The Narragansett Electric Company

d/b/a National Grid

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES

Compliance Filing

Compliance Attachment 15 through Compliance Attachment 30

Book 7 of 7

August 16, 2018

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket Nos. 4770/4780

Submitted by:

nationalgrid

Compliance Attachment 15

Compliance Attachment 15

Narragansett Gas Allocator Study

COMPLIANCE ATTACHMENT 15

Tabulation of External and Internal Allocators

National Grid – Rhode Island
DESCRIPTION OF GAS ALLOCATION FACTORS

NOTE: ALL PAGE REFERENCES ARE TO THE COST OF SERVICE PROGRAM PAGE NUMBERING AT THE BOTTOM CENTER OF THE PAGE.

The listing of all allocation factors and ratio tables is in Pages 22 to 37 of Schedule PMN-3. Also see the Workpapers Supporting the Cost of Service Study for the detail supporting the external allocators.

External Allocators, Page 22

Production Allocators:

1. DSWNLNG – LNG Production Allocator
This allocator is based on the Remaining Design Winter Demands. (See Supporting Workpapers for detail.) Allocator Ratio is on Page 30, Line 10.

Distribution Allocators:

2. DISTR – Distribution Allocator – Distribution Function
This allocator is based on a 12-month RSUM allocation factor developed for each rate using total annual sales and transportation volumes. (See Supporting Workpapers for detail.) Allocator Ratio is on Page 30, Line 1, second section.

3. DISTRL4 – Distribution Allocator – Mains Less Than 4 Inches
This allocator is based on a 12-month RSUM allocation factor developed for each rate except for the C&I XLarge LLF and C&I XLarge HLF class using annual sales and transportation volumes. (See Supporting Workpapers for detail.) Allocator Ratio is on Page 30, Line 2, second section.

External Allocators, Page 23

1. EGAS – Commodity-Related Direct Gas Cost Allocator
This allocator is used to allocate Gas Costs related items to customer classes. Allocation is based on Gas Cost revenues for the test year. Allocator Ratio is on Page 31, Line 3.

National Grid – Rhode Island
DESCRIPTION OF GAS ALLOCATION FACTORS

External Allocators, Page 24

Note: The customer allocation factors described below in Items 1, 2, 5, 6, 7 and 8 were developed for the test year ending June 2017 and ratioed to the rate year using the change in the number of customers by class. The customer class ratios were developed by dividing the rate year number of customers on Page 24, line 20 by the test year number of customers on Page 24, line 26. The ratio was applied internally in the cost of service study.

Customer Function Allocators:

1. CUST380 – Acct 380 Gas Services – Customer Services Function
This allocator represents the direct assignment of Plant Acct 380 – Gas Services to the customer classes. Allocation factor ratioed internally in the cost of service study to the rate year based on the change in the number of customers from test year to rate year. (See Supporting Workpapers for detail.) Allocator Ratio is on Page 32, Line 1.

2. CUST381 – CUST382 CUST383 CUST384 – Acct 381 to Acct 384 Gas Meters – Customer Meters Function
These allocators represent the direct assignment of Plant Acct 381 to 384 – Gas Meters, Meter Installations, Regulators, and Regulator Installations to the customer classes. Allocation factor ratioed internally in the cost of service study to the rate year based on the change in the number of customers from test year to rate year. (See Supporting Workpapers for detail.) Allocator Ratio is on Page 32, Lines 2 to 5.

3. CUST385 – Other Measuring and Regulating Station Equipment
This allocator is used to allocate Other Measuring and Regulating Station Equipment to the customer classes. The allocator is based on the DISTR or RSUM allocator. Allocator Ratio is on Page 32, Line 6.

4. CUST386 – Acct 386 Other Property on Customer Premises
This allocator is used to allocate Acct 386 Other Property on Customer Premises. The allocator is based on the DISTR or RSUM allocator. Allocator Ratio is on Page 32, Line 7.

5. CUSTDEP – Customer Deposits – Customer Deposits Function
This allocator represents the assignment of customer deposits to customer classes. Allocation factor ratioed internally in the cost of service study to the rate year based on the change in the number of customers from test year to rate year. (See Supporting Workpapers for detail.) Allocator

National Grid – Rhode Island
DESCRIPTION OF GAS ALLOCATION FACTORS

Ratio is on Page 32, Line 8.

6. CUST902 – Acct 902 Meter Reading Expense – Customer Meter Reading Function
This allocator was developed based on an estimate of meter reading costs by customer classes. Allocation factor ratioed internally in the cost of service study to the rate year based on the change in the number of customers from test year to rate year. (See Supporting Workpapers for detail). Allocator Ratio is on Page 32, Line 9.

7. CUST903 – Acct 903 Customer Billing, Mailing and Customer Calls Expense – Customer Records and Collection Function
This allocator was developed based on an analysis and assignment of Credits and Collection, Customer Billing, Mailing and Customer Inquiries costs to customer classes. Allocation factor ratioed internally in the cost of service study to the rate year based on the change in the number of customers from test year to rate year. (See Supporting Workpapers for detail.) Allocator Ratio is on Page 32, Line 10.

8. CUST908 – Customer Assistance Expenses – Customer Information Function
This allocator was developed using the number of customers responsible for the different cost categories of Customer Assistance Expenses. (See Supporting Workpapers for detail.) Allocator Ratio is on Page 32, Line 12.

9. CUST912 – Demonstrating and Selling Expenses – Customer Information Function
This allocator was developed internally in the cost of service model. Since these costs are not totally related to the total number of customers or the amount of sales, a weighted allocation factor was developed. The allocator is based on a 50% weighting on the annual number of customers (Page 24, Lines 18 and 19) and a 50% weighting on the total sales and transportation volumes (Page 23, Line 2). Allocator Ratio is on Page 32, Line 13.

National Grid – Rhode Island
DESCRIPTION OF GAS ALLOCATION FACTORS

External Allocators, Page 25

1.	C904RNH – C904RH C904R21 C904R22 C904R33 C904R23 C904R34 C904R24	Uncollectible Base Accounts Allocator These allocators directly assign the base uncollectible amounts to rate classes based on the actual base rate write-offs for the test year and ratioed to the rate year based on the change in the number of customers. The costs were functionalized based on claimed revenues. (See Supporting Workpapers for detail.) The allocation to customer classes is on Page 12, Lines 4 to 11, Total Company column. Allocator Ratios are on Page 33, Lines 1 to 8. In order to be consistent with the last NG RI Electric rate case, claimed revenues (REVCLAIM) were used to allocate all Acct 904 expenses, and these allocators were not used.

National Grid – Rhode Island
DESCRIPTION OF GAS ALLOCATION FACTORS

(Noted – See Allocator Descriptions)

Internal Allocators, Page 25

1.	C488R21 – C488R22 C488R33 C488R23 C488R34 C488R24	Late Payment Charges The functionalization of each rate class assignment of Late Payment Charges is based on claimed revenues, Page 21, Line 10. The allocation to rate classes, Page 8, Lines 5 to 10, is based on Company records for the test year. The test year allocation percentages were ratioed to the rate year based on the change in the number of customers internally in the cost of service program. (See Supporting Workpapers for detail.) Allocator Ratios are on Page 33, Lines 9 to 14.

National Grid – Rhode Island
DESCRIPTION OF GAS ALLOCATION FACTORS

Reference for Internal Allocators Not Shown in Allocation Factor Table
(Noted – See Allocator Descriptions)

Internal Allocators, Page 26

1. REVCLAIM – Claimed Revenues Less Gas Costs (Page 26, Line 27)
This allocator is computed using the bottom up approach starting with rate of return times rate base plus expenses. Ratio is on Page 34, Line 27. The formula is as follows:

Plus (((1 * 2) – (3 * 2)) / 4) + (3 * 2)
Where 1 = Page 29, Line 1 (bottom) – Claimed Rate of Return
2 = Page 7, Line 6 – Rate Base
3 = Page 1, Line 27 – Actual Rate of Return
4 = 1 – Incremental Tax Rate Net of Uncollectibles = 0.6365 – Page 17

Plus Page 9, Line 6
Page 10, Line12
Page 11, Line 25
Page 12, Lines15, 20, and 25
Page 13, Lines 15, 16 and 17
Page 15, Line 28
Page 16, Lines 4, 5 and 6

Less Page 8, Lines 2, 3 and 17

2. CWCEXP – Total Working Cash Expense Allocator (Page 26, Line 29)
This allocator is used to allocate cash working capital. Ratio is on Page 34, Line 29. The formula is the total of the following line items in the cost of service study:

Page 9, Line 6
Page 10, Line 13
Page 11, Line 25
Page 12, Lines 1, 2, 3, 14, 20 and 25
Page 13, Lines 15, 16 and 17
Page 16, Lines 4 and 5

National Grid – Rhode Island
Description of Gas Allocation Factors
Page and Line Locations
Other Internal Allocators

<u>Pages 26, 27, and 28</u>

The source of data for all Other allocators developed internally in the cost of service study on Pages 26, 27, and 28 is noted in Sub-Page 3 in the following allocation factor pages from the cost of service study. These formulas are also the same for all functional cost of service schedules.

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NATIONAL GRID - RHODE ISLAND
GAS COST OF SERVICE STUDY
12 MONTHS ENDED AUGUST 31, 2019

	INTERNALLY DEVELOPED-26	ALLOC	TOTAL COMPANY	RESIDENTIAL NON-HEATING RATE 10, 11 & 80	RESIDENTIAL HEATING RATE 12 & 13
1	TOTAL GAS PLANT IN SERVICE	PLANT	1,310,853,604	37,879,547	859,511,377
2	SUM OF ALLOCATED LABOR EXP	LABOR	61,263,330	2,079,271	41,383,211
3	ACCT 305-STRUCTURES & IMPROVE	PLT305	1,799,946	14,955	1,355,111
4	ACCT 311-LP GAS EQUIP	PLT311	8,403,279	69,819	6,326,508
5	ACCT 320-OTHER EQUIPMENT	PLT320	489,062	4,063	368,196
6	ACCT 375-GAS DIST STATION STR	PLT375	10,212,827	92,073	5,204,659
7	ACCT 376-MAINS	PLT376	696,026,030	7,072,636	400,790,813
8	ACCT 378-GAS MEAS & REG STA EQ	PLT378	32,114,706	289,529	16,366,291
9	ACCT 380-SERVICES	PLT380	352,943,574	22,274,396	287,075,835
10	ACCT 381-METERS	PLT381	63,693,810	3,230,792	44,010,127
11	ACCT 382-METER INSTALLATION	PLT382	49,868,002	2,529,494	34,456,992
12	ACCT 386-OTHER PROP CUST PREM	PLT386	381,896	3,443	194,622
13	ACCT 383-HOUSE REGULATORS	PLT383	937,222	47,539	647,587
14	ACCT 396-POWER OPERATED EQUIP	PLT396	0	0	0
15	ACCT 390-STRUCTURES & IMPROV	PLT390	9,155,973	310,753	6,184,834
16	ACCT 391-OFFICE FURN & EQUIP	PLT391	2,384,968	80,946	1,611,039
17	ACCT 392-TRANSPORTATION EQUIP	PLT392	625,738	21,237	422,684
18	ACCT 393-STORES EQUIPMENT	PLT393	16,876	494	11,008
19	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	5,315,407	155,569	3,467,022
20	ACCT 395-LABORATORY EQUIPMENT	PLT395	237,430	6,949	154,866
21	ACCT 397-COMMUNICATION EQUIP	PLT397	975,600	33,112	659,015
22	ACCT 398-MISCELLANEOUS EQUIP	PLT398	3,867,999	131,279	2,612,823
23	ACCT 376 MAINS & 380 SERVICES	PLT37680	1,048,969,604	29,347,032	687,866,648
24	TOTAL DISTRIBUTION PLANT	DISTRPLT	1,223,974,353	35,822,729	798,348,379
25	ACCT 381 - 384 METER & HSE REGUL	PLT3814	117,433,311	5,956,663	81,142,186
26	ACCT 871-879 DIST OPER EXP	EXP8719	15,987,219	648,427	10,588,629
27	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	215,109,660	6,821,954	142,747,394
28	TOTAL GENERAL PLANT	GENPLT	23,035,102	755,785	15,430,718
29	TOTAL WORKING CASH EXPENSE	CWCEXP	118,371,617	3,736,095	79,509,702
30	ACCT 304-LAND & LAND RIGHTS	PLT304	853,973	7,095	642,924
31	ACCT 360-LAND & LAND RIGHTS	PLT360	261,152	2,170	196,611
32	ACCT 374-LAND & LAND RIGHTS	PLT374	925,104	8,340	471,451
33	ACCT 871-880 DIST OPER EXP	EXP8710	22,875,542	927,811	15,150,891
34	TOTAL LNG PLANT	LNGPLT	33,737,186	280,307	25,399,439
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	169,755	5,761	114,669
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NATIONAL GRID - RHODE ISLAND
GAS COST OF SERVICE STUDY
12 MONTHS ENDED AUGUST 31, 2019

	INTERNALLY DEVELOPED-26	ALLOC	COMM & IND SMALL RATE 21	COMM & IND MEDIUM RATE 22	C & I LARGE LOW LOAD FAC RATE 33	C & I LARGE HIGH LOAD FAC RATE 23	C & I X LARGE LOW LOAD FAC RATE 34	C & I X LARGE HIGH LOAD FAC RATE 24
1	TOTAL GAS PLANT IN SERVICE	PLANT	107,889,575	149,189,752	66,168,256	26,635,003	11,688,422	51,891,673
2	SUM OF ALLOCATED LABOR EXP	LABOR	5,498,249	6,563,634	2,400,620	938,846	460,983	1,938,516
3	ACCT 305-STRUCTURES & IMPROVE	PLT305	175,014	196,974	46,670	6,496	3,995	731
4	ACCT 311-LP GAS EQUIP	PLT311	817,077	919,598	217,885	30,328	18,653	3,411
5	ACCT 320-OTHER EQUIPMENT	PLT320	47,553	53,520	12,681	1,765	1,086	199
6	ACCT 375-GAS DIST STATION STR	PLT375	677,004	1,420,868	715,266	292,144	324,397	1,486,416
7	ACCT 376-MAINS	PLT376	52,142,854	109,235,213	55,058,215	22,362,004	8,843,328	40,520,965
8	ACCT 378-GAS MEAS & REG STA EQ	PLT378	2,128,870	4,467,986	2,249,187	918,660	1,020,080	4,674,103
9	ACCT 380-SERVICES	PLT380	31,624,077	8,947,370	1,764,014	789,020	126,969	341,893
10	ACCT 381-METERS	PLT381	6,673,187	7,360,817	1,239,493	471,021	219,832	488,540
11	ACCT 382-METER INSTALLATION	PLT382	5,224,660	5,763,028	970,440	368,778	172,113	382,494
12	ACCT 386-OTHER PROP CUST PREM	PLT386	25,316	53,132	26,746	10,924	12,130	55,583
13	ACCT 383-HOUSE REGULATORS	PLT383	98,193	108,311	18,239	6,931	3,235	7,189
14	ACCT 396-POWER OPERATED EQUIP	PLT396	0	0	0	0	0	0
15	ACCT 390-STRUCTURES & IMPROV	PLT390	821,728	980,953	358,779	140,313	68,895	289,717
16	ACCT 391-OFFICE FURN & EQUIP	PLT391	214,046	255,521	93,456	36,549	17,946	75,466
17	ACCT 392-TRANSPORTATION EQUIP	PLT392	56,159	67,040	24,520	9,589	4,708	19,800
18	ACCT 393-STORES EQUIPMENT	PLT393	1,377	1,927	871	354	154	691
19	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	433,783	606,957	274,199	111,462	48,657	217,757
20	ACCT 395-LABORATORY EQUIPMENT	PLT395	19,376	27,112	12,248	4,979	2,173	9,727
21	ACCT 397-COMMUNICATION EQUIP	PLT397	87,558	104,524	38,229	14,951	7,341	30,870
22	ACCT 398-MISCELLANEOUS EQUIP	PLT398	347,144	414,410	151,569	59,276	29,105	122,393
23	ACCT 376 MAINS & 380 SERVICES	PLT37680	83,766,931	118,182,583	56,822,230	23,151,025	8,970,297	40,862,859
24	TOTAL DISTRIBUTION PLANT	DISTRPLT	99,886,780	139,763,517	63,139,579	25,666,320	11,204,283	50,142,765
25	ACCT 381 - 384 METER & HSE REGUL	PLT3814	12,303,464	13,571,258	2,285,274	868,430	405,307	900,729
26	ACCT 871-879 DIST OPER EXP	EXP8719	1,503,075	1,858,207	533,871	212,341	130,015	512,654
27	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	18,938,473	23,783,684	9,610,395	3,852,153	1,741,924	7,613,683
28	TOTAL GENERAL PLANT	GENPLT	2,022,016	2,507,204	971,703	384,448	182,406	780,822
29	TOTAL WORKING CASH EXPENSE	CWCEXP	10,769,321	12,814,810	4,803,821	1,771,793	954,123	4,011,951
30	ACCT 304-LAND & LAND RIGHTS	PLT304	83,034	93,453	22,142	3,082	1,896	347
31	ACCT 360-LAND & LAND RIGHTS	PLT360	25,393	28,579	6,771	943	580	106
32	ACCT 374-LAND & LAND RIGHTS	PLT374	61,325	128,706	64,791	26,463	29,385	134,643
33	ACCT 871-880 DIST OPER EXP	EXP8710	2,150,696	2,658,842	763,897	303,832	186,034	733,538
34	TOTAL LNG PLANT	LNGPLT	3,280,372	3,691,970	874,755	121,762	74,886	13,694
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	15,235	18,187	6,652	2,601	1,277	5,371
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	INTERNALLY DEVELOPED-26	ALLOC	TOTAL COMPANY INPUT
1	TOTAL GAS PLANT IN SERVICE	PLANT	Page 3 Line 30
2	SUM OF ALLOCATED LABOR EXP	LABOR	Page 20 Line 27
3	ACCT 305-STRUCTURES & IMPROVE	PLT305	Page 2 Line 6
4	ACCT 311-LP GAS EQUIP	PLT311	Page 2 Line 8
5	ACCT 320-OTHER EQUIPMENT	PLT320	Page 2 Line 9
6	ACCT 375-GAS DIST STATION STR	PLT375	Page 3 Line 2
7	ACCT 376-MAINS	PLT376	Page 3 Lines 3 & 4
8	ACCT 378-GAS MEAS & REG STA EQ	PLT378	Page 3 Line 6
9	ACCT 380-SERVICES	PLT380	Page 3 Line 8
10	ACCT 381-METERS	PLT381	Page 3 Line 9
11	ACCT 382-METER INSTALLATION	PLT382	Page 3 Line 10
12	ACCT 386-OTHER PROP CUST PREM	PLT386	Page 3 Line 14
13	ACCT 383-HOUSE REGULATORS	PLT383	Page 3 Line 11
14	ACCT 396-POWER OPERATED EQUIP	PLT396	Page 3 Line 24
15	ACCT 390-STRUCTURES & IMPROV	PLT390	Page 3 Line 18
16	ACCT 391-OFFICE FURN & EQUIP	PLT391	Page 3 Line 19
17	ACCT 392-TRANSPORTATION EQUIP	PLT392	Page 3 Line 20
18	ACCT 393-STORES EQUIPMENT	PLT393	Page 3 Line 21
19	ACCT 394-TOOLS, SHOP & GAR EQ	PLT394	Page 3 Line 22
20	ACCT 395-LABORATORY EQUIPMENT	PLT395	Page 3 Line 23
21	ACCT 397-COMMUNICATION EQUIP	PLT397	Page 3 Line 25
22	ACCT 398-MISCELLANEOUS EQUIP	PLT398	Page 3 Line 26
23	ACCT 376 MAINS & 380 SERVICES	PLT37680	Page 3 Lines 3, 4 & 8
24	TOTAL DISTRIBUTION PLANT	DISTRPLT	Page 3 Line 16
25	ACCT 381 - 384 METER & HSE REGUL	PLT3814	Page 3 Lines 9 to 12
26	ACCT 871-879 DIST OPER EXP	EXP8719	Page 11 Lines 5 to 11
27	REV CLAIMED ROR LESS GAS COSTS	REVCLAIM	See allocator descriptions
28	TOTAL GENERAL PLANT	GENPLT	Page 3 Line 28
29	TOTAL WORKING CASH EXPENSE	CWCEXP	See allocator descriptions
30	ACCT 304-LAND & LAND RIGHTS	PLT304	Page 2 Line 5
31	ACCT 360-LAND & LAND RIGHTS	PLT360	Page 2 Line 11
32	ACCT 374-LAND & LAND RIGHTS	PLT374	Page 3 Line 1
33	ACCT 871-880 DIST OPER EXP	EXP8710	Page 11 Lines 5 to 12
34	TOTAL LNG PLANT	LNGPLT	Page 2 Line 10 & 15
35	ACCT 399-OTHER TANGIBLE PROP	PLT399	Page 3 Line 27
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NATIONAL GRID - RHODE ISLAND
GAS COST OF SERVICE STUDY
12 MONTHS ENDED AUGUST 31, 2019

	INTERNALLY DEVELOPED CONT-27	ALLOC	TOTAL COMPANY	RESIDENTIAL NON-HEATING RATE 10, 11 & 80	RESIDENTIAL HEATING RATE 12 & 13
1	ACCT 813-OTH GAS SUPPLY EXP	EXP813	3,156	47	2,318
2	ACCT 846-OTHER EXPENSES	EXP846	0	0	0
3	ACCT 847.2-MAINT STRUCT & INMPROV	EXP8472	0	0	0
4	ACCT 847.3-MAINT LNG PROCESS TERM I	EXP8473	0	0	0
5	ACCT 847.5-MAINT MEAS/REG EQUIP	EXP8475	0	0	0
6	ACCT 847.8-MAINT OF VAPORIZING EQ	EXP8478	0	0	0
7	ACCT 871-SYSTEM CONTROL & DISP	EXP871	1,129,133	10,180	575,428
8	ACCT 873-COMP STA FUEL & POW	EXP873	17,727	160	9,034
9	ACCT 874-MAINS & SERVICE EXP	EXP874	3,583,261	100,249	2,349,740
10	ACCT 875-OPER STATION EXP - GEN	EXP875	851,170	7,674	433,773
11	ACCT 878-METER & HOUSE REG EXP	EXP878	9,977,694	506,107	6,894,227
12	ACCT 879-CUSTOMER INSTALL EXP	EXP879	396,016	23,768	310,007
13	ACCT 880-OTHER EXPENSE	EXP880	6,888,322	279,384	4,562,262
14	ACCT 887-MAINTENANCE OF MAINS	EXP887	2,512,497	25,531	1,446,764
15	ACCT 889-MT OF M & R STA EQ	EXP889	703,429	6,342	358,481
16	ACCT 890-MT OF REG EQ (INDUST)	EXP890	526,105	4,743	268,114
17	ACCT 891-MT OF REG EQ (CITY GATE)	EXP891	0	0	0
18	ACCT 892-MAINTENANCE OF SERV	EXP892	4,097,618	258,602	3,332,904
19	ACCT 893-MAINT MET & HOUSE REG	EXP893	1,639,972	83,186	1,133,162
20	ACCT 902-METER READING EXP	EXP902	518,073	28,664	380,747
21	ACCT 903-CUST RECORDS & COLL	EXP903	6,688,765	371,832	5,841,781
22	ACCT 908-CUST ASSISTANCE EXP	EXP908	350,483	2,915	38,924
23	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	3,396,670	107,721	2,254,040
24	ACCT 904-UNCOLL ACCTS EXP BASE	EXP904B	3,396,670	107,721	2,254,040
25	ACCT 920-ADMIN & GEN SALARY	EXP920	5,941,228	201,645	4,013,283
26	ACCT 923-OUTSIDE SERV EMPLOYED	EXP923	1,880,943	63,839	1,270,572
27	ACCT 930-MISC GEN EXP	EXP930	872,462	29,611	589,346
28	ACCT 932-MAINT OF GENERAL PLT	EXP932	8,477	278	5,679
29	ACCT 863-MAINTENANCE OF MAINS	EXP863	161	2	93
30	STORAGE LABOR ACCTS 846-847	LABSO	0	0	0
31	DIST LAB OPER ACCT 861 & 871 - 880	LABDO	13,828,869	573,940	9,190,421
32	DIST LABOR MAINT ACCT 886 - 894	LABDM	5,243,751	215,064	3,639,605
33	CUST ACCTS LAB ACCT 902,903 & 905	LABCA	2,887,130	160,447	2,494,996
34	SALES LABOR ACCT 912 - 916	LABSA	522,812	18,988	346,740
35	CUST SERV & INFO LABOR 908-910	LABSI	405,502	3,372	45,034
36	TOTAL STORAGE LABOR	TLABSO	1,455,519	12,093	1,095,805
37	TOTAL DISTR OPER LABOR	TLABDO	16,055,450	666,350	10,670,167
38	TOTAL DISTR MAINT LABOR	TLABDM	5,688,363	233,299	3,948,204
39	TOTAL SALES LABOR	TLABSA	535,188	19,437	354,948
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NATIONAL GRID - RHODE ISLAND
GAS COST OF SERVICE STUDY
12 MONTHS ENDED AUGUST 31, 2019

