Post & Schell P.C.
ATTORNEYS AT LAW

17 North Second Street
12th Floor
Harrisburg, PA 17101-1601
717-731-1970 Main
717-731-1985 Main Fax
www.postschell.com

Nicholas A. Stobbe

nstobbe@postschell.com
717-612-6033 Direct
717-731-1985 Direct Fax
File #: 203275

April 17, 2024

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Pennsylvania Public Utility Commission, *et al.* v. National Fuel Gas Distribution Corporation
Docket Nos. R-2024-3045177, *et al.*

Dear Secretary Chiavetta:

Attached for filing on behalf of National Fuel Gas Distribution Corporation is the Joint Petition for Settlement, along with all Statements in Support thereof, in the above-referenced proceeding.

Copies will be provided as indicated on the Certificate of Service.

Respectfully submitted,

Nicholas A. Stobbe

NAS/kls
Attachments

cc: The Honorable Charece Z. Collins (*via email; w/attachments*)
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

VIA E-MAIL

Steven C. Gray, Esquire
Rebecca Lyttle, Esquire
Office of Small Business Advocate
555 Walnut Street
Forum Place, 1st Floor
Harrisburg, PA 17101
sgray@pa.gov
relyttle@pa.gov

Melanie J. El Atieh, Esquire
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
oca1307f2024@paoca.org
melatieh@paoca.org

Carrie B. Wright, Esquire
Bureau of Investigation & Enforcement
Commonwealth Keystone Building
400 North Street, 2nd Floor West
P.O. Box 3265
Harrisburg, PA 17105-3265
carwright@pa.gov

Date: April 17, 2024

Nicholas A. Stobbe

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission Office of Small Business Advocate Office of Consumer Advocate v. National Fuel Gas Distribution Corporation	: : : : : : :	Docket Nos. R-2024-3045177 C-2024-3045469 C-2024-3045964

JOINT PETITION FOR SETTLEMENT OF
THE SECTION 1307(f) RATE INVESTIGATION

TO ADMINISTRATIVE LAW JUDGE CHARECE Z. COLLINS:

I. INTRODUCTION

The Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), and National Fuel Gas Distribution Corporation ("Distribution"), being all of the parties to the above-captioned proceeding (hereinafter collectively referred to as the "Parties"), hereby join in this "Joint Petition for Settlement of the Section 1307(f) Rate Investigation" ("Settlement") and respectfully request that Administrative Law Judge Charece Z. Collins (the "ALJ") and the Commission approve this Settlement, including the rates to become effective for service furnished on and after August 1, 2024, that are set forth in the form of a tariff supplement provided as **Appendix A** hereto. The Parties agree that such rates are subject to revision for actual over/under recoveries of purchased gas costs through June 30, 2024, and for updates related to the calculation of the Monthly Metered Transportation ("MMT") balancing charge. In addition, the Parties request that the ALJ and the Commission make the findings required by the Public Utility Code as provided herein.

The terms and conditions of the Settlement are set forth in their entirety hereinafter. Distribution's, I&E's, OCA's, and OSBA's Statements in Support of the Settlement are provided as Appendices "B" through "E" hereto.

II. UPDATED RATE INFORMATION

In 1307(f) rate investigations and settlement thereof, Distribution typically gathers and compiles certain rate information, including:

a. The agreed upon rates provided in the settlement.

b. The current rates for each customer class as of the date of the filing by the Company.

c. The requested and negotiated changes in gas costs for each customer class.

d. The impact upon each customer class, (i.e., under the proposed rate each customer would have paid X, and under the agreed upon amount, each customer will pay Y) expressed in terms of a dollar amount and percentage, for each.

The information responsive to a-d is contained in the tables below:

PROJECTED AND CURRENT RETAIL GAS COSTS[1]

PROJECTED GAS COSTS	Natural Gas Supply Charge ($)	Gas Adjustment Charge ($)	Distribution Charge ($)	Total Gas Costs ($)
Demand	$1.5902	$(0.1455)	$0.2914	$1.7361
Commodity	$3.5105	$(0.1943)	$0.0000	$3.3162
Total Projected Gas Costs	$5.1007	$(0.3398)	$0.2914	$5.0523
CURRENT GAS COSTS (02/2024)	$4.1854	$(1.1113)	$0.3907	$3.4648

[1] The rates in this table will be adjusted to reflect actual gas costs through June 30, 2024, as outlined in this Settlement and will be applicable to all retail classes.

Increase/(Decrease)	0.9153	0.7715	(0.0993)	1.5875
% change	21.87%	(69.42%)	(25.42%)	45.82%

MONTLY METERED TRANSPORTATION (MMT) RATES[2]

MMT Rate (Proposed/Estimated)	$0.45
MMT Rate (Current)	$0.37
Increase/(Decrease)	$0.08
% Change	21.62%

RATE IMPACT PER INDIVIDUAL CUSTOMER CLASS

	Annual Amount ($)	**Difference ($)**	**Difference (%)**
Current Residential			
Total	$809.25		
Proposed Residential			
Total	$969.90	$160.65	19.85%
Current Small Commercial UL			
Total	$3,347.58		
Proposed Small Commercial UL			
Total	$4,167.09	$819.51	24.48%
Current Small VIS			
Total	$2,402.29		
Proposed Small VIS			
Total	$2,807.78	$405.49	16.88%

[2] The MMT Rate will be adjusted to reflect actual gas delivery volumes through June 30, 2024, as outlined in the Settlement.

III. BACKGROUND

In support of this Settlement, the Parties state the following:

1. Distribution is a public utility subject to the Commission's regulatory jurisdiction with regard to its Pennsylvania operations. Distribution provides retail natural gas sales and transportation services to customers in fourteen counties in northwestern Pennsylvania.

2. Distribution also provides natural gas services in western New York, subject to the regulatory jurisdiction of the New York Public Service Commission.

3. Because Distribution's annual operating revenues derived from providing gas services to customers in Pennsylvania exceed $40 million, Distribution's recovery of purchased gas costs ("PGC") is governed by Section 1307(f) of the Public Utility Code, 66 Pa.C.S. § 1307(f), and the Commission's regulations at 52 Pa. Code §§ 53.61 — 53.65 and 53.68.

4. On December 29, 2023, Distribution filed data and exhibits supporting recovery of purchased gas costs in compliance with the Commission's regulations at 52 Pa. Code §§ 53.64 - 53.65.

5. On January 16, 2024, OSBA filed a Notice of Appearance, Complaint, Public Statement, and Verification.

6. On January 18, 2024, I&E filed a Notice of Appearance.

7. On January 31, 2024, Distribution filed additional supporting data and exhibits as well as the prepared, written testimony of eight witnesses in support of Supplement No. 269 to Tariff Gas — Pa. P.U.C. No. 9, to be effective for service rendered on and after August 1, 2024. Distribution also submitted a Tariff Addendum. The Tariff Supplement and the Addendum set forth the specific rates proposed by Distribution for recovery of purchased gas costs effective on August 1, 2024.

8. On February 1, 2024, OCA filed a Notice of Appearance, Complaint, and Public Statement.

9. Also on February 1, 2024, the ALJ issued a Prehearing Conference Order which, among other things, scheduled a telephonic prehearing conference for February 16, 2024, and set forth certain rules for the proceeding.

10. On February 13, 2024, I&E, OCA, OSBA, and Distribution submitted prehearing conference memoranda.

11. A prehearing conference was held on February 16, 2024, with the ALJ presiding. At the prehearing conference, the Parties and the ALJ established a litigation schedule for the proceeding, among other things.

12. On February 16, 2024, the ALJ issued a Prehearing Order.

13. On February 20, 2024, the Commission issued a telephonic Evidentiary Hearings Notice, scheduling telephonic evidentiary hearings for April 3 and 4, 2024.

14. On February 29, 2024, OCA filed a Notice of Appearance.

15. During the discovery phase of this proceeding, the intervening parties propounded numerous discovery requests to Distribution. Distribution responded to all of these discovery requests.

16. On March 8, 2024, I&E, OCA, and OSBA filed their respective direct testimonies.

17. On March 12, 2024, Distribution filed an unopposed Motion for Protective Order.

18. On March 13, 2024, the ALJ granted Distribution's Motion for Protective Order and issued a Protective Order.

19. On March 18, 2024, OCA filed a Withdrawal of Appearance.

20. On March 22, 2024, Distribution, OSBA, and OCA filed Rebuttal Testimony. I&E filed a letter indicating that it would not be filing Rebuttal Testimony.

21. On March 29, 2024, the OCA filed Surrebuttal Testimony. Distribution, I&E, and OSBA all filed letters indicating that they would not be filing Surrebuttal Testimony.

22. On April 2, 2024, the Parties informed the ALJ that they reached a settlement in principle of all issues in the proceeding and requested that the respective witnesses be excused from attending the hearings on April 3 and 4, 2024, as all parties had mutually agreed to waive cross-examination. Later that day, the ALJ informed the Parties that the respective witnesses were excused from attending the Evidentiary Hearings.

23. On April 3, 2024, the Telephonic Evidentiary Hearings were held as scheduled. Counsel appeared on behalf of Distribution, I&E, OCA, and OSBA, respectively. During the Evidentiary Hearing, all testimony and exhibits submitted by the Parties were admitted into the record. Further, the ALJ stated that the Joint Petition for Settlement and accompanying Statements in Support of Settlement would be due for filing on or before April 17, 2024.

24. On April 3, 2024, the Commission issued a Hearing Cancellation Notice, cancelling the April 4, 2024 Evidentiary Hearing.

25. The terms and conditions of the Settlement are set forth in Sections IV – IX below.

IV. PROPOSED FINDINGS OF FACT

26. Effective on November 1, 2000, Distribution realigned its pipeline and storage capacity in order to identify specific capacity as being held for its New York customers and for its Pennsylvania customers. Generally, delivery points located in Pennsylvania were assigned to the Pennsylvania Division, and delivery points located in New York were assigned to the New York

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Division. The realignment was approved by the Commission in the Order entered on October 25, 2001, at Docket No. R-00994898.

27. Distribution relies primarily upon gas supplies transported by Tennessee Gas Pipeline, LLC ("Tennessee"), Columbia Gas Transmission, LLC ("Columbia Transmission"), Texas Eastern Transmission, LP ("Texas Eastern" or "TETCO") and National Fuel Gas Supply Corporation ("Supply") to meet the requirements of its sales customers in Pennsylvania (Distribution PGC Exhibit No. 8, pp. 2-5).

28. In most instances, Tennessee, Columbia Transmission, and Texas Eastern transport Distribution's gas supplies to Distribution's pipeline capacity on Supply. Supply, in turn, either delivers such gas supplies to Distribution for use by Distribution's sales customers or injects such supplies into storage fields for later delivery to Distribution for use by its sales customers (Distribution PGC Exhibit No. 4, p. 2, Distribution PGC Exhibit No. 8, pp. 4-5).

29. Supply is an affiliate of Distribution and is subject to the regulatory jurisdiction of the Federal Energy Regulatory Commission ("FERC") (Distribution PGC Exhibit No. 4, p. 2). Supply owns and operates a transmission system and storage fields, and Supply charges Distribution for transportation and storage services under Supply's FERC-approved tariff (Distribution PGC Exhibit No. 4, p. 2).

30. Distribution's capacity on Supply, Tennessee, Columbia Transmission, and Texas Eastern is critical for the operation of the system, the provision of reliable service to customers and Distribution's least cost fuel procurement policy (Distribution PGC Exhibit No. 8, pp. 2-4).

31. The availability of storage enhances Distribution's ability to buy gas and to utilize its firm upstream transportation capacity at high load factors (Distribution PGC Exhibit No. 8, p. 8).

32. At least through July 31, 2025, the end of the application period in this proceeding, Distribution will continue to rely principally upon gas supplies transported through facilities of Tennessee, Columbia Transmission, Texas Eastern and Supply, as well as storage (particularly on Supply), to meet the needs of its Pennsylvania sales customers (Distribution PGC Exhibit No. 8, pp. 2-5, PGC Exhibit No. 30).

33. Distribution has fully and vigorously represented the interests of its ratepayers in proceedings before the FERC. (Distribution PGC Exhibit No. 6; Distribution PGC Statement No. 3).

34. Distribution attempts to mitigate the cost of natural gas supplies to its PGC customers through net revenues resulting from off-system sales activities (Distribution PGC Exhibit No. 8, pp. 15-18).

35. Distribution attempts to enter into asset management arrangements, pursuant to FERC Order 712, in order to mitigate the cost of providing gas supplies to its PGC customers (Distribution PGC Exhibit No. 8, p. 19).

36. Distribution participates in a sharing mechanism under which it retains 25 percent of the net revenues from off-system sales, capacity releases and asset management arrangements, including storage fill contracts (Distribution PGC Exhibit No. 8, pp. 17-19).

37. When engaged in off-system sales, Distribution may sell gas at any point on its transportation and storage capacity upstream of its capacity on Supply.

38. During the twelve months ended November 30, 2023, Distribution purchased 214,351 Mcf of locally-produced gas to serve customers in Pennsylvania (Distribution PGC Exhibit No. 1, Schedule 1, Sheet 1).

39. Locally-produced gas continues to be a useful resource in meeting the requirements of Distribution's sales customers, and Distribution expects to continue to purchase local non-firm, dedicated and excess local production gas in the near-term into its system and Supply's system that will not increase the weighted average commodity cost of gas supplies that it sells to its customers (Distribution PGC Exhibit No. 8, p. 14).

a. Distribution purchases dedicated, non-firm, life of reserves locally produced gas from Appalachian producers that is priced at an Appalachian Index ("AI"). The AI is the simple average of the first of the month spot prices for gas delivered to Dominion Energy Transmission, Inc. and Columbia Transmission (Distribution PGC Exhibit No. 4, p. 13).

b. Distribution purchases excess non-firm local production gas at 80 percent of the AI rate (Distribution PGC Exhibit No. 4, p. 13).

40. Distribution has implemented, with the Commission's approval, a system-wide customer choice program throughout its Pennsylvania service territory under which all customers, except those served under Distribution's Low Income Residential Assistance Program, may choose a natural gas supplier other than Distribution (Distribution PGC Exhibit No. 13; Distribution PGC St. No. 6).

41. To maintain service to several remote pockets of customers without constructing additional or replacing pipeline facilities, Distribution has entered into various agreements or tariff sales purchase agreements. Distribution has two exchange agreements – one with UGI Central Penn Gas, Inc (formerly PPL Gas Utilities Corporation and North Penn Gas Company) and one with Columbia Gas of Pennsylvania, Inc. Under the agreements, each company takes from the other volumes of gas needed to provide service. The agreements do not contemplate purchases of

gas; instead they contemplate that each company will receive approximately the same volumes of gas from the other over time. If needed, additional deliveries are arranged to eliminate any balance that has built up over time. The companies do not charge each other for this service. Distribution also serves some customers via two interconnects with Peoples Natural Gas Company LLC's ("Peoples") where Distribution is receiving firm gas supplies, subject to Peoples' tariff provisions. (Distribution PGC Exhibit No. 4, pp. 4-5).

V. <u>STANDARDS AND FINDINGS</u>

A. <u>Historic Reconciliation Period Standards.</u>

42. With respect to Distribution's gas purchases and gas purchasing practices during the twelve-month historic reconciliation period ended November 30, 2023, it is requested that the ALJ and the Commission find that Distribution has met the standards of Section 1318 of the Public Utility Code, 66 Pa.C.S. § 1318, as required by Section 1307(f)(5) of the Public Utility Code, 66 Pa.C.S. § 1307(f)(5), as to all actual purchased gas costs in the historic period. It is requested that the Commission find that, during the twelve months ended November 30, 2023:

a. Distribution met the requirements of Section 1318(a) of the Public Utility Code by pursuing a least-cost fuel procurement policy, consistent with its obligation to provide safe, adequate and reliable service to its customers; and

b. Distribution met the requirements of Section 1318(b) of the Public Utility Code relating to purchases from and services provided by affiliates.

