redacted]	[redacted]
	Liquefaction Cost	[redacted]	[redacted]	[redacted]
(2)	Truck Loading Charge	[redacted]	[redacted]	[redacted]
	O&M Charge	[redacted]	[redacted]	[redacted]
	TOTAL EST'D DELIVERED COST /Dth	[redacted]	[redacted]	[redacted]

Notes:

All prices in $ US per MMBtu

(1) [redacted]

(2)