	INTERNALLY DEVELOPED CONT-27	ALLOC	COMM & IND SMALL RATE 21	COMM & IND MEDIUM RATE 22	C & I LARGE LOW LOAD FAC RATE 33	C & I LARGE HIGH LOAD FAC RATE 23	C & I X LARGE LOW LOAD FAC RATE 34	C & I X LARGE HIGH LOAD FAC RATE 24
1	ACCT 813-OTH GAS SUPPLY EXP	EXP813	278	391	77	28	8	9
2	ACCT 846-OTHER EXPENSES	EXP846	0	0	0	0	0	0
3	ACCT 847.2-MAINT STRUCT & INMPROV	EXP8472	0	0	0	0	0	0
4	ACCT 847.3-MAINT LNG PROCESS TERM I	EXP8473	0	0	0	0	0	0
5	ACCT 847.5-MAINT MEAS/REG EQUIP	EXP8475	0	0	0	0	0	0
6	ACCT 847.8-MAINT OF VAPORIZING EQ	EXP8478	0	0	0	0	0	0
7	ACCT 871-SYSTEM CONTROL & DISP	EXP871	74,850	157,092	79,080	32,300	35,865	164,339
8	ACCT 873-COMP STA FUEL & POW	EXP873	1,175	2,466	1,241	507	563	2,580
9	ACCT 874-MAINS & SERVICE EXP	EXP874	286,146	403,709	194,104	79,083	30,642	139,587
10	ACCT 875-OPER STATION EXP - GEN	EXP875	56,424	118,420	59,613	24,348	27,036	123,883
11	ACCT 878-METER & HOUSE REG EXP	EXP878	1,045,361	1,153,079	194,168	73,786	34,437	76,530
12	ACCT 879-CUSTOMER INSTALL EXP	EXP879	36,983	18,959	3,409	1,395	448	1,046
13	ACCT 880-OTHER EXPENSE	EXP880	647,621	800,635	230,026	91,490	56,019	220,884
14	ACCT 887-MAINTENANCE OF MAINS	EXP887	188,224	394,314	198,748	80,722	31,922	146,272
15	ACCT 889-MT OF M & R STA EQ	EXP889	46,630	97,865	49,265	20,122	22,343	102,380
16	ACCT 890-MT OF REG EQ (INDUST)	EXP890	34,875	73,195	36,846	15,050	16,711	76,571
17	ACCT 891-MT OF REG EQ (CITY GATE)	EXP891	0	0	0	0	0	0
18	ACCT 892-MAINTENANCE OF SERV	EXP892	367,150	103,878	20,480	9,160	1,474	3,969
19	ACCT 893-MAINT MET & HOUSE REG	EXP893	171,820	189,524	31,914	12,128	5,660	12,579
20	ACCT 902-METER READING EXP	EXP902	41,749	36,717	21,444	5,360	1,018	2,375
21	ACCT 903-CUST RECORDS & COLL	EXP903	331,853	125,222	13,182	2,576	415	1,905
22	ACCT 908-CUST ASSISTANCE EXP	EXP908	234,568	64,452	5,569	2,513	404	1,138
23	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	299,046	375,554	151,752	60,827	27,506	120,223
24	ACCT 904-UNCOLL ACCTS EXP BASE	EXP904B	299,046	375,554	151,752	60,827	27,506	120,223
25	ACCT 920-ADMIN & GEN SALARY	EXP920	533,212	636,532	232,809	91,048	44,705	187,994
26	ACCT 923-OUTSIDE SERV EMPLOYED	EXP923	168,810	201,521	73,705	28,825	14,153	59,517
27	ACCT 930-MISC GEN EXP	EXP930	78,302	93,474	34,188	13,370	6,565	27,607
28	ACCT 932-MAINT OF GENERAL PLT	EXP932	744	923	358	141	67	287
29	ACCT 863-MAINTENANCE OF MAINS	EXP863	12	25	13	5	2	9
30	STORAGE LABOR ACCTS 846-847	LABSO	0	0	0	0	0	0
31	DIST LAB OPER ACCT 861 & 871 - 880	LABDO	1,312,930	1,603,787	442,855	175,712	108,347	420,877
32	DIST LABOR MAINT ACCT 886 - 894	LABDM	458,135	488,244	180,975	73,353	35,835	152,538
33	CUST ACCTS LAB ACCT 902,903 & 905	LABCA	149,179	64,049	13,248	3,022	544	1,647
34	SALES LABOR ACCT 912 - 916	LABSA	34,937	41,450	17,816	8,831	8,092	45,958
35	CUST SERV & INFO LABOR 908-910	LABSI	271,390	74,569	6,444	2,907	468	1,317
36	TOTAL STORAGE LABOR	TLABSO	141,525	159,282	37,739	5,253	3,231	591
37	TOTAL DISTR OPER LABOR	TLABDO	1,524,324	1,862,012	514,159	204,004	125,792	488,643
38	TOTAL DISTR MAINT LABOR	TLABDM	496,980	529,642	196,320	79,573	38,874	165,472
39	TOTAL SALES LABOR	TLABSA	35,764	42,431	18,238	9,040	8,284	47,046
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	INTERNALLY DEVELOPED CONT-27	ALLOC	TOTAL COMPANY INPUT
1	ACCT 813-OTH GAS SUPPLY EXP	EXP813	Page 9 Line 4
2	ACCT 846-OTHER EXPENSES	EXP846	Page 10 Line 6
3	ACCT 847.2-MAINT STRUCT & INMPROV	EXP8472	Page 10 Line 8
4	ACCT 847.3-MAINT LNG PROCESS TERM I	EXP8473	Page 10 Line 9
5	ACCT 847.5-MAINT MEAS/REG EQUIP	EXP8475	Page 10 Line 10
6	ACCT 847.8-MAINT OF VAPORIZING EQ	EXP8478	Page 10 Line 11
7	ACCT 871-SYSTEM CONTROL & DISP	EXP871	Page 11 Line 5
8	ACCT 873-COMP STA FUEL & POW	EXP873	Page 11 Line 6
9	ACCT 874-MAINS & SERVICE EXP	EXP874	Page 11 Line 7
10	ACCT 875-OPER STATION EXP - GEN	EXP875	Page 11 Line 8
11	ACCT 878-METER & HOUSE REG EXP	EXP878	Page 11 Line 10
12	ACCT 879-CUSTOMER INSTALL EXP	EXP879	Page 11 Line 11
13	ACCT 880-OTHER EXPENSE	EXP880	Page 11 Line 12
14	ACCT 887-MAINTENANCE OF MAINS	EXP887	Page 11 Line 16
15	ACCT 889-MT OF M & R STA EQ	EXP889	Page 11 Line 18
16	ACCT 890-MT OF REG EQ (INDUST)	EXP890	Page 11 Line 19
17	ACCT 891-MT OF REG EQ (CITY GATE)	EXP891	Page 11 Line 20
18	ACCT 892-MAINTENANCE OF SERV	EXP892	Page 11 Line 21
19	ACCT 893-MAINT MET & HOUSE REG	EXP893	Page 11 Line 22
20	ACCT 902-METER READING EXP	EXP902	Page 12 Line 2
21	ACCT 903-CUST RECORDS & COLL	EXP903	Page 12 Line 3
22	ACCT 908-CUST ASSISTANCE EXP	EXP908	Page 12 Line 17
23	ACCT 904-UNCOLLECTIBLE ACCTS	EXP904	Page 12 Line 13
24	ACCT 904-UNCOLL ACCTS EXP BASE	EXP904B	Page 12 Lines 4 to 11
25	ACCT 920-ADMIN & GEN SALARY	EXP920	Page 13 Line 1
26	ACCT 923-OUTSIDE SERV EMPLOYED	EXP923	Page 13 Line 3
27	ACCT 930-MISC GEN EXP	EXP930	Page 13 Line 10
28	ACCT 932-MAINT OF GENERAL PLT	EXP932	Page 13 Line 14
29	ACCT 863-MAINTENANCE OF MAINS	EXP863	Page 11 Line 3
30	STORAGE LABOR ACCTS 846-847	LABSO	Page 18 Line 4 & 6 to 9
31	DIST LAB OPER ACCT 861 & 871 - 880	LABDO	Page 19 Line 3 & 5 to 12
32	DIST LABOR MAINT ACCT 886 - 894	LABDM	Page 19 Lines 15 to 22
33	CUST ACCTS LAB ACCT 902,903 & 905	LABCA	Page 19 Lines 26 to 28
34	SALES LABOR ACCT 912 - 916	LABSA	Page 20 Lines 7 to 9
35	CUST SERV & INFO LABOR 908-910	LABSI	Page 20 Lines 2 to 4
36	TOTAL STORAGE LABOR	TLABSO	Page 18 Line 10
37	TOTAL DISTR OPER LABOR	TLABDO	Page 19 Line 13
38	TOTAL DISTR MAINT LABOR	TLABDM	Page 19 Line 23
39	TOTAL SALES LABOR	TLABSA	Page 20 Line 10
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NATIONAL GRID - RHODE ISLAND
GAS COST OF SERVICE STUDY
12 MONTHS ENDED AUGUST 31, 2019

	INTERNALLY DEVELOPED CONT-28	ALLOC	TOTAL COMPANY	RESIDENTIAL NON-HEATING RATE 10, 11 & 80	RESIDENTIAL HEATING RATE 12 & 13
1	TOTAL CUST ACCTS LABOR	TLABCA	3,145,632	174,812	2,718,388
2	CUSTOMER SERVICE & INFO LABOR	TLABSE	413,231	3,436	45,893
3	ACCT 888-MNT COMPRESSOR STA EQ	EXP888	62,659	565	31,932
4	ACCT 894-MAINT OF OTHER EQUIP	EXP894	(11,633)	(105)	(5,928)
5	ACCT 921-OFFICE SUPPLIES & EXP	EXP921	4,660,737	158,185	3,148,315
6	ACCT 926-EMPLOY PENSION & BENF	EXP926	8,437,151	286,356	5,699,272
7	ACCT 380-384-SERV,METRS & REGUL	PLT3804	470,376,885	28,231,059	368,218,021
8	ACCT 925-INJURIES & DAMAGES	EXP925	1,358,329	46,102	917,547
9	ACCT 302-GAS FRANCHISES & CON	PLT302	213,499	6,169	139,989
10	ACCT 303-MISC INTANGIBLE PLT	PLT303	5,085	147	3,334
11	ACCT 303-MISC INTANG PLT - SOFT	PLT303SL	29,888,379	1,014,409	20,189,518
12	ACCT 307-OTHER POWER EQUIP	PLT307	46,159	384	34,751
13	ACCT 361-STRUCTURES & IMPROV	PLT361	3,385,050	28,125	2,548,475
14	ACCT 362-GAS HOLDERS & LNG EQ	PLT362	4,605,653	38,266	3,467,420
15	ACCT 363-PURIFICATION EQUIP	PLT363	13,892,912	115,430	10,459,443
16	ACCT 377-DIST COMP STATION EQ	PLT377	248,716	2,242	126,751
17	ACCT 379-DIST MEAS & REG GS EQ	PLT379	12,106,307	109,144	6,169,614
18	ACCT 384-HOUSE REGUL INSTALLS	PLT384	2,934,277	148,838	2,027,480
19	ACCT 385-IND MEAS & REG STA EQ	PLT385	796,108	7,177	405,712
20	ACCT 387-DIST OTHER EQUIP	PLT387	785,775	7,084	400,446
21	ACCT 389-LAND & LAND RIGHTS	PLT389	285,357	9,685	192,758
22	ACCT 378 & 379-GAS M & R STAT EQ	PLT3789	44,221,014	398,673	22,535,905
23	CUSTOMER ACCTS EXP 902 - 903	EXP9023	7,206,837	400,496	6,222,527
24					
25	ACCT 876-OPER STAT EXP - INDUST	EXP876	32,219	290	16,419
26	ACCT 905-MISC CUST ACCTS EXP	EXP905	419,475	23,311	362,184
27	ACCT 910-CUST SERVICE MISC EXP	EXP910	446,797	3,716	49,620
28	ACCT 912-DEMO & SELLING EXP	EXP912	475,198	17,259	315,162
29	ACCT 916-MISC SALES EXP	EXP916	156,197	5,673	103,593
30	ACCT 924-PROPERTY INSURANCE	EXP924	308,560	8,916	202,319
31	ACCT 928-REGULATORY COMM EXP	EXP928	1,910,229	60,581	1,267,634
32	ACCT 929-DUPLICATE CHRG - CREDIT	EXP929	0	0	0
33	ACCT 931-RENTS	EXP931	8,956,830	303,994	6,050,314
34					
35					
36	ACCT 909-INFO & INST ADV EXP & EE	EXP909	851,744	7,083	94,593
37	ACCT 913-ADVERTISING EXP	EXP913	51,675	1,877	34,272
38					
39					
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NATIONAL GRID - RHODE ISLAND
GAS COST OF SERVICE STUDY
12 MONTHS ENDED AUGUST 31, 2019

	INTERNALLY DEVELOPED CONT-28	ALLOC	COMM & IND SMALL RATE 21	COMM & IND MEDIUM RATE 22	C & I LARGE LOW LOAD FAC RATE 33	C & I LARGE HIGH LOAD FAC RATE 23	C & I X LARGE LOW LOAD FAC RATE 34	C & I X LARGE HIGH LOAD FAC RATE 24
1	TOTAL CUST ACCTS LABOR	TLABCA	162,535	69,784	14,434	3,292	593	1,794
2	CUSTOMER SERVICE & INFO LABOR	TLABSE	276,563	75,991	6,566	2,963	477	1,342
3	ACCT 888-MNT COMPRESSOR STA EQ	EXP888	4,154	8,718	4,388	1,792	1,990	9,120
4	ACCT 894-MAINT OF OTHER EQUIP	EXP894	(771)	(1,618)	(815)	(333)	(369)	(1,693)
5	ACCT 921-OFFICE SUPPLIES & EXP	EXP921	418,291	499,342	182,632	71,425	35,070	147,477
6	ACCT 926-EMPLOY PENSION & BENF	EXP926	757,216	903,940	330,612	129,297	63,486	266,971
7	ACCT 380-384-SERV,METRS & REGUL	PLT3804	43,927,541	22,518,628	4,049,288	1,657,450	532,276	1,242,622
8	ACCT 925-INJURIES & DAMAGES	EXP925	121,907	145,529	53,226	20,816	10,221	42,981
9	ACCT 302-GAS FRANCHISES & CON	PLT302	17,572	24,299	10,777	4,338	1,904	8,452
10	ACCT 303-MISC INTANGIBLE PLT	PLT303	419	579	257	103	45	201
11	ACCT 303-MISC INTANG PLT - SOFT	PLT303SL	2,682,416	3,202,183	1,171,184	458,032	224,899	945,739
12	ACCT 307-OTHER POWER EQUIP	PLT307	4,488	5,051	1,197	167	102	19
13	ACCT 361-STRUCTURES & IMPROV	PLT361	329,139	370,437	87,769	12,217	7,514	1,374
14	ACCT 362-GAS HOLDERS & LNG EQ	PLT362	447,822	504,012	119,418	16,622	10,223	1,869
15	ACCT 363-PURIFICATION EQUIP	PLT363	1,350,851	1,520,347	360,223	50,141	30,838	5,639
16	ACCT 377-DIST COMP STATION EQ	PLT377	16,487	34,603	17,419	7,115	7,900	36,199
17	ACCT 379-DIST MEAS & REG GS EQ	PLT379	802,522	1,684,301	847,878	346,308	384,540	1,762,000
18	ACCT 384-HOUSE REGUL INSTALLS	PLT384	307,424	339,102	57,102	21,699	10,127	22,506
19	ACCT 385-IND MEAS & REG STA EQ	PLT385	52,774	110,759	55,756	22,773	25,287	115,869
20	ACCT 387-DIST OTHER EQUIP	PLT387	52,089	109,322	55,033	22,478	24,959	114,365
21	ACCT 389-LAND & LAND RIGHTS	PLT389	25,610	30,573	11,182	4,373	2,147	9,029
22	ACCT 378 & 379-GAS M & R STAT EQ	PLT3789	2,931,391	6,152,287	3,097,065	1,264,969	1,404,620	6,436,103
23	CUSTOMER ACCTS EXP 902 - 903	EXP9023	373,602	161,938	34,626	7,936	1,433	4,280
24								
25	ACCT 876-OPER STAT EXP - INDUST	EXP876	2,136	4,482	2,256	922	1,023	4,689
26	ACCT 905-MISC CUST ACCTS EXP	EXP905	21,746	9,426	2,015	462	83	249
27	ACCT 910-CUST SERVICE MISC EXP	EXP910	299,028	82,163	7,100	3,204	516	1,451
28	ACCT 912-DEMO & SELLING EXP	EXP912	31,755	37,675	16,194	8,026	7,355	41,772
29	ACCT 916-MISC SALES EXP	EXP916	10,438	12,384	5,323	2,638	2,418	13,731
30	ACCT 924-PROPERTY INSURANCE	EXP924	25,396	35,118	15,575	6,270	2,751	12,215
31	ACCT 928-REGULATORY COMM EXP	EXP928	168,179	211,205	85,343	34,208	15,469	67,611
32	ACCT 929-DUPLICATE CHRG - CREDIT	EXP929	0	0	0	0	0	0
33	ACCT 931-RENTS	EXP931	803,856	959,617	350,976	137,261	67,397	283,415
34								
35								
36	ACCT 909-INFO & INST ADV EXP & EE	EXP909	570,047	156,630	13,535	6,107	983	2,767
37	ACCT 913-ADVERTISING EXP	EXP913	3,453	4,097	1,761	873	800	4,542
38								
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1	TOTAL CUST ACCTS LABOR	TLABCA	Page 19 Line 29
2	CUSTOMER SERVICE & INFO LABOR	TLABSE	Page 20 Line 5
3	ACCT 888-MNT COMPRESSOR STA EQ	EXP888	Page 11 Line 17
4	ACCT 894-MAINT OF OTHER EQUIP	EXP894	Page 11 Line 23
5	ACCT 921-OFFICE SUPPLIES & EXP	EXP921	Page 13 Line 2
6	ACCT 926-EMPLOY PENSION & BENF	EXP926	Page 13 Line 6
7	ACCT 380-384-SERV,METRS & REGUL	PLT3804	Page 3 Lines 8 to 12
8	ACCT 925-INJURIES & DAMAGES	EXP925	Page 13 Line 5
9	ACCT 302-GAS FRANCHISES & CON	PLT302	Page 2 Line 1
10	ACCT 303-MISC INTANGIBLE PLT	PLT303	Page 2 Line 2
11	ACCT 303-MISC INTANG PLT - SOFT	PLT303SL	Page 2 Line 3
12	ACCT 307-OTHER POWER EQUIP	PLT307	Page 2 Line 7
13	ACCT 361-STRUCTURES & IMPROV	PLT361	Page 2 Line 12
14	ACCT 362-GAS HOLDERS & LNG EQ	PLT362	Page 2 Line 13
15	ACCT 363-PURIFICATION EQUIP	PLT363	Page 2 Line 14
16	ACCT 377-DIST COMP STATION EQ	PLT377	Page 3 Line 5
17	ACCT 379-DIST MEAS & REG GS EQ	PLT379	Page 3 Line 7
18	ACCT 384-HOUSE REGUL INSTALLS	PLT384	Page 3 Line 12
19	ACCT 385-IND MEAS & REG STA EQ	PLT385	Page 3 Line 13
20	ACCT 387-DIST OTHER EQUIP	PLT387	Page 3 Line 15
21	ACCT 389-LAND & LAND RIGHTS	PLT389	Page 3 Line 17
22	ACCT 378 & 379-GAS M & R STAT EQ	PLT3789	Page 3 Lines 6 & 7
23	CUSTOMER ACCTS EXP 902 - 903	EXP9023	Page 12 Lines 2 & 3
24			
25	ACCT 876-OPER STAT EXP - INDUST	EXP876	Page 11 Line 9
26	ACCT 905-MISC CUST ACCTS EXP	EXP905	Page 12 Line 14
27	ACCT 910-CUST SERVICE MISC EXP	EXP910	Page 12 Line 19
28	ACCT 912-DEMO & SELLING EXP	EXP912	Page 12 Line 22
29	ACCT 916-MISC SALES EXP	EXP916	Page 12 Line 24
30	ACCT 924-PROPERTY INSURANCE	EXP924	Page 13 Line 4
31	ACCT 928-REGULATORY COMM EXP	EXP928	Page 13 Line 8
32	ACCT 929-DUPLICATE CHRG - CREDIT	EXP929	Page 13 Line 9
33	ACCT 931-RENTS	EXP931	Page 13 Line 11
34			
35			
36	ACCT 909-INFO & INST ADV EXP & EE	EXP909	Page 12 Line 18
37	ACCT 913-ADVERTISING EXP	EXP913	Page 12 Line 23
38			
39			
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National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

ALLOCATORS, Page 22

Demand-Related Production Allocators:

1. DSWNLNG LNG Production Demand Des Wn
   Ratio Page 30 Line 10 (top section)
   Items Allocated
   Page 2 Lines 5-10, 11-15
   Page 10 Lines 2, 3, 5, 6, 8-12
   Page 18 Line 2

Demand-Related Distribution Allocators:

2. DISTR Distribution RSUM Allocator
   Ratio Page 30 Line 1 (bottom section)
   Items Allocated
   Page 3 Lines 1, 2, 4-7, 15
   Page 8 Lines 2, 3
   Page 11 Line 5

3. DISTRL4 Distr RSUM Allocator Less than 4”
   Ratio Page 30 Line 2 (bottom section)
   Items Allocated
   Page 3 Line 3

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

ALLOCATORS, Page 23

Commodity-Related Allocators:

1. EGAS Direct Gas Cost Allocator
   Ratio Page 31 Line 3
   Items Allocated
   Page 9 Lines 1, 3, 4

ALLOCATORS, Page 24

Customer-Related Allocators:

1. CUST380 Acct 380 – Services
   Ratio Page 32 Line 1
   Items Allocated
   Page 3 Line 8

2. CUST381 Acct 381 – Meters
   Ratio Page 32 Line 2
   Items Allocated
   Page 3 Line 9

3. CUST382 Acct 382 – Meter Installation
   Ratio Page 32 Line 3
   Items Allocated
   Page 3 Line 10

4. CUST383 Acct 383 – House Regulators
   Ratio Page 32 Line 4
   Items Allocated
   Page 3 Line 11

5. CUST384 Acct 384 – House Regul Installs
   Ratio Page 32 Line 5
   Items Allocated
   Page 3 Line 12

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

6. CUST385 Acct 385 – Ind Meas & Reg Sta Eq
Ratio Page 32 Line 6
<u>Items Allocated</u>
Page 3 Line 13

7. CUST386 Acct 386 – Other Prop Cust Prem
Ratio Page 32 Line 7
<u>Items Allocated</u>
Page 3 Line14

8. CUSTDEP Customer Deposits
Ratio Page 32 Line 8
<u>Items Allocated</u>
Page 7 Line 3
Page 16 Line 6

9. CUST902 Acct 902 – Meter Read Exp
Ratio Page 32 Line 9
<u>Items Allocated</u>
Page 12 Line 2

10. CUST903 Acct 903 – Billing, Postage & Calls
Ratio Page 32 Line 10
<u>Items Allocated</u>
Page 12 Line 3

11. CUST908 Acct 908 – Cust Assistance Exp
Ratio Page 32 Line 12
<u>Items Allocated</u>
Page 12 Lines 17, 18, 19

12. CUST912 Acct 912 – Demo & Selling Exp
Ratio Page 32 Line 13
<u>Items Allocated</u>
Page 12 Lines 22, 23, 24

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

ALLOCATORS, Page 25

Externally Developed Uncollectible Accounts Allocators:

1. C904RNH Resid Non Htg Rate 10, 11 & 80
   Ratio Page 33 Line 1
   Items Allocated
   None

2. C904RH Resid Heating Rate 12 & 13
   Ratio Page 33 Line 2
   Items Allocated
   None

3. C904R21 Comm & Ind Small Rate 21
   Ratio Page 33 Line 3
   Items Allocated
   None

4. C904R22 Comm & Ind Medium Rate 22
   Ratio Page 33 Line 4
   Items Allocated
   None

5. C904R33 C&I Large LLF Rate 33
   Ratio Page 33 Line 5
   Items Allocated
   None

6. C904R23 C&I Large HLF Rate 23
   Ratio Page 33 Line 6
   Items Allocated
   None

7. C904R34 C&I XLarge LLF Rate 34
   Ratio Page 33 Line 7
   Items Allocated
   None

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

8. C904R24 C&I XLarge HLF Rate 24
Ratio Page 33 Line 8
Items Allocated
None

Internally Developed Late Payment Charges Allocators:

9. C488R21 Comm & Ind Small Rate 21
Ratio Page 33 Line 9
Items Allocated
Page 8 Line 5

10. C488R22 Comm & Ind Medium Rate 22
Ratio Page 33 Line 10
Items Allocated
Page 8 Line 6

11. C488R33 C&I Large Low Load Fac Rate 33
Ratio Page 33 Line 11
Items Allocated
Page 8 Line 7

12. C488R23 C&I Large High Load Fac Rate 23
Ratio Page 33 Line 12
Items Allocated
Page 8 Line 8

13. C488R34 C&I XLarge Low Load Fac Rate 34
Ratio Page 33 Line 13
Items Allocated
Page 8 Line 9

14. C488R24 C&I XLarge High Load Fac Rate 24
Ratio Page 33 Line 14
Items Allocated
Page 8 Line 10

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Description of Gas Allocation Factors
Items Allocated
All Allocators

ALLOCATORS, Page 26

Internally Developed Allocators:

1. PLANT — Total Gas Plant in Service
   Ratio — Page 34, Line 1
   Items Allocated
   Page 2 — Lines 1, 2
   Page 3 — Line 29
   Page 5 — Line 28
   Page 6 — Lines 8-10
   Page 7 — Lines 1, 2
   Page 8 — Lines 12-16
   Page 13 — Line 4
   Page 14 — Line 2
   Page 15 — Line 27
   Page 16 — Lines 1, 3
   Page 17 — Lines 6, 13,14

2. LABOR — Sum of Allocated Labor Exp
   Ratio — Page 34, Line 2
   Items Allocated
   Page 2 — Line 3
   Page 3 — Lines 17, 18, 19, 20, 25, 26, 27
   Page 13 — Lines 1, 2, 3, 5, 6, 9, 10, 11
   Page 16 — Line 2

3. PLT305 — Acct 305 – Structures & Improve
   Ratio — Page 34, Line 3
   Items Allocated
   Page 4 — Line 6
   Page 14 — Line 9

4. PLT311 — Acct 311 – LP Gas Equip
   Ratio — Page 34, Line 4
   Items Allocated
   Page 4 — Line 8
   Page 14 — Line 11