B. <u>Projected Period Findings.</u>

43. With respect to the eight-month interim period beginning on December 1, 2023, and with respect to the twelve-month period beginning August 1, 2024, when rates established under this Settlement will be in effect, it is requested that the Commission find, based upon

information presently available and based upon evidence of record in this proceeding concerning Distribution's projected purchases and purchasing policies, that the rates to be adopted by the Commission result from Distribution's compliance with the provisions of Section 1318 of the Public Utility Code, including Sections 1318(a)(1), 1318(a)(2), 1318(a)(3), 1318(a)(4), 1318(b)(1), 1318(b)(2) and 1318(b)(3), 66 Pa.C.S. §§ 1318(a)(1), 1318(a)(2), 1318(a)(3), 1318(a)(4), 1318(b)(1), 1318(b)(2) and 1318(b)(3).

44. The Parties agree that, based upon evidence of record in this proceeding concerning Distribution's projected gas purchases and gas purchasing policies, Distribution's projected gas purchases and projected gas purchasing policies may comply with the standards of Section 1318 of the Public Utility Code. Nevertheless, it is expressly understood and agreed that this Section of the Settlement, Section V.B., is made solely for the purpose of setting prospective rates that shall be subject to the standards of Section 1318 of the Public Utility Code, 66 Pa.C.S. § 1318, and further review in an appropriate future proceeding. Section IV.B. of the Settlement is not intended in any way to limit or prevent I&E, OCA and OSBA from reviewing, after such projected gas purchases actually have been made and gas purchasing practices actually have been implemented, whether Distribution's gas purchases and gas purchasing practices complied with Section 1318. If, in an appropriate future proceeding, gas purchases and gas purchasing practices from December 1, 2023, through July 31, 2024, and the twelve-month application period commencing August 1, 2024, and ending on July 31, 2025, were challenged, the Commission's findings based upon Section IV of the Settlement shall not bar the examination of such purchases and practices, including, but not limited to, disallowance of, or reductions to, such costs during the eight-month interim period commencing December 1, 2023, and ending on July 31, 2024, and the twelve-month application period commencing August 1, 2024, and ending on July 31, 2025.

VI. TERMS AND CONDITIONS OF SETTLEMENT

A. Approval of Filing

45. The Company's 2024 Section 1307(f) filing is approved except as modified herein, including a revised Exhibit NJH--1.

B. PGC Rates

46. The Parties request that the ALJ and the Commission approve the form of tariff supplement provided as **Appendix A** hereto, including the rates set forth therein. The rates in **Appendix A** are subject to further updates for actual over/under recoveries of purchased gas costs through June 30, 2024, for updates related to the calculation of the MMT balancing charge and for updates to the forecasts of wellhead prices. The Company's Exhibits will be updated to reflect changes to National Fuel Supply Gas Corporation's rates effective February 1, 2024. The Company will reflect this update and any other applicable updates in the tariff in its August 2024 compliance filing.

C. Certified Natural Gas ("CNG")

47. The Company's proposal regarding the CNG Pilot Program, as detailed in Distribution Statement No. 2, is approved, with the following modifications:

a) Distribution will pursue the least cost CNG, and will undertake commercially reasonable efforts to minimize the cost impact to its PGC customers from the costs associated with purchasing CNG, consistent with current practices for procuring firm supplies of non-certified gas.

b) In its 2025 PGC filing:

 i) Distribution will report the daily quantities of CNG purchased, the price paid including applicable demand charge, published index price and applicable index price adjustment for each transaction;
 ii) Distribution will identify the overall PGC rate impact of its CNG purchase(s);
 iii) Distribution will identify the BTU content of its CNG purchases and any impact of a change in BTU content from that of other purchases on usage;

iv) Distribution will provide an estimate of the methane mitigation amounts resulting from purchases under the Pilot Program.

c) Distribution will limit its CNG transaction contract price, including possible demand charge, to not exceed $.07/Dth ("premium") over the published index price. The total annual CNG premium cost shall not exceed $175,000.

d) Distribution will not use or reference any crediting agency affiliated with the Company when evaluating potential CNG purchases.

e) The CNG Pilot Program will end on July 31, 2027, unless otherwise extended by the Commission.

D. National Fuel Gas Supply Corporation Capacity

48. Distribution will be permitted to acquire the additional National Fuel Gas Supply Corporation capacity for the winter of 2024-2025 as proposed in this proceeding. The additional National Fuel Gas Supply capacity will be limited to one year.

E. Design Day Forecasting

49. Distribution will analyze its design day forecasting model with the goal of focusing on forecasting requirements for days with 50 Heating Degree Days ("HDD") or greater. This analysis will include evaluation of the use of daily sendout data, as available. Distribution will provide the results of its analysis as part of its 2025 PGC prefiling, including the workpapers and Excel files regarding the analysis. The Company will not be required to propose any changes to its design day forecasting model as a result of this review.

F. Audit Ordered Refund

50. Distribution will refund the $111,398, including interest as calculated in the over/under cycle of August 2023 through July 2024, to its PGC customers, as directed by the August Report filed at Docks No. D-2022-3031418 on December 21, 2023, as part of the E-Factor in its annual PGC filing on August 1, 2024.

G. Reporting of Prior Period Adjustments

51. Distribution will begin to implement controls to prevent, detect and correct errors in reporting of prior period adjustments and within the spreadsheet used for amortizing over/under collection balances. Distribution will report the controls that it has implemented in its next annual PGC filing.

H. Contract Renewals and Changes

52. The Parties agree that the Commission should approve the renewals, extensions and changes in pipelines and storage capacity contracts that are explained in PGC Exhibits 4 and 8 and in Distribution PGC Statement No. 7, subject to the terms of Paragraph 48 of the Settlement, *supra*.

I. Tariff Changes

53. The Parties request that the Commission approve the tariff changes that are set forth in the form of tariff supplement provided as **Appendix A** hereto. The tariff changes are identified in the List of Changes that is included at pages 2-3 of **Appendix A** hereto.

VII. PROPOSED CONCLUSIONS OF LAW

54. The Commission has jurisdiction over the parties and subject matter of this proceeding. 66 Pa.C.S. §§ 1307(f), 1317-18.

55. Distribution has met the requirements of Section 1318 of the Public Utility Code by pursuing a least cost fuel procurement policy, consistent with its obligation to provide safe, adequate and reliable service to its customers. 66 Pa.C.S. § 1318.

56. Distribution's rates for purchased gas costs, as the parties have agreed upon in this proceeding, during the relevant time period are just and reasonable and in compliance with 66 Pa.C.S. § 1318.

57. Distribution has fully and vigorously represented the interests of its ratepayers in proceedings before the FERC and other relevant non-PUC proceedings during the relevant time period in compliance with 66 Pa.C.S. § 1318(a)(1).

58. Distribution has taken all prudent steps necessary to negotiate favorable gas supply contracts and to relieve the utility from terms in existing contracts with its gas supplier which are or may be adverse to the interests of the utility's ratepayers in compliance with 66 Pa.C.S. § 1318(a)(2).

59. Distribution has taken all prudent steps necessary to obtain lower cost gas supplies on both short-term and long-term bases both within and outside the Commonwealth, including the use of gas transportation arrangements with pipelines and other distribution companies in compliance with 66 Pa.C.S. § 1318(a)(3).

60. Distribution has not withheld from the market or caused to be withheld from the market any gas supplies which should have been utilized as part of a least cost fuel procurement policy in compliance with 66 Pa.C.S. § 1318(a)(4).

61. Distribution has fully and vigorously attempted to obtain less costly gas supplies on both short-term and long-term bases from nonaffiliated interests in compliance with 66 Pa.C.S. § 1318(b)(1).

62. Neither Distribution nor its affiliated interests have withheld from the market any gas supplies which should have been utilized as part of a least cost fuel procurement policy in compliance with 66 Pa.C.S. § 1318(b)(3).

63. The Settlement is in the public interest.

VIII. PROPOSED ORDERING PARAGRAPHS

64. That the Settlement among Distribution, I&E, OCA, and OSBA in the above-captioned case is hereby approved and adopted without modification.

65. That Distribution shall file a tariff supplement, to become effective on one day's notice of the final Commission order approving the Settlement, containing changes in rates to provide for the recovery of its costs of purchased gas, consistent with the terms and conditions of the Settlement. Said tariff supplement shall be accompanied by a red-lined version that shall fully set forth all changes that will be made to Distribution's current tariffs.

66. That Distribution, I&E, OCA and OSBA shall comply with the terms and conditions of the Settlement submitted in this proceeding as though each term and condition stated therein had been the subject of an individual ordering paragraph.

67. That upon Distribution's filing of a tariff supplement acceptable to the Commission as conforming with this order and the Settlement and the Commission's approval thereof, the purchased gas rates established therein shall become effective for service rendered on and after August 1, 2024.

68. That the complaints filed by the OCA and OSBA in these proceedings at Docket Nos. C-2024-3045964 and C-2024-3045469, respectively, be marked closed.

69. That the investigation at Docket No. R-2024-3045177 be marked closed.

IX. CONDITIONS OF SETTLEMENT

70. The Parties acknowledge and agree that this Settlement shall have the same force and effect as if the Parties had fully litigated this proceeding with regard to the historic period ended November 30, 2023.

71. This Settlement is conditioned upon the Commission's approval of terms and conditions contained herein without modification. If the Commission modifies the Settlement, any of the Parties may elect to withdraw from this Settlement and may proceed with litigation. In such event, this Settlement shall be void and of no effect. Such election to withdraw must be made

in writing, filed with the Secretary of the Commission and served upon all Parties within five (5) business days after the entry of an order modifying the Settlement.

72. This Settlement is proposed by the Parties to settle certain issues in the instant proceeding and is made without any admission against, or prejudice to, any position which any Party to this Settlement may adopt during any subsequent litigation of this or any other proceeding if the Commission disapproves this Settlement or if the Commission modifies the Settlement and one or more of the Parties elect to withdraw from the Settlement and proceed to litigation.

73. If the Commission does not approve the Settlement and the proceedings continue to hearings on the issues that are the subjects of this Settlement, the Parties reserve their respective rights to conduct full cross-examination, briefing and argument on these subjects.

74. The Commission's approval of this Settlement shall not be construed to represent approval of any Party's position on any issue, except to the extent required to effectuate the terms and agreements of this Settlement in this and future proceedings involving Distribution.

75. It is understood and agreed among the Parties that this Settlement is the result of compromises and does not necessarily represent the position(s) that would be advanced by any Party in this proceeding if it were fully litigated.

76. This Settlement is being presented in this Section 1307(f) proceeding in an effort to resolve outstanding issues in a manner which is fair and reasonable. The Settlement is the product of compromise. This Settlement is presented without prejudice to any position which any of the Parties may have advanced and without prejudice to the position any of the Parties may advance in the future on the merits of the issues in future proceedings. This Settlement does not preclude the Parties from taking other positions in proceedings under Section 1307(f) concerning the recovery of purchased gas costs by other natural gas distribution companies.

77. Distribution's, I&E's, OCA's, and OSBA's respective Statements in Support of the Settlement, setting forth the basis upon which they believe the Settlement is fair, just and reasonable and is, therefore, in the public interest are provided in Appendices "B" through "E" hereto.

X. CONCLUSION

WHEREFORE, the Parties, by their respective counsel, respectfully request that Administrative Law Judge Charece Z. Collins and the Pennsylvania Public Utility Commission:

(1) approve this "Joint Petition for Settlement of the Section 1307(f) Rate Investigation; and

(2) make the findings required by the Public Utility Code as provided herein.

Respectfully submitted,

______________________________ Date: 04/17/2024

Anthony D. Kanagy, Esquire
Post & Schell P.C.
17 North 2nd Street, 12th Floor
Harrisburg, PA 17101-1601

Nicholas A. Stobbe, Esquire
Post & Schell P.C.
17 North 2nd Street, 12th Floor
Harrisburg, PA 17101-1601

Counsel for National Fuel Gas Distribution Corporation

______________________________ Date: ____________________

Carrie B. Wright, Esquire
Bureau of Investigation & Enforcement
Commonwealth Keystone Building
400 North Street, 2nd Floor West
Harrisburg, PA 17105-3265

Counsel for Bureau of Investigation & Enforcement

X. CONCLUSION

WHEREFORE, the Parties, by their respective counsel, respectfully request that Administrative Law Judge Charece Z. Collins and the Pennsylvania Public Utility Commission:

(1) approve this "Joint Petition for Settlement of the Section 1307(f) Rate Investigation; and

(2) make the findings required by the Public Utility Code as provided herein.

Respectfully submitted,

____________________________ Date: ____________

Anthony D. Kanagy, Esquire
Post & Schell P.C.
17 North 2nd Street, 12th Floor
Harrisburg, PA 17101-1601

Nicholas A. Stobbe, Esquire
Post & Schell P.C.
17 North 2nd Street, 12th Floor
Harrisburg, PA 17101-1601

Counsel for National Fuel Gas Distribution Corporation

Carrie B Wright Date: April 16, 2024

Carrie B. Wright, Esquire
Bureau of Investigation & Enforcement
Commonwealth Keystone Building
400 North Street, 2nd Floor West
Harrisburg, PA 17105-3265

Counsel for Bureau of Investigation & Enforcement

/s/ Melanie Joy El Atieh
Melanie Joy El Atieh, Esquire
Deputy Consumer Advocate
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923

Date: April 16, 2024

For Office of Consumer Advocate

____
Steven C. Gray, Esquire
Rebecca Lytle, Esquire
Office of Small Business Advocate
555 Walnut Street
Forum Place, 1st Floor
Harrisburg, PA 17101-1923

Date: ____________________

For Office of Small Business Advocate

______________________________ Date: ___________________

Melanie J. El Atieh, Esquire
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923

For Office of Consumer Advocate

/s/ *Steven C. Gray* Date: April 17, 2024

Steven C. Gray, Esquire
Rebecca Lytle, Esquire
Office of Small Business Advocate
555 Walnut Street
Forum Place, 1st Floor
Harrisburg, PA 17101-1923

For Office of Small Business Advocate

APPENDIX A

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
BUFFALO, NEW YORK

RATES, RULES AND REGULATIONS

GOVERNING THE FURNISHING

OF

NATURAL GAS SERVICE

IN
TERRITORY DESCRIBED HEREIN

Issued: Effective:

D. L. DeCAROLIS, PRESIDENT
BUFFALO, NEW YORK

This Supplement includes increases and decreases to existing rates.
See page 2.

LIST OF CHANGES MADE BY THIS TARIFF

INCREASE:

1. Gas Adjustment Charges increase for Residential, Commercial and Public Authority, Small Volumes Industrial, Intermediate Volume Industrial, and Large Industrial Service
   Pages 36, 41, 41A, 42, 53, 55, 65, 76.

2. The Natural Gas Supply Charge for Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial Service Classes increase.
   Pages 36A, 41, 41A, 42, 53, 55, 66 and 76A.

3. Commodity Charges for Sales Services increase.
   Pages 50, 62, 73, 80

4. Commodity Charges for Transportation Service increase.
   Page 50, 63, 74, 81

5. Components of Natural Gas Vehicle rates increase.
   Pages 83 and 84.

6. Priority Standby Service monthly rate increase.
   Pages 93, 95

7. The price for purchase of gas by Distribution from a transportation service customer in the event of a curtailment or interruption will increase.
   Pages 106, 117 and 146G.

8. Purchased gas costs in Rider A increase.
   Page 147

9. The Price to Compare shown in Rider H increases.
   Page 169.

10. MMT Service Rates increased for Residential, “Small” Commercial/ Public Authority >25,000, “Large” Commercial/ Public Authority, Intermediate Volume Industrial, Large Volume Industrial, and Large Industrial Service Classes.
    Pages 100 and 101.

11. The Merchant Function Charge in Ridger G increases.
    Page 168.

LIST OF CHANGES MADE BY THIS TARIFF

DECREASE:

12. Weighted average demand cost of upstream capacity decreases.
Page 131.

13. Distribution Charge for Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial Service Classes decrease.
Pages 36, 41, 41A, 42, 53, 55, 65, 66, 76.

14. Demand Charges for Load Balancing Service decrease.
Pages 48, 61, 72, 79, 82.

15. SATC Transportation Service rates decrease for Residential and Small Volume Industrial.
Page 119A, 120, and 121.

16. Certain Demand Transfer Recovery Rates ("DTR") decrease.
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17. SATC Alternative Capacity Release Rate decrease.
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RESIDENTIAL SERVICE RATE SCHEDULE

RESIDENTIAL CLASSIFICATION

This classification shall include gas supplied for residential purposes such as a private dwelling, apartment house with a single meter supplying four or less dwelling units, separately metered apartments of a multiple dwelling, accessory buildings to dwellings or apartment houses such as garages, except at residences receiving service under Rate Schedule LIRAS for Low Income Residential Assistance Service and other places of residence where gas is used for residential purposes.

Churches and missions (places of worship) shall be entitled to Service under the Residential service rate schedule.

AVAILABILITY OF SERVICE

Gas Service shall be available at one location, except as otherwise provided, for residential customers.

APPLICABILITY

Applicable in all areas served under this tariff.

MONTHLY RATE

Basic Service Charge

$14.00	per Month		

Distribution Charges

32.525¢	per 100 cubic feet		(D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.061)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.459)¢	Per 100 cubic feet	Total Gas Adjustment Charge	(I)

(D) Indicates Decrease

(I) Indicates Increase

RESIDENTIAL SERVICE RATE SCHEDULE (cont.)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.919¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
53.075¢	per 100 cubic feet Charge	Total Natural Gas Supply	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 1.8032% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223. The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge. Residential rate classes shall be subject to Rider F - LIRA Discount Charge as set forth in this tariff.

RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease (I) Indicates Increase

COMMERCIAL AND PUBLIC AUTHORITY SERVICE RATE SCHEDULE (cont.)

APPLICABILITY

Applicable in all areas served under this tariff.

MONTHLY RATE

For “Small” Commercial/Public Authority Customers using not more than 250,000 cubic feet per year:

Basic Service Charge

$27.00	per Month		

Distribution Charges

25.908¢	per 100 cubic feet		(D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.012)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.410)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.174¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
52.330¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non=purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

(D) Indicates Decrease (I) Indicates Increase

COMMERCIAL AND PUBLIC AUTHORITY SERVICE RATE SCHEDULE (Cont'd)

For "Small" Commercial/Public Authority Customers using greater than 250,000 cubic feet but not more than 1,000,000 cubic feet per year:

Basic Service Charge

$37.00	per Month		

Distribution Charges

23.469¢	per 100 cubic feet		(D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.012)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.410)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.174¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
52.330¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

(D) Indicates Decrease (I) Indicates Increase

Commercial and Public Authority Service Rate Schedule (Cont'd)

For "Large" Commercial/Public Authority Customers:

Basic Service Charge

$151.00	per Month		

Distribution Charges

19.536¢	per 100 cubic feet		(D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.012)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.410)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.174¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
52.330¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

APPLICATION PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

RULES AND REGULATIONS

The Rules and Regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease (I) Indicates Increase

1. The purchased gas demand costs applicable to the Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial classes, the "DC", shall be obtained from Rider "A" - Section 1307(f) Purchased Gas Costs.

2. The number 12 shall be multiplied by the sum of (a) the volume of gas (expressed in Mcf) purchased from the Company by all Residential, Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial customers, during the Company peak Sales Month and (b) the volume of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month.

   (a) "Company Peak Sales Month" is defined as the calendar month within which the Company experienced the System-Wide Peak Sales Day, such month being December, January or February preceding the Section 1307(f) Application Period for which the determination of the rate per Gas BDU is being made.

   (b) "System-Wide Peak Sales Day" is defined as the day of maximum gas purchased by the Company, including all volumes of gas purchased from the Company throughout its entire system in the states of Pennsylvania and New York.

3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.

4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

   The current rate per Gas BDU is as follows:

   Purchased Gas Demand Cost $0.8170/BDU (D)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

(D) Indicates Decrease (I) Indicates Increase

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be $3.8728 per Mcf, subject to revision as provided below: (I)

The current components of the rate are as follows:

Purchased Gas Commodity Costs, set forth in Rider "A"	$3.3162/Mcf	(I)
Non Gas Costs	$0.5566/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus

2. The amount of $0.5566 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. Commodity Charge for Transportation Service

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule shall be $1.0066 per Mcf, which includes $0.5566 for recovery of non-gas costs and $0.4500 for recovery of purchased gas. (I)

(I)

(D) Indicates Decrease (I) Indicates Increase

SVIS
Small Volume Industrial Service Rate Schedule (Cont'd)

MONTHLY RATE

Basic Service Charge

$82.00	per Month		

Distribution Charges

23.636¢	per 100 cubic feet		(D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.012)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.410)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.174¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
52.330¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge.

APPLICATION PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

RULES AND REGULATIONS

The Rules and Regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease (I) Indicates Increase

IVIS
INTERMEDIATE VOLUME INDUSTRIAL SERVICE RATE SCHEDULE (Cont'd)

MONTHLY RATE

Basic Service Charge
$252.00 per Month

Distribution Charges

16.261¢	per 100 cubic feet		(D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.012)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.410)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.174¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
52.330¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with the provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

APPLICATION PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

RULES AND REGULATIONS

(D) Indicates Decrease (I) Indicates Increase

Industrial and Large Industrial customers, during the Company peak Sales Month defined in Rate Schedule CPA-LBS and (b) the volumes of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS.

3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.

4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

The current rate per Gas BDU is as follows:

Purchased Gas Demand Cost $0.817/BDU (D)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

b. <u>Determination of Customer's Gas BDUs</u>

The Customer's Gas BDUs shall be determined as follows: The actual volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Gas BDUs applicable to Customer shall be zero (0).

(D) Indicates Decrease (I) Indicates Increase

2. Margin Demand Charge

a. The rate per Margin BDU shall be $.5122 per Margin BDU.

b. Determination of Customer's Margin BDUs

The Customer's Margin BDUs shall be determined as follows: The actual deliveries of gas to the Customer by Company, including not only volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities but also volumes of Customer-owned gas transported to the Customer's load balancing facilities through the Company's facilities, during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Margin BDUs applicable to Customer shall be zero (0).

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be $3.6970 per Mcf, subject to revision as provided below: (I)

The current components of the rate are as follows:

Purchased Gas Commodity Costs, set forth in Rider "A"	$3.3162/Mcf	(I)
Non Gas Costs	$0.3808/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus

(D) Indicates Decrease (I) Indicates Increase

2. The amount of $0.3808 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. <u>Commodity Charge for Transportation Service</u>

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule shall be $0.8308 per Mcf, which includes $0.3808 for recovery of non-gas costs and $0.4500 for recovery of purchased gas. (I)

V. SURCHARGE

The non-purchased gas cost Demand Charges and the non-purchased gas cost Commodity Charge for Sales Service and the non-purchased gas cost Commodity Charge for Transportation Service shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor "E" of Company's 1307(f) rate in accordance with procedures set forth in Rider "A" - Section 1307(f) Purchased Gas Costs.

VII. SPECIAL PROVISIONS

Monthly metered Special Provisions A through J contained in the Company's Rate Schedule for Transportation Service shall apply to transportation service under this rate schedule.

VIII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease (I) Indicates Increase

LVIS
Large Volume Industrial Service (Cont'd)

C. An Industrial Customer, for which the Company estimates that the total volumes of gas purchased from the Company or transported by the Company during the next succeeding twelve months will be not less than 50,000 Mcf, if the Industrial Customer has used total volumes of gas in at least one billing month of not less than 4,167 Mcf, even if the Customer disagrees with the Company's estimate.

D. An Industrial Customer for which the Company estimates that total volumes of gas to be used by the customer during the next succeeding twelve months will not be less than 50,000 Mcf of gas per year whether the gas is purchased by the Industrial Customer from the Company, delivered by the Company to the Industrial Customer, or obtained by the customer from another source.

An Industrial Customer that meets the above criteria under this rate schedule at the beginning of an Application Period is required to continue to be subject to this rate schedule during all months of such Application Period. An Industrial Customer that meets the above criteria under this rate schedule during an Application Period is required to continue to be subject to this rate schedule during all or remaining months of such Application Period.

MONTHLY RATE

Basic Service Charge
$1,023.00 per Month

Distribution Charges
13.157¢ per 100 cubic feet (D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.012)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.410)¢	Per 100 cubic feet	Total Gas Adjustment Charge	(I)

(D) Indicates Decrease (I) Indicates Increase

LVIS
Large Volume Industrial Service (Cont'd)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.174¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
52.330¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

RULES AND REGULATIONS

The Rules and Regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

APPLICABLE PERIOD

The Application Period shall be the twelve months beginning March 1 of each year.

(D) Indicates Decrease (I) Indicates Increase

Commercial and Public Authority, Small Volume Industrial, Intermediate Volume Industrial, Large Volume Industrial and Large Industrial customers, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS and (b) the volume of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS.

3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.

4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

The current rate per Gas BDU is as follows:

Purchased Gas Demand Cost	$0.8170/BDU	(D)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

b. <u>Determination of Customer's Gas BDUs</u>

The Customer's Gas BDUs shall be determined as follows: The actual volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered qualifying load balancing facilities during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered qualifying load balancing facilities that ended during on of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Gas BDUs applicable to Customer shall be zero (0).

2. Margin Demand Charge

a. The rate per Margin BDU shall be $.3182 per Margin BDU.

b. Determination of Customer's Margin BDUs

The Customer's Margin BDUs shall be determined as follows: The actual deliveries of gas to the Customer by Company, including not only volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities but also volumes of Customer-owned gas transported to the Customer's load balancing facilities through the Company's facilities, during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Margin BDUs applicable to Customer shall be zero (0).

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be $3.5635 per Mcf, subject to revision as provided below: (I)

The current components of the rate are as follows:

Purchased Gas Commodity Costs, set forth in Rider "A"	$3.3162/Mcf	(I)
Non Gas Costs	$0.2473/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus

D) Indicates Decrease (I) Indicates Increase

2. The amount of $0.2473 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. Commodity Charge for Transportation Service

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule (I)
shall be $0.6973 per Mcf, which includes $0.2473 for recovery of non-gas costs
and $0.4500 for recovery of purchased gas. (I)

V. SURCHARGE

The non-purchased gas cost Demand Charges and the non-purchased gas cost Commodity Charge for Sales Service and the non-purchased gas cost Commodity Charge for Transportation Service shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor "E" of Company's 1307(f) rate in accordance with procedures set forth in Rider "A" - Section 1307(f) Purchased Gas Costs.

VII. SPECIAL PROVISIONS

Monthly metered Special Provisions A through J contained in the Company's Rate Schedule for Transportation Service shall apply to transportation service under this rate schedule.

VIII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease (I) Indicates Increase

LIS
Large Industrial Service (Cont'd)

C. An Industrial Customer, for which the Company estimates that the total volumes of gas purchased from the Company or transported by the Company during the next succeeding twelve months will be not less than 200,000 Mcf, if the Industrial Customer has used total volumes of gas in at least one billing month of not less than 17,000 Mcf, even if the Customer disagrees with the Company's estimate.

An Industrial Customer that meets the above criteria under this rate schedule at the beginning of an Application Period is required to continue to be subject to this rate schedule during all months of such Application Period. An Industrial Customer that meets the above criteria under this rate schedule during an Application Period is required to continue to be subject to this rate schedule during all or remaining months of such Application Period.

MONTHLY RATE

Basic Service Charge
$1,165.00 per Month

Distribution Charges
8.907¢ per 100 cubic feet (D)

Gas Adjustment Charge

(3.398)¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
(0.012)¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
(3.410)¢	per 100 cubic feet	Total Gas Adjustment Charge	(I)

(D) Indicates Decrease

(I) Indicates Increase

LIS
Large Industrial Service (Cont'd)

Natural Gas Supply Charge

51.007¢	per 100 cubic feet	Purchased Gas Cost Component (Rider A)	(I)
0.174¢	per 100 cubic feet	Merchant Function Charge (Rider G)	(I)
1.149¢	per 100 cubic feet	Gas Procurement Charge (Rider H)	
52.330¢	per 100 cubic feet	Total Natural Gas Supply Charge	(I)

The Natural Gas Supply Charge shall include a Merchant Function Charge (Rider G) to recover uncollectible costs associated with purchase gas costs of 0.3398% and the Gas Procurement Charge (Rider H) to recover costs of procuring natural gas pursuant to 52 Pa. Code §62.223.

The above non-purchased gas cost rates shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

GAS SHORTAGE CURTAILMENT

Service under this schedule to an LIS Industrial Customer is subject to curtailment and excess consumption penalty as set forth in Rule 26 of this tariff.

RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease　　(I) Indicates Increase

LBS and (b) volume of service (expressed in Mcf) to all customers under the "Monthly Volume" provisions of Rate Schedule SB, during the Company Peak Sales Month defined in Rate Schedule CPA-LBS.

3. The amount determined in Item 1 above shall be divided by the amount determined in Item 2 above to determine the amount included in the rate for recovery of purchased gas costs.

4. The rate per Gas BDU shall be the amount for purchased gas demand costs (Item 3).

The current rate per Gas BDU is as follows:

Purchased Gas Demand Cost	$0.8170/BDU	(D)

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made, under Items 1, 2 and 3, above, of the component to be included in the rate for purchased gas demand costs and the rate per Gas BDU shall be changed accordingly.

b. <u>Determination of Customer's Gas BDUs</u>

The Customer's Gas BDUs shall be determined as follows: The actual volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Gas BDUs applicable to Customer shall be zero (0).

(D) Indicates Decrease (I) Indicates Increase

2. Margin Demand Charge

a. The rate per Margin BDU shall be $.2517 per Margin BDU.

b. Determination of Customer's Margin BDUs

The Customer's Margin BDUs shall be determined as follows: The actual deliveries of gas to the Customer by Company, including not only volumes of gas purchased by the Customer from the Company and used by the Customer in the separately-metered load balancing facilities but also volumes of Customer-owned gas transported to the Customer's load balancing facilities through the Company's facilities, during such Customer's Peak billing Cycle, as defined hereinafter, shall be multiplied by a fraction. The numerator shall be the number 30. The denominator shall be the number of days of service for which such Customer was billed in such Customer's Peak Billing Cycle.

The Customer's Peak Billing Cycle shall be the single billing cycle of maximum delivery to the Customer's separately-metered load balancing facilities that ended during one of the months of December, January, February and March during the period beginning with the most recently-completed billing cycle ended in December and ending with the current billing cycle.

If the customer used no gas under this rate schedule during the most recently concluded billing cycles ended in December, January, February or March, then the level of Margin BDUs applicable to Customer shall be zero (0).

B. COMMODITY CHARGES FOR SALES AND FOR TRANSPORTATION SERVICE

1. Commodity Charge for Sales Service

The monthly Commodity Charge for Sales Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas sold to the Customer by the Company during the applicable billing cycle.

The rate per Mcf shall be determined as follows and shall be $3.5086 per Mcf, subject to revision as provided below: (I)

The current components of the rate are as follows:

Purchased Gas Commodity Costs, set forth in Rider "A"	$3.3162/Mcf	(I)
Non Gas Costs	$0.1924/Mcf	

a. Determination of Rate per Mcf

The rate per Mcf shall be the sum of:

(D) Indicates Decrease (I) Indicates Increase

1. The net amount per Mcf for recovery of the commodity component of purchased gas costs and for recovery or refund of "E" factor amounts, the "PGCC", as determined in Rider "A" - Section 1307(f) Purchased Gas Costs of this tariff; plus

2. The amount of $.1924 per Mcf for recovery of non-gas costs.

Each time there is a change in the provision for recovery of purchased gas costs pursuant to Rider "A" of this tariff, a recomputation shall be made of the commodity component of purchased gas costs (Item 1, above) and the rate per Mcf shall be changed accordingly. The component included in the rate for recovery of non-gas costs shall remain constant until changed in accordance with a procedure, other than a proceeding pursuant to Section 1307(f) of the Public Utility Code, 66 Pa.C.S. Section 1307(f).

2. <u>Commodity Charge for Transportation Service</u>

The monthly Commodity Charge for Transportation Service shall be the product of multiplying the rate per Mcf, determined as provided below, by the volume of gas transported by the Company to the Customer's load balancing facilities.

The rate per Mcf for transportation of gas under this rate schedule (I)
shall be $0.6424 per Mcf, which includes $0.1924 for recovery of non-gas costs and $0.4500 for recovery of purchased gas. (I)

V. SURCHARGE

The non-purchased gas cost Demand Charges and the non-purchased gas cost Commodity Charge for Sales Service and the non-purchased gas cost Commodity Charge for Transportation Service shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor "E" of Company's 1307(f) rate in accordance with procedures set forth in Rider "A" - Section 1307(f) Purchased Gas Costs.