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

5.	PLT320		Acct 320 – Other Equipment	
		Ratio	Page 34	Line 5
			Items Allocated	
			Page 4	Line 9
			Page 14	Line 12
6.	PLT375		Acct 375 – Gas Dist Station Str	
		Ratio	Page 34	Line 6
			Items Allocated	
			Page 5	Line 2
			Page 15	Line 2
7.	PLT376		Acct 376 – Mains	
		Ratio	Page 34	Line 7
			Items Allocated	
			Page 5	Line 3
			Page 11	Lines 3, 16
			Page 15	Line 3
8.	PLT378		Acct 378 – Gas Meas & Reg Sta Eq	
		Ratio	Page 34	Line 8
			Items Allocated	
			Page 5	Line 5
			Page 15	Line 5
9.	PLT380		Acct 380 – Services	
		Ratio	Page 34	Line 9
			Items Allocated	
			Page 5	Line 7
			Page 11	Line 21
			Page 15	Line 7
10.	PLT381		Acct 381 – Meters	
		Ratio	Page 34	Line 10
			Items Allocated	
			Page 5	Line 8
			Page 15	Line 8

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

11. PLT382 — Acct 382 – Meter Installation
    Ratio: Page 34 Line 11
    Items Allocated
    Page 5 Line 9
    Page 15 Line 9

12. PLT386 — Acct 386 – Other Prop Cust Prem
    Ratio: Page 34 Line 12
    Items Allocated
    Page 5 Line 13
    Page 15 Line 13

13. PLT383 — Acct 383 – House Regulators
    Ratio: Page 34 Line 13
    Items Allocated
    Page 5 Line 10
    Page 15 Line 10

14. PLT396 — Acct 396 – Power Operated Equip
    Ratio: Page 34 Line 14
    Items Allocated
    Page 5 Line 23
    Page 15 Line 23

15. PLT390 — Acct 390 – Structures & Improv
    Ratio: Page 34 Line 15
    Items Allocated
    Page 5 Line 17
    Page 15 Line 17

16. PLT391 — Acct 391 – Office Furn & Equip
    Ratio: Page 34 Line 16
    Items Allocated
    Page 5 Line 18
    Page 15 Line 18

17. PLT392 — Acct 392 – Transportation Equip
    Ratio: Page 34 Line 17
    Items Allocated
    Page 5 Line 19
    Page 15 Line 19

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

18.	PLT393		Acct 393 – Stores Equipment		
		Ratio		Page 34	Line 18
				Items Allocated	
				Page 5	Line 20
				Page 15	Line 20
19.	PLT394		Acct 394 – Tools, Shop & Gar Eq		
		Ratio		Page 34	Line 19
				Items Allocated	
				Page 5	Line 21
				Page 15	Line 21
20.	PLT395		Acct 395 – Laboratory Equipment		
		Ratio		Page 34	Line 20
				Items Allocated	
				Page 5	Line 22
				Page 15	Line 22
21.	PLT397		Acct 397 – Communication Equip		
		Ratio		Page 34	Line 21
				Items Allocated	
				Page 5	Line 24
				Page 15	Line 24
22.	PLT398		Acct 398 – Miscellaneous Equip		
		Ratio		Page 34	Line 22
				Items Allocated	
				Page 5	Line 25
				Page 15	Line 25
23.	PLT37680		Acct 376 Mains & 380 Services		
		Ratio		Page 34	Line 23
				Items Allocated	
				Page 6	Line 5
				Page 11	Line 7

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

24.	DISTRPLT		Total Distribution Plant	
		Ratio	Page 34	Line 24
			Items Allocated	
			Page 3	Lines 21, 22, 23, 24
			Page 6	Lines 4, 7
			Page 20	Lines 25
25.	PLT3814		Acct 381-384 – Meter & Hse Regul	
		Ratio	Page 34	Line 25
			Items Allocated	
			Page 11	Lines 10, 22
26.	EXP8719		Acct 871-879 – Dist Oper Exp	
		Ratio	Page 34	Line 26
			Items Allocated	
			Page 11	Line 12
27.	REVCLAIM		Rev Claimed ROR Less Gas Costs	
		Ratio	Page 34	Line 27
			Items Allocated	
			Page 12	Lines 4-11
			Page 13	Lines 7, 8, 16, 17
			Page 14	Line 1
28.	GENPLT		Total General Plant	
		Ratio	Page 34	Line 28
			Items Allocated	
			Page 13	Line 14
29.	CWCEXP		Total Working Cash Expense	
		Ratio	Page 34	Line 29
			Items Allocated	
			Page 6	Line 11
30.	PLT304		Acct 304 – Land & Land Rights	
		Ratio	Page 34	Line 30
			Items Allocated	
			Page 4	Line 5
			Page 14	Line 8

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

31. PLT360 Acct 360 – Land & Land Rights
    Ratio Page 34 Line 31
    Items Allocated
    Page 4 Line 11
    Page 14 Line 14

32. PLT374 Acct 374 – Land & Land Rights
    Ratio Page 34 Line 32
    Items Allocated
    Page 5 Line 1
    Page 15 Line 1

33. EXP8710 Acct 871-880 – Distr Oper Exp
    Ratio Page 34 Line 33
    Items Allocated
    Page 11 Line 13

34. LNGPLT Total LNG Plant
    Ratio Page 34 Line 34
    Items Allocated
    Page 20 Line 26

35. PLT399 Acct 399 – Other Tangible Property
    Ratio Page 34 Line 35
    Items Allocated
    Page 5 Line 26

ALLOCATORS, Page 27

Internally Developed Allocators:

1. EXP813 Acct 813 – Other Gas Supply Exp
   Ratio Page 35 Line 1
   Items Allocated
   Page 18 Line 1

2. EXP846 Acct 846 – Other Expenses
   Ratio Page 35 Line 2
   Items Allocated
   Page 18 Line 4

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

3. EXP8472 Acct 847.2 – Maint Structures & Improv
Ratio Page 35 Line 3
Items Allocated
Page 18 Line 6

4. EXP8473 Acct 847.3 – Maint LNG Process Term Eq
Ratio Page 35 Line 4
Items Allocated
Page 18 Line 7

5. EXP8475 Acct 847.5 – Maint Meas/Reg Equip
Ratio Page 35 Line 5
Items Allocated
Page 18 Line 8

6. EXP8478 Acct 847.8 – Maint Vaporizing Eq
Ratio Page 35 Line 6
Items Allocated
Page 18 Line 9

7. EXP871 Acct 871 – System Control & Disp
Ratio Page 35 Line 7
Items Allocated
Page 19 Line 5

8. EXP873 Acct 873 – Comp Sta Fuel & Pow
Ratio Page 35 Line 8
Items Allocated
Page 19 Line 6

9. EXP874 Acct 874 – Mains & Service Exp
Ratio Page 35 Line 9
Items Allocated
Page 19 Line 7

10. EXP875 Acct 875 – Gas System T&D Training
Ratio Page 35 Line 10
Items Allocated
Page 19 Line 8

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

11. EXP878 Acct 878 – Meter & House Reg Exp
Ratio Page 35 Line 11
Items Allocated
Page 19 Line 10

12. EXP879 Acct 879 – Customer Install Exp
Ratio Page 35 Line 12
Items Allocated
Page 19 Line 11

13. EXP880 Acct 880 – Other Expense
Ratio Page 35 Line 13
Items Allocated
Page 19 Line 12

14. EXP887 Acct 887 – Maintenance of Mains
Ratio Page 35 Line 14
Items Allocated
Page 19 Line 15

15. EXP889 Acct 889 – Mt of M & R Sta Eq
Ratio Page 35 Line 15
Items Allocated
Page 19 Line 17

16. EXP890 Acct 890 – Mt of Reg Eq (Indust)
Ratio Page 35 Line 16
Items Allocated
Page 19 Line 18

17. EXP891 Acct 891 – Mt of Reg Eq (City Gate)
Ratio Page 35 Line 17
Items Allocated
Page 19 Line 19

18. EXP892 Acct 892 – Maintenance of Serv
Ratio Page 35 Line 18
Items Allocated
Page 19 Line 20

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

19. EXP893 Acct 893 – Maint Met & House Reg
Ratio Page 35 Line 19
Items Allocated
Page 19 Line 21

20. EXP902 Acct 902 – Meter Reading Exp
Ratio Page 35 Line 20
Items Allocated
Page 19 Line 26

21. EXP903 Acct 903 – Cust Records & Coll
Ratio Page 35 Line 21
Items Allocated
Page 19 Line 27

22. EXP908 Acct 908 – Cust Assistance Exp
Ratio Page 35 Line 22
Items Allocated
Page 20 Line 2

23. EXP904 Acct 904 – Uncollectible Accts
Ratio Page 35 Line 23
Items Allocated
None

24. EXP904B Acct 904 – Uncoll Accts Exp Base
Ratio Page 35 Line 24
Items Allocated
Page 12 Line 12

25. EXP920 Acct 920 – Admin & Gen Salary
Ratio Page 35 Line 25
Items Allocated
Page 20 Line 11

26. EXP923 Acct 923 – Outside Serv Employed
Ratio Page 35 Line 26
Items Allocated
Page 20 Line 13

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

27. EXP930 — Acct 930 – Miscs Gen Exp
    Ratio: Page 35 Line 27
    Items Allocated: Page 20 Line 19

28. EXP932 — Acct 932 – Maint of General Plant
    Ratio: Page 35 Line 28
    Items Allocated: Page 20 Line 22

29. EXP863 — Acct 863 – Maintenance of Mains
    Ratio: Page 35 Line 29
    Items Allocated: Page 19 Line 3

30. LABSO — Storage Labor Accts 846-847
    Ratio: Page 35 Line 30
    Items Allocated: Page 18 Lines 3, 5

31. LABDO — Dist Labor Oper Acct 861 & 871-880
    Ratio: Page 35 Line 31
    Items Allocated: Page 19 Lines 1, 2, 4

32. LABDM — Dist Labor Maint Acct 886-894
    Ratio: Page 35 Line 32
    Items Allocated: Page 19 Line 14

33. LABCA — Cust Accts Labor Acct 902-903 & 905
    Ratio: Page 35 Line 33
    Items Allocated: Page 19 Line 25

34. LABSA — Sales Labor Acct 912-916
    Ratio: Page 35 Line 34
    Items Allocated: Page 20 Line 6

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

35. LABSI — Cust Serv & Info Labor 908-910
Ratio — Page 35 — Line 35
Items Allocated
Page 20 — Line 1

36. TLABSO — Total Storage Labor
Ratio — Page 35 — Line 36
Items Allocated
Page 10 — Line 1, 4, 7

37. TLABDO — Total Distr Oper Labor
Ratio — Page 35 — Line 37
Items Allocated
Page 11 — Lines 1, 2, 4

38. TLABDM — Total Distr Maint Labor
Ratio — Page 35 — Line 38
Items Allocated
Page 11 — Line 15

39. TLABSA — Total Sales Labor
Ratio — Page 35 — Line 39
Items Allocated
Page 12 — Line 21

ALLOCATORS, Page 28

Internally Developed Allocators:

1. TLABCA — Total Cust Accts Labor
Ratio — Page 36 — Line 1
Items Allocated
Page 12 — Line 1

2. TLABSE — Customer Service & Info Labor
Ratio — Page 36 — Line 2
Items Allocated
Page 12 — Line 16

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

3.	EXP888		Acct. 888 – Maint Compressor Sta Eq	
		Ratio	Page 36	Line 3
			Items Allocated	
			Page 19	Line 16
4.	EXP894		Acct. 894 – Maint of Other Equip	
		Ratio	Page 36	Line 4
			Items Allocated	
			Page 19	Line 22
5.	EXP921		Acct. 921 – Office Supplies & Exp	
		Ratio	Page 36	Line 5
			Items Allocated	
			Page 20	Line 12
6.	EXP926		Acct. 926 – Employ Pension & Benf	
		Ratio	Page 36	Line 6
			Items Allocated	
			Page 20	Line 16
7.	PLT3804		Acct. 380-384 – Serv, Metrs & Regul	
		Ratio	Page 36	Line 7
			Items Allocated	
			Page 11	Line 11
8.	EXP925		Acct. 925 – Injuries and Damages	
		Ratio	Page 36	Line 8
			Items Allocated	
			Page 7	Line 4
			Page 20	Line 15
9.	PLT302		Acct. 302 – Gas Franchises & Con	
		Ratio	Page 36	Line 9
			Items Allocated	
			Page 4	Line 1
			Page 14	Line 4
10.	PLT303		Acct 303 – Misc Intangible Plt	
		Ratio	Page 36	Line 10
			Items Allocated	
			Page 4	Line 2

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

Page 14 Line 5

11. PLT303SL Acct 303 – Misc Intangible Plt - SL
Ratio Page 36 Line 11
Items Allocated
Page 4 Line 3
Page 14 Line 6

12. PLT307 Acct 307 – Other Power Equip
Ratio Page 36 Line 12
Items Allocated
Page 4 Line 7
Page 14 Line 10

13. PLT361 Acct 361 – Structures & Improv
Ratio Page 36 Line 13
Items Allocated
Page 4 Line 12
Page 14 Line 15

14. PLT362 Acct 362 – Gas Holders & LNG Eq
Ratio Page 36 Line 14
Items Allocated
Page 4 Line 13
Page 14 Line 16

15. PLT363 Acct 363 – Purification Equip
Ratio Page 36 Line 15
Items Allocated
Page 4 Line 14
Page 14 Line 17

16. PLT377 Acct 377 – Dist Comp Station Eq
Ratio Page 36 Line 16
Items Allocated
Page 5 Line 4
Page 11 Line 6, 17
Page 15 Line 4

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

17.	PLT379		Acct 379 – Dist Meas & Reg Gs Eq	
		Ratio	Page 36	Line 17
			Items Allocated	
			Page 5	Line 6
			Page 15	Line 6
18.	PLT384		Acct 384 – House Regul Installs	
		Ratio	Page 36	Line 18
			Items Allocated	
			Page 5	Line 11
			Page 15	Line 11
19.	PLT385		Acct 385 – Ind Meas & Reg Sta Eq	
		Ratio	Page 36	Line 19
			Items Allocated	
			Page 5	Line 12
			Page 11	Lines 9,19
			Page 15	Line 12
20.	PLT387		Acct 387 – Dist Other Equip	
		Ratio	Page 36	Line 20
			Items Allocated	
			Page 5	Line 14
			Page 11	Line 23
			Page 15	Line 14
21.	PLT389		Acct 389 – Land & Land Rights	
		Ratio	Page 36	Line 21
			Items Allocated	
			Page 5	Line 16
			Page 15	Line 16
22.	PLT3789		Acct 378 & 379 – Gas M & R Stat Eq	
		Ratio	Page 36	Line 22
			Items Allocated	
			Page 11	Lines 8, 18, 20

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

23. EXP9023 Customer Accounts Exp 902-903
Ratio Page 36 Line 23
Items Allocated
Page 12 Line 14

24. EXP876 Acct 876 – Oper Stat Exp – Indust
Ratio Page 36 Line 25
Items Allocated
Page 19 Line 9

25. EXP905 Acct 905 – Misc Cust Accts Exp
Ratio Page 36 Line 26
Items Allocated
Page 19 Line 28

26. EXP910 Acct 910 – Cust Service Misc Exp
Ratio Page 36 Line 27
Items Allocated
Page 20 Line 4

27. EXP912 Acct 912 – Demo & Selling Exp
Ratio Page 36 Line 28
Items Allocated
Page 20 Line 7

28. EXP916 Acct 916 – Misc Sales Exp
Ratio Page 36 Line 29
Items Allocated
Page 20 Line 9

29. EXP924 Acct 924 – Property Insurance
Ratio Page 36 Line 30
Items Allocated
Page 20 Line 14

30. EXP928 Acct 928 – Regulatory Comm Exp
Ratio Page 36 Line 31
Items Allocated
Page 20 Line 17

National Grid – Rhode Island
Description of Gas Allocation Factors
Items Allocated
All Allocators

31. EXP929 Acct 929 – Duplicate Chrg - Credit
Ratio Page 36 Line 32
Items Allocated
Page 20 Line 18

32. EXP931 Acct 931 - Rents
Ratio Page 36 Line 33
Items Allocated
Page 20 Line 20

33. EXP909 Acct 909 – Info & Inst Adv Exp
Ratio Page 36 Line 36
Items Allocated
Page 20 Line 3

34. EXP913 Acct 913 – Advertising Exp
Ratio Page 36 Line 37
Items Allocated
Page 20 Line 8

Compliance Attachment 16

Compliance Attachment 16

Narragansett Gas Revenue Allocation, Firm and Non-Firm Distribution Rate Design

Revenue-per-Customer Targets by Rate Class for Rate Years 1, 2, 3

Allocation of results of Rate Year 1 Allocated Cost of Service Study

Years 2 and 3 Base Rate Increases

Gas-related Grid Mod revenue requirements for Rate Years 1, 2, 3

The Narragansett Electric Company
Summary of Current and Proposed Gas Rates

		Reference	Residential Non Heating	Low Income Residential Non Heating	Residential Heating	Low Income Residential Heating	Small C&I	Medium C&I	Large Low Load Factor C&I	Large High Load Factor C&I	XLarge Low Load Factor C&I	XLarge High Load Factor C&I	Gas Lights
	Rates Effective November 1, 2017		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
(1)	Customer Charge	Docket No. 4323	$13.00	$11.70	$13.00	$11.70	$22.00	$70.00	$175.00	$175.00	$425.00	$425.00	$9.52
	Peak												
(2)	Headblock	Docket No. 4323	$0.4386	$0.3947	$0.4672	$0.4205	$0.5431	$0.1865	$0.1727	$0.1007	$0.0328	$0.0256	
(3)	Tailblock	Docket No. 4323			$0.3010	$0.2709	$0.2242						
(4)	Off Peak												
(5)	Headblock	Docket No. 4323	$0.4386	$0.3947	$0.4672	$0.4205	$0.5431	$0.1865	$0.1727	$0.1007	$0.0328	$0.0256	
(6)	Tailblock	Docket No. 4323			$0.3010	$0.2709	$0.2242						
(7)	Demand	Docket No. 4323						$1.30	$1.30	$1.80	$1.30	$1.80	
	Proposed Rates Year 1 September 1, 2018												
(8)	Customer Charge	Page 5, Col (d)	$14.00	$14.00	$14.00	$14.00	$25.00	$85.00	$200.00	$200.00	$500.00	$500.00	$9.52
(9)	Peak												
(10)	Volumetric	Page 5, Col (h)	$0.5456	$0.5456	$0.5534	$0.5534	$0.4852	$0.2484	$0.2429	$0.1617	$0.0421	$0.0369	
(11)	Off Peak	Page 5, Col (h)											
(12)	Volumetric		$0.5456	$0.5456	$0.4960	$0.4960	$0.4284	$0.2484	$0.2429	$0.1617	$0.0421	$0.0369	
(13)	Demand	Page 5, Col (i)						$1.50	$1.50	$2.05	$1.50	$2.05	
	Proposed Rates Year 2 September 1, 2019												
(14)	Customer Charge	Page 8, Col (n)	$14.00	$14.00	$14.00	$14.00	$25.00	$85.00	$200.00	$200.00	$500.00	$500.00	$9.52
(15)	Peak												
(16)	Volumetric	Page 8, Col (p)	$0.5922	$0.5922	$0.5803	$0.5803	$0.5109	$0.2647	$0.2574	$0.1719	$0.0479	$0.0413	
(17)	Off Peak	Page 8, Col (p)											
(18)	Volumetric		$0.5922	$0.5922	$0.5201	$0.5201	$0.4510	$0.2647	$0.2574	$0.1719	$0.0479	$0.0413	
(19)	Demand	Page 8, Col (q)						$1.50	$1.50	$2.05	$1.50	$2.05	
	Proposed Rates Year 3 September 1, 2020												
(20)	Customer Charge	Page 9, Col (n)	$14.00	$14.00	$14.00	$14.00	$25.00	$85.00	$200.00	$200.00	$500.00	$500.00	$9.52
(21)	Peak												
(22)	Volumetric	Page 9, Col (p)	$0.6162	$0.6162	$0.5943	$0.5943	$0.5241	$0.2731	$0.2649	$0.1771	$0.0509	$0.0435	
(23)	Off Peak	Page 9, Col (p)											
(24)	Volumetric		$0.6162	$0.6162	$0.5327	$0.5327	$0.4627	$0.2731	$0.2649	$0.1771	$0.0509	$0.0435	
(25)	Demand	Page 9, Col (q)						$1.50	$1.50	$2.05	$1.50	$2.05	

The Narragansett Electric Company
Summary of Current and Proposed Non-Firm Gas Rates

		Reference	Medium C&I Non Firm [1]	Large Low Load Factor C&I Non-Firm [1]	Large High Load Factor C&I Non-Firm [1]	Extra Large Low Load Factor C&I Non-Firm	Extra Large High Load Factor C&I Non-Firm
	Rates Effective November 1, 2017		(a)	(b)	(c)	(d)	(e)
(1)	Customer Charge Non Firm Sales	Docket No. 4323	$185.00	$405.00	$405.00	$625.00	$625.00
(2)	Customer Charge Non Firm Transportation	Docket No. 4323	$275.00	$485.00	$485.00	$715.00	$715.00
(3)	Volumetric	Docket No. 4323	$0.2206	$0.2147	$0.1436	$0.0912	$0.0733
	Proposed Rates Year 1 September 1, 2018						
(4)	Customer Charge	Page 6	$185.00	$405.00	$405.00	$625.00	$625.00
(5)	Volumetric	Page 6	$0.2236	$0.2177	$0.1456	$0.0919	$0.0738
	Proposed Rates Year 2 September 1, 2019						
(6)	Customer Charge	No change	$185.00	$405.00	$405.00	$625.00	$625.00
(7)	Volumetric	No change	$0.2236	$0.2177	$0.1456	$0.0919	$0.0738
	Proposed Rates Year 3 September 1, 2020						
(8)	Customer Charge	No change	$185.00	$405.00	$405.00	$625.00	$625.00
(9)	Volumetric	No change	$0.2236	$0.2177	$0.1456	$0.0919	$0.0738

[1] Proposed Volumetric rates effective September 1, 2018 were based on current effective rates increased by 50% of proposed average increase.

The Narragansett Electric Company
Distribution Revenue Allocation Year 1

	Rate Class	Present Revenue	Proposed Distribution Revenune @ Equalized ROR	Proposed Distribution Revenue Increase	Proposed Total Distribution Revenue % Increase	% of Avg Increase	Proposed Adjusted Distribution Revenue % Increase	Proposed Distribution Revenue Increase	Proposed Distribution Revenue	Distribution Revenue Allocator	Increase due to Grid Mod	Year 1 Proposed Distribution Revenue
		(a)	(b)	(c)= (b) - (a)	(d) = (c) / (a)	(e)	(f) =(d) x (e)	(g)= (a) x (f)	(h) = (a) + (g)	(i)= (h) /Ln 10 (h)	(j)= ((i) x Ln 1 (j)	(k) = (h) + (j)
(1)											$0	
(2)	Residential Non-Heat	$4,754,494	$6,821,954	$2,067,460		140.0%	3.87%	$183,952	$4,938,446	2.30%	$0	$4,938,446
(3)	Residential Heat	$138,374,964	$142,747,394	$4,372,430		100.0%	2.76%	$3,824,098	$142,199,062	66.10%	$0	$142,199,062
(4)	Small Commercial	$16,893,996	$18,938,473	$2,044,477		130.0%	3.59%	$606,942	$17,500,938	8.14%	$0	$17,500,938
(5)	Medium Commercial	$24,617,034	$23,783,684	($833,350)		100.0%	2.76%	$680,311	$25,297,344	11.76%	$0	$25,297,344
(6)	Large LLF C&I	$10,586,080	$9,610,395	($975,685)		65.1%	1.80%	$190,391	$10,776,471	5.01%	$0	$10,776,471
(7)	Large HLF C&I	$3,626,809	$3,852,153	$225,344		130.0%	3.59%	$130,299	$3,757,107	1.75%	$0	$3,757,107
(8)	Extra Large LLF C&I	$1,977,222	$1,741,924	($235,298)		65.1%	1.80%	$35,560	$2,012,782	0.94%	$0	$2,012,782
(9)	Extra Large HLF C&I	$8,455,593	$7,613,683	($841,910)		65.1%	1.80%	$152,074	$8,607,667	4.00%	$0	$8,607,667
(10)	Total Firm Service	$209,286,191	$215,109,660	$5,823,469		100.0%	2.76%	$5,803,626	$215,089,817	100.00%	$0	$215,089,817
(11)	Non-Firm Service	$1,436,005				50%	1.38%	$19,843	$1,455,848			$1,455,848
(12)	Total RI Delivery Service	$210,722,196		$5,823,469	2.76%			$5,823,469	$216,545,665			$216,545,665

Col (a) Compliance Attachment 14, Schedule 2, Pg 3, Ln 5
Col (b) Compliance Attachment 14, Schedule 2, Pg 3, Ln 10
Col (e) Mr. Oliver's Testimony Schedule BRO-3
Col (j) Ln (1) Page 7, Line 3