VII. SPECIAL PROVISIONS

Monthly metered Special Provisions A through J contained in the Company's Rate Schedule for Transportation Service shall apply to transportation service under this rate schedule.

VIII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

(D) Indicates Decrease (I) Indicates Increase

RATE SCHEDULE – NGV

NATURAL GAS VEHICLE SERVICE

I. APPLICABILITY

Throughout the territory served under this tariff.

II. AVAILABILITY

Sales Service under this rate schedule is available for use of natural gas by a customer directly in a natural gas motor vehicle ("NGV").

III. NATURE OF SERVICE

Service provided in this rate schedule shall be firm service subject to the curtailment priorities of Rule 26. For curtailment purposes, service under this rate schedule shall be defined as curtailment priority number (6), firm large noncritical commercial and industrial requirements other than requirement for boiler fuel use.

IV. RATE

Rates per 100 cu. Ft. shall be established by the Company on the first day of each calendar month for each of the categories set forth below to compete with alternative vehicle fuels. The rates shall not be less than the 100% load factor base cost of gas, plus the take-or-pay surcharge, plus the surcharge for Transition Cost, plus the incremental operating cost incurred by the Company for operating Company owned NGV compression equipment on a per Ccf basis, if any, plus $0.01 per cu. ft., plus the state tax adjustment surcharge, and not more than the tailblock rate of the Commercial and Public Authority Service Rate Schedule, including all applicable surcharges, plus the incremental operating cost incurred by the Company for operating Company owned NGV compression equipment on a per Ccf basis, if any.

The 100% load factor base cost of gas shall be $0.26631 per 100 cu. ft. (as calculated by adding the purchase gas components of the Load Balancing Service Rates).

Purchased Gas 100% Load Factor Demand Cost	$0.08170/Ccf	(D)
plus		
Purchased Gas Commodity Cost	$0.33162/Ccf	(I)
Equals		
100% Load Factor Base Cost of Gas	$0.41332/Ccf	(I)

The incremental operating cost for compression shall be $0.13436/Ccf.

(D) Indicates Decrease (I) Indicates Increase

Natural gas vehicle customers are classified into the following categories:

NGV(1) All natural gas vehicle customers utilizing Company owned filling facilities. A uniform rate shall be established each month within the parameters set forth above, for customers utilizing Company-owned filling facilities.

The minimum NGV(1) rate shall be:	$0.59863/Ccf	(I)

The current components of the minimum NGV(1) rate are as follows:

100% load factor base cost of gas:	$0.41332/Ccf	(I)
Incremental operating cost of Company owned NGV compression equipment:	$0.13436/Ccf	
Transition Cost Surcharge	$0.00000/Ccf	
State Tax Adjustment Surcharge	$0.00000/Ccf	
Minimum allowable Non-Gas cost	$0.01000/Ccf	

The maximum NGV(1) rate shall be:	$0.81892/Ccf	(I)

The current components of the maximum NGV(1) rate are as follows:

Tailblock rate of the Commercial and Public Authority Service Rate schedule:	$0.68456/Ccf	(I)
Incremental operating cost of Company owned NGV compression equipment:	$0.13436/Ccf	
State Tax Adjustment Surcharge	$0.00000/Ccf	

NGV(2) Natural gas vehicle customers utilizing customer owned filling facilities. A uniform rate will be established each month within the parameters set forth above, to customers utilizing customer owned filling facilities.

The minimum NGV(2) rate shall be:	$0.42332/Ccf	(I)

The current components of the minimum NGV(2) rate are as follows:

100% load factor base cost of gas:	$0.41332/Ccf	(I)
Transition Cost Surcharge	$0.00000/Ccf	
State Tax Adjustment Surcharge	$0.00000/Ccf	
Minimum allowable Non-Gas cost	$0.01000/Ccf	

The maximum NGV(2) rate shall be:	$0.68456/Ccf	(I)

(D) Indicates Decrease (I) Indicates Increase

The current components of the maximum NGV(2) rate are as follows:

Tailblock rate of the Commercial and Public Authority Service Rate schedule:	$0.68456 /Ccf (I)
State Tax Adjustment Surcharge	$0.00000/Ccf

V. SURCHARGE

All non-purchased gas cost charges under this rate schedule will be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge as set forth in this tariff.

VI. AMOUNTS TO BE INCLUDED IN OVER/UNDERCOLLECTION OF GAS COSTS

Purchased gas cost revenues billed under this rate schedule shall be included as revenues for recovery of gas costs for purposes of computing Factor “E” of Company’s 1307(f) rate in accordance with procedures set forth in Rider “A” - section 1307(f) Purchased Gas Costs. Purchased gas cost revenues recovered under this rate schedule shall be the 100% load factor base cost of gas as defined above.

VII. RULES AND REGULATIONS

The rules and regulations set forth in this tariff shall govern, where applicable, the supply of gas service under this rate schedule.

RATE SCHEDULE PSB

PRIORITY STANDBY SERVICE

APPLICABILITY

Throughout the territory served under this tariff.

AVAILABILITY OF SERVICE

Service under this rate schedule is available to all customers under the Residential, Commercial and Public Authority, and SVIS Rate Schedules which enter into a contract for service under this Rate Schedule. A customer will be permitted to enter into a contract, prepared by the Company, for service under this rate schedule, however, only if the Company projects that sufficient volumes of gas will be available to the Company during the period of the customer's contract for Priority Standby Service.

Service under this rate schedule is mandatory for all customers categorized as Priority 1 under the curtailment priorities of Rule 26 who enter into contracts with the Company to receive Transportation Service and who do not have dual or alternate fuel equipment on site which is installed and operable with sufficient amounts of alternate fuel available on site during each winter period of each year commencing on December 1 and ending on March 31 of the following year. Service under this rate schedule is voluntary for all other customers.

NATURE OF SERVICE

Priority standby service shall permit the customer to purchase gas on a firm basis subject to curtailment priorities of Rule 26. The Company will take all reasonable steps to obtain or to maintain gas supplies sufficient to enable the Company to provide reasonably continuous service to each Customer receiving Priority Standby Service.

MONTHLY RATE

The monthly rate shall be $1.1779 per Mcf, which shall be applied to the (I)
total monthly volumes transported by the customer during the month.

The rate shall equal the PGDC portion of the commodity rate applicable to the corresponding sales rate classification.

(D) Indicates Decrease (I) Indicates Increase

MONTHLY RATE

The monthly rate shall be $0.5547 per Mcf, which shall be applied to the Monthly Volume, as defined below. (I)

MONTHLY VOLUME

The Mcf volume of gas to which the Monthly Rate set forth above shall be applied, shall be determined for each billing cycle, as set forth below;

1. The volume of gas specified in the Service Agreement under this rate schedule shall be adjusted for each billing cycle by, multiplying such volume, expressed in Mcf, by a fraction. The numerator of the fraction shall be the number of days in the billing cycle applicable to the customer and the denominator shall be thirty (30).

2. If the volume determined under item 1, above, is greater than the sum of the Mcf volume of gas purchased by the customer under rate schedules other than load balancing rate schedules during the billing cycle, the Monthly Rate shall be applied to the difference between: (a) the volume determined under item 1, above, and (b) the Mcf volume of gas purchased by the customer under the rate schedules other than load balancing rate schedules during such billing cycle.

3. If the volume determined under item 1, above, is equal to or less than the Mcf volume of gas purchased by the customer under rate schedules other than load balancing rate schedules during the billing cycle, then the Monthly Volume shall be zero (0) Mcf.

RATE SCHEDULE FOR MONTHLY METERED TRANSPORTATION SCHEDULE (cont'd)

MONTHLY RATES

Commodity Rates

The commodity rates set forth below contain a component, presently $0.5800 per Mcf, for recovery of purchased gas costs.

For transportation of gas to Residential Customers, the monthly rate for transportation of gas both within and outside the Commonwealth of Pennsylvania shall be:

$3.4111 Mcf (I)

For transportation of gas to Commercial and Public Authority Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

$2.7494	per Mcf for Small Commercial/Public Authority using not more than 250 Mcf per year	(I)
$2.5055	per Mcf for Small Commercial/Public Authority using greater than 250 Mcf but not more than 1,000 Mcf per year	(I)
$2.1122	per Mcf for Large Commercial/Public Authority	(I)

For transportation of gas to Commercial and Public Authority Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

$2.7494	per Mcf for Small Commercial/Public Authority using not more than 250 Mcf per year	(I)
$2.5055	per Mcf for Small Commercial/Public Authority using greater than 250 Mcf but not more than 1,000 Mcf per year	(I)
$2.1122	per Mcf for Large Commercial/Public Authority	(I)

For transportation of gas to Small Volume Industrial Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

$2.5222 per Mcf for SVIS Customers (I)

For transportation of gas to Small Volume Industrial Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

$2.5225 per Mcf for SVIS Customers (I)

(D) Indicates Decrease (I) Indicates Increase

RATE SCHEDULE FOR MONTHLY METERED TRANSPORTATION SCHEDULE (cont'd)

For transportation of gas to Intermediate Volume Industrial Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:
$1.7847 per Mcf for IVIS Customers (I)

For transportation of gas to Intermediate Volume Industrial Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

$1.7847 per Mcf for IVIS Customers (I)

For transportation of gas to Large Volume Industrial Customers and any entity that is not a Gas Service Customer, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

$1.4743 per Mcf (I)

For transportation of gas to Large Volume Industrial Customers and any entity that is not a Gas Service Customer, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

$1.4743 per Mcf (I)

For transportation of gas to Large Industrial Customers, the monthly rate for transportation of gas produced within the Commonwealth of Pennsylvania shall be:

$1.4093 per Mcf (I)

For transportation of gas to Large Industrial Customers, the monthly rate for transportation of gas produced outside the Commonwealth of Pennsylvania shall be:

$1.4093 per Mcf (I)

Provided, however, that the Company, in its sole discretion, may reduce by contract the portion of the above rates applicable to the Customer that are for recovery of gas or the portion of the rate for recovery of non-gas costs of service if it is reasonably necessary to do so to meet competition from another supplier of energy including gas from another supplier of gas that has constructed, or could construct, facilities to deliver supplies of gas to a MMT Customer of the Company without use of the Company's facilities or another transportation of gas. The Company may also reduce or eliminate the compensation for line losses provided for in Special Provisions paragraph B of this rate schedule in order to meet the competitive circumstances for alternate fuels or bypass situations cited above excluding competition from other Pennsylvania local distribution companies. The Company will reduce the applicable rate only if:

(a) Either (1) the MMT Customer has facilities in place and operable to use an alternative fuel or obtain gas from an alternative supplier or (2) in the Company's judgment, such facilities would be constructed;

(D) Indicates Decrease (I) Indicates Increase

E. In the event of interruption or curtailment of transportation service, pursuant to items C and D, above, and during such period of interruption or curtailment, the MMT Customer must sell to the Company all or a portion of the MMT Customer’s supply of gas at the higher of (1) the Transportation Service Customer’s cost of purchased gas at the point of delivery to the Company or (2) the Company’s average cost of purchased gas per Mcf, as determined based upon the Company’s Section 1307(f) Rate, which is $5.5551. (I)

F. If for any reason (including the default of an MMNGS Supplier), the MMNGS Supplier fails to provide sufficient daily deliveries of natural gas supplies to meet the MMT Customers DDQ pursuant to the terms of MMNGS supply service, and/or MMT Customer’s MMNGS Supplier does not provide complete compensation to the Company for services provided under Rate Schedule MMNGS, Special Provision D.3, the Company shall charge the MMT Customer for the deficient daily deliveries under the applicable gas sales rate schedule plus applicable surcharge as set forth in Rate Schedule SB Special Provisions.

E. In the event of interruption or curtailment of transportation service, pursuant to items C and D, above, and during such period of interruption or curtailment, the DMT Service Customer must sell to the Company all or a portion of the DMT Service Customer's supply of gas at the higher of (1) the Transportation Service Customer's cost of purchased gas at the point of delivery to the Company or (2) the Company's average cost of purchased gas per Mcf, as determined based upon the Company's Section 1307(f) Rate, which is $5.5551. (I)

F. If a Gas Service Customer receiving gas transported by the Company uses less than the amount of gas delivered into the Company's system for transportation to such Customer ("excess deliveries"), the Gas Service Customer receiving gas transported by the Company may use such gas during the banking/balancing period defined below, following which the Company shall have the right, but not the obligation, to purchase remaining excess deliveries of gas from the DMT service Customer at a rate equal to the lowest of (1) the cost at which it was acquired by the DMT Service Customer, including pipeline transportation charges, or (2) the Company's average commodity delivered cost of gas to National Fuel Gas Supply Corporation, or (3) the Company's average commodity cost of locally produced gas during the month when excess deliveries were received by the Company. The cost at which the DMT Service Customer acquired the gas will be determined from such Customer's contract with the supplier or by a sworn affidavit setting forth the Customer's cost of gas, including cost of delivery of such gas to the Company's system. Upon request by the Company, the DMT Service Customer will be required to furnish to the Company the DMT service Customer's choice of (1) a copy of this contract or (2) an affidavit. The banking/balancing period shall be the three billing months after the billing month in which the Company received excess deliveries in behalf of the Customer.

G. "Underdeliveries" are volumes of gas taken from the Company by a Gas Service Customer in excess of the sum of (1) any excess deliveries of the customer at the beginning of the day and (2) the volume of gas delivered to the Company for the customer's account, after adjustment for line losses less volumes of volumes of gas determined to be sales by the Company to the customer. Cumulative underdeliveries, as determined each day, in excess of two percent of the volume of gas delivered by the Company to the customer that day, shall be a sale of gas by the Company to the customer under the applicable rate schedule plus applicable surcharges as set forth in Rate Schedule SB Special Provisions and shall not be recharacterized as transportation service under any circumstances. Cumulative underdeliveries of not more than two percent of the volume of gas delivered to a customer by the Company on any day may be offset by volumes of gas delivered to the Company for the customer's account, after adjustment for line losses, in excess of the volume of gas taken by the customer from the Company on subsequent days within the same billing month.

RATE SCHEDULE SATC
SMALL AGGREGATION TRANSPORTATION CUSTOMER SERVICE (Cont'd)

RATES AND CHARGES

A. Customer Transportation Service Rates

The Company will provide transportation services to deliver gas supplies to the SATC Customer(s). The Customer shall be billed the charges for the transportation services rendered for it at the appropriate charges provided herein for which service the SATC Customer qualifies.

The SATC Customer shall pay the following transportation charges for the transportation of gas. The commodity rates set forth below contain a component, presently $0.02914 per Ccf, for the recovery of purchased gas (D) demand costs and shall be adjusted pursuant to Rider A of the tariff. Such purchased gas costs collected though these rates shall be included as revenues for the recovery of purchased gas costs as specified in Rider A of this tariff.

RATE SCHEDULE SATC
SMALL AGGREGATION TRANSPORTATION CUSTOMER SERVICE (Cont.)

1. Residential Transportation Rates

SATC Customers that meet the qualifications under the Residential Service Rate Schedule classification:

Rates per Residential SATC Customer per Month:

$14.00	Basic Service Charge	
$0.32525	per 100 cubic feet (I)	(D)

2. Commercial and Public Authority Transportation Rates

SATC Customers that meet the qualifications under the Commercial and Public Authority Service Rate Schedule classification:

a. Rates per Commercial/Public Authority customer per month for "Small" Commercial/Public Customers using not more than 250,000 cubic feet per year:

$27.00	Basic Service Charge	
$0.25908	per 100 cubic feet	(D)

b. Rates per Commercial/Public Authority customer per month for "Small" Commercial/Public Customers using greater than 250,000 cubic feet but not more than 1,000,000 cubic feet per year:

$37.00	Basic Service Charge	
$0.23469	per 100 cubic feet	(D)

c. Rates per Commercial/Public Authority customer per month for "Large" Commercial/Public Customers:

$151.00	Basic Service Charge	
$0.19536	per 100 cubic feet	(D)

(D) Indicates Decrease (I) Indicates Increase

RATE SCHEDULE SATC
SMALL AGGREGATION TRANSPORTATION CUSTOMER SERVICE (Cont.)

3. Small Volume Industrial Service Transportation Rates

SATC Customers that meet the qualifications under the Small Volume Industrial Service Rate Schedule classification:

Rates per Small Volume Industrial Service SATC Customer per Month:

$82.00	Basic Service Charge	
$0.23636	per 100 cubic feet	(D)

4. Intermediate Volume Industrial Service Transportation Rates

SATC Customers that meet the qualifications under the Intermediate Volume Industrial Service Rate Schedule classification:

Rates per Intermediate Volume Industrial Service SATC Customer per Month:

$252.00	Basic Service Charge	
$0.16261	per 100 cubic feet	(D)

B. Miscellaneous Customer Surcharges

1. Residential rate classes shall be subject to surcharges in accordance with Rider F - LIRA Discount Charge as set forth in this tariff.

2. The above non-purchased gas cost SATC rates shall be subject to surcharges in accordance with provisions of Rider B - State Tax Adjustment Surcharge.

RATE SCHEDULE SATS
SMALL AGGREGATION TRANSPORTATION SUPPLIER SERVICE (Cont.)

C. Total Upstream Capacity Requirements for SATS Suppliers

SATS Suppliers shall be required to provide sufficient firm pipeline transportation and storage capacity to meet the estimated extreme day requirements of their SATC Customer groups as further described below. The SATS Suppliers' estimated extreme day requirements of their SATC Customer Group used for Supplier capacity allocations and requirements shall be based on a sixty-two (62) degree day extreme peak day calculation. The Company shall utilize peaking and temperature swing storage capacity retained by the Company and recovered through SATC rates to provide for any variances between actual and forecasted usage and for any peak delivery requirements for days colder than sixty-two (62) degree days.

Such sufficient pipeline transportation and storage capacity shall be provided through the following means:

1. Released ESS Storage Capacity and Associated EFT Capacity

a. Requirements To Be Met Through ESS Storage

55% of extreme peak day requirements shall be provided through the Company's ESS storage and associated EFT transportation capacity on NFGSC. Such NFGSC Storage and transmission capacity shall be released to SATS Suppliers at the maximum rate under the pipeline's FERC gas tariff.

b. Initial Assignment of ESS Storage Capacity

In a month a SATS Supplier begins to serve SATC customers, it shall be provided with an initial assignment of storage capacity, based on the percentage set forth at C.1.a. above, to meet the Supplier's requirements for the upcoming winter period. Approximately fifteen days prior to the close of nominations for the month, the Company will calculate the quantity of storage capacity released to match the SATS Supplier's winter requirements based on the number of SATC Customers aggregated by the Supplier. If the initial assignment takes place in a month other than April, the Company will transfer storage gas to the Supplier pursuant to C.1.c below. The SATS Supplier shall be responsible for all taxes and pipeline fees associated with moving or transferring the storage gas to the Company.

(D) Indicates Decrease
(I) Indicates Increase

RATE SCHEDULE SATS
SMALL AGGREGATION TRANSPORTATION SUPPLIER SERVICE (Cont.)

c. Additional Assignments of ESS Storage Capacity

Approximately fifteen days prior to the close of nominations for each month, the Company will recalculate the quantity of storage capacity released to match the SATS Supplier's revised winter requirements based on the number of SATC Customers aggregated by the Supplier. If additional SATC Customers join a SATS Supplier's SATC Customer Group, the Company will release additional capacity as required, based on the percentage set forth at C.1.a. above. In addition, the SATS Supplier will be required to pay the Company for storage gas transferred and all taxes and pipeline fees associated with moving or transferring the storage gas to the Supplier. The storage gas transfer rate shall be the sum of (1) the higher of the Company's average cost of gas based upon the Company's Section 1307f rate, or the DMI for the first day of month in which gas is transferred plus all transportation costs to the Company's City Gate, plus (2) the demand Transfer Recovery Rate ("DTR Rate"). The DTR rate shall equal the per Mcf System Average Unrecovered Demand Charge revenue beginning in the month of April through the initial month that storage capacity is released to the Supplier. The System Average Unrecovered demand Charge Revenue shall equal the sum of the differences between the average demand charge revenues and the average fixed demand costs beginning the month of April through the initial month that storage capacity is released to the Supplier.

The DTR by month shall be as follows:

Capacity Transfer Month	DTR $/Mcf	
April	$0.00	
May	$0.00	
June	$0.00	
July	$0.00	
August	$0.00	
September	$0.00	
October	$0.00	
November	$0.64	(D)
December	$1.05	(D)
January	$0.94	(D)
February	$0.49	(D)
March	$0.00	

(D) Indicates Decrease (I) Indicates Increase

RATE SCHEDULE SATS
SMALL AGGREGATION TRANSPORTATION SUPPLIER SERVICE (Cont.)

2. Released Transmission Capacity Not Included in SATC Transportation Rates

45% of extreme peak day requirements is to be provided by the release of pipeline capacity upstream of NFGSC and the release of associated EFT transportation capacity on NFGSC which is not included in transportation rates. All such capacity shall be released to SATS Suppliers, and SATS Suppliers shall take such released capacity, at the maximum rate under the pipeline's FERC gas tariff. The actual pipeline capacity path upstream of NFGSC to be released to the Supplier by the Company shall be designated by the Company from its available capacity. The Company will attempt to accommodate a Supplier's request for particular capacity on a first-come first-serve basis.

As an alternative to the above, the Company may designate an alternative capacity path(s) from its available capacity. The capacity release rate for the pipeline capacity path released to the Supplier shall be $7.0861/Dth which equals the weighted average demand cost of upstream (D) capacity, however, capacity released on NFGSC will be released at the maximum rate under NFGSC's FERC gas tariff. The Company will post a listing of the alternative capacity path(s) designated, including the associated quantity of capacity, on its web site.

For capacity termination notices, prior to the termination notice date of any capacity contract in this Section C.2., the Company will issue a request for proposals to qualified Suppliers under this tariff to determine if the Company should terminate, renew, or replace such contract, in whole or in part. The Company will terminate a proportionate share of the capacity contract if: (1) Suppliers demonstrate that they will provide comparable firm capacity to serve the Company's core customers, (2) the Suppliers agree to assign such comparable capacity at the contracted price to the Company upon Company request if such capacity is required to meet supply requirements of SATC Customers due to the termination of the SATS Supplier pursuant to Section H.1. or if the Supplier has reduced the level of delivery requirements from the previous periods requirements, and 3) the Commission approves such comparable capacity. Comparable capacity must have firm rights for at least the seven (7) winter months, and such capacity must have primary delivery rights into available primary receipt rights on NFGSC held by the Company. Comparable capacity must have firm capacity rights sufficient in volume and duration (with renewal rights) to serve the customers to be served by the SATS Supplier. The Company will post a listing of capacity contracts, including the associated quantity of capacity, that it determines to be of critical status on its web site.

E. In the event of interruption or curtailment of transportation service, pursuant to items C and D, above, and during such period of interruption or curtailment, the DMLMT Service customer must sell to the Company all or a portion of the DMLMT Service Customer's supply of gas at the higher of (1) the Transportation Service Customer's cost of purchased gas at the point of delivery to the Company or (2) the Company's average cost of purchased gas per Mcf, as determined based upon the Company's Section 1307(f) Rate which is $5.5551. (I)

F. If a Gas Service Customer receiving gas transported by the Company uses less than the amount of gas delivered into the Company's system for transportation to such Customer ("excess deliveries"), the Gas Service Customer receiving gas transported by the Company may use such gas during the banking/balancing period defined below, following which the Company shall have the right, but not the obligation, to purchase remaining excess deliveries of gas from the DMLMT Service Customer at a rate equal to the lowest of (1) the cost at which it was acquired by the DMLMT Service Customer, including pipeline transportation charges, or (2) the Company's average commodity delivered cost of gas to National Fuel Gas Supply Corporation, or (3) the Company's average commodity cost of locally-produced gas during the month when excess deliveries were received by the Company. The cost at which the DMLMT Service Customer acquired the gas will be determined from such Customer's contract with the supplier or by a sworn affidavit setting forth the Customer's cost of gas, including cost of delivery of such gas to the Company's system. Upon request by the Company, the DMLMT service Customer will be required to furnish to the Company the DMLMT Service Customer's choice of (1) a copy of this contract or (2) an affidavit. The banking/balancing period shall be the three billing months after the billing month in which the Company received excess deliveries in behalf of the Customer.

G. "Underdeliveries" are volumes of gas taken from the Company by a Gas Service Customer in excess of the sum of (1) any excess deliveries of the customer at the beginning of the day and (2) the volume of gas delivered to the Company for the customer's account, after adjustment for line losses less volumes of gas determined to be sales by the Company to the customer. Cumulative underdeliveries, as determined each day, in excess of two percent of the volume of gas delivered by the Company to the customer that day, shall be a sale of gas by the Company to the customer under the applicable rate schedule plus applicable surcharges as set forth in Rate Schedule SB Special Provisions and shall not be recharacterized as transportation service under any circumstances. Cumulative underdeliveries of not more than two percent of the volume of gas delivered to a customer by the Company on any day may be offset by volumes of gas delivered to the Company for the customer's account, after adjustment for line losses, in excess of the volume of gas taken by the customer from the Company on subsequent days within the same billing month.

(D) Indicates Decrease (I) Indicates Increase

RIDER A
SECTION 1307(F) PURCHASED GAS COSTS
PROVISION FOR RECOVERY OF PURCHASED GAS COSTS

Rates for each Mcf (1,000 cubic feet) of gas supplied under Residential, Low Income Residential Assistance Service, Commercial and Public Authority, Commercial and Public Authority Load Balancing Service ("LBS"), Small Volume Industrial, Intermediate Volume Industrial, Intermediate Volume Industrial LBS, Large Industrial, Large Industrial LBS, Large Volume Industrial, Large Volume Industrial LBS and Natural Gas Vehicle Service rate schedules of this tariff, shall include $3.3112 per Mcf for recovery of purchased gas commodity costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. (I)

Rates for each Mcf (1,000 cubic feet) of gas supplied under Residential, Commercial and Public Authority, Small Volume Industrial Service, Intermediate Volume Industrial, Large Volume Industrial Service, Large Industrial Service and Standby Service rate schedules of this tariff, shall include $2.1744 per Mcf for recovery of purchased gas demand costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. (I)

Rates for each Mcf (1,000 cubic feet) of gas transported under the Small Aggregation Transportation Customer Rate Schedule shall include $0.4425 per Mcf for the recovery of purchased gas demand costs. (I)

Such rates for gas service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of purchased gas costs.

The amounts per Mcf for recovery of purchased gas costs (commodity and demand) included in rates under each rate schedule of the tariff are as follows:

	Total	Distribution Charges	Gas Adjustment Charge	Natural Gas Supply Charge	
Residential	$5.0523	$0.2914	$(0.3398)	$5.1007	(I)
Low Income Residential Assistance Service	$5.0523	$0.2914	$(0.3398)	$5.1007	(I)
Commercial/Public Authority	$5.0523	$0.2914	$(0.3398)	$5.1007	(I)
Small Volume Industrial	$5.0523	$0.2914	$(0.3398)	$5.1007	(I)
Intermediate Volume Industrial	$5.0523	$0.2914	$(0.3398)	$5.1007	(I)
Large Volume Industrial	$5.0523	$0.2914	$(0.3398)	$5.1007	(I)
Large Industrial	$5.0523	$0.2914	$(0.3398)	$5.1007	(I)
Standby	$0.5547				(I)
Priority Standby	$1.1779				(I)
Small Aggregation Transportation					(I)
Customer Rate Schedule	$0.2914	$0.2914			(I)

(D) Indicates Decrease (I) Indicates Increase

Rider G
Merchant Function Charge (MFC) Rider

Applicability:

The Merchant Function Charge (MFC) shall be added to the Natural Gas Supply Charge and Gas Adjustment Charge of Residential, LIRAS, Commercial and Public Authority, SVIS, IVIS, LVIS and LIS rate schedules.

Such charges shall be updated quarterly and effective each February 1, May 1, August 1, and November 1 of the year. The charge will also be updated whenever there is a change to the Sales Service Rate Customer Charge, Distribution Charge, Natural Gas Supply Charge or Gas Adjustment Charge.

Calculation of Rate:

For customers receiving service in the Residential classification, the MFC shall equal 1.8032% times the Natural Gas Supply Charge and the Gas Adjustment Clause as calculated for Rider A.

The current Residential MFC Charge is:

Natural Gas Supply Charge per Mcf	$0.0919	(I)
Gas Adjustment clause (E-Factor) per Mcf	$(0.0061)	(I)
Total Residential MFC per Mcf	$0.0858	(I)

For customers receiving service in the Non-Residential classifications, the MFC shall equal 0.3398% times the Natural Gas Supply Charge and Gas Adjustment Clause as calculated for Rider A.

The current Non-Residential MFC Charge is:

Natural Gas Supply Charge per Mcf	$0.0174	(I)
Gas Adjustment clause (E-Factor) per Mcf	$(0.0012)	(I)
Total Non-Residential MFC per Mcf	$0.0162	(I)

(D) Indicates Decrease (I) Indicates Increase

Rider H
Gas Procurement Charge (GPC)

APPLICABILITY

Effective June 1, 2013, the Gas Procurement Charge will be included in the Natural Gas Supply Charge of Residential, LIRAS, Commercial and Public Authority, SVIS, IVIS, LVIS and LIS rate schedules.

The charge is designed to recover the costs of procuring natural gas pursuant to 52 Pa. Code §62.223. The natural gas procurement costs included in the GPC charge will only be updated in a base rate case.

The GPC to be included in the Natural Gas Supply Charge shall be $0.1149 / Mcf and is not reconcilable.

Price To Compare Component	Residential (¢ per 100 cubic feet)	Non Residential (¢ per 100 cubic feet)	
Natural Gas Supply Charge			
Purchased Gas Cost Component (Rider A)	51.007	51.007	(I)
Merchant Function Charge associated with Natural Gas Supply Charge(Rider G)	0.919	0.174	(I)
Gas Procurement Charge (Rider H)	1.149	1.149	
Subtotal Natural Gas Supply Charge	53.075	52.330	(I)
Gas Adjustment Charge			
Purchased Gas Cost Component (Rider A)	(3.398)	(3.398)	(I)
Merchant Function Charge associated with Gas Adjustment Charge (Rider G)	(0.061)	(0.012)	(I)
Subtotal Gas Adjustment Charge	(3.459)	(3.410)	(I)
Total Price To Compare	49.616	48.920	(I)

(D) Indicates Decrease (I) Indicates Increase

APPENDIX B

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission Office of Small Business Advocate Office of Consumer Advocate v. National Fuel Gas Distribution Corporation	:	Docket Nos. R-2024-3045177 C-2024-3045469 C-2024-3045964

STATEMENT OF NATIONAL FUEL GAS DISTRIBUTION CORPORATION IN SUPPORT OF THE JOINT PETITION FOR SETTLEMENT OF THE RATE INVESTIGATION PURSUANT TO 66 PA.C.S. § 1307(f)

TO ADMINISTRATIVE LAW JUDGE CHARECE Z. COLLINS:

I. INTRODUCTION

National Fuel Gas Distribution Corporation ("Distribution" or the "Company") files this Statement in Support of the Joint Petition for Settlement of the Section 1307(f) Rate Investigation ("Settlement") entered into by Distribution, the Bureau of Investigation & Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), and the Office of Small Business Advocate ("OSBA") (hereinafter, collectively "Parties") in the above-captioned purchased gas cost ("PGC") proceeding. Distribution respectfully requests that Administrative Law Judge Charece Z. Collins ("ALJ") recommend approval of, and the Commission approve, the Settlement, including the terms and conditions thereof, without modification.

The Settlement, if approved, will resolve all of the issues in this proceeding, including whether Distribution's historic natural gas costs were and projected natural gas costs will be incurred under a least cost fuel procurement policy. The Settlement is in the interests of

Distribution, its customers, and the other Parties and is otherwise in the public interest. Accordingly, it should be approved without modification.

The Settlement was achieved after a comprehensive investigation of Distribution's natural gas procurement policies and operations. Distribution responded to numerous formal discovery requests. The Statutory Parties (*i.e.*, I&E, OCA, and OSBA) have years of experience in evaluating Distribution's annual PGC filings and thoroughly evaluated the Company's 2024 filing. Moreover, OCA, and OSBA submitted Direct and Rebuttal Testimony, with the OCA also submitted Surrebuttal Testimony in this proceeding.