The Narragansett Electric Company
Rate Design Year 1

	Rate	CURRENT RATES	Annual Customers	Existing Customer Charge	Weather Normalized Sales: Sales (therms)	Transp (therms)	Total Therms	Annual Proposed Blocking Therms	First Block % usage	First Block Therms	Tail Block Therms	MADQ Demand Therms	Dist Chrg Head Per Therms	Dist Chrg Tail Per Therms	Demand Per Therms	Existing Base Revenues	RDM & ISR Adjust & Norm ERC	Present Sales Revenues	Initial Target Rev Req for Class
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
(1)	80	Gas Lights	2,326	$9.52												$22,148		$22,148	
(2)	10	Res, Non-Heat	201,541	$13.00	3,673,573	0	3,673,573	NA	100.00%	3,673,573	0		$0.4386			$4,231,262	$420,115	$4,651,378	
(3)	11	Res,Low Income Non-Heat	2,492	$11.70	101,774	0	101,774	NA	100.00%	101,774	0		$0.3947			$69,327	$11,639	$80,966	
(4)		Total Non Heat	204,033		3,775,348	0	3,775,348			3,775,348	0					$4,322,737	$431,754	$4,754,491	$4,938,446
(5)	12	Res, Heat Peak	1,261,573	$13.00	144,054,319	0	144,054,319	125	74.85%	107,825,814	36,228,505		$0.4672	$0.3010		$77,681,449	$16,474,269	$94,155,718	
(6)	12	Res, Heat Off-Peak	1,258,710	$13.00	33,442,491	0	33,442,491	30	78.60%	26,285,200	7,157,291		$0.4672	$0.3010		$30,798,020	$3,824,534	$34,622,554	
(7)	13	Res,Low Income Heat Peak	103,030	$11.70	11,536,022	0	11,536,022	125	79.11%	9,125,974	2,410,048		$0.4205	$0.2709		$5,695,805	$1,319,277	$7,015,082	
(8)	13	Res,Low Inc Heat Off-Peak	101,871	$11.70	2,725,461	0	2,725,461	30	83.32%	2,270,725	454,736		$0.4205	$0.2709		$2,269,919	$311,688	$2,581,606	
(9)		Total Heating	2,725,184		191,758,293	0	191,758,293			145,507,713	46,250,580					$116,445,193	$21,929,767	$138,374,960	$142,199,062
(10)	21	C&I Small Peak	111,874	$22.00	19,048,352	0	19,048,352	135	46.60%	8,877,404	10,170,948		$0.5431	$0.2242		$9,562,873	$2,167,482	$11,730,354	
(11)	21	C&I Small Off-Peak	111,049	$22.00	3,838,817	0	3,838,817	20	32.91%	1,263,285	2,575,531		$0.5431	$0.2242		$3,706,602	$436,813	$4,143,415	
(12)	21	C&I Small FT-2 Peak	4,163	$22.00	0	1,392,814	1,392,814	135	46.86%	652,721	740,093		$0.5431	$0.2242		$612,007	$158,486	$770,494	
(13)	21	C&I Small FT-2 Off-Peak	4,231	$22.00	0	351,777	351,777	20	33.66%	118,400	233,376		$0.5431	$0.2242		$209,708	$40,028	$249,736	
(14)		Total C&I Small	231,317		22,887,169	1,744,590	24,631,759			10,911,811	13,719,949					$14,091,191	$2,802,809	$16,893,999	$17,500,938
(15)	22	C&I Medium Sales	40,181	$70.00	31,579,424	0	31,579,424	NA	100.00%	31,579,424	0	2,412,345	$0.1865		$1.30	$11,838,281	$2,579,878	$14,418,160	
(16)	22	C&I Medium FT-1	3,928	$70.00	0	5,321,965	5,321,965	NA	100.00%	5,321,965	0	398,547	$0.1865		$1.30	$1,785,617	$434,778	$2,220,395	
(17)	22	C&I Medium FT-2	18,305	$70.00	0	18,345,461	18,345,461	NA	100.00%	18,345,461	0	1,366,900	$0.1865		$1.30	$6,479,749	$1,498,731	$7,978,480	
(18)	22	Total C&I Medium	62,414		31,579,424	23,667,426	55,246,850			55,246,850	0	4,177,792				$20,103,647	$4,513,387	$24,617,034	$25,297,344
(19)	33	C&I Large LLF Sales	1,404	$175.00	5,970,565	0	5,970,565	NA	100.00%	5,970,565	0	537,935	$0.1727		$1.30	$1,976,132	$506,158	$2,482,290	
(20)	33	C&I Large LLF FT-1	1,461	$175.00	0	8,160,548	8,160,548	NA	100.00%	8,160,548	0	652,793	$0.1727		$1.30	$2,513,632	$691,815	$3,205,447	
(21)	33	C&I Large LLF FT-2	2,608	$175.00	0	12,236,040	12,236,040	NA	100.00%	12,236,040	0	993,434	$0.1727		$1.30	$3,861,029	$1,037,316	$4,898,345	
(22)	33	Total C&I Large LLF	5,473		5,970,565	20,396,587	26,367,153			26,367,153	0	2,184,163				$8,350,794	$2,235,289	$10,586,082	$10,776,471
(23)	23	C&I Large HLF Sales	670	$175.00	2,712,395	0	2,712,395	NA	100.00%	2,712,395	0	61,187	$0.1007		$1.80	$500,525	$180,202	$680,726	
(24)	23	C&I Large HLF FT-1	1,031	$175.00	0	5,161,579	5,161,579	NA	100.00%	5,161,579	0	258,686	$0.1007		$1.80	$1,165,831	$342,917	$1,508,747	
(25)	23	C&I Large HLF FT-2	735	$175.00	0	5,228,802	5,228,802	NA	100.00%	5,228,802	0	241,549	$0.1007		$1.80	$1,089,953	$347,383	$1,437,335	
(26)	23	Total C&I Large HLF	2,436		2,712,395	10,390,381	13,102,776			13,102,776	0	561,421				$2,756,308	$870,501	$3,626,809	$3,757,107
(27)	34	C&I XLarge LLF Sales	48	$425.00	428,805	0	428,805	NA	100.00%	428,805	0	43,562	$0.0328		$1.30	$91,095	$9,893	$100,988	
(28)	34	C&I XLarge LLF FT-1	324	$425.00	0	11,221,498	11,221,498	NA	100.00%	11,221,498	0	779,109	$0.0328		$1.30	$1,518,606	$258,902	$1,777,508	
(29)	34	C&I XLarge LLF FT-2	36	$425.00	0	581,031	581,031	NA	100.00%	581,031	0	39,201	$0.0328		$1.30	$85,319	$13,406	$98,724	
(30)	34	Tot C&I XLarge LLF	408		428,805	11,802,529	12,231,334			12,231,334	0	861,871				$1,695,020	$282,201	$1,977,221	$2,012,782
(31)	24	C&I XLarge HLF Sales	36	$425.00	761,197	0	761,197	NA	100.00%	761,197	0	67,357	$0.0256		$1.80	$156,030	$15,163	$171,193	
(32)	24	C&I XLarge HLF FT-1	888	$425.00	0	63,406,498	63,406,498	NA	100.00%	63,406,498	0	2,339,952	$0.0256		$1.80	$6,212,521	$1,263,052	$7,475,572	
(33)	24	C&I XLarge HLF FT-2	192	$425.00	0	5,443,394	5,443,394	NA	100.00%	5,443,394	0	266,355	$0.0256		$1.80	$700,390	$108,432	$808,822	
(34)	24	Tot C&I XLarge HLF	1,116		761,197	68,849,892	69,611,089			69,611,089	0	2,673,665				$7,068,941	$1,386,647	$8,455,588	$8,607,667
(35)		Total	3,232,381		259,873,195	136,851,405	396,724,601			336,754,072	59,970,529	10,458,912				$174,833,830	$34,452,354	$209,286,184	$215,089,817

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The Narragansett Electric Company
Rate Design Year 1

	Rate		Annual Customers	Existing Customer Charge	Cost Study @ Equalized ROR Cust $ [1]	Proposed Customer Charges	Existing Dist Charges: Head Per Therms	Existing Dist Charges: Tail Per Therms	Seasonal Adj	Proposed Charges Therm Blocks: First	Proposed Charges Therm Blocks: MADQ	Proposed Revenue Recovery: Customer Charges	Proposed Revenue Recovery: Therms First Block	Proposed Revenue Recovery: MADQ	Total Revenues @ Prop Rates	Class Target Rev Req	$ Variance to target with & Discount	Final Class Increase	Target Revenue Requirement By Class	Final Base Percent Increase
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
(1)	80	Gas Lights	2,326	$9.52	$29.45	$9.52						$22,148			$22,148			$0	$22,148	0.00%
(2)	10	Res, Non-Heat	201,541	$13.00	$27.85	$14.00	$0.4386			$0.5456		$2,821,574	$2,004,302		$4,825,876			$174,498	$4,825,876	3.75%
(3)	11	Res,Low Income Non-Heat	2,492	$11.70	$27.85	$14.00	$0.3947			$0.5456		$34,888	$55,528		$90,416			$9,450	$90,416	11.67%
(4)		Total Non Heat	204,033							$0.5456		$2,878,610	$2,059,830		$4,938,440	$4,938,446	($7)	$183,948	$4,938,440	3.89%
(5)	12	Res, Heat Peak	1,261,573	$13.00	$28.06	$14.00	$0.4672	$0.3010	102.0%	$0.5534		$17,662,022	$79,719,660		$97,381,682			$3,225,964	$97,381,682	3.43%
(6)	12	Res, Heat Off-Peak	1,258,710	$13.00	$28.06	$14.00	$0.4672	$0.3010	91.4%	$0.4960		$17,621,940	$16,587,476		$34,209,416			($413,138)	$34,209,416	-1.19%
(7)		Total Residential Heat	2,520,283	$13.00	$28.06	$14.00	$0.4672	$0.3010				$35,283,962	$96,307,136		$131,591,098			$2,812,826	$131,591,098	2.18%
(8)	13	Res,Low Income Heat Peak	103,030	$11.70	$28.06	$14.00	$0.4205	$0.2709	102.0%	$0.5534		$1,442,420	$6,384,035		$7,826,455			$811,373	$7,826,455	11.57%
(9)	13	Res,Low Inc Heat Off-Peak	101,871	$11.70	$28.06	$14.00	$0.4205	$0.2709	91.4%	$0.4960		$1,426,194	$1,351,829		$2,778,023			$196,416	$2,778,023	7.61%
(10)		Total Heating Low Income	204,901	$11.70	$28.06	$14.00	$0.4205	$0.2709				$2,868,614	$7,735,863		$10,604,477			$1,007,789	$10,604,477	10.50%
(11)		Total Residential Heating	2,725,184			$14.00				$0.5425		$38,152,576	$104,042,999		$142,195,575	$142,199,062	($3,487)	$3,820,615	$142,195,575	2.76%
(12)	21	C&I Small Peak	111,874	$22.00	$44.79	$25.00	$0.5431	$0.2242	102.0%	$0.4852		$2,796,850	$9,242,260		$12,039,110			$308,756	$12,039,110	2.63%
(13)	21	C&I Small Off-Peak	111,049	$22.00	$44.79	$25.00	$0.5431	$0.2242	90.1%	$0.4284		$2,776,225	$1,644,549		$4,420,774			$277,359	$4,420,774	6.69%
(14)	21	C&I Small FT-2 Peak	4,163	$22.00	$44.79	$25.00	$0.5431	$0.2242	102.0%	$0.4852		$104,075	$675,793		$779,868			$9,375	$779,868	1.22%
(15)	21	C&I Small FT-2 Off-Peak	4,231	$22.00	$44.79	$25.00	$0.5431	$0.2242	90.1%	$0.4284		$105,775	$150,701		$256,476			$6,740	$256,476	2.70%
(16)		Total C&I Small	231,317	$22.00	$44.79	$25.00	$0.5431	$0.2242		$0.4757		$5,782,925	$11,713,304		$17,496,229	$17,500,938	($4,709)	$602,229	$17,496,229	3.56%
								Demand			Prop Dem									
(17)	22	C&I Medium Sales	40,181	$70.00	$105.88	$85.00	$0.1865	$1.30		$0.2484	$1.50	$3,415,385	$7,844,329	$3,618,518	$14,878,232			$460,072	$14,878,232	3.19%
(18)	22	C&I Medium FT-1	3,928	$70.00	$105.88	$85.00	$0.1865	$1.30		$0.2484	$1.50	$333,880	$1,321,976	$597,820	$2,253,676			$33,281	$2,253,676	1.50%
(19)	22	C&I Medium FT-2	18,305	$70.00	$105.88	$85.00	$0.1865	$1.30		$0.2484	$1.50	$1,555,925	$4,557,012	$2,050,351	$8,163,288			$184,808	$8,163,288	2.32%
(20)	22	Total C&I Medium	62,414	$70.00	$105.88	$85.00	$0.1865	$1.30		$0.2484	$1.50	$5,305,190	$13,723,317	$6,266,688	$25,295,196	$25,297,344	($2,149)	$678,161	$25,295,196	2.75%
(21)	33	C&I Large LLF Sales	1,404	$175.00	$216.28	$200.00	$0.1727	$1.30		$0.2429	$1.50	$280,800	$1,450,250	$806,903	$2,537,953			$55,663	$2,537,953	2.24%
(22)	33	C&I Large LLF FT-1	1,461	$175.00	$216.28	$200.00	$0.1727	$1.30		$0.2429	$1.50	$292,200	$1,982,197	$979,189	$3,253,586			$48,140	$3,253,586	1.50%
(23)	33	C&I Large LLF FT-2	2,608	$175.00	$216.28	$200.00	$0.1727	$1.30		$0.2429	$1.50	$521,600	$2,972,134	$1,490,152	$4,983,886			$85,540	$4,983,886	1.75%
(24)	33	Total C&I Large LLF	5,473	$175.00	$216.28	$200.00	$0.1727	$1.30		$0.2429	$1.50	$1,094,600	$6,404,581	$3,276,244	$10,775,425	$10,776,471	($1,045)	$189,343	$10,775,425	1.79%
(25)	23	C&I Large HLF Sales	670	$175.00	$191.72	$200.00	$0.1007	$1.80		$0.1617	$2.05	$134,000	$438,594	$125,433	$698,027			$17,301	$698,027	2.54%
(26)	23	C&I Large HLF FT-1	1,031	$175.00	$191.72	$200.00	$0.1007	$1.80		$0.1617	$2.05	$206,200	$834,627	$530,306	$1,571,134			$62,386	$1,571,134	4.13%
(27)	23	C&I Large HLF FT-2	735	$175.00	$191.72	$200.00	$0.1007	$1.80		$0.1617	$2.05	$147,000	$845,497	$495,174	$1,487,672			$50,336	$1,487,672	3.50%
(28)	23	Total C&I Large HLF	2,436	$175.00	$191.72	$200.00	$0.1007	$1.80		$0.1617	$2.05	$487,200	$2,118,719	$1,150,914	$3,756,833	$3,757,107	($275)	$130,024	$3,756,833	3.59%
(29)	34	C&I XLarge LLF Sales	48	$425.00	$491.66	$500.00	$0.0328	$1.30		$0.0421	$1.50	$24,000	$18,053	$65,343	$107,395			$6,407	$107,395	6.34%
(30)	34	C&I XLarge LLF FT-1	324	$425.00	$491.66	$500.00	$0.0328	$1.30		$0.0421	$1.50	$162,000	$472,425	$1,168,663	$1,803,088			$25,580	$1,803,088	1.44%
(31)	34	C&I XLarge LLF FT-2	36	$425.00	$491.66	$500.00	$0.0328	$1.30		$0.0421	$1.50	$18,000	$24,461	$58,801	$101,262			$2,538	$101,262	2.57%
(32)	34	Tot C&I XLarge LLF	408	$425.00	$491.66	$500.00	$0.0328	$1.30		$0.0421	$1.50	$204,000	$514,939	$1,292,806	$2,011,745	$2,012,782	($1,037)	$34,525	$2,011,745	1.75%
(33)	24	C&I XLarge HLF Sales	36	$425.00	$515.72	$500.00	$0.0256	$1.80		$0.0369	$2.05	$18,000	$28,088	$138,083	$184,171			$12,978	$184,171	7.58%
(34)	24	C&I XLarge HLF FT-1	888	$425.00	$515.72	$500.00	$0.0256	$1.80		$0.0369	$2.05	$444,000	$2,339,700	$4,796,903	$7,580,602			$105,030	$7,580,602	1.40%
(35)	24	C&I XLarge HLF FT-2	192	$425.00	$515.72	$500.00	$0.0256	$1.80		$0.0369	$2.05	$96,000	$200,861	$546,028	$842,889			$34,067	$842,889	4.21%
(36)	24	Tot C&I XLarge HLF	1,116	$425.00	$515.72	$500.00	$0.0256	$1.80		$0.0369	$2.05	$558,000	$2,568,649	$5,481,013	$8,607,663	$8,607,667	($4)	$152,075	$8,607,663	1.80%
(37)		Total	3,232,381									$54,463,101	$143,146,339	$17,467,665	$215,077,105	$215,089,817	($12,712)	$5,790,921	$215,077,105	2.77%

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The Narragansett Electric Company
Non-Firm Rates

	Rate Class	Current Customer Charge	Proposed Customer Charge	Annual Customers (1)	Customer Charges	Total Proposed Non-firm Revenue	Total Present Non-firm Revenue (1)	Total Non-firm Revenue Increase	Proposed Volumetric Rev	Non-firm Therms	Proposed Volumetric Rate	Final Base Percent Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(1)	Medium C&I											
(2)	Large Low Load Factor C&I											
(3)	Large High Load Factor C&I											
(4)	Extra Large Low Load Factor C&I	$625	$625	24	$15,000	$469,722	$463,320	$6,402	$454,722	4,947,118	$0.0919	1.38%
(5)	Extra Large High Load Factor C&I	$625	$625	96	$60,000	$986,125	$972,685	$13,440	$926,125	12,533,193	$0.0738	1.38%
(6)	Total			120	$75,000	$1,455,848	$1,436,005	$19,843	$1,380,848	17,480,311		1.38%

Notes:
(1) Source file is "Non Firm Revenue Detail Apr 16-Jun 17 Rev 11-15.xlsx"

The Narragansett Electric Company
Gas Base Distribution Revenue Requirement and
Increases for Data Years 2 and 3

Section 1: Distribution Revenue Requirement and Data Year Increases

		Year 1	Year 2	Year 3
(1)	Base Distribution Revenue Requirement	$215,089,817	$215,089,817	$222,752,188
(2)	Annual Increase in Base Distribution Revenue Requirement		$5,726,761	$3,362,798
(3)	Incremental Grid Modernization Revenue Requirement	$0	$1,935,610	$587,318
(4)	Total	$215,089,817	$222,752,188	$226,702,304
(5)	Yearly Increase		$7,662,371	$3,950,116

Section 2: Allocation of Data Year Increases to Rate Classes

		Rate Year Base Rate Revenue Requirement	Allocation of Year 2 Increase	Year 2 Increase	Year 2 Base Rate Revenue Requirement	Allocation of Year 3 Increase	Year 3 Increase	Year 3 Base Rate Revenue Requirement
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(6)	Rate 10/11/80	$4,938,440	2.3%	$175,938	$5,114,378	2.3%	$90,700	$5,205,078
(7)	Rate 12/13	$142,195,575	66.1%	$5,065,882	$147,261,457	66.1%	$2,611,570	$149,873,027
(8)	Rate 21	$17,496,229	8.1%	$623,323	$18,119,552	8.1%	$321,337	$18,440,889
(9)	Rate 22	$25,295,196	11.8%	$901,171	$26,196,367	11.8%	$464,573	$26,660,940
(10)	Rate 23 Low Load	$10,775,425	5.0%	$383,887	$11,159,312	5.0%	$197,902	$11,357,214
(11)	Rate 23 High Load	$3,756,833	1.7%	$133,842	$3,890,675	1.7%	$68,998	$3,959,673
(12)	Rate 24 Low Load	$2,011,745	0.9%	$71,671	$2,083,416	0.9%	$36,948	$2,120,364
(13)	Rate 24 High Load	$8,607,663	4.0%	$306,657	$8,914,320	4.0%	$158,088	$9,072,408
(14)	Total	$215,077,105	100.0%	$7,662,371	$222,739,476	100.0%	$3,950,116	$226,689,592

(1) Compliance Attachment 2
(2) Compliance Attachment 1
(a) Lines (6) thru (13): Page 5, Column (m)
(b) Each line in Column (a) as a percent of Column (a), Line (14)
(c) (Line (2) + Line (3)) x Column (b)
(d) Column (a) + Column (c)
(e) Each line in Column (d) as a percent of Column (d), Line (14)
(f) (Line (2) +Line (3)) x Column (e)
(g) Column (d) + Column (f)

The Narragansett Electric Company
Rate Design Year 2

	Rate		Annual Customers	Weather Normalized Sales: Sales (therms)	Transp (therms)	Total Therms	MADQ Demand Therms	Year 1 Distribution Rates: Customer Charge	Dist Chrg Therms	Demand Per Therms	Year 1 Base Revenues	Year 2 Base Revenue	Revenue Increase	Percent Increase Equal ROR	Initial Target Rev Req for Class	Year 2 Charges: Customer Charges	Seasonal Adj	Dist Chrg Therms	Demand Per Therm	Year 2 Revenue Recovery: Customer Charges	Dist Chrg	MADQ	Total Revenues @ Year 2 Rates
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
(1)	80	Gas Lights	2,326	0	0	0		$9.52			$22,148	$22,937	$789	3.56%	$22,937	$9.52				$22,148			$22,148
(2)	10	Res, Non-Heat	201,541	3,673,573	0	3,673,573		$14.00	$0.5456		$4,825,876	$4,997,803	$171,928	3.56%	$4,997,803	$14.00		$0.5922		$2,821,574	$2,175,490		$4,997,064
(3)	11	Res,Low Income Non-Heat	2,492	101,774	0	101,774		$14.00	$0.5456		$90,416	$93,637	$3,221	3.56%	$93,637	$14.00		$0.5922		$34,888	$60,271		$95,159
(4)		Total Non Heat	204,033	3,775,348	0	3,775,348		$14.00	$0.5456		$4,938,440	$5,114,378	$175,938	3.56%	$5,114,378			$0.5922		$2,878,610	$2,235,761		$5,114,371
(5)	12	Res, Heat Peak	1,261,573	144,054,319	0	144,054,319		$14.00	$0.5534		$97,381,682	$100,851,017	$3,469,335	3.56%	$100,851,017	$14.00	102.0%	$0.5803		$17,662,022	$83,600,662		$101,262,684
(6)	12	Res, Heat Off-Peak	1,258,710	33,442,491	0	33,442,491		$14.00	$0.4960		$34,209,416	$35,428,166	$1,218,750	3.56%	$35,428,166	$14.00	91.4%	$0.5201		$17,621,940	$17,394,682		$35,016,622
(7)		Total Heating	2,520,283	177,496,810	0	177,496,810		$14.00								$14.00				$35,283,962	$100,995,344		$136,279,306
(8)	13	Res,Low Income Heat Peak	103,030	11,536,022	0	11,536,022		$14.00	$0.5534		$7,826,455	$8,105,281	$278,827	3.56%	$8,105,281	$14.00	102.0%	$0.5803		$1,442,420	$6,694,829		$8,137,249
(9)	13	Res,Low Inc Heat Off-Peak	101,871	2,725,461	0	2,725,461		$14.00	$0.4960		$2,778,023	$2,876,993	$98,970	3.56%	$2,876,993	$14.00	91.4%	$0.5201		$1,426,194	$1,417,614		$2,843,808
(10)		Total Heating Low Income	204,901	14,261,483	0	14,261,483		$14.00	$0.0000							$14.00				$2,868,614	$8,112,443		$10,981,057
(11)		Total Heating	2,725,184	191,758,293	0	191,758,293		$14.00	$0.5425		$142,195,575	$147,261,457	$5,065,882	3.56%	$147,261,457	$14.00		$0.5689		$38,152,576	$109,107,786		$147,260,362
(12)	21	C&I Small Peak	111,874	19,048,352	0	19,048,352		$25.00	$0.4852		$12,039,110	$12,468,017	$428,907	3.56%	$12,468,017	$25.00	102.0%	$0.5109		$2,796,850	$9,731,263		$12,528,113
(13)	21	C&I Small Off-Peak	111,049	3,838,817	0	3,838,817		$25.00	$0.4284		$4,420,774	$4,578,269	$157,495	3.56%	$4,578,269	$25.00	90.1%	$0.4510		$2,776,225	$1,731,386		$4,507,611
(14)	21	C&I Small FT-2 Peak	4,163	0	1,392,814	1,392,814		$25.00	$0.4852		$779,868	$807,652	$27,784	3.56%	$807,652	$25.00	102.0%	$0.5109		$104,075	$711,549		$815,624
(15)	21	C&I Small FT-2 Off-Peak	4,231	0	351,777	351,777		$25.00	$0.4284		$256,476	$265,613	$9,137	3.56%	$265,613	$25.00	90.1%	$0.4510		$105,775	$158,659		$264,434
(16)		Total C&I Small	231,317	22,887,169	1,744,590	24,631,759		$25.00	$0.4757		$17,496,229	$18,119,552	$623,323	3.56%	$18,119,552	$25.00		$0.5008		$5,782,925	$12,332,857		$18,115,782
(17)	22	C&I Medium Sales	40,181	31,579,424	0	31,579,424	2,412,345	$85.00	$0.2484	$1.50	$14,878,232	$15,408,286	$530,054	3.56%	$15,408,286	$85.00		$0.2647	$1.50	$3,415,385	$8,359,073	$3,618,518	$15,392,976
(18)	22	C&I Medium FT-1	3,928	0	5,321,965	5,321,965	398,547	$85.00	$0.2484	$1.50	$2,253,676	$2,333,966	$80,290	3.56%	$2,333,966	$85.00		$0.2647	$1.50	$333,880	$1,408,724	$597,820	$2,340,424
(19)	22	C&I Medium FT-2	18,305	0	18,345,461	18,345,461	1,366,900	$85.00	$0.2484	$1.50	$8,163,288	$8,454,115	$290,827	3.56%	$8,454,115	$85.00		$0.2647	$1.50	$1,555,925	$4,856,043	$2,050,351	$8,462,319
(20)	22	Total C&I Medium	62,414	31,579,424	23,667,426	55,246,850	4,177,792	$85.00	$0.2484	$1.50	$25,295,196	$26,196,367	$901,171	3.56%	$26,196,367	$85.00		$0.2647	$1.50	$5,305,190	$14,623,841	$6,266,688	$26,195,719
			0	0	0																		
(21)	33	C&I Large LLF Sales	1,404	5,970,565	0	5,970,565	537,935	$200.00	$0.2429	$1.50	$2,537,953	$2,628,371	$90,418	3.56%	$2,628,371	$200.00		$0.2574	$1.50	$280,800	$1,536,823	$806,903	$2,624,526
(22)	33	C&I Large LLF FT-1	1,461	0	8,160,548	8,160,548	652,793	$200.00	$0.2429	$1.50	$3,253,586	$3,369,499	$115,913	3.56%	$3,369,499	$200.00		$0.2574	$1.50	$292,200	$2,100,525	$979,189	$3,371,914
(23)	33	C&I Large LLF FT-2	2,608	0	12,236,040	12,236,040	993,434	$200.00	$0.2429	$1.50	$4,983,886	$5,161,442	$177,557	3.56%	$5,161,442	$200.00		$0.2574	$1.50	$521,600	$3,149,557	$1,490,152	$5,161,308
(24)	33	Total C&I Large LLF	5,473	5,970,565	20,396,587	26,367,153	2,184,163	$200.00	$0.2429	$1.50	$10,775,425	$11,159,312	$383,887	3.56%	$11,159,312	$200.00		$0.2574	$1.50	$1,094,600	$6,786,905	$3,276,244	$11,157,749
(25)	23	C&I Large HLF Sales	670	2,712,395	0	2,712,395	61,187	$200.00	$0.1617	$2.05	$698,027	$722,895	$24,868	3.56%	$722,895	$200.00		$0.1719	$2.05	$134,000	$466,261	$125,433	$725,694
(26)	23	C&I Large HLF FT-1	1,031	0	5,161,579	5,161,579	258,686	$200.00	$0.1617	$2.05	$1,571,134	$1,627,107	$55,974	3.56%	$1,627,107	$200.00		$0.1719	$2.05	$206,200	$887,275	$530,306	$1,623,782
(27)	23	C&I Large HLF FT-2	735	0	5,228,802	5,228,802	241,549	$200.00	$0.1617	$2.05	$1,487,672	$1,540,672	$53,000	3.56%	$1,540,672	$200.00		$0.1719	$2.05	$147,000	$898,831	$495,174	$1,541,006
(28)	23	Total C&I Large HLF	2,436	2,712,395	10,390,381	13,102,776	561,421	$200.00	$0.1617	$2.05	$3,756,833	$3,890,675	$133,842	3.56%	$3,890,675	$200.00		$0.1719	$2.05	$487,200	$2,252,367	$1,150,914	$3,890,481
(29)	34	C&I XLarge LLF Sales	48	428,805	0	428,805	43,562	$500.00	$0.0421	$1.50	$107,395	$111,221	$3,826	3.56%	$111,221	$500.00		$0.0479	$1.50	$24,000	$20,540	$65,343	$109,882
(30)	34	C&I XLarge LLF FT-1	324	0	11,221,498	11,221,498	779,109	$500.00	$0.0421	$1.50	$1,803,088	$1,867,325	$64,237	3.56%	$1,867,325	$500.00		$0.0479	$1.50	$162,000	$537,510	$1,168,663	$1,868,173
(31)	34	C&I XLarge LLF FT-2	36	0	581,031	581,031	39,201	$500.00	$0.0421	$1.50	$101,262	$104,870	$3,608	3.56%	$104,870	$500.00		$0.0479	$1.50	$18,000	$27,831	$58,801	$104,632
(32)	34	Tot C&I XLarge LLF	408	428,805	11,802,529	12,231,334	861,871	$500.00	$0.0421	$1.50	$2,011,745	$2,083,416	$71,671	3.56%	$2,083,416	$500.00		$0.0479	$1.50	$204,000	$585,881	$1,292,806	$2,082,687
(33)	24	C&I XLarge HLF Sales	36	761,197	0	761,197	67,357	$500.00	$0.0369	$2.05	$184,171	$190,732	$6,561	3.56%	$190,732	$500.00		$0.0413	$2.05	$18,000	$31,437	$138,083	$187,520
(34)	24	C&I XLarge HLF FT-1	888	0	63,406,498	63,406,498	2,339,952	$500.00	$0.0369	$2.05	$7,580,602	$7,850,669	$270,067	3.56%	$7,850,669	$500.00		$0.0413	$2.05	$444,000	$2,618,688	$4,796,903	$7,859,591
(35)	24	C&I XLarge HLF FT-2	192	0	5,443,394	5,443,394	266,355	$500.00	$0.0369	$2.05	$842,889	$872,918	$30,029	3.56%	$872,918	$500.00		$0.0413	$2.05	$96,000	$224,812	$546,028	$866,840
(36)	24	Tot C&I XLarge HLF	1,116	761,197	68,849,892	69,611,089	2,673,665	$500.00	$0.0369	$2.05	$8,607,663	$8,914,320	$306,657	3.56%	$8,914,320	$500.00		$0.0413	$2.05	$558,000	$2,874,938	$5,481,013	$8,913,951
(37)		Total	3,232,381	259,873,195	136,851,405	396,724,601	10,458,912				$215,077,105	$222,739,476	$7,662,371	3.56%	$222,739,476						$150,800,337	$17,467,665	$222,731,103

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company
Rate Design Year 3

	Rate		Annual Customers	Weather Normalized Sales: Sales (therms)	Weather Normalized Sales: Transp (therms)	Weather Normalized Sales: Total Therms	MADQ Demand Therms	Year 2 Distribution Rates: Customer Charge	Year 2 Distribution Rates: Dist Chrg Therms	Year 2 Distribution Rates: Demand Per Therms	Year 2 Base Revenues	Year 3 Base Revenue	Revenue Increase	Percent Increase Equal ROR	Initial Target Rev Req for Class	Year 3 Charges: Customer Charges	Year 3 Charges: Seasonal Adj	Year 3 Charges: Dist Chrg Therms	Demand Per Therm	Year 3 Revenue Recovery: Customer Charges	Year 3 Revenue Recovery: Dist Chrg	Year 3 Revenue Recovery: MADQ	Total Revenues @ Year 3 Rates
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
(1)	80	Gas Lights	2,326	0	0	0		$9.52			$22,148	$22,541	$393	1.77%	$22,541	$9.52				$22,148			$22,148
(2)	10	Res, Non-Heat	201,541	3,673,573	0	3,673,573		$14.00	$0.5922		$4,997,064	$5,085,691	$88,626	1.77%	$5,085,691	$14.00		$0.6162		$2,821,574	$2,263,656		$5,085,230
(3)	11	Res,Low Income Non-Heat	2,492	101,774	0	101,774		$14.00	$0.5922		$95,159	$96,846	$1,688	1.77%	$96,846	$14.00		$0.6162		$34,888	$62,713		$97,601
(4)		Total Non Heat	204,033	3,775,348	0	3,775,348		$0.00	$0.5922		$5,114,371	$5,205,078	$90,707	1.77%	$5,205,078			$0.6162		$2,878,610	$2,326,369		$5,204,979
(5)	12	Res, Heat Peak	1,261,573	144,054,319	0	144,054,319		$14.00	$0.5803		$101,262,684	$103,059,267	$1,796,583	1.77%	$103,059,267	$14.00	102.0%	$0.5943		$17,662,022	$85,613,896		$103,275,918
(6)	12	Res, Heat Off-Peak	1,258,710	33,442,491	0	33,442,491		$14.00	$0.5201		$35,016,622	$35,637,880	$621,258	1.77%	$35,637,880	$14.00	91.4%	$0.5327		$17,621,940	$17,813,573		$35,435,513
(7)		Total Heating	2,520,283	177,496,810	0	177,496,810		$14.00	$0.0000							$14.00				$35,283,962	$103,427,469		$138,711,431
(8)	13	Res,Low Income Heat Peak	103,030	11,536,022	0	11,536,022		$14.00	$0.5803		$8,137,249	$8,281,619	$144,369	1.77%	$8,281,619	$14.00	102.0%	$0.5943		$1,442,420	$6,856,051		$8,298,471
(9)	13	Res,Low Inc Heat Off-Peak	101,871	2,725,461	0	2,725,461		$14.00	$0.5201		$2,843,808	$2,894,262	$50,454	1.77%	$2,894,262	$14.00	91.4%	$0.5327		$1,426,194	$1,451,752		$2,877,946
(10)		Total Heating Low Income	204,901	14,261,483	0	14,261,483		$14.00	$0.0000							$14.00				$2,868,614	$8,307,803		$11,176,417
(11)		Total Heating	2,725,184	191,758,293	0	191,758,293		$14.00	$0.5689		$147,260,362	$149,873,027	$2,612,665	1.77%	$149,873,027	$14.00		$0.5826		$38,152,576	$111,735,272		$149,887,848
(12)	21	C&I Small Peak	111,874	19,048,352	0	19,048,352		$25.00	$0.5109		$12,528,113	$12,752,943	$224,830	1.79%	$12,752,943	$25.00	102.0%	$0.5241		$2,796,850	$9,983,872		$12,780,722
(13)	21	C&I Small Off-Peak	111,049	3,838,817	0	3,838,817		$25.00	$0.4510		$4,507,611	$4,588,505	$80,894	1.79%	$4,588,505	$25.00	90.1%	$0.4627		$2,776,225	$1,776,330		$4,552,555
(14)	21	C&I Small FT-2 Peak	4,163	0	1,392,814	1,392,814		$25.00	$0.5109		$815,624	$830,261	$14,637	1.79%	$830,261	$25.00	102.0%	$0.5241		$104,075	$730,020		$834,095
(15)	21	C&I Small FT-2 Off-Peak	4,231	0	351,777	351,777		$25.00	$0.4510		$264,434	$269,179	$4,746	1.79%	$269,179	$25.00	90.1%	$0.4627		$105,775	$162,777		$268,552
(16)		Total C&I Small	231,317	22,887,169	1,744,590	24,631,759		$25.00	$0.5008		$18,115,782	$18,440,889	$325,107	1.79%	$18,440,889	$25.00		$0.5138		$5,782,925	$12,652,999		$18,435,924
(17)	22	C&I Medium Sales	40,181	31,579,424	0	31,579,424	2,412,345	$85.00	$0.2647	$1.50	$15,392,976	$15,666,346	$273,370	1.78%	$15,666,346	$85.00		$0.2731	$1.50	$3,415,385	$8,624,341	$3,618,518	$15,658,243
(18)	22	C&I Medium FT-1	3,928	0	5,321,965	5,321,965	398,547	$85.00	$0.2647	$1.50	$2,340,424	$2,381,989	$41,565	1.78%	$2,381,989	$85.00		$0.2731	$1.50	$333,880	$1,453,429	$597,820	$2,385,128
(19)	22	C&I Medium FT-2	18,305	0	18,345,461	18,345,461	1,366,900	$85.00	$0.2647	$1.50	$8,462,319	$8,612,605	$150,286	1.78%	$8,612,605	$85.00		$0.2731	$1.50	$1,555,925	$5,010,145	$2,050,351	$8,616,421
(20)	22	Total C&I Medium	62,414	31,579,424	23,667,426	55,246,850	4,177,792	$85.00	$0.2647	$1.50	$26,195,719	$26,660,940	$465,220	1.78%	$26,660,940	$85.00		$0.2731	$1.50	$5,305,190	$15,087,915	$6,266,688	$26,659,793
			0	0	0																		
(21)	33	C&I Large LLF Sales	1,404	5,970,565	0	5,970,565	537,935	$200.00	$0.2574	$1.50	$2,624,526	$2,671,445	$46,918	1.79%	$2,671,445	$200.00		$0.2649	$1.50	$280,800	$1,581,603	$806,903	$2,669,306
(22)	33	C&I Large LLF FT-1	1,461	0	8,160,548	8,160,548	652,793	$200.00	$0.2574	$1.50	$3,371,914	$3,432,194	$60,279	1.79%	$3,432,194	$200.00		$0.2649	$1.50	$292,200	$2,161,729	$979,189	$3,433,118
(23)	33	C&I Large LLF FT-2	2,608	0	12,236,040	12,236,040	993,434	$200.00	$0.2574	$1.50	$5,161,308	$5,253,576	$92,268	1.79%	$5,253,576	$200.00		$0.2649	$1.50	$521,600	$3,241,327	$1,490,152	$5,253,078
(24)	33	Total C&I Large LLF	5,473	5,970,565	20,396,587	26,367,153	2,184,163	$200.00	$0.2574	$1.50	$11,157,749	$11,357,214	$199,465	1.79%	$11,357,214	$200.00		$0.2649	$1.50	$1,094,600	$6,984,659	$3,276,244	$11,355,503
(25)	23	C&I Large HLF Sales	670	2,712,395	0	2,712,395	61,187	$200.00	$0.1719	$2.05	$725,694	$738,600	$12,906	1.78%	$738,600	$200.00		$0.1771	$2.05	$134,000	$480,365	$125,433	$739,798
(26)	23	C&I Large HLF FT-1	1,031	0	5,161,579	5,161,579	258,686	$200.00	$0.1719	$2.05	$1,623,782	$1,652,660	$28,879	1.78%	$1,652,660	$200.00		$0.1771	$2.05	$206,200	$914,116	$530,306	$1,650,622
(27)	23	C&I Large HLF FT-2	735	0	5,228,802	5,228,802	241,549	$200.00	$0.1719	$2.05	$1,541,006	$1,568,412	$27,407	1.78%	$1,568,412	$200.00		$0.1771	$2.05	$147,000	$926,021	$495,174	$1,568,195
(28)	23	Total C&I Large HLF	2,436	2,712,395	10,390,381	13,102,776	561,421	$200.00	$0.1719	$2.05	$3,890,481	$3,959,673	$69,192	1.78%	$3,959,673	$200.00		$0.1771	$2.05	$487,200	$2,320,502	$1,150,914	$3,958,615
(29)	34	C&I XLarge LLF Sales	48	428,805	0	428,805	43,562	$500.00	$0.0479	$1.50	$109,882	$111,870	$1,988	1.81%	$111,870	$500.00		$0.0509	$1.50	$24,000	$21,826	$65,343	$111,169
(30)	34	C&I XLarge LLF FT-1	324	0	11,221,498	11,221,498	779,109	$500.00	$0.0479	$1.50	$1,868,173	$1,901,969	$33,797	1.81%	$1,901,969	$500.00		$0.0509	$1.50	$162,000	$571,174	$1,168,663	$1,901,837
(31)	34	C&I XLarge LLF FT-2	36	0	581,031	581,031	39,201	$500.00	$0.0479	$1.50	$104,632	$106,525	$1,893	1.81%	$106,525	$500.00		$0.0509	$1.50	$18,000	$29,574	$58,801	$106,375
(32)	34	Tot C&I XLarge LLF	408	428,805	11,802,529	12,231,334	861,871	$500.00	$0.0479	$1.50	$2,082,687	$2,120,364	$37,677	1.81%	$2,120,364	$500.00		$0.0509	$1.50	$204,000	$622,575	$1,292,806	$2,119,381
(33)	24	C&I XLarge HLF Sales	36	761,197	0	761,197	67,357	$500.00	$0.0413	$2.05	$187,520	$190,853	$3,333	1.78%	$190,853	$500.00		$0.0435	$2.05	$18,000	$33,112	$138,083	$189,195
(34)	24	C&I XLarge HLF FT-1	888	0	63,406,498	63,406,498	2,339,952	$500.00	$0.0413	$2.05	$7,859,591	$7,999,305	$139,714	1.78%	$7,999,305	$500.00		$0.0435	$2.05	$444,000	$2,758,183	$4,796,903	$7,999,085
(35)	24	C&I XLarge HLF FT-2	192	0	5,443,394	5,443,394	266,355	$500.00	$0.0413	$2.05	$866,840	$882,250	$15,409	1.78%	$882,250	$500.00		$0.0435	$2.05	$96,000	$236,788	$546,028	$878,816
(36)	24	Tot C&I XLarge HLF	1,116	761,197	68,849,892	69,611,089	2,673,665	$500.00	$0.0413	$2.05	$8,913,951	$9,072,408	$158,456	1.78%	$9,072,408	$500.00		$0.0435	$2.05	$558,000	$3,028,082	$5,481,013	$9,067,096
(37)		Total	3,232,381	259,873,195	136,851,405	396,724,601	10,458,912				$222,731,103	$226,689,592	$3,958,489	1.78%	$226,689,592						$154,758,373	$17,467,665	$226,689,139

Revenue Per Customer for RDM

	Illustrative Year 1	Sep-18 (a)	Oct-18 (b)	Nov-18 (c)	Dec-18 (d)	Jan-19 (e)	Feb-19 (f)	Mar-19 (g)	Apr-19 (h)	May-19 (i)	Jun-19 (j)	Jul-19 (k)	Aug-19 (l)	Total Sep 18-Aug19 (m)
	Residential non-heat													
(1)	Number of Customers	17,323	17,314	17,273	17,225	17,144	17,034	16,952	16,842	16,791	16,742	16,707	16,686	
(2)	Final Revenue Requirement	$324,756	$339,306	$377,209	$446,030	$494,252	$482,385	$574,234	$495,270	$404,170	$349,419	$318,681	$310,582	
(3)	Revenue Per Customer	$18.74	$19.59	$21.83	$25.89	$28.82	$28.31	$33.87	$29.40	$24.07	$20.87	$19.07	$18.61	**$289**
	Residential heat													
(4)	Number of Customers	223,841	224,029	224,567	225,660	227,181	228,469	229,303	229,423	229,132	228,571	227,825	227,183	
(5)	Final Revenue Requirement	$5,312,200	$5,854,384	$9,988,526	$15,940,393	$21,147,941	$22,875,015	$20,330,962	$14,925,301	$8,900,902	$6,306,649	$5,405,152	$5,208,150	
(6)	Revenue Per Customer	$23.73	$26.13	$44.47	$70.63	$93.08	$100.12	$88.66	$65.05	$38.84	$27.59	$23.72	$22.92	**$625**
	Small C&I													
(7)	Number of Customers	19,003	18,915	18,966	19,086	19,289	19,487	19,601	19,608	19,544	19,429	19,272	19,117	
(8)	Final Revenue Requirement	$693,886	$747,386	$1,126,348	$2,006,893	$2,608,185	$2,719,228	$2,510,442	$1,847,882	$1,037,299	$833,060	$689,948	$675,670	
(9)	Revenue Per Customer	$36.51	$39.51	$59.38	$105.15	$135.21	$139.54	$128.07	$94.24	$53.07	$42.87	$35.80	$35.34	**$905**
	Medium C&I													
(10)	Number of Customers	5,146	5,153	5,162	5,173	5,188	5,201	5,211	5,220	5,227	5,236	5,244	5,253	
(11)	Final Revenue Requirement	$1,455,858	$1,611,296	$1,901,454	$2,584,176	$3,078,390	$2,981,862	$2,906,231	$2,396,340	$1,870,795	$1,482,101	$1,514,612	$1,512,083	
(12)	Revenue Per Customer	$282.91	$312.69	$368.35	$499.55	$593.36	$573.32	$557.71	$459.06	$357.90	$283.05	$288.82	$287.85	**$4,865**

	Illustrative Year 2	Sep-19 (a)	Oct-19 (b)	Nov-19 (c)	Dec-19 (d)	Jan-20 (e)	Feb-20 (f)	Mar-20 (g)	Apr-20 (h)	May-20 (i)	Jun-20 (j)	Jul-20 (k)	Aug-20 (l)	Sep 19-Aug 20 (m)
	Residential non-heat													
(13)	Number of Customers	17,323	17,314	17,273	17,225	17,144	17,034	16,952	16,842	16,791	16,742	16,707	16,686	
(14)	Final Revenue Requirement	$331,779	$347,583	$388,772	$463,529	$515,966	$503,217	$603,010	$517,432	$418,612	$359,243	$325,923	$317,157	
(15)	Revenue Per Customer	$19.15	$20.07	$22.50	$26.91	$30.09	$29.54	$35.57	$30.72	$24.93	$21.45	$19.50	$19.00	**$299**
	Residential heat													
(16)	Number of Customers	223,841	224,029	224,567	225,660	227,181	228,469	229,303	229,423	229,132	228,571	227,825	227,183	
(17)	Final Revenue Requirement	$5,418,209	$5,986,652	$10,321,742	$16,562,620	$22,022,650	$23,832,925	$21,164,452	$15,495,544	$9,177,946	$6,457,830	$5,512,970	$5,306,821	
(18)	Revenue Per Customer	$24.20	$26.72	$45.96	$73.39	$96.93	$104.31	$92.29	$67.54	$40.05	$28.25	$24.19	$23.35	**$647**
	Small C&I													
(19)	Number of Customers	19,003	18,915	18,966	19,086	19,289	19,487	19,601	19,608	19,544	19,429	19,272	19,117	
(20)	Final Revenue Requirement	$705,440	$761,880	$1,160,856	$2,087,831	$2,720,668	$2,837,325	$2,617,342	$1,919,716	$1,066,272	$851,400	$700,940	$686,112	
(21)	Revenue Per Customer	$37.12	$40.27	$61.20	$109.39	$141.04	$145.60	$133.53	$97.90	$54.55	$43.82	$36.37	$35.89	**$937**
	Medium C&I													
(22)	Number of Customers	5,146	5,153	5,162	5,173	5,188	5,201	5,211	5,220	5,227	5,236	5,244	5,253	
(23)	Final Revenue Requirement	$1,482,873	$1,647,879	$1,964,328	$2,695,267	$3,220,392	$3,117,355	$3,037,257	$2,493,003	$1,933,630	$1,518,982	$1,543,499	$1,541,254	
(24)	Revenue Per Customer	$288.16	$319.79	$380.53	$521.02	$620.73	$599.37	$582.85	$477.58	$369.93	$290.10	$294.33	$293.40	**$5,038**

	Illustrative Year 3	Sep-20 (a)	Oct-20 (b)	Nov-20 (c)	Dec-20 (d)	Jan-21 (e)	Feb-21 (f)	Mar-21 (g)	Apr-21 (h)	May-21 (i)	Jun-21 (j)	Jul-21 (k)	Aug-21 (l)	Sep 20-Aug 21 (m)
	Residential non-heat													
(25)	Number of Customers	17,323	17,314	17,273	17,225	17,144	17,034	16,952	16,842	16,791	16,742	16,707	16,686	
(26)	Final Revenue Requirement	$335,397	$351,846	$394,727	$472,540	$527,149	$513,946	$617,830	$528,846	$426,051	$364,303	$329,652	$320,543	
(27)	Revenue Per Customer	$19.36	$20.32	$22.85	$27.43	$30.74	$30.17	$36.44	$31.40	$25.37	$21.75	$19.73	$19.21	**$305**
	Residential heat													
(28)	Number of Customers	223,841	224,029	224,567	225,660	227,181	228,469	229,303	229,423	229,132	228,571	227,825	227,183	
(29)	Final Revenue Requirement	$5,473,222	$6,055,290	$10,494,594	$16,885,394	$22,476,397	$24,329,833	$21,596,818	$15,791,354	$9,321,716	$6,536,284	$5,568,922	$5,358,024	
(30)	Revenue Per Customer	$24.45	$27.02	$46.73	$74.82	$98.93	$106.49	$94.18	$68.83	$40.68	$28.59	$24.44	$23.58	**$659**
	Small C&I													
(31)	Number of Customers	19,003	18,915	18,966	19,086	19,289	19,487	19,601	19,608	19,544	19,429	19,272	19,117	
(32)	Final Revenue Requirement	$711,421	$769,383	$1,178,681	$2,129,642	$2,778,775	$2,898,331	$2,672,563	$1,956,824	$1,081,267	$860,892	$706,628	$691,516	
(33)	Revenue Per Customer	$37.43	$40.67	$62.14	$111.58	$144.06	$148.73	$136.34	$99.79	$55.32	$44.30	$36.66	$36.17	**$953**
	Medium C&I													
(34)	Number of Customers	5,146	5,153	5,162	5,173	5,188	5,201	5,211	5,220	5,227	5,236	5,244	5,253	
(35)	Final Revenue Requirement	$1,496,795	$1,666,731	$1,996,729	$2,752,516	$3,293,571	$3,187,180	$3,104,779	$2,542,815	$1,966,013	$1,537,988	$1,558,386	$1,556,287	
(36)	Revenue Per Customer	$290.86	$323.44	$386.81	$532.09	$634.84	$612.80	$595.81	$487.12	$376.12	$293.73	$297.17	$296.26	**$5,127**

Compliance Attachment 17

Compliance Attachment 17

Narragansett Gas Bill Impacts:

November 1, 2017 vs. Rate Year 1

Rate Year 1 vs. Rate Year 2

Rate Year 2 vs. Rate Year 3

Summary of Current and Proposed Rates

		Reference	Residential Non Heating	Low Income Residential Non Heating	Residential Heating	Low Income Residential Heating	Small C&I	Medium C&I	Large Low Load Factor C&I	Large High Load Factor C&I	XLarge Low Load Factor C&I	XLarge High Load Factor C&I
	Current Rates in effect November 1, 2017		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
(1)	Customer Charge	Docket No. 4323	$13.00	$11.70	$13.00	$11.70	$22.00	$70.00	$175.00	$175.00	$425.00	$425.00
	Peak											
(2)	Headblock	Docket No. 4323	$0.4386	$0.3947	$0.4672	$0.4205	$0.5431	$0.1865	$0.1727	$0.1007	$0.0328	$0.0256
(3)	Tailblock	Docket No. 4323	$0.0000	$0.0000	$0.3010	$0.2709	$0.2242					
(4)	Off Peak											
(5)	Headblock	Docket No. 4323	$0.4386	$0.3947	$0.4672	$0.4205	$0.5431	$0.1865	$0.1727	$0.1007	$0.0328	$0.0256
(6)	Tailblock	Docket No. 4323			$0.3010	$0.2709	$0.2242					
(7)	Demand	Docket No. 4323						$1.30	$1.30	$1.80	$1.30	$1.80
(8)	GCR	Docket No. 4719	$0.4859	$0.4859	$0.5291	$0.5291	$0.5291	$0.5291	$0.5291	$0.4859	$0.5291	$0.4859
(9)	Base DAC	Docket No. 4708	$0.0481	$0.0481	$0.0209	$0.0209	$0.0310	$0.0202	$0.0140	$0.0098	($0.0004)	($0.0020)
(10)	ISR Factor	Docket No. 4678	$0.1908	$0.1908	$0.1221	$0.1221	$0.1327	$0.0890	$0.0846	$0.0808	$0.0239	$0.0217
(11)	Total DAC		$0.2389	$0.2389	$0.1430	$0.1430	$0.1637	$0.1092	$0.0986	$0.0906	$0.0235	$0.0197
(12)	Energy Efficiency Factor	Docket No. 4654	$0.0888	$0.0888	$0.0888	$0.0888	$0.0726	$0.0726	$0.0726	$0.0726	$0.0726	$0.0726
(13)	LIHEAP Enhancement		$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81
	Proposed Rates Year 1											
(14)	Customer Charge	Compliance Attachment 16, Pg 1, Ln (8)	$14.00	$14.00	$14.00	$14.00	$25.00	$85.00	$200.00	$200.00	$500.00	$500.00
(15)	Peak											
(16)	Volumetric	Compliance Attachment 16, Pg 1, Ln (10)	$0.5456	$0.5456	$0.5534	$0.5534	$0.4852	$0.2484	$0.2429	$0.1617	$0.0421	$0.0369
(17)	Off Peak											
(18)	Volumetric	Compliance Attachment 16, Pg 1, Ln (12)	$0.5456	$0.5456	$0.4960	$0.4960	$0.4284	$0.2484	$0.2429	$0.1617	$0.0421	$0.0369
(19)	Demand	Compliance Attachment 16, Pg 1, Ln (13)						$1.50	$1.50	$2.05	$1.50	$2.05
(20)	GCR	Compliance Attachment 18, Workpaper 8, Pg 1	$0.4797	$0.4797	$0.5226	$0.5226	$0.5226	$0.5226	$0.5226	$0.4797	$0.5226	$0.4797
(21)	Base DAC	Compliance Attachment 18, Workpaper 8, Pg 6, Section 2, Column (E) excluding LIDRF	$0.0477	$0.0475	$0.0208	$0.0206	$0.0307	$0.0201	$0.0139	$0.0097	($0.0004)	($0.0019)
(22)	Low Income Discount Recovery Factor (LIDRF)	Compliance Attachment 18, Workpaper 8, Pg 6, Ln 3	$0.0119	$0.0000	$0.0119	$0.0000	$0.0119	$0.0119	$0.0119	$0.0119	$0.0119	$0.0119
(23)	ISR Factor		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(24)	Total DAC	Compliance Attachment 18, Workpaper 8, Pg 6, Ln 16-25	$0.0596	$0.0475	$0.0327	$0.0206	$0.0426	$0.0320	$0.0258	$0.0216	$0.0115	$0.0100
(25)	Energy Efficiency Factor	Compliance Attachment 18, Workpaper 8, Pg 7 Ln 6	$0.0876	$0.0876	$0.0876	$0.0876	$0.0716	$0.0716	$0.0716	$0.0716	$0.0716	$0.0716
(26)	LIHEAP Enhancement		$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81