For the reasons set forth herein, the Settlement is just and reasonable and Distribution's 2024 1307(f) Filing, as modified by the Settlement, should be approved.

II. COMMISSION POLICY FAVORS SETTLEMENT

Commission policy promotes settlements. *See* 52 Pa. Code § 5.231. Settlements reduce the time and expense that the parties must expend litigating a case and, at the same time, conserve precious administrative resources. The Commission has stated that settlement results are often preferable to those achieved at the conclusion of a fully-litigated proceeding. *See* 52 Pa. Code § 69.401. To accept a settlement, the Commission must first determine that the proposed terms and conditions are in the public interest. *Pa. Pub. Util. Comm'n v. York Water Co.*, Docket No. R-00049165 (Order entered Oct. 4, 2004); *Pa. Pub. Util. Comm'n v. C.S. Water and Sewer Assocs.*, 74 Pa. P.U.C. 767 (1991).

III. THE SETTLEMENT IS IN THE PUBLIC INTEREST

A. PGC RATES

The Settlement rates that Distribution proposes to place into effect on August 1, 2024 are supported by record evidence. Distribution explained in detail the development of its natural gas supply rates utilizing cost projections, sales projections, and the reconciliation process.

Distribution's testimony and exhibits provided full support for the rates and their underlying calculations. See Distribution PGC St. No. 5, PGC Exhibit No. 21.

In Distribution's pre-filing, filed on December 29, 2023, it provided 27 exhibits detailing its gas purchases, gas contracts, peak day requirements and other information required by the Commission's regulations.[1] In its annual filing made on January 31, 2024, Distribution offered the testimony of 8 witnesses explaining the filing and why it was reasonable, along with additional exhibits supporting the filing. Additional detail regarding the Company's gas purchasing practices is also provided in the Proposed Findings of Fact set forth in Paragraphs 26-41 of the Settlement.

The Settlement rates also reflect the adjustments that were agreed to by the Parties in this proceeding. Accordingly, under the terms of the Settlement, the Parties agree that, on August 1, 2024 Distribution will place into effect the natural gas rates set forth in **Appendix A** of the Settlement, as modified by the Settlement, and subject to updates for actual over/under recoveries of purchased gas costs through June 30, 2024, for updates related to the calculation of the Monthly Metered Transportation ("MMT") balancing charge and for updates to the forecasts of wellhead prices. Settlement ¶ 46. Furthermore, the Settlement also dictates that the rates will reflect changes to National Fuel Gas Supply Corporation's ("Supply") rates effective February 1, 2024. Settlement ¶ 46. The Company will reflect this update and any other applicable updates in the tariff in its August 2024 compliance filing.

B. CERTIFIED NATURAL GAS

As part of the Company's main filing in this proceeding, it proposed a pilot program to allow the Company to procure Certified Natural Gas ("CNG"). As explained by Distribution witness Mr. Cuthbertson, CNG is a "natural gas that has been evaluated and verified by an

[1] On January 10, 2023, Distribution filed and served PGC Exhibit Nos. 12, 21, and 22, which were unintentionally omitted from the December 30, 2023, 30-day prefiling materials.

independent third-party to have been produced with reduced green-house-gas ("GHG") emissions and environmental impacts, beyond current environmental regulations." Distribution PGC St. No. 2, pp. 8-9. Mr. Cuthbertson went on to explain the benefits of CNG, noting that "[c]ertified natural gas wells can reduce methane emissions up to 80% from traditional wells. CNG provides the same reliability as conventional natural gas and is compatible with all existing natural gas infrastructure." Distribution PGC St. No. 2, p. 9.

Beyond the explanation of what CNG is and its associated benefits, Mr. Cuthbertson also detailed the goal of the Company's CNG pilot proposal, stating:

> [The] Company aims to identify and purchase natural gas from operators who are implementing best practices in the production of natural gas including lowering emissions. The Company also intends to quantify CO2 abated by measuring the methane intensity of the CNG versus the intensity of the traditionally extracted natural gas.

Distribution PGC St. No. 2, pp. 9-10.

Furthermore, Mr. Cuthbertson explained in detail the mechanics of the proposed CNG pilot program, noting that: (1) Distribution is seeking three-year authorization to purchase CNG; (2) the costs will be limited to $175,000 per year associated with any CNG premium; (3) the pilot will limit CNG purchases to those certified and that have obtained specific ratings, namely, MiQ or Oil and Gas Methane Partnership ("OGMP 2.0") 2.0 ratings. Distribution PGC St. No. 2, p. 10. Mr. Cuthbertson also detailed the identified ratings and why the Company believes them to be appropriate and explained that the Company's purchase of CNG would be made under the Company's current Gas Cost Management Plan ("Plan"). Distribution PGC St. No. 2, pp. 10-12. Additionally, Mr. Cuthbertson explained that the CNG pilot program "allows the [C]ompany to gain market knowledge related to the quantification and certification of methane reductions associated with procuring CNG that has lower methane intensity compared to national and regional methane emission averages of conventional natural gas" and that the CNG pilot program will allow the Company "a cost-effective opportunity to test CNG as a new reliable, low cost and low carbon energy source for its customers." Distribution PGC St. No. 2, pp. 12-13.

In response to the Company's CNG proposal, OCA, I&E, and OSBA all addressed it in Direct Testimony. The OCA recommended that the pilot program be approved, but the Company should: (1) report the daily quantities of CNG purchased; (2) identify the PGC rate impact of its CNG purchases; and (3) identify the BTU Content of its CNG purchases and any impact of a change in BTU contend from that of other purchases on usage. OCA St. No. 1, p. 15. Mr. Mierzwa also noted the concerns surrounding global warming, largely caused by GHG, and explained that the proposal may provide the Company and other Pennsylvania natural gas distribution companies ("NGDC") with experience and knowledge to minimize the costs associated with implementing GHG reduction strategies. OCA St. No. 1, pp. 14-15.

In direct testimony, I&E opposed the approval of the CNG program, with I&E witness Sakaya noting three concerns. According to Mr. Sakaya: (1) there are too many certifications standards for CNG; (2) Mr. Sakaya did not know the names of the independent third-party certifiers and if there are any potential conflicts of interest with the Company; and (3) Mr. Sakaya argued that the Company did not detail how the proposal would be subject to reporting requirements during the pilot run to gauge its progress. I&E St. No. 1, p. 6.

Similarly, the OSBA opposed the approval of the CNG pilot program. OSBA witness Ewen noted several concerns, namely: (1) he was unaware of any State or Federal requirement to procure CNG; (2) according to Mr. Ewen, it was unclear how the Company intends to offer this supply option to customers, including whether it contemplates voluntary participation; and (3) customers of Distribution can shop for gas suppliers already in Pennsylvania. OSBA St. No. 1, p. 1. If the pilot were to be approved by the Commission, Mr. Ewen recommended that the Company complete a more comprehensive review of the program structure and its implementation, including a review of the market availability of CNG supply, a specific plan for offering the CNG supply to customers, and a quantification of potential CO2e abatement impacts and other environmental benefits. OSBA St. No. 1, p. 3.

In rebuttal, Distribution witness Mr. Cuthbertson addressed the parties' concerns. In response to I&E witness Sakaya's concerns regarding the number of certification standards, Mr. Cuthbertson noted that the Company's pilot "is only pursuing certifications from two entities, MiQ and OGMP 2.0." PGC Distribution St. No. 2R, p. 3. Mr. Cuthbertson went on to describe these certifications, their design, and their associated benefits. Distribution PGC St. No. 2R, pp. 3-5. Mr. Cuthbertson also responded to Mr. Sakaya's concerns related to him not knowing the names of the third-party certifiers and whether there are conflicts of interest, explaining that "the Company is only pursuing certifications from MiQ and or OGMP 2.0" and that the Company is "not affiliated with these entities and does not have any conflicts of interest with these entities." Distribution PGC St. No. 2R, pp. 4-5. Mr. Cuthbertson also addressed Mr. Sakaya's cost concerns with the program, explaining that the program is "consistent with how the Company implements its obligation to pursue a least cost fuel procurement strategy" and noted that certain of the Company's traditional gas supplies incur incremental fees. Distribution PGC St. No. 2R, pp. 5-6. Moreover, Mr. Cuthbertson explained that the current CNG premium is approximately $0.03 to $0.07/Dth, which is consistent with the incremental costs that are typically paid for contracting for term gas. Distribution PGC St. No. 2R, p. 7. Similarly, Mr. Cuthbertson detailed the Request for Proposal ("RFP") process that the Company would use in procuring CNG and noted Distribution's agreeability to the reporting requirements recommended by Mr. Sakaya should the program be approved.

Similarly, Mr. Cuthbertson addressed OSBA witness Ewen's concerns – to the extent they differed from Mr. Sakaya's - noting that the anticipated CNG premium is in line with incremental costs associated for winter term gas supplies:

> Under its least cost purchasing strategy, the Company purchases gas with different terms and delivery options. For example, the Company incurs demand fees for winter take or release transactions, demand charges for winter peaking supplies, and additional incremental charges for fixed price transactions. For the winter of 2023-2024, the Company entered into take or release contracts with suppliers with demand charges ranging from $0.01 to $0.08. These demand charges are paid to suppliers to provide the Company with delivery flexibility of firm supplies during varying temperature conditions during the winter delivery period. The Company also incurs demand charges for peaking service, where the Company does not hold firm upstream capacity and relies on third parties to make deliveries directly to the Company's interconnects on National Fuel Gas Supply Corporation. During the winter of 2023-2024, the demand charges for this service ranged from $0.06 - $0.10 per dekatherm ("Dth").

Distribution PGC St. No. 2R, p. 6.

Mr. Cuthbertson also described where the Company intends to take receipt of CNG supplies, and the indices that will be considered by the Company under the pilot. Distribution PGC St. No. 2R, pp. 11-12. Additionally, Mr. Cuthbertson explained that:

> The daily quantity of CNG and the associated premium is dependent on the proposed cost cap. The Company has proposed an annual cap of $175,000 of funding for the CNG Pilot Program to cover the certification cost premium. The Company will also cap the CNG unit cost premium to $0.07 per Dth for the certification. The Company will limit the daily quantity of CNG to 7,500 Dth/day. The proposed CNG Pilot Program will have an upper limit on both the daily quantity of CNG, the incremental fee per Dth of the certification, and the annual CNG premium spent.

Distribution PGC St. No. 2R, p. 13.

OCA witness Mr. Mierzwa also submitted rebuttal testimony responsive to I&E and OSBA's concerns with respect to the CNG proposal. OCA St. No. 1R, pp. 2-4.

The Settlement reflects a thoughtful compromise of all parties' positions with respect to CNG. Under the Settlement, Distribution has re-affirmed commitments that it made in the filing and also agreed to certain reporting requirements. The CNG terms are set forth below:

a) Distribution will pursue the least cost CNG and will undertake commercially reasonable efforts to minimize the cost impact to its PGC customers from the costs associated with purchasing CNG, consistent with current practices for procuring firm supplies of non-certified gas.

b) In its 2025 PGC filing:

   i) Distribution will report the daily quantities of CNG purchased, the price paid including applicable demand charge, published index price and applicable index price adjustment for each transaction;
   ii) Distribution will identify the overall PGC rate impact of its CNG purchase(s);
   iii) Distribution will identify the BTU content of its CNG purchases and any impact of a change in BTU content from that of other purchases on usage;
   iv) Distribution will provide an estimate of the methane mitigation amounts resulting from purchases under the Pilot Program.

c) Distribution will limit its CNG transaction contract price, including possible demand charge, to not exceed $.07/Dth ("premium") over the published index price. The total annual CNG premium cost shall not exceed $175,000.

d) Distribution will not use or reference any crediting agency affiliated with the Company when evaluating potential CNG purchases.

e) The CNG Pilot Program will end on July 31, 2027, unless otherwise extended by the Commission.

Settlement ¶ 47.

Under the Settlement, Distribution has appropriately addressed the various parties' concerns regarding the pilot. Indeed, the Settlement memorializes the parties' reporting concerns under the program, and also makes commitments regarding price caps, the term of the pilot, affiliate purchases, and a commitment for Distribution to pursue least-cost CNG. As such, the Settlement reflects a compromise of all parties' positions on this issue, adequately protects

Distributions customers, and allows Distribution to begin procuring CNG supply into its system. For these reasons, the CNG Settlement provisions should be approved without modification.

C. DESIGN DAY REQUIREMENTS

Through Direct Testimony, Company witness Lisa A. Petko detailed Distribution's forecasted design day model, noting that "Distribution expects its design day capacity for the winter of 2024-2025 to be 350,876 Dth/day. Distribution St. No. 7, p. 14. Moreover, Ms. Petko confirmed that Distribution will "review its design day firm capacity requirements again after analyzing its system usage during this winter of 2023." Distribution St. No. 7, p. 11. Ms. Petko also outlined the Company's proposal to acquire an additional minimum intermediate supply of 5,000 Dth/day with Supply for the winter of 2024-2025 if needed. Distribution PGC St. No. 7, p. 12.

The OCA was the only party to express concerns with the Company's design day forecasting model in this proceeding. Specifically, OCA Witness Jerome D. Mierzwa argued that Distribution's design day forecasting model over-estimated expected customer requirements under design day conditions. OCA St. No. 1, p. 11. Mr. Mierzwa went on to explain that "[a]ccurate forecasting of customer design day requirements is essential to ensuring the provision of reliable service on a least-cost basis." OCA St. No. 1, p. 11. In turn, Mr. Mierzwa recommended that the Company evaluate its design day forecasting model to determine why the model "over forecasted demands" during the three most recent winter seasons and "modify the model to address the Company's findings." Moreover, Mr. Mierzwa recommended that the Company should evaluate its design day forecast using daily rather than monthly usage. OCA St. No. 1, p. 11. Lastly, Mr. Mierzwa recommended that the Company not be permitted to increase its capacity entitlements from Supply by an additional 5,000 Dth/day for the winter of 2024-2025. OCA St. No. 1, p. 12.

In Rebuttal Testimony, Company witness Ms. Petko addressed many of Mr. Mierzwa's concerns. Specifically, Ms. Petko noted that that the Company requires "contingency capacity to serve its sales and transportation customers should there be a capacity or supplier failure, or a force majeure event." Distribution PGC St. No. 7R, p. 2. Ms. Petko further explained that the "Company must be prepared with sufficient firm capacity to provide firm service to customers even during those rate and unusual circumstances rather than taking a wait and see approach." Distribution PGC St. No. 7R, p. 2. Ms. Petko also explained that "it is appropriate for the Company to seek additional [Supply] capacity. To maintain contract flexibility, the Company proposes to limit the contract term for this incremental capacity to no more than two years rather than a long term commitment." Distribution PGC St. No. 7R, p. 3.

Company witness Gregory D. Harts also addressed a number of Mr. Mierzwa's concerns on this point in his Rebuttal Testimony. Namely, Mr. Harts argued that the Company's design day forecasting model does not overestimate the Company's design day requirements, explaining that:

> A review of actual design day estimates from the prior ten winters demonstrates that the Company's design day forecast is reasonably in-line with historical actuals. In fact, the design day estimate from the winter of 2013-2014, which experienced peak day usage at 68 HDDs on January 7, 2014, resulted in a peak day requirement that exceeded the Company's forecast and contracted pipeline capacity at the time, as noted in Exhibit LAP-2.
>
> This demonstrates the reasonableness of the Company's model. The model is not intended to forecast usage for days that are significantly lower than 74 HDD. It is intended to forecast usage when temperatures are extremely cold, so that the Company can ensure that it has sufficient supply to provide reliable service to customers. Based upon the 2014 winter, the Company's model is not overstating capacity when the HDD are close to 74.

Distribution PGC St. No. 4R, pp. 4-5.

Further, Mr. Harts explained that the Company does not obtain daily meter reading data for the vast majority of its customers and, therefore, Distribution cannot reasonably utilize daily metered usage data to develop its design day forecast. Distribution PGC St. No. 4R, p. 6.