Summary of Current and Proposed Rates

			Residential Non Heating	Low Income Residential Non Heating	Residential Heating	Low Income Residential Heating	Small C&I	Medium C&I	Large Low Load Factor C&I	Large High Load Factor C&I	XLarge Low Load Factor C&I	XLarge High Load Factor C&I
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Proposed Rates Year 2											
(1)	Customer Charge	Compliance Attachment 16, Pg 1, Ln (14)	$14.00	$14.00	$14.00	$14.00	$25.00	$85.00	$200.00	$200.00	$500.00	$500.00
(2)	Peak											
(3)	Volumetric	Compliance Attachment 16, Pg 1, Ln (16)	$0.5922	$0.5922	$0.5803	$0.5803	$0.5109	$0.2647	$0.2574	$0.1719	$0.0479	$0.0413
(4)	Off Peak											
(5)	Volumetric	Compliance Attachment 16, Pg 1, Ln (18)	$0.5922	$0.5922	$0.5201	$0.5201	$0.4510	$0.2647	$0.2574	$0.1719	$0.0479	$0.0413
(6)	Demand	Compliance Attachment 16, Pg 1, Ln (19)						$1.50	$1.50	$2.05	$1.50	$2.05
(7)	GCR	Compliance Attachment 18, Workpaper 8, Pg 1	$0.4797	$0.4797	$0.5226	$0.5226	$0.5226	$0.5226	$0.5226	$0.4797	$0.5226	$0.4797
(8)	Base DAC	Compliance Attachment 18, Workpaper 8, Pg 6, Section 2, Column (E) excluding LIDRF	$0.0477	$0.0475	$0.0208	$0.0206	$0.0307	$0.0201	$0.0139	$0.0097	($0.0004)	($0.0019)
(9)	Low Income Discount Recovery Factor (LIDRF)	Compliance Attachment 18, Workpaper 8, Pg 6, Ln 3	$0.0119	$0.0000	$0.0119	$0.0000	$0.0119	$0.0119	$0.0119	$0.0119	$0.0119	$0.0119
(10)	ISR Factor		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(11)	Total DAC	Compliance Attachment 18, Workpaper 8, Pg 6, Ln 16-25	$0.0596	$0.0475	$0.0327	$0.0206	$0.0426	$0.0320	$0.0258	$0.0216	$0.0115	$0.0100
(12)	Energy Efficiency Factor	Compliance Attachment 18, Workpaper 8, Pg 7 Ln 6	$0.0876	$0.0876	$0.0876	$0.0876	$0.0716	$0.0716	$0.0716	$0.0716	$0.0716	$0.0716
(13)	LIHEAP Enhancement		$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81
	Proposed Rates Year 3											
(14)	Customer Charge	Compliance Attachment 16, Pg 1, Ln (20)	$14.00	$14.00	$14.00	$14.00	$25.00	$85.00	$200.00	$200.00	$500.00	$500.00
(15)	Peak											
(16)	Volumetric	Compliance Attachment 16, Pg 1, Ln (22)	$0.6162	$0.6162	$0.5943	$0.5943	$0.5241	$0.2731	$0.2649	$0.1771	$0.0509	$0.0435
(17)	Off Peak											
(18)	Volumetric	Compliance Attachment 16, Pg 1, Ln (24)	$0.6162	$0.6162	$0.5327	$0.5327	$0.4627	$0.2731	$0.2649	$0.1771	$0.0509	$0.0435
(19)	Demand	Compliance Attachment 16, Pg 1, Ln (25)						$1.50	$1.50	$2.05	$1.50	$2.05
(20)	GCR	Compliance Attachment 18, Workpaper 8, Pg 1	$0.4797	$0.4797	$0.5226	$0.5226	$0.5226	$0.5226	$0.5226	$0.4797	$0.5226	$0.4797
(21)	Base DAC	Compliance Attachment 18, Workpaper 8, Pg 6, Section 2, Column (E) excluding LIDRF	$0.0477	$0.0475	$0.0208	$0.0206	$0.0307	$0.0201	$0.0139	$0.0097	($0.0004)	($0.0019)
(22)	Low Income Discount Recovery Factor (LIDRF)	Compliance Attachment 18, Workpaper 8, Pg 6, Ln 3	$0.0119	$0.0000	$0.0119	$0.0000	$0.0119	$0.0119	$0.0119	$0.0119	$0.0119	$0.0119
(23)	ISR Factor		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(24)	Total DAC	Compliance Attachment 18, Workpaper 8, Pg 6, Ln 16-25	$0.0596	$0.0475	$0.0327	$0.0206	$0.0426	$0.0320	$0.0258	$0.0216	$0.0115	$0.0100
(25)	Energy Efficiency Factor	Compliance Attachment 18, Workpaper 8, Pg 7 Ln 6	$0.0876	$0.0876	$0.0876	$0.0876	$0.0716	$0.0716	$0.0716	$0.0716	$0.0716	$0.0716
(26)	LIHEAP Enhancement		$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81	$0.81

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Line No.

Residential Heating:

Line No.		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		548	$852.93	$864.16	($11.23)	-1.3%	$53.77	($3.57)	$6.48	($66.92)	($0.65)	$0.00	($0.34)
(8)		608	$926.26	$939.43	($13.16)	-1.4%	$58.97	($3.96)	$7.19	($74.25)	($0.72)	$0.00	($0.39)
(9)		667	$998.37	$1,013.58	($15.21)	-1.5%	$63.93	($4.34)	$7.88	($81.43)	($0.79)	$0.00	($0.46)
(10)		726	$1,070.46	$1,085.88	($15.43)	-1.4%	$70.71	($4.74)	$8.57	($88.64)	($0.86)	$0.00	($0.46)
(11)		785	$1,142.56	$1,156.69	($14.13)	-1.2%	$78.93	($5.09)	$9.26	($95.86)	($0.94)	$0.00	($0.42)
(12)	**Average Customer**	**845**	**$1,215.89**	**$1,226.67**	**($10.78)**	**-0.9%**	$89.28	($5.49)	$9.97	($103.18)	($1.04)	$0.00	($0.32)
(13)		905	$1,289.22	$1,296.59	($7.37)	-0.6%	$99.64	($5.88)	$10.66	($110.49)	($1.08)	$0.00	($0.22)
(14)		964	$1,361.29	$1,365.30	($4.01)	-0.3%	$109.86	($6.27)	$11.38	($117.71)	($1.14)	$0.00	($0.12)
(15)		1,023	$1,433.38	$1,433.66	($0.28)	0.0%	$120.46	($6.64)	$12.07	($124.92)	($1.24)	$0.00	($0.01)
(16)		1,082	$1,505.49	$1,501.17	$4.31	0.3%	$131.89	($7.04)	$12.76	($132.12)	($1.31)	$0.00	$0.13
(17)		1,142	$1,578.86	$1,569.25	$9.61	0.6%	$144.08	($7.44)	$13.49	($139.44)	($1.37)	$0.00	$0.29

Residential Heating Low Income:

Line No.		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Difference due to: Base Rates	Total Bill Discount	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(22)		548	$634.58	$821.75	($187.17)	-22.8%	$94.91	($205.18)	($3.57)	($0.14)	($66.92)	($0.65)	$0.00	($5.62)
(23)		608	$688.99	$894.19	($205.20)	-22.9%	$102.85	($222.77)	($3.96)	($0.19)	($74.25)	($0.72)	$0.00	($6.16)
(24)		667	$742.52	$965.55	($223.03)	-23.1%	$110.51	($240.08)	($4.34)	($0.21)	($81.43)	($0.79)	$0.00	($6.69)
(25)		726	$796.05	$1,035.26	($239.21)	-23.1%	$119.81	($257.39)	($4.74)	($0.22)	($88.64)	($0.86)	$0.00	($7.18)
(26)		785	$849.58	$1,103.62	($254.04)	-23.0%	$130.41	($274.70)	($5.09)	($0.24)	($95.86)	($0.94)	$0.00	($7.62)
(27)	**Average Customer**	**845**	**$904.00**	**$1,171.30**	**($267.31)**	**-22.8%**	$142.98	($292.29)	($5.49)	($0.27)	($103.18)	($1.04)	$0.00	($8.02)
(28)		905	$958.45	$1,238.94	($280.48)	-22.6%	$155.56	($309.90)	($5.88)	($0.28)	($110.49)	($1.08)	$0.00	($8.41)
(29)		964	$1,011.94	$1,305.40	($293.47)	-22.5%	$167.95	($327.19)	($6.27)	($0.30)	($117.71)	($1.14)	$0.00	($8.80)
(30)		1,023	$1,065.45	$1,371.56	($306.11)	-22.3%	$180.70	($344.50)	($6.64)	($0.33)	($124.92)	($1.24)	$0.00	($9.18)
(31)		1,082	$1,118.99	$1,436.95	($317.96)	-22.1%	$194.19	($361.81)	($7.04)	($0.33)	($132.12)	($1.31)	$0.00	($9.54)
(32)		1,142	$1,173.47	$1,502.93	($329.46)	-21.9%	$208.41	($379.42)	($7.44)	($0.32)	($139.44)	($1.37)	$0.00	($9.88)

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 1 vs Current Year

Residential Non-Heating:

Difference due to:

Line		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(7)		144	$359.42	$356.75	$2.67	0.7%	$29.46	($0.91)	$1.65	($27.46)	($0.15)	$0.00	$0.08
(8)		158	$376.47	$374.81	$1.66	0.4%	$31.10	($0.97)	$1.82	($30.15)	($0.19)	$0.00	$0.05
(9)		172	$393.59	$392.89	$0.70	0.2%	$32.78	($1.06)	$1.98	($32.83)	($0.19)	$0.00	$0.02
(10)		189	$414.42	$414.83	($0.41)	-0.1%	$34.88	($1.17)	$2.19	($36.08)	($0.22)	$0.00	($0.01)
(11)		202	$430.28	$431.61	($1.33)	-0.3%	$36.41	($1.24)	$2.35	($38.56)	($0.25)	$0.00	($0.04)
(12)	**Average Customer**	220	**$452.35**	**$454.87**	**($2.52)**	**-0.6%**	$38.62	($1.36)	$2.55	($41.98)	($0.27)	$0.00	($0.08)
(13)		238	$474.38	$478.08	($3.70)	-0.8%	$40.82	($1.46)	$2.75	($45.41)	($0.29)	$0.00	($0.11)
(14)		251	$490.25	$494.83	($4.59)	-0.9%	$42.35	($1.54)	$2.91	($47.89)	($0.28)	$0.00	($0.14)
(15)		268	$511.09	$516.84	($5.75)	-1.1%	$44.45	($1.64)	$3.08	($51.14)	($0.33)	$0.00	($0.17)
(16)		282	$528.19	$534.92	($6.74)	-1.3%	$46.14	($1.74)	$3.25	($53.82)	($0.36)	$0.00	($0.20)
(17)		297	$546.52	$554.24	($7.73)	-1.4%	$47.93	($1.81)	$3.43	($56.67)	($0.37)	$0.00	($0.23)

Residential Non-Heating Low Income:

Difference due to:

Line		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Base Rates	Total Bill Discount	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(22)		144	$266.65	$334.15	($67.50)	-20.2%	$49.33	($86.22)	($0.91)	($0.07)	($27.46)	($0.15)	$0.00	($2.03)
(23)		158	$279.19	$351.58	($72.39)	-20.6%	$51.44	($90.27)	($0.97)	($0.08)	($30.15)	($0.19)	$0.00	($2.17)
(24)		172	$291.75	$369.02	($77.27)	-20.9%	$53.55	($94.33)	($1.06)	($0.09)	($32.83)	($0.19)	$0.00	($2.32)
(25)		189	$306.99	$390.19	($83.21)	-21.3%	$56.12	($99.26)	($1.17)	($0.10)	($36.08)	($0.22)	$0.00	($2.50)
(26)		202	$318.66	$406.38	($87.72)	-21.6%	$58.08	($103.03)	($1.24)	($0.09)	($38.56)	($0.25)	$0.00	($2.63)
(27)	**Average Customer**	**220**	**$334.83**	**$428.83**	**($94.00)**	**-21.9%**	$60.80	($108.26)	($1.36)	($0.11)	($41.98)	($0.27)	$0.00	($2.82)
(28)		238	$350.97	$451.23	($100.25)	-22.2%	$63.51	($113.48)	($1.46)	($0.12)	($45.41)	($0.29)	$0.00	($3.01)
(29)		251	$362.65	$467.39	($104.74)	-22.4%	$65.48	($117.26)	($1.54)	($0.11)	($47.89)	($0.28)	$0.00	($3.14)
(30)		268	$377.88	$488.63	($110.74)	-22.7%	$68.04	($122.18)	($1.64)	($0.17)	($51.14)	($0.33)	$0.00	($3.32)
(31)		282	$390.43	$506.08	($115.65)	-22.9%	$70.15	($126.24)	($1.74)	($0.17)	($53.82)	($0.36)	$0.00	($3.47)
(32)		297	$403.90	$524.72	($120.81)	-23.0%	$72.42	($130.60)	($1.81)	($0.16)	($56.67)	($0.37)	$0.00	($3.62)

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

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National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 1 vs Current Year

C & I Small:

Line		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(1)–(4)													
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		830	$1,271.11	$1,379.14	($108.04)	-7.8%	$2.00	($5.43)	$9.58	($110.14)	($0.80)	$0.00	($3.24)
(8)		919	$1,373.19	$1,479.80	($106.61)	-7.2%	$14.75	($5.97)	$10.66	($121.95)	($0.90)	$0.00	($3.20)
(9)		1,010	$1,477.55	$1,583.50	($105.96)	-6.7%	$27.12	($6.56)	$11.71	($134.02)	($1.03)	$0.00	($3.18)
(10)		1,099	$1,579.66	$1,681.23	($101.57)	-6.0%	$42.80	($7.12)	$12.74	($145.85)	($1.10)	$0.00	($3.05)
(11)		1,187	$1,680.61	$1,775.89	($95.28)	-5.4%	$60.19	($7.71)	$13.78	($157.50)	($1.18)	$0.00	($2.86)
(12)	**Average Customer**	**1,277**	**$1,783.77**	**$1,869.39**	**($85.62)**	**-4.6%**	$81.18	($8.30)	$14.81	($169.45)	($1.29)	$0.00	($2.57)
(13)		1,367	$1,886.93	$1,962.86	($75.93)	-3.9%	$102.17	($8.88)	$15.83	($181.39)	($1.38)	$0.00	($2.28)
(14)		1,456	$1,989.02	$2,055.31	($66.29)	-3.2%	$122.95	($9.46)	$16.88	($193.20)	($1.47)	$0.00	($1.99)
(15)		1,544	$2,089.98	$2,146.69	($56.70)	-2.6%	$143.53	($10.01)	$17.90	($204.88)	($1.54)	$0.00	($1.70)
(16)		1,635	$2,194.37	$2,241.18	($46.81)	-2.1%	$164.83	($10.60)	$18.98	($216.98)	($1.64)	$0.00	($1.40)
(17)		1,725	$2,297.51	$2,334.66	($37.15)	-1.6%	$185.82	($11.20)	$20.00	($228.91)	($1.74)	$0.00	($1.11)

C & I Medium:

Line		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(18)–(21)													
(22)		6,907	$7,977.83	$7,862.85	$114.98	1.5%	$696.60	($44.90)	$81.48	($614.74)	($6.91)	$0.00	$3.45
(23)		7,650	$8,721.99	$8,614.53	$107.46	1.2%	$752.19	($49.73)	$90.28	($680.86)	($7.65)	$0.00	$3.22
(24)		8,391	$9,463.68	$9,363.83	$99.85	1.1%	$807.57	($54.54)	$99.01	($746.82)	($8.37)	$0.00	$3.00
(25)		9,136	$10,209.66	$10,117.42	$92.24	0.9%	$863.29	($59.38)	$107.80	($813.11)	($9.13)	$0.00	$2.77
(26)		9,880	$10,954.69	$10,870.03	$84.66	0.8%	$918.94	($64.23)	$116.59	($879.31)	($9.87)	$0.00	$2.54
(27)	**Average Customer**	**10,623**	**$11,698.85**	**$11,621.78**	**$77.08**	**0.7%**	$974.54	($69.03)	$125.33	($945.46)	($10.61)	$0.00	$2.31
(28)		11,366	$12,443.01	$12,373.51	$69.50	0.6%	$1,030.13	($73.87)	$134.13	($1,011.60)	($11.37)	$0.00	$2.09
(29)		12,111	$13,188.96	$13,127.08	$61.88	0.5%	$1,085.84	($78.71)	$142.90	($1,077.89)	($12.12)	$0.00	$1.86
(30)		12,855	$13,934.01	$13,879.70	$54.31	0.4%	$1,141.50	($83.58)	$151.68	($1,144.09)	($12.83)	$0.00	$1.63
(31)		13,596	$14,675.68	$14,629.00	$46.68	0.3%	$1,196.88	($88.39)	$160.43	($1,210.04)	($13.60)	$0.00	$1.40
(32)		14,340	$15,420.76	$15,381.68	$39.08	0.3%	$1,252.53	($93.19)	$169.20	($1,276.26)	($14.37)	$0.00	$1.17

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 1 vs Current Year

C & I LLF Large:

Line		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(1)–(4)							Difference due to:						
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		37,587	$40,270.08	$39,772.33	$497.76	1.3%	$3,501.06	($244.31)	$443.53	($3,179.88)	($37.58)	$0.00	$14.93
(8)		41,634	$44,338.16	$43,820.14	$518.02	1.2%	$3,845.68	($270.61)	$491.29	($3,522.24)	($41.64)	$0.00	$15.54
(9)		45,683	$48,408.60	$47,870.30	$538.31	1.1%	$4,190.52	($296.96)	$539.06	($3,864.78)	($45.68)	$0.00	$16.15
(10)		49,731	$52,478.23	$51,919.58	$558.66	1.1%	$4,535.29	($323.26)	$586.82	($4,207.23)	($49.72)	$0.00	$16.76
(11)		53,777	$56,545.42	$55,966.54	$578.88	1.0%	$4,879.83	($349.54)	$634.54	($4,549.53)	($53.79)	$0.00	$17.37
(12)	**Average Customer**	**57,825**	**$60,615.01**	**$60,015.80**	**$599.21**	**1.0%**	$5,224.60	($375.86)	$682.34	($4,891.99)	($57.86)	$0.00	$17.98
(13)		61,873	$64,684.61	$64,065.08	$619.54	1.0%	$5,569.37	($402.18)	$730.09	($5,234.46)	($61.87)	$0.00	$18.59
(14)		65,920	$68,752.66	$68,112.86	$639.80	0.9%	$5,913.98	($428.48)	$777.86	($5,576.83)	($65.93)	$0.00	$19.19
(15)		69,967	$72,821.40	$72,161.32	$660.08	0.9%	$6,258.68	($454.78)	$825.60	($5,919.22)	($70.01)	$0.00	$19.80
(16)		74,016	$76,891.88	$76,211.45	$680.44	0.9%	$6,603.52	($481.09)	$873.37	($6,261.76)	($74.02)	$0.00	$20.41
(17)		78,063	$80,959.93	$80,259.21	$700.72	0.9%	$6,948.14	($507.40)	$921.14	($6,604.14)	($78.04)	$0.00	$21.02

C & I HLF Large:

Line		Annual Consumption (Therms)	Proposed Rates Yr 1 [1]	Current Rates [1]	Difference	% Chg	Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(18)–(21)							Difference due to:						
(22)		41,956	$38,044.38	$37,930.84	$113.54	0.3%	$3,307.17	($260.14)	$495.08	($3,390.04)	($41.94)	$0.00	$3.41
(23)		46,471	$41,871.24	$41,778.76	$92.49	0.2%	$3,630.80	($288.14)	$548.35	($3,754.83)	($46.47)	$0.00	$2.77
(24)		50,991	$45,701.93	$45,630.55	$71.38	0.2%	$3,954.74	($316.14)	$601.71	($4,120.07)	($51.00)	$0.00	$2.14
(25)		55,507	$49,529.53	$49,479.25	$50.28	0.1%	$4,278.43	($344.16)	$654.98	($4,484.96)	($55.52)	$0.00	$1.51
(26)		60,028	$53,360.98	$53,331.81	$29.18	0.1%	$4,602.42	($372.18)	$708.35	($4,850.25)	($60.04)	$0.00	$0.88
(27)	**Average Customer**	**64,545**	**$57,189.35**	**$57,181.30**	**$8.06**	**0.0%**	$4,926.17	($400.21)	$761.62	($5,215.23)	($64.54)	$0.00	$0.24
(28)		69,062	$61,017.76	$61,030.80	($13.04)	0.0%	$5,249.92	($428.18)	$814.92	($5,580.23)	($69.08)	$0.00	($0.39)
(29)		73,583	$64,849.14	$64,883.31	($34.16)	-0.1%	$5,573.92	($456.24)	$868.26	($5,945.50)	($73.58)	$0.00	($1.02)
(30)		78,099	$68,676.80	$68,732.00	($55.21)	-0.1%	$5,897.61	($484.22)	$921.55	($6,310.39)	($78.10)	$0.00	($1.66)
(31)		82,619	$72,507.49	$72,583.83	($76.34)	-0.1%	$6,221.54	($512.24)	$974.91	($6,675.62)	($82.64)	$0.00	($2.29)
(32)		87,137	$76,337.59	$76,434.87	($97.28)	-0.1%	$6,545.46	($540.24)	$1,028.22	($7,040.66)	($87.15)	$0.00	($2.92)

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

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National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 1 vs Current Year

C & I LLF Extra-Large:

							Difference due to:						
(1)		Annual	Proposed	Current									
(2)		Consumption (Therms)	Rates Yr 1 [1]	Rates [1]	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		233,835	$186,911.09	$185,168.50	$1,742.59	0.9%	$6,250.10	($1,519.94)	$2,782.63	($5,588.66)	($233.82)	$0.00	$52.28
(8)		259,019	$206,373.90	$204,543.64	$1,830.26	0.9%	$6,826.27	($1,683.62)	$3,082.29	($6,190.56)	($259.03)	$0.00	$54.91
(9)		284,197	$225,832.69	$223,914.59	$1,918.10	0.9%	$7,402.39	($1,847.30)	$3,381.96	($6,792.30)	($284.19)	$0.00	$57.54
(10)		309,381	$245,295.48	$243,289.65	$2,005.82	0.8%	$7,978.56	($2,010.99)	$3,681.64	($7,394.19)	($309.37)	$0.00	$60.17
(11)		334,562	$264,756.27	$262,662.70	$2,093.57	0.8%	$8,554.70	($2,174.64)	$3,981.31	($7,996.03)	($334.58)	$0.00	$62.81
(12)	**Average Customer**	**359,745**	**$284,218.38**	**$282,037.08**	**$2,181.30**	**0.8%**	$9,130.87	($2,338.36)	$4,280.97	($8,597.90)	($359.72)	$0.00	$65.44
(13)		384,928	$303,680.48	$301,411.44	$2,269.04	0.8%	$9,707.03	($2,502.03)	$4,580.67	($9,199.78)	($384.92)	$0.00	$68.07
(14)		410,110	$323,141.96	$320,785.21	$2,356.75	0.7%	$10,283.18	($2,665.73)	$4,880.31	($9,801.63)	($410.09)	$0.00	$70.70
(15)		435,293	$342,604.05	$340,159.55	$2,444.49	0.7%	$10,859.35	($2,829.40)	$5,180.00	($10,403.50)	($435.29)	$0.00	$73.33
(16)		460,471	$362,062.86	$359,530.63	$2,532.23	0.7%	$11,435.46	($2,993.06)	$5,479.60	($11,005.26)	($460.48)	$0.00	$75.97
(17)		485,655	$381,525.66	$378,905.70	$2,619.97	0.7%	$12,011.64	($3,156.75)	$5,779.30	($11,607.17)	($485.65)	$0.00	$78.60

C & I HLF Extra-Large:

							Difference due to:						
(18)		Annual	Proposed	Current									
(19)		Consumption (Therms)	Rates Yr 1 [1]	Rates [1]	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(22)		486,528	$344,248.05	$341,493.68	$2,754.37	0.8%	$10,894.09	($3,016.49)	$5,838.33	($10,557.66)	($486.53)	$0.00	$82.63
(23)		538,924	$380,654.45	$377,703.31	$2,951.14	0.8%	$11,970.42	($3,341.35)	$6,467.10	($11,694.65)	($538.92)	$0.00	$88.53
(24)		591,320	$417,060.04	$413,912.24	$3,147.80	0.8%	$13,046.66	($3,666.16)	$7,095.84	($12,831.64)	($591.33)	$0.00	$94.43
(25)		643,718	$453,467.64	$450,123.12	$3,344.52	0.7%	$14,123.01	($3,991.05)	$7,724.63	($13,968.69)	($643.72)	$0.00	$100.34
(26)		696,109	$489,870.16	$486,328.97	$3,541.19	0.7%	$15,199.19	($4,315.89)	$8,353.30	($15,105.56)	($696.09)	$0.00	$106.24
(27)	**Average Customer**	**748,506**	**$526,277.19**	**$522,539.23**	**$3,737.96**	**0.7%**	$16,275.54	($4,640.70)	$8,982.06	($16,242.57)	($748.51)	$0.00	$112.14
(28)		800,903	$562,684.18	$558,749.55	$3,934.63	0.7%	$17,351.88	($4,965.61)	$9,610.82	($17,379.60)	($800.90)	$0.00	$118.04
(29)		853,294	$599,086.68	$594,955.36	$4,131.32	0.7%	$18,428.06	($5,290.43)	$10,239.53	($18,516.48)	($853.30)	$0.00	$123.94
(30)		905,692	$635,494.29	$631,166.23	$4,328.06	0.7%	$19,504.42	($5,615.29)	$10,868.31	($19,653.51)	($905.71)	$0.00	$129.84
(31)		958,088	$671,899.90	$667,375.19	$4,524.71	0.7%	$20,580.65	($5,940.12)	$11,497.06	($20,790.53)	($958.09)	$0.00	$135.74
(32)		1,010,485	$708,306.88	$703,585.51	$4,721.37	0.7%	$21,657.00	($6,265.04)	$12,125.81	($21,927.53)	($1,010.51)	$0.00	$141.64

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 2 vs Year 1

Residential Heating:

Line No.		Annual Consumption (Therms)	Proposed Rates Yr 2	Proposed Rates Yr 1	Difference	% Chg	Base Rates	GCR	DAC Base DAC	DAC ISR & RDA	EE	LIHEAP	GET
(1)–(4)							Difference due to:						
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		548	$867.85	$852.93	$14.92	1.7%	$14.47	$0.00	$0.00	$0.00	$0.00	$0.00	$0.45
(8)		608	$942.82	$926.26	$16.55	1.8%	$16.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50
(9)		667	$1,016.53	$998.37	$18.16	1.8%	$17.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.54
(10)		726	$1,090.23	$1,070.46	$19.77	1.8%	$19.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.59
(11)		785	$1,163.94	$1,142.56	$21.37	1.9%	$20.73	$0.00	$0.00	$0.00	$0.00	$0.00	$0.64
(12)	**Average Customer**	**845**	**$1,238.89**	**$1,215.89**	**$23.01**	**1.9%**	$22.32	$0.00	$0.00	$0.00	$0.00	$0.00	$0.69
(13)		905	$1,313.86	$1,289.22	$24.64	1.9%	$23.90	$0.00	$0.00	$0.00	$0.00	$0.00	$0.74
(14)		964	$1,387.54	$1,361.29	$26.25	1.9%	$25.46	$0.00	$0.00	$0.00	$0.00	$0.00	$0.79
(15)		1,023	$1,461.24	$1,433.38	$27.85	1.9%	$27.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.84
(16)		1,082	$1,534.95	$1,505.49	$29.46	2.0%	$28.58	$0.00	$0.00	$0.00	$0.00	$0.00	$0.88
(17)		1,142	$1,609.95	$1,578.86	$31.09	2.0%	$30.16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.93

Residential Heating Low Income:

Line No.		Annual Consumption (Therms)	Proposed Rates Yr 2	Proposed Rates Yr 1	Difference	% Chg	Base Rates	Total Bill Discount	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(18)–(21)							Difference due to:							
(22)		548	$645.77	$634.58	$11.19	1.8%	$14.47	($3.62)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34
(23)		608	$701.41	$688.99	$12.42	1.8%	$16.06	($4.01)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.37
(24)		667	$756.14	$742.52	$13.62	1.8%	$17.62	($4.40)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.41
(25)		726	$810.87	$796.05	$14.83	1.9%	$19.18	($4.79)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.44
(26)		785	$865.61	$849.58	$16.03	1.9%	$20.73	($5.18)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.48
(27)	**Average Customer**	**845**	**$921.25**	**$904.00**	**$17.26**	**1.9%**	$22.32	($5.58)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.52
(28)		905	$976.94	$958.45	$18.48	1.9%	$23.90	($5.98)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.55
(29)		964	$1,031.62	$1,011.94	$19.68	1.9%	$25.46	($6.36)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.59
(30)		1,023	$1,086.34	$1,065.45	$20.89	2.0%	$27.02	($6.75)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.63
(31)		1,082	$1,141.09	$1,118.99	$22.09	2.0%	$28.58	($7.14)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.66
(32)		1,142	$1,196.79	$1,173.47	$23.32	2.0%	$30.16	($7.54)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.70

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 2 vs Year 1

Residential Non-Heating:

							Difference due to:							
(1)		Annual	Proposed	Proposed										
(2)		Consumption (Therms)	Rates Yr 2	Rates Yr 1	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		144	$365.32	$359.42	$5.90	1.6%	$4.66	$0.91	$0.00	$0.00	$0.15	$0.00	$0.18
(8)		158	$383.00	$376.47	$6.53	1.7%	$5.17	$0.97	$0.00	$0.00	$0.19	$0.00	$0.20
(9)		172	$400.69	$393.59	$7.10	1.8%	$5.64	$1.06	$0.00	$0.00	$0.19	$0.00	$0.21
(10)		189	$422.19	$414.42	$7.77	1.9%	$6.15	$1.17	$0.00	$0.00	$0.22	$0.00	$0.23
(11)		202	$438.63	$430.28	$8.36	1.9%	$6.62	$1.24	$0.00	$0.00	$0.25	$0.00	$0.25
(12)	**Average Customer**	220	**$461.43**	**$452.35**	**$9.08**	**2.0%**	$7.18	$1.36	$0.00	$0.00	$0.27	$0.00	$0.27
(13)		238	$484.16	$474.38	$9.78	2.1%	$7.74	$1.46	$0.00	$0.00	$0.29	$0.00	$0.29
(14)		251	$500.58	$490.25	$10.33	2.1%	$8.20	$1.54	$0.00	$0.00	$0.28	$0.00	$0.31
(15)		268	$522.10	$511.09	$11.01	2.2%	$8.71	$1.64	$0.00	$0.00	$0.33	$0.00	$0.33
(16)		282	$539.81	$528.19	$11.63	2.2%	$9.18	$1.74	$0.00	$0.00	$0.36	$0.00	$0.35
(17)		297	$558.76	$546.52	$12.24	2.2%	$9.69	$1.81	$0.00	$0.00	$0.37	$0.00	$0.37

Residential Non-Heating Low Income:

							Difference due to:							
(18)		Annual	Proposed	Proposed										
(19)		Consumption (Therms)	Rates Yr 2	Rates Yr 1	Difference	% Chg	Base Rates	Total Bill	GCR	DAC		EE	LIHEAP	GET
(20)								Discount		Base DAC	ISR			
(21)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(22)		144	$272.66	$266.65	$6.01	2.3%	$6.71	($1.94)	$0.91	$0.00	$0.00	$0.15	$0.00	$0.18
(23)		158	$285.78	$279.19	$6.59	2.4%	$7.36	($2.13)	$0.97	$0.00	$0.00	$0.19	$0.00	$0.20
(24)		172	$298.92	$291.75	$7.16	2.5%	$8.02	($2.32)	$1.06	$0.00	$0.00	$0.19	$0.00	$0.21
(25)		189	$314.87	$306.99	$7.88	2.6%	$8.81	($2.55)	$1.17	$0.00	$0.00	$0.22	$0.00	$0.24
(26)		202	$327.09	$318.66	$8.43	2.6%	$9.41	($2.73)	$1.24	$0.00	$0.00	$0.25	$0.00	$0.25
(27)	**Average Customer**	**220**	**$344.01**	**$334.83**	**$9.19**	**2.7%**	$10.25	($2.97)	$1.36	$0.00	$0.00	$0.27	$0.00	$0.28
(28)		238	$360.90	$350.97	$9.93	2.8%	$11.09	($3.21)	$1.46	$0.00	$0.00	$0.29	$0.00	$0.30
(29)		251	$373.10	$362.65	$10.45	2.9%	$11.70	($3.38)	$1.54	$0.00	$0.00	$0.28	$0.00	$0.31
(30)		268	$389.06	$377.88	$11.18	3.0%	$12.49	($3.61)	$1.64	$0.00	$0.00	$0.33	$0.00	$0.34
(31)		282	$402.22	$390.43	$11.78	3.0%	$13.14	($3.81)	$1.74	$0.00	$0.00	$0.36	$0.00	$0.35
(32)		297	$416.29	$403.90	$12.39	3.1%	$13.84	($4.01)	$1.81	$0.00	$0.00	$0.37	$0.00	$0.37

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 2 vs Year 1

C & I Small:

Line		Annual Consumption (Therms)	Proposed Rates Yr 2	Proposed Rates Yr 1	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		830	$1,292.63	$1,271.11	$21.53	1.7%	$20.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.65
(8)		919	$1,397.03	$1,373.19	$23.83	1.7%	$23.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.71
(9)		1,010	$1,503.74	$1,477.55	$26.19	1.8%	$25.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.79
(10)		1,099	$1,608.16	$1,579.66	$28.50	1.8%	$27.65	$0.00	$0.00	$0.00	$0.00	$0.00	$0.86
(11)		1,187	$1,711.40	$1,680.61	$30.79	1.8%	$29.86	$0.00	$0.00	$0.00	$0.00	$0.00	$0.92
(12)	**Average Customer**	**1,277**	**$1,816.89**	**$1,783.77**	**$33.12**	**1.9%**	$32.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.99
(13)		1,367	$1,922.38	$1,886.93	$35.45	1.9%	$34.39	$0.00	$0.00	$0.00	$0.00	$0.00	$1.06
(14)		1,456	$2,026.78	$1,989.02	$37.76	1.9%	$36.62	$0.00	$0.00	$0.00	$0.00	$0.00	$1.13
(15)		1,544	$2,130.03	$2,089.98	$40.04	1.9%	$38.84	$0.00	$0.00	$0.00	$0.00	$0.00	$1.20
(16)		1,635	$2,236.77	$2,194.37	$42.40	1.9%	$41.13	$0.00	$0.00	$0.00	$0.00	$0.00	$1.27
(17)		1,725	$2,342.24	$2,297.51	$44.73	1.9%	$43.39	$0.00	$0.00	$0.00	$0.00	$0.00	$1.34

C & I Medium:

Line		Annual Consumption (Therms)	Proposed Rates Yr 2	Proposed Rates Yr 1	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(21)													
(22)		6,907	$8,093.90	$7,977.83	$116.07	1.5%	$112.58	$0.00	$0.00	$0.00	$0.00	$0.00	$3.48
(23)		7,650	$8,850.54	$8,721.99	$128.55	1.5%	$124.70	$0.00	$0.00	$0.00	$0.00	$0.00	$3.86
(24)		8,391	$9,604.68	$9,463.68	$141.00	1.5%	$136.77	$0.00	$0.00	$0.00	$0.00	$0.00	$4.23
(25)		9,136	$10,363.18	$10,209.66	$153.52	1.5%	$148.92	$0.00	$0.00	$0.00	$0.00	$0.00	$4.61
(26)		9,880	$11,120.71	$10,954.69	$166.02	1.5%	$161.04	$0.00	$0.00	$0.00	$0.00	$0.00	$4.98
(27)	**Average Customer**	**10,623**	**$11,877.36**	**$11,698.85**	**$178.51**	**1.5%**	$173.15	$0.00	$0.00	$0.00	$0.00	$0.00	$5.36
(28)		11,366	$12,634.01	$12,443.01	$191.00	1.5%	$185.27	$0.00	$0.00	$0.00	$0.00	$0.00	$5.73
(29)		12,111	$13,392.47	$13,188.96	$203.51	1.5%	$197.41	$0.00	$0.00	$0.00	$0.00	$0.00	$6.11
(30)		12,855	$14,150.02	$13,934.01	$216.02	1.6%	$209.54	$0.00	$0.00	$0.00	$0.00	$0.00	$6.48
(31)		13,596	$14,904.15	$14,675.68	$228.47	1.6%	$221.61	$0.00	$0.00	$0.00	$0.00	$0.00	$6.85
(32)		14,340	$15,661.73	$15,420.76	$240.97	1.6%	$233.74	$0.00	$0.00	$0.00	$0.00	$0.00	$7.23

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

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National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 2 vs Year 1

C & I LLF Large:

							Difference due to:						
(1)		Annual	Proposed	Proposed									
(2)		Consumption (Therms)	Rates Yr 2	Rates Yr 1	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)													
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		37,587	$40,831.95	$40,270.08	$561.87	1.4%	$545.01	$0.00	$0.00	$0.00	$0.00	$0.00	$16.86
(8)		41,634	$44,960.52	$44,338.16	$622.36	1.4%	$603.69	$0.00	$0.00	$0.00	$0.00	$0.00	$18.67
(9)		45,683	$49,091.49	$48,408.60	$682.89	1.4%	$662.40	$0.00	$0.00	$0.00	$0.00	$0.00	$20.49
(10)		49,731	$53,221.63	$52,478.23	$743.40	1.4%	$721.10	$0.00	$0.00	$0.00	$0.00	$0.00	$22.30
(11)		53,777	$57,349.30	$56,545.42	$803.88	1.4%	$779.77	$0.00	$0.00	$0.00	$0.00	$0.00	$24.12
(12)	**Average Customer**	**57,825**	**$61,479.40**	**$60,615.01**	**$864.39**	**1.4%**	$838.46	$0.00	$0.00	$0.00	$0.00	$0.00	$25.93
(13)		61,873	$65,609.52	$64,684.61	$924.91	1.4%	$897.16	$0.00	$0.00	$0.00	$0.00	$0.00	$27.75
(14)		65,920	$69,738.06	$68,752.66	$985.40	1.4%	$955.84	$0.00	$0.00	$0.00	$0.00	$0.00	$29.56
(15)		69,967	$73,867.29	$72,821.40	$1,045.90	1.4%	$1,014.52	$0.00	$0.00	$0.00	$0.00	$0.00	$31.38
(16)		74,016	$77,998.31	$76,891.88	$1,106.42	1.4%	$1,073.23	$0.00	$0.00	$0.00	$0.00	$0.00	$33.19
(17)		78,063	$82,126.85	$80,959.93	$1,166.92	1.4%	$1,131.91	$0.00	$0.00	$0.00	$0.00	$0.00	$35.01

C & I HLF Large:

							Difference due to:						
(18)		Annual	Proposed	Proposed									
(19)		Consumption (Therms)	Rates Yr 2	Rates Yr 1	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)													
(22)		41,956	$38,485.56	$38,044.38	$441.19	1.2%	$427.95	$0.00	$0.00	$0.00	$0.00	$0.00	$13.24
(23)		46,471	$42,359.91	$41,871.24	$488.66	1.2%	$474.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.66
(24)		50,991	$46,238.12	$45,701.93	$536.19	1.2%	$520.11	$0.00	$0.00	$0.00	$0.00	$0.00	$16.09
(25)		55,507	$50,113.21	$49,529.53	$583.68	1.2%	$566.17	$0.00	$0.00	$0.00	$0.00	$0.00	$17.51
(26)		60,028	$53,992.21	$53,360.98	$631.22	1.2%	$612.29	$0.00	$0.00	$0.00	$0.00	$0.00	$18.94
(27)	**Average Customer**	**64,545**	**$57,868.07**	**$57,189.35**	**$678.72**	**1.2%**	$658.36	$0.00	$0.00	$0.00	$0.00	$0.00	$20.36
(28)		69,062	$61,743.98	$61,017.76	$726.22	1.2%	$704.43	$0.00	$0.00	$0.00	$0.00	$0.00	$21.79
(29)		73,583	$65,622.90	$64,849.14	$773.76	1.2%	$750.55	$0.00	$0.00	$0.00	$0.00	$0.00	$23.21
(30)		78,099	$69,498.05	$68,676.80	$821.25	1.2%	$796.61	$0.00	$0.00	$0.00	$0.00	$0.00	$24.64
(31)		82,619	$73,376.27	$72,507.49	$868.78	1.2%	$842.71	$0.00	$0.00	$0.00	$0.00	$0.00	$26.06
(32)		87,137	$77,253.88	$76,337.59	$916.29	1.2%	$888.80	$0.00	$0.00	$0.00	$0.00	$0.00	$27.49

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

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National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 2 vs Year 1

C & I LLF Extra-Large:

							Difference due to:						
(1)		Annual	Proposed	Proposed									
(2)		Consumption (Therms)	Rates Yr 2	Rates Yr 1	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		233,835	$188,309.28	$186,911.09	$1,398.19	0.7%	$1,356.24	$0.00	$0.00	$0.00	$0.00	$0.00	$41.95
(8)		259,019	$207,922.67	$206,373.90	$1,548.77	0.8%	$1,502.31	$0.00	$0.00	$0.00	$0.00	$0.00	$46.46
(9)		284,197	$227,532.01	$225,832.69	$1,699.32	0.8%	$1,648.34	$0.00	$0.00	$0.00	$0.00	$0.00	$50.98
(10)		309,381	$247,145.38	$245,295.48	$1,849.91	0.8%	$1,794.41	$0.00	$0.00	$0.00	$0.00	$0.00	$55.50
(11)		334,562	$266,756.74	$264,756.27	$2,000.47	0.8%	$1,940.46	$0.00	$0.00	$0.00	$0.00	$0.00	$60.01
(12)	**Average Customer**	**359,745**	**$286,369.43**	**$284,218.38**	**$2,151.05**	**0.8%**	$2,086.52	$0.00	$0.00	$0.00	$0.00	$0.00	$64.53
(13)		384,928	$305,982.11	$303,680.48	$2,301.63	0.8%	$2,232.58	$0.00	$0.00	$0.00	$0.00	$0.00	$69.05
(14)		410,110	$325,594.16	$323,141.96	$2,452.20	0.8%	$2,378.64	$0.00	$0.00	$0.00	$0.00	$0.00	$73.57
(15)		435,293	$345,206.83	$342,604.05	$2,602.78	0.8%	$2,524.70	$0.00	$0.00	$0.00	$0.00	$0.00	$78.08
(16)		460,471	$364,816.20	$362,062.86	$2,753.33	0.8%	$2,670.73	$0.00	$0.00	$0.00	$0.00	$0.00	$82.60
(17)		485,655	$384,429.58	$381,525.66	$2,903.92	0.8%	$2,816.80	$0.00	$0.00	$0.00	$0.00	$0.00	$87.12

C & I HLF Extra-Large:

							Difference due to:						
(18)		Annual	Proposed	Proposed									
(19)		Consumption (Therms)	Rates Yr 2	Rates Yr 1	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(22)		486,528	$346,454.98	$344,248.05	$2,206.93	0.6%	$2,140.72	$0.00	$0.00	$0.00	$0.00	$0.00	$66.21
(23)		538,924	$383,099.05	$380,654.45	$2,444.60	0.6%	$2,371.27	$0.00	$0.00	$0.00	$0.00	$0.00	$73.34
(24)		591,320	$419,742.32	$417,060.04	$2,682.28	0.6%	$2,601.81	$0.00	$0.00	$0.00	$0.00	$0.00	$80.47
(25)		643,718	$456,387.60	$453,467.64	$2,919.96	0.6%	$2,832.36	$0.00	$0.00	$0.00	$0.00	$0.00	$87.60
(26)		696,109	$493,027.77	$489,870.16	$3,157.61	0.6%	$3,062.88	$0.00	$0.00	$0.00	$0.00	$0.00	$94.73
(27)	**Average Customer**	**748,506**	**$529,672.47**	**$526,277.19**	**$3,395.28**	**0.6%**	$3,293.43	$0.00	$0.00	$0.00	$0.00	$0.00	$101.86
(28)		800,903	$566,317.14	$562,684.18	$3,632.96	0.6%	$3,523.97	$0.00	$0.00	$0.00	$0.00	$0.00	$108.99
(29)		853,294	$602,957.29	$599,086.68	$3,870.61	0.6%	$3,754.49	$0.00	$0.00	$0.00	$0.00	$0.00	$116.12
(30)		905,692	$639,602.58	$635,494.29	$4,108.29	0.6%	$3,985.04	$0.00	$0.00	$0.00	$0.00	$0.00	$123.25
(31)		958,088	$676,245.87	$671,899.90	$4,345.97	0.6%	$4,215.59	$0.00	$0.00	$0.00	$0.00	$0.00	$130.38
(32)		1,010,485	$712,890.52	$708,306.88	$4,583.64	0.6%	$4,446.13	$0.00	$0.00	$0.00	$0.00	$0.00	$137.51

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

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National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 3 vs. Year 2

Residential Heating:

Line No.		Annual Consumption (Therms)	Proposed Rates Yr 3	Proposed Rates Yr 2	Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR & RDA	EE	LIHEAP	GET
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		548	$875.59	$867.85	$7.74	0.9%	$7.51	$0.00	$0.00	$0.00	$0.00	$0.00	$0.23
(8)		608	$951.41	$942.82	$8.59	0.9%	$8.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.26
(9)		667	$1,025.95	$1,016.53	$9.42	0.9%	$9.14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.28
(10)		726	$1,100.48	$1,090.23	$10.26	0.9%	$9.95	$0.00	$0.00	$0.00	$0.00	$0.00	$0.31
(11)		785	$1,175.02	$1,163.94	$11.09	1.0%	$10.75	$0.00	$0.00	$0.00	$0.00	$0.00	$0.33
(12)	**Average Customer**	**845**	**$1,250.83**	**$1,238.89**	**$11.94**	**1.0%**	$11.58	$0.00	$0.00	$0.00	$0.00	$0.00	$0.36
(13)		905	$1,326.64	$1,313.86	$12.78	1.0%	$12.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.38
(14)		964	$1,401.15	$1,387.54	$13.62	1.0%	$13.21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.41
(15)		1,023	$1,475.69	$1,461.24	$14.45	1.0%	$14.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.43
(16)		1,082	$1,550.23	$1,534.95	$15.28	1.0%	$14.82	$0.00	$0.00	$0.00	$0.00	$0.00	$0.46
(17)		1,142	$1,626.09	$1,609.95	$16.13	1.0%	$15.65	$0.00	$0.00	$0.00	$0.00	$0.00	$0.48

Residential Heating Low Income:

Line No.		Annual Consumption (Therms)	Proposed Rates Yr 3	Proposed Rates Yr 2	Difference	% Chg	Difference due to: Base Rates	Total Bill Discount	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(22)		548	$651.57	$645.77	$5.81	0.9%	$7.51	($1.88)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.17
(23)		608	$707.85	$701.41	$6.44	0.9%	$8.33	($2.08)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.19
(24)		667	$763.21	$756.14	$7.07	0.9%	$9.14	($2.28)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.21
(25)		726	$818.56	$810.87	$7.69	0.9%	$9.95	($2.49)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.23
(26)		785	$873.92	$865.61	$8.32	1.0%	$10.75	($2.69)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.25
(27)	**Average Customer**	**845**	**$930.20**	**$921.25**	**$8.95**	**1.0%**	$11.58	($2.89)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.27
(28)		905	$986.52	$976.94	$9.59	1.0%	$12.40	($3.10)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.29
(29)		964	$1,041.83	$1,031.62	$10.21	1.0%	$13.21	($3.30)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.31
(30)		1,023	$1,097.18	$1,086.34	$10.84	1.0%	$14.02	($3.50)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.33
(31)		1,082	$1,152.55	$1,141.09	$11.46	1.0%	$14.82	($3.71)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34
(32)		1,142	$1,208.89	$1,196.79	$12.10	1.0%	$15.65	($3.91)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.36

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 3 vs. Year 2

Residential Non-Heating:

Line		Annual Consumption (Therms)	Proposed Rates Yr 3	Proposed Rates Yr 2	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		144	$368.88	$365.32	$3.56	1.0%	$3.46	$0.00	$0.00	$0.00	$0.00	$0.00	$0.11
(8)		158	$386.91	$383.00	$3.91	1.0%	$3.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.12
(9)		172	$404.94	$400.69	$4.26	1.1%	$4.13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.13
(10)		189	$426.87	$422.19	$4.68	1.1%	$4.54	$0.00	$0.00	$0.00	$0.00	$0.00	$0.14
(11)		202	$443.63	$438.63	$5.00	1.1%	$4.85	$0.00	$0.00	$0.00	$0.00	$0.00	$0.15
(12)	**Average Customer**	220	**$466.87**	**$461.43**	**$5.44**	**1.2%**	$5.28	$0.00	$0.00	$0.00	$0.00	$0.00	$0.16
(13)		238	$490.05	$484.16	$5.89	1.2%	$5.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.18
(14)		251	$506.79	$500.58	$6.21	1.2%	$6.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.19
(15)		268	$528.73	$522.10	$6.63	1.3%	$6.43	$0.00	$0.00	$0.00	$0.00	$0.00	$0.20
(16)		282	$546.79	$539.81	$6.98	1.3%	$6.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.21
(17)		297	$566.10	$558.76	$7.35	1.3%	$7.13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.22

Residential Non-Heating Low Income:

Line		Annual Consumption (Therms)	Proposed Rates Yr 3	Proposed Rates Yr 2	Difference	% Chg	Difference due to: Base Rates	Total Bill Discount	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(22)		144	$275.33	$272.66	$2.67	1.0%	$3.46	($0.86)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.08
(23)		158	$288.71	$285.78	$2.93	1.0%	$3.79	($0.95)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.09
(24)		172	$302.11	$298.92	$3.19	1.1%	$4.13	($1.03)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.10
(25)		189	$318.38	$314.87	$3.51	1.1%	$4.54	($1.13)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.11
(26)		202	$330.84	$327.09	$3.75	1.1%	$4.85	($1.21)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.11
(27)	**Average Customer**	**220**	**$348.10**	**$344.01**	**$4.08**	**1.2%**	$5.28	($1.32)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.12
(28)		238	$365.32	$360.90	$4.42	1.2%	$5.71	($1.43)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.13
(29)		251	$377.76	$373.10	$4.66	1.2%	$6.02	($1.51)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.14
(30)		268	$394.04	$389.06	$4.97	1.3%	$6.43	($1.61)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.15
(31)		282	$407.45	$402.22	$5.23	1.3%	$6.77	($1.69)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.16
(32)		297	$421.80	$416.29	$5.51	1.3%	$7.13	($1.78)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.17