In Surrebuttal, Mr. Mierzwa continued to argue that the Company's design day model "significantly overstated demands" during the three-day peak period experienced during the winter of 2104-2015. OCA St. No. 1SR, p. 2. Additionally, Mr. Mierzwa argued that "daily meter reading data for all customers is not necessary to develop a design day forecasting model based on daily usage." OCA St. No. 1SR, p. 4. Further, in response to Ms. Petko's rebuttal testimony, Mr. Mierzwa continued to recommend that Distribution not be permitted to obtain the additional Supply capacity or, if the Commission approves Distribution's acquisition of the same, the term of the contract be limited to one-year. OCA St. No. 1SR, p. 5.

The Settlement is the product of significant compromise between both the Company and the OCA. Under the Settlement, the Parties agreed that:

1. Distribution will be permitted to acquire the additional National Fuel Gas Supply Corporation capacity for the winter of 2024-2025 as proposed in this proceeding. The additional National Fuel Gas Supply capacity will be limited to one year.

2. Distribution will analyze its design day forecasting model with the goal of focusing on forecasting requirements for days with 50 Heating Degree Days ("HDD") or greater. This analysis will include evaluation of the use of daily sendout data, as available. Distribution will provide the results of its analysis as part of its 2025 PGC prefiling, including the workpapers and Excel files regarding the analysis. The Company will not be required to propose any changes to its design day forecasting model as a result of this review.

Settlement ¶¶ 49-51.

The Settlement on the issues related to the acquisition of additional Supply capacity, as well as the Company's design day forecasting model, reflects a carefully crafted compromise between both the OCA and Distribution's positions on the same. Under the Settlement, Distribution and the OCA agreed that the additional Supply capacity should be approved but limited the contract term to one year. Similarly, under the Settlement, Distribution has agreed to analyze its design day forecasting model in the area(s) emphasized by Mr. Mierzwa throughout this proceeding. As such, these settlement provisions are in the public interest and should be approved.

D. AUDIT ORDERED REFUND

The OCA was the only party to this proceeding to offer direct testimony on this issue. Specifically, OCA witness Mierzwa explained that the gas cost audit conducted by the Commission's Bureau of Audits at Docket No. D-2022-3031419 for the period of December 2017 – November 2020 found that the Company should refund $111,398 to its PGC customers. OCA St. No. 1, pp. 12-13. In turn, Mr. Mierzwa recommended that Distribution return the aforementioned refund to its customers in its May 2024 PGC filing. OCA St. No. 1, p. 13.

In rebuttal, Distribution witness Nicholas J. Hewa explained that Distribution will refund the $111,398 to its PGC customers in the Company's annual August 1, 2024, compliance filing. Mr. Hewa noted that the Company's interpretation required the audit report to mean that Distribution refund the aforementioned figure as part of its August annual PGC filing, rather than the May quarterly PGC filing. Distribution St. No. 5R, p. 2. Furthermore, Mr. Hewa noted that reflecting the refund in the May 2024 quarterly PGC filing would be administratively burdensome and complicate the reconciliation of E-Factor amounts that were established in the Company's 2023 annual PGC filing. Distribution PGC St. No. 5R, p. 2.

In surrebuttal, OCA witness Mierzwa continued to argue that the refund amount be parceled with the Company's May 2024 quarterly filing, with "appropriate" interest charges. OCA St. No. 1SR, p. 6.

In Settlement, all parties agreed that Distribution will refund the $111,398, including interest as calculated in the over/under cycle of August 2023 through July 2024, to its PGC customers as part of the E-Factor in its annual PGC filing on August 1, 2024. This settlement provision largely reflects the Company's position on this issue but acknowledges the concerns Mr. Mierzwa voiced on behalf of the OCA regarding interest. As such, Distribution submits that this settlement provision is in the public interest and should be approved without modification.

E. REPORTING OF PRIOR PERIOD ADJUSTMENTS

Related to Section III(D), *supra*, the OCA recommended that the Company "immediately begin evaluating and implementing controls to prevent errors such as those found in the audit report and identify and report the controls it has implemented in next year's annual PGC filing." OCA St. No. 1, p. 13. In rebuttal, Distribution witness Mr. Hewa agreed with this recommendation, and explained that "Distribution is currently in the process of evaluating and implementing such controls. Distribution will identify and report these controls in its annual PGC filing next year." Distribution PGC St. No. 3R, p. 3.

In Settlement, these controls were memorialized, with Distribution committing to:

> Implement controls to prevent, detect and correct errors in reporting of prior period adjustments and within the spreadsheet used for amortizing over/under collection balances. Distribution will report the controls that it has implemented in its next annual PGC filing.

Settlement ¶ 51.

As such, Distribution submits that this settlement position is in the public interest, reflects the OCA's position on this issue, and should be approved without modification.

F. CONTRACT RENEWALS AND CHANGES

The Settlement requests that the Commission approve the renewals, extensions and changes in pipeline and storage capacity contracts that are explained in Distribution's PGC

Statement No. 7 and in Distribution's PGC Exhibits 4 and 8. Settlement ¶ 52. These contracts are in the public interest for the reasons explained in the Company's testimony and exhibits, and these contracts should be approved.

G. TARIFF CHANGES

In its main filing made on January 31, 2024, Distribution identified the tariff changes that it was proposing to make in this proceeding. The majority of the proposed tariff changes related to changes in rates associated with changes in purchased gas costs. No party in this proceeding objected to the changes.

As such, the Settlement approves Distribution's Tariff, as filed. *See* Settlement ¶ 53.

H. APPROVAL OF FILING

Under the Settlement, the Parties have agreed that Distribution's 2024 Section 1307(f) filing is approved except as modified by the Settlement. Settlement ¶ 45. The Parties have thoroughly investigated Distribution's PGC filing through discovery and submission of testimony. Distribution has addressed the contested issues through the specific provisions of the Settlement and requests that the ALJs and the Commission approve the Company's 2024 PGC filing.

I. FINDINGS THAT DISTRIBUTION HAS FOLLOWED A LEAST COST GAS PROCUREMENT POLICY

Under the Settlement, the Parties recommend that the ALJ and the Commission make specific findings on certain matters which the Commission is required to address in order to determine whether Distribution is following a "least cost" gas procurement program, consistent with its obligation to provide safe, adequate and reliable service, as required under Section 1318(a) of the Public Utility Code, 66 Pa.C.S. § 1318(a). After investigation of Distribution's filing including substantial discovery, all Parties agree that Distribution is meeting its statutory obligations.

IV. CONCLUSION

Through cooperative efforts and the open exchange of information, the Parties have arrived at a Settlement that resolves all issues in the proceeding in a fair and equitable manner. The Settlement is the result of detailed examination of Distribution's natural gas procurement policies through numerous discovery responses, testimony and accompanying exhibits. A fair and reasonable compromise has been achieved in this case, as is evident by the fact that all Parties, including Distribution, I&E, OCA, and OSBA, have agreed to resolution of all of the issues.

WHEREFORE, National Fuel Gas Distribution Corporation respectfully requests that the Honorable Administrative Law Judge Charece Z. Collins recommend approval of, and the Pennsylvania Public Utility Commission approve by final order, the Settlement, including all terms, conditions and findings set forth therein without modification, and that the Pennsylvania Public Utility Commission's final order also terminate the proceeding and close the above-captioned docket.

Respectfully submitted,

Anthony D. Kanagy, Esquire
Nicholas A. Stobbe, Esquire
Post & Schell, P.C.
17 North Second Street
12th Floor
Harrisburg, PA 17101-1601
Phone: 717-731-1970
Fax: 717-731-1985
E-mail: akanagy@postschell.com
nstobbe@postschell.com

Of Counsel:
Post & Schell, P.C.

Date: April 17, 2024

Counsel for National Fuel Gas Distribution Corporation

APPENDIX C

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3045177
	:	
National Fuel Gas Distribution Corporation	:	
	:	

BUREAU OF INVESTIGATION AND ENFORCEMENT
STATEMENT IN SUPPORT OF
JOINT PETITION FOR SETTLEMENT OF
1307(f) RATES INVESTIGATION

TO: ADMINISTRATIVE LAW JUDGE CHARECE Z. COLLINS:

The Bureau of Investigation and Enforcement (I&E) of the Pennsylvania Public Utility Commission (PUC or Commission), by and through Prosecutor Carrie B. Wright, hereby respectfully submits that the terms and conditions of the foregoing Joint Petition for Settlement of Section 1307(f) Rate Investigation (Joint Petition or Settlement) are in the public interest and represent a fair, just, and reasonable balance of the interests of National Fuel Gas Distribution Corporation (NFG or Company), I&E, the Office of Consumer Advocate (OCA), the Office of Small Business Advocate (OSBA) and the NFG ratepayers.

I. BACKGROUND

I&E is charged with representing the public interest in Commission proceedings related to rates, rate-related services, and applications affecting the public interest. In negotiated settlements, it is incumbent upon I&E to identify how amicable resolution of any such proceeding benefits the public interest and to ensure that the public interest is served. Based upon I&E's analysis of NFG's Section 1307(f) purchased gas costs (PGC) filing, acceptance of this proposed Settlement is in the public interest and I&E recommends that Administrative Law Judge Charece Z. Collin (the ALJ) and the Commission approve the Settlement in its entirety.

1. On December 29, 2023, pursuant to 52 Pa. Code Sections 53.64 and 53.65 of the Commission's Rules and Regulations, NFG submitted its pre-filing information in support of its annual reconciliation of its purchased gas cost ("PGC") tariffs.

2. On January 16, 2024, the OSBA filed its Notice of Appearance, Formal Complaint and Public Statement.

3. On January 18, 2024, I&E filed its Notice of Appearance.

4. On February 1, 2024, the OCA filed a Notice of Appearance, a Formal Complaint, and a Public Statements.

5. On January 31, 2024, pursuant to 66 Pa. C.S. Section 1307(f) and 52 Pa. Code Section 53.64(a), NFG submitted its definitive PGC filing to the Commission, which included NFG's proposed *Pro Forma* Tariff Addendums and its supporting written direct testimony and supporting exhibits.

6. On February 16, 2024, ALJ Collins presided over a telephonic prehearing conference, during which the Parties agreed to a schedule for the conduct of the case including the service of testimony among the parties and the dates for evidentiary hearings. As no evidence of the need for public input hearings was presented nor a request for one made, none was scheduled or held.

7. In accordance with the procedural schedule established at the prehearing conference, I&E served to all active parties the following testimony:

- I&E Statement No. 1, the Direct Testimony of Esyan Sakaya

8. In accordance with Commission policy favoring settlements at 52 Pa. Code § 5.231, I&E participated in multiple telephonic settlement discussions with the Company and the other Parties to the proceeding. Following extensive settlement negotiations and recognizing that a settlement is the result of compromises made by all Parties, the Parties in this proceeding reached a full and complete Settlement of all issues.

9. The hearing which was scheduled for April 3, 2024, was held for the purposes of moving testimony and exhibits into the records, but no cross-examination of any witness was conducted.

II. TERMS AND CONDITIONS OF SETTLEMENT

10. "The prime determinant in the consideration of a proposed Settlement is whether the settlement is in the public interest."[1] The Commission has recognized that a settlement "reflects a compromise of the positions held by the parties of interest, which, arguably fosters and promotes the public interest."[2]

11. I&E submits that the Settlement in the instant proceeding balances the interests of the Company, its customers, and the Parties in a fair and equitable manner and presents a resolution for the Commission's adoption that best serves the public interest. Furthermore, the negotiated Settlement demonstrates that compromises are evident throughout the Stipulation. Accordingly, for the specific reasons articulated

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1 *Pennsylvania Public Utility Commission v. Philadelphia Electric Company*, 60 PA PUC 1, 22 (1985).
2 *Pennsylvania Public Utility Commission v. C S Water and Sewer Associates*, 74 PA PUC 767, 771 (1991).

below to achieve the full scope of benefits addressed in the Settlement, I&E requests that the Settlement be recommended by ALJ Collins and approved by the Commission, without modification.

Certified Natural Gas ("CNG") Pilot Program (Joint Petition ¶¶ 47.a-47.e).

The only issue addressed by I&E in this proceeding was the Company's proposed CNG pilot. In the Settlement, the Parties agree that NFG can implement a pilot program for the purchase of CNG as described in NFG Statement No. 2 that will end July 31, 2027, unless extended by the Commission. NFG will limit its CNG transaction contract price, including possible demand charge, not to exceed $0.07/Dth over the publish index price. Additionally, the total premium cost will not exceed $175,000.

Regarding this pilot, in the 2025 PGC proceeding NFG will provide the following information:

1. Distribution will report the daily quantities of CNG purchased, the price paid including applicable demand charge, published index price and applicable index price adjustment for each transaction;
2. Distribution will identify the overall PGC rate impact of its CNG purchase(s);
3. Distribution will identify the BTU content of its CNG purchases and any impact of a change in BTU content from that of other purchases on usage;
4. Distribution will provide an estimate of the methane mitigation amounts resulting from purchases under the Pilot Program.

In response to the Company's CNG Pilot proposal, I&E expressed concerns.[3] First, I&E noted that the Company did not provide any evidence that purchasing the

[3] I&E St. No. 1, p. 6.

certified natural gas at a higher cost does not violate its least cost gas procurement requirements.[4] As a result, I&E reasoned, the addition of the certified natural gas at a higher cost may not produce just and reasonable rates.[5] Additionally, I&E expressed concerns about the use of third-party certifications since there is no single, industry wide standard and no state or federal regulatory body monitors the certification programs which prevents transparency.[6] As a result, I&E recommended that the CNG pilot be denied; however, if the Commission were to approve it, I&E recommended that the Company be required to show how the purchase of CNG complies with the least cost fuel procurement obligation, the CNG price must be comparable to the price of traditional gas, and in future 1307(f) filings the Company must provide a report describing the details of the pilot for its duration.

Ultimately, after a full and complete review of the testimony and supporting exhibits submitted by the Parties, I&E supports the settled upon term as a full and fair compromise that provides regulatory certainty and a resolution of this issue and generally satisfies the concerns raised by I&E. Further, the CNG Pilot settlement terms represent a compromise of competing concerns. I&E recognizes that these settlement terms do not necessarily represent the position(s) that would be advanced by I&E or the other Parties in the event this proceeding were to be fully litigated. The Parties reached this compromise after lengthy negotiations and I&E believes the agreed upon Settlement

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4 I&E St. No. 1, p. 7.
5 *Id.*, p.9
6 *Id.*, p. 4.

terms facilitate the Commission's stated preference favoring negotiated settlements as in the public interest.

12. Additionally, after review of the filing and discovery, I&E agrees that the information provided by the Company indicates that its gas purchasing practices have satisfied its least cost procurement obligation under the Public Utility Code. 66 Pa. C.S. § 1318. Adhering to a least cost procurement policy benefits ratepayers is in the public interest because least cost gas directly impacts customer gas bills, while still ensuring that customers receive safe, adequate and reliable service.

I&E analyzed the Company's E-factor which is the experienced over/under collections, it reconciles variations between the projected gas costs and actual gas costs as well as variances between projected and actual sales. The E-factor also serves as the vehicle to pass through miscellaneous revenues and to calculate interest. This review is critical because the proper calculation of the E-factor ensures that rates are adjusted appropriately. I&E is satisfied that the Company's E-factor calculation is appropriate and accurate. Additionally, I&E believes the Company's projected gas costs are consistent with a least cost fuel procurement policy. While those costs are subject to review in a future PGC proceeding, I&E maintains that ratepayers are protected in that NFG gains no unwarranted financial advantages through its projected gas purchases and projected gas purchasing policies. Accordingly, I&E represents that the Settlement maintains the proper balance of the interests of all parties.

13. Based upon I&E's analysis of the filing, acceptance of this proposed Settlement is in the public interest because it appropriately resolves the issue raised by

I&E in testimony in a way that is mutually agreeable to the Company and I&E. Further, resolution of this case by settlement rather than litigation will avoid the substantial time and effort involved in continuing to formally pursue all issues in this proceeding at the risk of accumulating excessive expense.

14. I&E further submits that the acceptance of this Settlement negates the need for evidentiary hearings, which would compel the extensive devotion of time and expense for the preparation, presentation, and cross-examination of multiple witnesses, the preparation of Main and Reply Briefs, the preparation of Exceptions and Replies, and the potential of filed appeals, all yielding substantial savings for all parties and ultimately all customers. Moreover, the Settlement provides regulatory certainty with respect to the disposition of issues and final resolution of this case which all the Parties agree benefits their discrete interests and is in the public interest.

15. The Settlement is conditioned upon the Commission's approval of all terms without modification. Should the Commission fail to grant such approval or otherwise modify the terms and conditions of the Settlement, it may be withdrawn by the Company, I&E, or any other Party.

16. This Settlement is being presented only in the context of this Section 1307(f) proceeding to resolve certain outstanding issues in a manner that is fair and reasonable. I&E's agreement to settle this case is made without any admission or prejudice to any position that I&E might adopt during subsequent litigation in the event the Settlement is rejected by the Commission or otherwise properly withdrawn by any other Parties to the Settlement. Furthermore, the Settlement reflects compromises on all

sides, and is presented without prejudice to the positions that any of the parties may advance in future NFG proceedings on the merits of the issues.

17. If ALJ Collins recommends that the Commission adopt the Settlement as proposed, I&E agrees to waive the filing of Exceptions. However, I&E does not waive its right to file Replies to Exceptions with respect to any modifications to the terms and conditions of the Settlement or any additional matters that may be proposed by ALJ Collins in her Recommended Decision. Further, I&E does not waive the right to file Replies in the event any party files Exceptions.

WHEREFORE, the Commission's Bureau of Investigation and Enforcement represents that it supports the Joint Petition for Settlement of Section 1307(f) Rate Investigation as being in the public interest and respectfully requests that Administrative Law Judge Charece Z. Collins recommends, and the Commission approve, the terms and conditions contained in the Settlement without modification.

Respectfully submitted,

Carrie B Wright

Carrie B Wright
Prosecutor
PA Attorney ID No. 208185

Bureau of Investigation and Enforcement
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, Pennsylvania 17120
(717) 783-6156

Dated: April 17, 2024

APPENDIX D

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2024-3045177
Office of Consumer Advocate	:		C-2024-3045964
Office of Small Business Advocate	:		C-2024-3045469
	:		
v.	:		
	:		
National Fuel Gas Distribution Corporation	:		
	:		

STATEMENT OF THE OFFICE OF CONSUMER ADVOCATE
IN SUPPORT OF SETTLEMENT

The Office of Consumer Advocate (OCA), one of the signatory parties to the Stipulation in Settlement of the Rate Investigation pursuant to 66 Pa. C.S. § 1307(f) (Settlement), finds the terms and conditions of the Settlement regarding the Company's compliance with the requirements of 66 Pa. C.S. §§ 1307(f) and 1318 to be in the public interest for the following reasons:

I. INTRODUCTION

On December 29, 2023, National Fuel Gas Distribution Corporation (NFGD or Company) submitted its purchased gas cost (PGC) pre-filing information in support of its annual reconciliation of PGC rates pursuant to Section 1307(f) of the Public Utility Code. *See* 52 Pa. Code §§ 53.64, 53.65; *see also* 66 Pa. C.S. § 1307(f). On January 31, 2024, NFGD submitted its definitive filing providing additional supporting data and exhibits as well as the written testimony of witnesses in support of Supplement No. 269 to Tariff Gas — Pa. P.U.C. No. 9 (Supplement No. 236), to be effective for service rendered on and after August 1, 2024. NFGD also submitted a Tariff Addendum. Together Supplement No. 269 and the Addendum set forth the specific rates proposed by the Company for recovery of purchased gas costs effective on August 1, 2024.

The Company's filing proposed an increase of $2.0524 per Mcf in its rate for recovery of purchased gas costs for sales service, as compared to rates in effect as of November 1, 2023. NFGD St. 5 at 7. The Company also evaluated whether its current 12% fixed price purchasing target for winter supplies remains appropriate and reviewed whether distributing cost changes over multiple quarters may benefit customers. NFGD Exh. 8 at 14-20.

The Company's 1307(f) filing was assigned to the Office of Administrative Law Judge and was further assigned to the Honorable Administrative Law Judge (ALJ) Charece Z. Collins for investigation and scheduling of hearings to determine whether NFGD's gas costs comply with the standards set forth in the Public Utility Code. The OCA filed a Formal Complaint in this proceeding on February 1, 2024, to evaluate the reasonableness of the Company's proposed PGC rates. The OCA submitted the written Direct, Rebuttal, and Surrebuttal Testimonies of Jerome D. Mierzwa in this proceeding recommending that (1) NFGD re-evaluate its design day forecast, (2) NFGD issue a refund as determined by the Bureau of Audits and implement controls to prevent future similar errors, and (3) that the Certified Natural Gas (CNG) pilot program be approved.[1] A complete procedural history of this proceeding can be found in the Joint Petition for Settlement at Section III.

The OCA submits that the Company has met the requirements of 66 Pa. C.S. §§ 1307(f) and 1318, and the Settlement is in the public interest for the reasons set forth below.

II. SETTLEMENT

The Commission encourages parties in contested, on-the-record proceedings to settle cases. *See* 52 Pa. Code § 5.231. A settlement, by definition, reflects a compromise of the parties' positions. When active parties in a proceeding reach a settlement, the principal issue for

[1] *See* OCA Statements 1, 1R, 1SR of Jerome D. Mierzwa.

Commission consideration is whether the settlement suits the public interest. *Pa. PUC v. CS Water and Sewer Associates*, 74 Pa. PUC 767, 711 (1991); *see also Pa. PUC v. Phila. Electric Co.*, 60 Pa. PUC 1, 21 (1985).

The OCA submits that this proposed Settlement is in the public interest and should be approved. The OCA, with the assistance of its expert witness, Mr. Mierzwa, conducted discovery in this proceeding through three sets of interrogatories. As part of his review, Mr. Mierzwa reviewed the timing of the Company's purchasing in order to determine if the Company could reduce price volatility.

In his Direct Testimony, Mr. Mierzwa recommended that NFGD evaluate its design date forecasting model to determine why the model over-forecasted demands during the three most recent winter seasons and modify the model to address the Company's findings. OCA St. 1 at 12. This would include evaluating whether daily rather than monthly usage should be used to forecast design day demands. *Id*. Additionally, Mr. Mierzwa recommended that the Company be required to report its findings in next year's PGC proceeding and adjust its design day projections to reflect its findings. *Id*. Until this concern is resolved, Mr. Mierzwa further recommended that the Company not increase its interstate pipeline capacity entitlements. *Id*. In connection therewith, the Company proposed to acquire an additional 5,000 Dth of NFG Supply capacity for the winter of 2024-2025. NFGD St. 7 at 12. Mr. Mierzwa recommended that NFGD not be permitted to increase its capacity entitlements by this amount this year. OCA St. 1 at 12.

The Settlement provides that NFGD will analyze its design day forecasting model with the goal of focusing on forecasting requirements for days with 50 Heating Degree Days ("HDD") or greater. This analysis will include evaluation of the use of daily send-out data, as available. Distribution will provide the results of its analysis as part of its 2025 PGC prefiling, including the workpapers and Excel files regarding the analysis. The Company will not be required to propose any changes to its design day forecasting model as a result of this review. Settlement, ¶ 49. Additionally, while the Settlement provides that NFGD will be permitted to acquire the additional NFG Supply additional capacity for the winter of 2024-2025, the capacity will be limited to one year only. Settlement, ¶ 48. The Settlement provisions, taken together, address the OCA's concerns and recommendations on these issues and represent a reasonable compromise of the parties' positions in this proceeding and is in the public interest, thus, it should be approved.

Additionally, Mr. Mierzwa recognized that the Commission's Bureau of Audits recommended a refund of $111,398 attributable to errors in the reporting of prior period adjustments and the amortization of over/under collection balances during the audit period. OCA St. at 1-13. Mr. Mierzwa recommended that NFGD immediately begin evaluating and implementing controls to precent errors as those found in the PUC's Bureau of Audit's report and identify and report the controls it has implemented in the next year's annual PGC filing. *Id*. at 13.

The Settlement provides that NFGD will refund the $111,398, including interest to its PGC customers as part of the E-Factor in its annual PGC filing on August 1, 2024. Settlement ¶ 50. The Settlement also provides that NFGD will begin to implement controls to prevent, detect and correct errors in reporting of prior period adjustments and within the spreadsheet used for amortizing over/under collection balances, and that NFGD will report the controls that it has implemented in its next annual PGC filing. Settlement, ¶ 51. These Settlement provisions address the OCA's concerns and recommendations on this issue, and therefore serves the public interest.

Mr. Mierzwa reviewed the Company's Certified Natural Gas (CNG) pilot. CNG is natural gas that has been evaluated and verified by an independent third-party to have been produced with reduced greenhouse gas (GHG) emissions and environmental impacts, beyond current environmental regulations. OCA St. 1 at 13. CNG is a low carbon gas produced from certified wells. There are a number of ways to reduce methane emissions, including reducing leaks from the production, storage, and the transportation of natural gas. Certified wells can reduce methane emissions by up to 80% from traditional wells. CNG provides the same reliability as conventional natural gas and is compatible with all existing natural gas infrastructure. *Id*. at 13-14. The Company is proposing to implement a three-year pilot program designed to purchase CNG. The pilot program will limit the incremental costs associated with CNG premiums to $175,000 per year. *Id*. at 14. The $175,000 of annual funding will cover the premium associated with procuring certified natural gas. The Company believes that this premium is approximately $0.03-$0.07 Dth. This level of funding will allow the Company to purchase approximately 2.5 to 6.0 Bcf of CNG per year. *Id*. at 14. Mr. Mierzwa recommended that NFGD's proposed CNG pilot program be approved, and in next year's proceeding, NFGD should: (1) report the daily quantities of CNG purchased; (2) identify the PGC rate impact of its CNG purchases; and (3) identify the BTU content of its CNG purchases and any impact of a change in BTU content from that of other purchases on usage. *Id*. at 15.

In this proceeding, I&E Witness Sakaya and OSBA Witness Ewen expressed a concern that the potential purchase of higher cost CNG may be inconsistent with NFGD's obligation to pursue a least cost procurement strategy. I&E St. 1 at 10; OSBA St. 1 at 3. In Rebuttal testimony Mr. Mierzwa testified that the damage that may be caused by global warming largely caused by GHG is a significant world-wide concern. OCA St. 1R at 3. To begin to address this concern, states have begun adopting laws and policies that address carbon emissions associated with the energy delivered to customers. Should federal, state, or local legislation be adopted affecting NFGD, the CNG Pilot Program may provide the Company and other Pennsylvania natural gas distribution companies (NGDCs) with the experience and knowledge to minimize the costs associated with implementing GHG reduction strategies. While CNG may be slightly more expensive than gas from traditional supply sources, Mr. Mierzwa and the OCA submit that it is important that utilities such as NFGD be prepared to address changes in operations due to a growing body of law and policies designed to reduce GHG emissions. He testified that the incremental costs associated with the CNG pilot program are reasonable and prudent given the anticipated charges and may well save ratepayers costs in the long run. OCA St. 1R at 3.

In the Settlement, NFGD's CNG Pilot Program is approved with the following modifications:

a) Distribution will pursue the least cost CNG, and will undertake commercially reasonable efforts to minimize the cost impact to its PGC customers from the costs associated with purchasing CNG, consistent with current practices for procuring firm supplies of non-certified gas.

b) In its 2025 PGC filing:

   i) Distribution will report the daily quantities of CNG purchased, the price paid including applicable demand charge, published index price and applicable index price adjustment for each transaction;
   ii) Distribution will identify the overall PGC rate impact of its CNG purchase(s);
   iii) Distribution will identify the BTU content of its CNG purchases and any impact of a change in BTU content from that of other purchases on usage;
   iv) Distribution will provide an estimate of the methane mitigation amounts resulting from purchases under the Pilot Program.

c) Distribution will limit its CNG transaction contract price, including possible demand charge, to not exceed $.07/Dth ("premium") over the published index price. The total annual CNG premium cost shall not exceed $175,000.

d) Distribution will not use or reference any crediting agency affiliated with the Company when evaluating potential CNG purchases.

e) The CNG Pilot Program will end on July 31, 2027, unless otherwise extended by the Commission.

Settlement, ¶ 47. The compromises in the Settlement address the concerns of the parties in this proceeding while still permitting the CNG Pilot to go forward. This settlement term represents a reasonable compromise of the parties' positions in this proceeding and is in the public interest, thus, it should be approved.

As a result of its review of the filing and testimony in this proceeding, the OCA submits that NFGD's PGC filing meets the requirements of 66 Pa. C.S. § 1307(f) generally and specifically with regard to showing that the Company's natural gas costs are consistent with a least cost fuel procurement policy required by 66 Pa. C.S. § 1318. As such, the OCA submits that the Commission should approve NFGD's proposed PGC rate and tariff changes in accordance with the Settlement.

III. CONCLUSION

The Office of Consumer Advocate submits that the terms of the Settlement are in the public interest and in the interest of NFGD's ratepayers. Based on the above reasons, the Office of Consumer Advocate submits that the Commission should approve the proposed Settlement.

Respectfully submitted,

/s/ *Melanie Joy El Atieh*
Melanie Joy El Atieh
Deputy Consumer Advocate
PA Attorney ID # 209323
melatieh@paoca.org

Counsel for:
Patrick M. Cicero
Consumer Advocate

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
(717) 783-5048

DATED: April 17, 2024

APPENDIX E

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	**Docket No. R-2024-3045177**
	:	
v.	**:**	
	:	
National Fuel Gas Distribution Corporation 1307(f)	**:**	

STATEMENT OF
THE OFFICE OF SMALL BUSINESS ADVOCATE
IN SUPPORT OF THE
JOINT PETITION FOR SETTLEMENT OF
THE SECTION 1307(f) RATE INVESTIGATION

Introduction

The Small Business Advocate is authorized and directed to represent the interests of the small business consumers of utility services in the Commonwealth of Pennsylvania under the provisions of the Small Business Advocate Act, Act 181 of 1988, 73 P.S. §§ 399.41 – 399.50. Pursuant to that statutory authority, the Office of Small Business Advocate ("OSBA") filed a complaint in the above-captioned proceeding, which was initiated by National Fuel Gas Distribution Corporation ("NFG" or the "Company") on January 31, 2024.

The OSBA participated in the negotiations that led to the proposed settlement and is a signatory to the Joint Petition for Settlement of the Section 1307(f) Rate Investigation ("*Joint Petition*"). The OSBA submits this statement in support of the *Joint Petition*.

The *Joint Petition*

The *Joint Petition* sets forth a comprehensive list of issues that were resolved through the negotiation process. The following issue was of particular significance to the OSBA when it concluded that the *Joint Petition* was in the best interests of the small business customers of NFG.

In his Direct Testimony, OSBA witness Mark D. Ewen summarized NFG's proposed Pilot Program to procure Certified Natural Gas ("CNG"), as follows:

> CNG, or Independently Certified Gas as it is sometimes called, is natural gas primarily produced in a way that reduces methane emissions relative to current regulatory requirements. The certification is awarded by a third party auditing entity, based upon that entity's own certification measures and standards.

OSBA Statement No. 1, at 1.

The *Joint Petition* proposes that NFG's CNG Pilot Program costs shall be limited to $175,000 annually, and that the premium for the CNG will not exceed 7 cents over the "published index price." *Joint Petition*, at Paragraph C.47.c.

In addition, the Joint Petition proposes to impose reporting requirements upon NFG, including daily quantities of CNG, indexed pricing, and premiums paid for the CNG. *Joint Petition*, at Paragraph C.47.b.i.

The testimony of Mr. Ewen, in this proceeding, did not support NFG's proposed CNG Pilot Program. Furthermore, the OSBA is aware of the Commission's decision in the *Columbia Green Path Rider* case, at Docket R-2022-3032167 (Order entered June 15, 2023).

Weighing these clear trade-offs, the OSBA agrees to support this tailored pilot and will closely monitor its implementation and any effects of small business customers. In addition, the settlement of this proceeding, involving the CNG Pilot Program, provides this Commission with the opportunity to reconsider green energy programs administered by a natural gas distribution company ("NGDC").

Conclusion

For the reasons set forth in the *Joint Petition*, as well as the additional factors sets forth in this statement, the OSBA joins the proposed *Joint Petition* and respectfully requests that the ALJ and the Commission approve the *Joint Petition* in its entirety.

Respectfully submitted,

/s/ Steven C. Gray

Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney ID No. 77538

Commonwealth of Pennsylvania
Office of Small Business Advocate
Forum Place
555 Walnut Street, 1st Floor
Harrisburg, Pennsylvania 17101

Dated: April 17, 2024