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 3 vs. Year 2

C & I Small:

Line		Annual Consumption (Therms)	Proposed Rates Yr 3	Proposed Rates Yr 2	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		830	$1,303.76	$1,292.63	$11.12	0.9%	$10.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.33
(8)		919	$1,409.34	$1,397.03	$12.31	0.9%	$11.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.37
(9)		1,010	$1,517.27	$1,503.74	$13.53	0.9%	$13.13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.41
(10)		1,099	$1,622.89	$1,608.16	$14.73	0.9%	$14.29	$0.00	$0.00	$0.00	$0.00	$0.00	$0.44
(11)		1,187	$1,727.30	$1,711.40	$15.91	0.9%	$15.43	$0.00	$0.00	$0.00	$0.00	$0.00	$0.48
(12)	**Average Customer**	**1,277**	**$1,834.00**	**$1,816.89**	**$17.11**	**0.9%**	$16.60	$0.00	$0.00	$0.00	$0.00	$0.00	$0.51
(13)		1,367	$1,940.69	$1,922.38	$18.32	1.0%	$17.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.55
(14)		1,456	$2,046.29	$2,026.78	$19.51	1.0%	$18.92	$0.00	$0.00	$0.00	$0.00	$0.00	$0.59
(15)		1,544	$2,150.72	$2,130.03	$20.69	1.0%	$20.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.62
(16)		1,635	$2,258.68	$2,236.77	$21.91	1.0%	$21.25	$0.00	$0.00	$0.00	$0.00	$0.00	$0.66
(17)		1,725	$2,365.36	$2,342.24	$23.12	1.0%	$22.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.69

C & I Medium:

Line		Annual Consumption (Therms)	Proposed Rates Yr 3	Proposed Rates Yr 2	Difference	% Chg	Difference due to: Base Rates	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(22)		6,907	$8,153.71	$8,093.90	$59.81	0.7%	$58.02	$0.00	$0.00	$0.00	$0.00	$0.00	$1.79
(23)		7,650	$8,916.79	$8,850.54	$66.25	0.7%	$64.26	$0.00	$0.00	$0.00	$0.00	$0.00	$1.99
(24)		8,391	$9,677.35	$9,604.68	$72.66	0.8%	$70.48	$0.00	$0.00	$0.00	$0.00	$0.00	$2.18
(25)		9,136	$10,442.30	$10,363.18	$79.12	0.8%	$76.74	$0.00	$0.00	$0.00	$0.00	$0.00	$2.37
(26)		9,880	$11,206.27	$11,120.71	$85.56	0.8%	$82.99	$0.00	$0.00	$0.00	$0.00	$0.00	$2.57
(27)	**Average Customer**	**10,623**	**$11,969.36**	**$11,877.36**	**$91.99**	**0.8%**	$89.23	$0.00	$0.00	$0.00	$0.00	$0.00	$2.76
(28)		11,366	$12,732.43	$12,634.01	$98.43	0.8%	$95.47	$0.00	$0.00	$0.00	$0.00	$0.00	$2.95
(29)		12,111	$13,497.35	$13,392.47	$104.88	0.8%	$101.73	$0.00	$0.00	$0.00	$0.00	$0.00	$3.15
(30)		12,855	$14,261.35	$14,150.02	$111.32	0.8%	$107.98	$0.00	$0.00	$0.00	$0.00	$0.00	$3.34
(31)		13,596	$15,021.89	$14,904.15	$117.74	0.8%	$114.21	$0.00	$0.00	$0.00	$0.00	$0.00	$3.53
(32)		14,340	$15,785.91	$15,661.73	$124.18	0.8%	$120.46	$0.00	$0.00	$0.00	$0.00	$0.00	$3.73

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 3 vs. Year 2

C & I LLF Large:

							Difference due to:						
(1)		Annual	Proposed	Proposed									
(2)		Consumption (Therms)	Rates Yr 3	Rates Yr 2	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		37,587	$41,122.57	$40,831.95	$290.62	0.7%	$281.90	$0.00	$0.00	$0.00	$0.00	$0.00	$8.72
(8)		41,634	$45,282.44	$44,960.52	$321.91	0.7%	$312.26	$0.00	$0.00	$0.00	$0.00	$0.00	$9.66
(9)		45,683	$49,444.71	$49,091.49	$353.22	0.7%	$342.62	$0.00	$0.00	$0.00	$0.00	$0.00	$10.60
(10)		49,731	$53,606.15	$53,221.63	$384.52	0.7%	$372.98	$0.00	$0.00	$0.00	$0.00	$0.00	$11.54
(11)		53,777	$57,765.10	$57,349.30	$415.80	0.7%	$403.33	$0.00	$0.00	$0.00	$0.00	$0.00	$12.47
(12)	**Average Customer**	**57,825**	**$61,926.50**	**$61,479.40**	**$447.10**	**0.7%**	$433.69	$0.00	$0.00	$0.00	$0.00	$0.00	$13.41
(13)		61,873	$66,087.92	$65,609.52	$478.40	0.7%	$464.05	$0.00	$0.00	$0.00	$0.00	$0.00	$14.35
(14)		65,920	$70,247.75	$69,738.06	$509.69	0.7%	$494.40	$0.00	$0.00	$0.00	$0.00	$0.00	$15.29
(15)		69,967	$74,408.28	$73,867.29	$540.98	0.7%	$524.75	$0.00	$0.00	$0.00	$0.00	$0.00	$16.23
(16)		74,016	$78,570.60	$77,998.31	$572.29	0.7%	$555.12	$0.00	$0.00	$0.00	$0.00	$0.00	$17.17
(17)		78,063	$82,730.43	$82,126.85	$603.58	0.7%	$585.47	$0.00	$0.00	$0.00	$0.00	$0.00	$18.11

C & I HLF Large:

							Difference due to:						
(18)		Annual	Proposed	Proposed									
(19)		Consumption (Therms)	Rates Yr 3	Rates Yr 2	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)			------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
(22)		41,956	$38,710.48	$38,485.56	$224.92	0.6%	$218.17	$0.00	$0.00	$0.00	$0.00	$0.00	$6.75
(23)		46,471	$42,609.03	$42,359.91	$249.12	0.6%	$241.65	$0.00	$0.00	$0.00	$0.00	$0.00	$7.47
(24)		50,991	$46,511.47	$46,238.12	$273.35	0.6%	$265.15	$0.00	$0.00	$0.00	$0.00	$0.00	$8.20
(25)		55,507	$50,410.77	$50,113.21	$297.56	0.6%	$288.64	$0.00	$0.00	$0.00	$0.00	$0.00	$8.93
(26)		60,028	$54,314.01	$53,992.21	$321.80	0.6%	$312.15	$0.00	$0.00	$0.00	$0.00	$0.00	$9.65
(27)	**Average Customer**	**64,545**	**$58,214.09**	**$57,868.07**	**$346.01**	**0.6%**	$335.63	$0.00	$0.00	$0.00	$0.00	$0.00	$10.38
(28)		69,062	$62,114.21	$61,743.98	$370.23	0.6%	$359.12	$0.00	$0.00	$0.00	$0.00	$0.00	$11.11
(29)		73,583	$66,017.37	$65,622.90	$394.47	0.6%	$382.63	$0.00	$0.00	$0.00	$0.00	$0.00	$11.83
(30)		78,099	$69,916.72	$69,498.05	$418.68	0.6%	$406.11	$0.00	$0.00	$0.00	$0.00	$0.00	$12.56
(31)		82,619	$73,819.17	$73,376.27	$442.91	0.6%	$429.62	$0.00	$0.00	$0.00	$0.00	$0.00	$13.29
(32)		87,137	$77,721.00	$77,253.88	$467.13	0.6%	$453.11	$0.00	$0.00	$0.00	$0.00	$0.00	$14.01

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption: Year 3 vs. Year 2

C & I LLF Extra-Large:

							Difference due to:						
(1)		Annual	Proposed	Proposed									
(2)		Consumption (Therms)	Rates Yr 3	Rates Yr 2	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)													
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		233,835	$189,032.48	$188,309.28	$723.20	0.4%	$701.50	$0.00	$0.00	$0.00	$0.00	$0.00	$21.70
(8)		259,019	$208,723.76	$207,922.67	$801.09	0.4%	$777.06	$0.00	$0.00	$0.00	$0.00	$0.00	$24.03
(9)		284,197	$228,410.97	$227,532.01	$878.96	0.4%	$852.59	$0.00	$0.00	$0.00	$0.00	$0.00	$26.37
(10)		309,381	$248,102.23	$247,145.38	$956.85	0.4%	$928.14	$0.00	$0.00	$0.00	$0.00	$0.00	$28.71
(11)		334,562	$267,791.47	$266,756.74	$1,034.73	0.4%	$1,003.69	$0.00	$0.00	$0.00	$0.00	$0.00	$31.04
(12)	**Average Customer**	**359,745**	**$287,482.04**	**$286,369.43**	**$1,112.61**	**0.4%**	$1,079.24	$0.00	$0.00	$0.00	$0.00	$0.00	$33.38
(13)		384,928	$307,172.61	$305,982.11	$1,190.50	0.4%	$1,154.78	$0.00	$0.00	$0.00	$0.00	$0.00	$35.71
(14)		410,110	$326,862.55	$325,594.16	$1,268.38	0.4%	$1,230.33	$0.00	$0.00	$0.00	$0.00	$0.00	$38.05
(15)		435,293	$346,553.10	$345,206.83	$1,346.27	0.4%	$1,305.88	$0.00	$0.00	$0.00	$0.00	$0.00	$40.39
(16)		460,471	$366,240.33	$364,816.20	$1,424.14	0.4%	$1,381.41	$0.00	$0.00	$0.00	$0.00	$0.00	$42.72
(17)		485,655	$385,931.61	$384,429.58	$1,502.03	0.4%	$1,456.97	$0.00	$0.00	$0.00	$0.00	$0.00	$45.06

C & I HLF Extra-Large:

							Difference due to:						
(18)		Annual	Proposed	Proposed									
(19)		Consumption (Therms)	Rates Yr 3	Rates Yr 2	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)													
(22)		486,528	$347,558.45	$346,454.98	$1,103.47	0.3%	$1,070.36	$0.00	$0.00	$0.00	$0.00	$0.00	$33.10
(23)		538,924	$384,321.36	$383,099.05	$1,222.30	0.3%	$1,185.63	$0.00	$0.00	$0.00	$0.00	$0.00	$36.67
(24)		591,320	$421,083.46	$419,742.32	$1,341.14	0.3%	$1,300.90	$0.00	$0.00	$0.00	$0.00	$0.00	$40.23
(25)		643,718	$457,847.58	$456,387.60	$1,459.98	0.3%	$1,416.18	$0.00	$0.00	$0.00	$0.00	$0.00	$43.80
(26)		696,109	$494,606.57	$493,027.77	$1,578.80	0.3%	$1,531.44	$0.00	$0.00	$0.00	$0.00	$0.00	$47.36
(27)	**Average Customer**	**748,506**	**$531,370.11**	**$529,672.47**	**$1,697.64**	**0.3%**	$1,646.71	$0.00	$0.00	$0.00	$0.00	$0.00	$50.93
(28)		800,903	$568,133.62	$566,317.14	$1,816.48	0.3%	$1,761.99	$0.00	$0.00	$0.00	$0.00	$0.00	$54.49
(29)		853,294	$604,892.59	$602,957.29	$1,935.31	0.3%	$1,877.25	$0.00	$0.00	$0.00	$0.00	$0.00	$58.06
(30)		905,692	$641,656.73	$639,602.58	$2,054.15	0.3%	$1,992.52	$0.00	$0.00	$0.00	$0.00	$0.00	$61.62
(31)		958,088	$678,418.85	$676,245.87	$2,172.98	0.3%	$2,107.79	$0.00	$0.00	$0.00	$0.00	$0.00	$65.19
(32)		1,010,485	$715,182.34	$712,890.52	$2,291.82	0.3%	$2,223.07	$0.00	$0.00	$0.00	$0.00	$0.00	$68.75

Footnote 1 - See Page 1 for detail of proposed and current rates used in bill impacts

Compliance Attachment 18

Narragansett Gas Development of Rates Associated With the

Distribution Adjustment Clause and Gas Cost Recovery Clause

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

Line No.	Description (a)	Source: Reference (b)	Source: Line # (c)	High Load[1] (d)	Low Load[2] (e)
1	Fixed Cost Factor - $/dktherm	Page 2	Line (18)	$1.1441	$1.5652
2	Variable Cost Factor -$/dktherm	Page 3	Line (13)	$3.5618	$3.5618
3	Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$4.7059	$5.1270
4	Uncollectible %	Attachment 2 Schedule 22 Pg 7	Line 15	1.91%	1.91%
5	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) / [1 - (4)]		$4.7975	$5.2268
6	**GCR Charge on a per therm basis**	(5) / 10		**$0.4797**	**$0.5226**

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

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Fixed Cost Calculation ($ per Dth)

Line No.	Description	Source: Reference	Source: Line #	Amount	High Load Factor Total	Low Load Factor Total
	(a)	(b)	(c)	(d)	(e)	(f)
1	Fixed Costs (net of Cap Rel to marketers)	Dk 4719		$53,921,320		
	Less:					
2	NGPMP Customer Benefit	Dk 4719		($10,900,000)		
3	Interruptible Costs			$0		
4	FT-2 Storage Demand Costs	Dk 4719		($2,040,370)		
5	Systeme Pressure to DAC	Dk 4719		($3,153,600)		
6	Refunds			$0		
7	Total Credits	sum[(2):(6)]		($16,093,970)		
	Plus:					
8	Supply Related LNG O&M Costs	Attachment 2 Schedule 32 -GAS Pg 5 including adj from DIV 43-1	Line 12	$829,823		
9	Portable LNG Storage Cost			$0		
10	Working Capital Requirement	Page 4	Line 17	$385,115		
11	Deferred Fixed Cost Under-recovered	Dk 4719	Line (17)	$1,169,851		
12	Reconciliation Amount from Fixed costs- Marketers	Dk 4719	Line (50)	$36,098		
13	Total Additions	sum[(8):(12)]		$2,420,886		
14	Total Fixed Costs	(1) + (7) + (13)		$40,248,236		
15	Design Winter Sales Percentage	Dk 4719	Lines (10) & (11)		2.12%	97.88%
16	Allocated Supply Fixed Costs	(14) x (15)			$854,081	$39,394,155
17	Sales (Dt) Nov 2017 - Oct 2018	Dk 4719	Line (9)	25,914,442	746,482	25,167,960
18	**Fixed Factor**	(16) / (17)			**$1.1441**	**$1.5652**

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Variable Cost Calculation ($ per Dth)

Line No.	Description	Source: Reference	Source: Line #	Amount
	(a)	(b)	(c)	(d)
1	Variable Costs, excluding Refunds	Dk 4719		$78,329,672
	Less:			
2	Non-Firm Sales			$0
3	Refunds	Dk 4719		$0
4	Total Credits	sum [(2):(3)]		$0
	Plus:			
5	Working Capital	Page 4	Line 33	$594,195
6	Deferred Variable Cost Under-recovered	Dk 4719	Line (35)	$12,377,603
7	Supply Related LNG O&M	Attachment 2 Schedule 32 -GAS Pg 5 including adj from DIV 43-1	Line 15 - Line 12	$302,244
8	Inventory Financing - LNG	Page 5	Line 22	$182,998
9	Inventory Financing - Storage	Page 5	Line 12	$516,598
10	Total Additions	sum [(5):(9)]		$13,973,637
11	Total Variable Supply Costs	(1) + (4) + (10)		$92,303,309
12	Sales (Dt) Nov 2017 - Oct 2018	Dk 4719	Line (9)	25,914,442
13	**Variable Cost Factor**	(11) / (12)		**$3.5618**

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Working Capital Estimate

Line No.	Description (a)	Source (b)	Nov-17 (c)	Dec-17 (d)	Jan-18 (e)	Feb-18 (f)	Mar-18 (g)	Apr-18 (h)	May-18 (i)	Jun-18 (j)	Jul-18 (k)	Aug-18 (l)	Sep-18 (m)	Oct-18 (n)	Total (o)
1	**Fixed Costs**	Dk 4719	$4,414,408	$4,448,398	$4,447,065	$4,444,929	$4,447,065	$4,531,059	$4,531,771	$4,531,059	$4,531,771	$4,531,771	$4,530,656	$4,531,368	$53,921,320
2	Capacity Release Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Less: System Pressure to DAC	Dk 4719	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($262,800)	($3,153,600)
4	Less: Credits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5															
6	Allowable Working Capital Costs	sum[(1):(5)]	$4,151,608	$4,185,598	$4,184,265	$4,182,129	$4,184,265	$4,268,259	$4,268,971	$4,268,259	$4,268,971	$4,268,971	$4,267,856	$4,268,568	$50,767,720
7	Net Payment Lag	Attachment 2 Schedule 42-GAS Ln1	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	
8	Number of Days Lag	(7) X 365	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
9	Working Capital Requirement	[(6) * (8)] / 365	$374,475	$377,541	$377,421	$377,228	$377,421	$384,997	$385,061	$384,997	$385,061	$385,061	$384,961	$385,025	
10	Cost of Capital	Attachment 2 Schedule 1-GAS Pg 4	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
11	Return on Working Capital Requirement	(9) * (10)	$26,775	$26,994	$26,986	$26,972	$26,986	$27,527	$27,532	$27,527	$27,532	$27,532	$27,525	$27,529	
12	Weighted Cost of Debt	Attachment 2 Schedule 1-GAS Pg 4	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	
13	Interest Expense	(9) * (12)	$9,025	$9,099	$9,096	$9,091	$9,096	$9,278	$9,280	$9,278	$9,280	$9,280	$9,278	$9,279	
14	Taxable Income	(11) - (13)	$17,750	$17,895	$17,890	$17,881	$17,890	$18,249	$18,252	$18,249	$18,252	$18,252	$18,247	$18,250	
15	1 - Combined Tax Rate	1 - 0.21	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
16	Return and Tax Requirement	(14) / (15)	$22,469	$22,652	$22,645	$22,634	$22,645	$23,100	$23,104	$23,100	$23,104	$23,104	$23,098	$23,101	
17	**Fixed Working Capital Requirement**	(13) + (16)	$31,493	$31,751	$31,741	$31,725	$31,741	$32,378	$32,384	$32,378	$32,384	$32,384	$32,375	$32,381	$385,115
18	**Variable Costs**	Dk 4719	$5,645,914	$10,998,135	$17,208,947	$15,542,321	$10,715,275	$5,484,110	$3,165,666	$2,024,140	$1,607,551	$1,477,419	$1,545,483	$2,914,712	$78,329,672
19	Less: Non-firm Sales														$0
20	Less: Supply Refunds														$0
21	Less: Balancing Related System Pressure Commodity to DAC		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Allowable Working Capital Costs	sum[(18):(21)]	$5,645,914	$10,998,135	$17,208,947	$15,542,321	$10,715,275	$5,484,110	$3,165,666	$2,024,140	$1,607,551	$1,477,419	$1,545,483	$2,914,712	$78,329,672
23	Net Payment Lag	Attachment 2 Schedule 42-GAS Ln1	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	
24	Number of Days Lag	(23) X 365	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	32.92	
25	Working Capital Requirement	[(22) * (24)] / 365	$509,261	$992,032	$1,552,247	$1,401,917	$966,518	$494,667	$285,543	$182,577	$145,001	$133,263	$139,403	$262,907	
26	Cost of Capital	Attachment 2 Schedule 1-GAS Pg 4	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
27	Return on Working Capital Requirement	(25) * (26)	$36,412	$70,930	$110,986	$100,237	$69,106	$35,369	$20,416	$13,054	$10,368	$9,528	$9,967	$18,798	
28	Weighted Cost of Debt	Attachment 2 Schedule 1-GAS Pg 4	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	
29	Interest Expense	(25) * (28)	$12,273	$23,908	$37,409	$33,786	$23,293	$11,921	$6,882	$4,400	$3,495	$3,212	$3,360	$6,336	
30	Taxable Income	(27) - (29)	$24,139	$47,022	$73,577	$66,451	$45,813	$23,447	$13,535	$8,654	$6,873	$6,317	$6,608	$12,462	
31	1 - Combined Tax Rate	1 - 0.21	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
32	Return and Tax Requirement	(30) / (31)	$30,556	$59,522	$93,135	$84,115	$57,991	$29,680	$17,133	$10,955	$8,700	$7,996	$8,364	$15,774	
33	**Variable Working Capital Requirement**	(29) + (32)	$42,829	$83,430	$130,544	$117,901	$81,284	$41,601	$24,014	$15,355	$12,195	$11,207	$11,724	$22,110	$594,195

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Inventory Finance Estimate

Line No.	Description (a)	Source (b)	Nov-17 (c)	Dec-17 (d)	Jan-18 (e)	Feb-18 (f)	Mar-18 (g)	Apr-18 (h)	May-18 (i)	Jun-18 (j)	Jul-18 (k)	Aug-18 (l)	Sep-18 (m)	Oct-18 (n)	Total (o)
1	**Storage Inventory Balance**	Dk 4719	$9,436,055	$8,139,654	$6,127,822	$4,288,451	$2,610,887	$2,653,444	$3,877,029	$5,066,626	$5,878,226	$6,941,021	$8,623,396	$10,069,304	
2	Hedging														
3	Subtotal	(1) + (2)	$9,436,055	$8,139,654	$6,127,822	$4,288,451	$2,610,887	$2,653,444	$3,877,029	$5,066,626	$5,878,226	$6,941,021	$8,623,396	$10,069,304	
4	Cost of Capital	Attachment 2 Schedule 1-GAS Pg 4	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
5	Return on Working Capital Requirement	(3) * (4)	$674,678	$581,985	$438,139	$306,624	$186,678	$189,721	$277,208	$362,264	$420,293	$496,283	$616,573	$719,955	$5,270,402
6	Weighted Cost of Debt	Attachment 2 Schedule 1-GAS Pg 4	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	
7	Interest Charges Financed	(3) * (6)	$227,409	$196,166	$147,681	$103,352	$62,922	$63,948	$93,436	$122,106	$141,665	$167,279	$207,824	$242,670	$1,776,457
8	Taxable Income	(5) - (7)	$447,269	$385,820	$290,459	$203,273	$123,756	$125,773	$183,771	$240,158	$278,628	$329,004	$408,749	$477,285	
9	1 - Combined Tax Rate	1 - 0.21	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
10	Return and Tax Requirement	(8) / (9)	$566,163	$488,379	$367,669	$257,307	$156,653	$159,207	$232,622	$303,998	$352,694	$416,461	$517,404	$604,158	$4,422,715
11	Working Capital Requirement	(7) + (10)	$793,572	$684,545	$515,350	$360,659	$219,576	$223,155	$326,058	$426,103	$494,359	$583,740	$725,228	$846,828	$6,199,172
12	Storage-Related Inventory Costs	(11) / 12	$66,131	$57,045	$42,946	$30,055	$18,298	$18,596	$27,172	$35,509	$41,197	$48,645	$60,436	$70,569	$516,598
13	**LNG Inventory Balance**	Dk 4719	$3,270,413	$3,192,464	$1,258,328	$519,480	$441,531	$1,081,591	$1,739,817	$2,380,668	$2,612,172	$2,737,694	$3,376,487	$3,500,813	
14	Cost of Capital	Attachment 2 Schedule 1-GAS Pg 4	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	7.15%	
15	Return on Working Capital Requirement	(13) * (14)	$233,835	$228,261	$89,970	$37,143	$31,569	$77,334	$124,397	$170,218	$186,770	$195,745	$241,419	$250,308	$1,866,969
16	Weighted Cost of Debt	Attachment 2 Schedule 1-GAS Pg 4	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	
17	Interest Charges Financed	(13) * (16)	$78,817	$76,938	$30,326	$12,519	$10,641	$26,066	$41,930	$57,374	$62,953	$65,978	$81,373	$84,370	$629,286
18	Taxable Income	(15) - (17)	$155,018	$151,323	$59,645	$24,623	$20,929	$51,267	$82,467	$112,844	$123,817	$129,767	$160,045	$165,939	
19	1 - Combined Tax Rate	1 - 0.21	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	0.7900	
20	Return and Tax Requirement	(18) / (19)	$196,225	$191,548	$75,500	$31,169	$26,492	$64,895	$104,389	$142,840	$156,730	$164,262	$202,589	$210,049	$1,566,688
21	Working Capital Requirement	(17) + (20)	$275,042	$268,486	$105,825	$43,688	$37,133	$90,962	$146,319	$200,214	$219,684	$230,240	$283,963	$294,418	$2,195,974
22	LNG-Related Inventory Costs	(21) / 12	$22,920	$22,374	$8,819	$3,641	$3,094	$7,580	$12,193	$16,685	$18,307	$19,187	$23,664	$24,535	$182,998
23	Total Inventory Financing Costs	(12) + (22)	$89,051	$79,419	$51,765	$33,696	$21,392	$26,176	$39,365	$52,193	$59,504	$67,832	$84,099	$95,104	$699,595

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National Grid - RI Gas
Summary of DAC Factors

Section 1: DAC factor (not including annual ISR component) September 1, 2018

Line No.	Description	Reference	Amount	Factor: Residential/ Small/ Medium C&I	Factor: Large/ X-Large	Residential Low Income
1	System Pressure (SP)	Dk 4708	$3,153,600	$0.0079	$0.0079	$0.0079
2	Advanced Gas Technology Program (AGT)	Dk 4708	$0	$0.0000	$0.0000	
3	Low Income Discount Recovery Factor (LIDRF)	Attachment 20 Schedule 2	$4,550,593	$0.0119	$0.0119	
4	Environmental Response Cost Factor (ERCF)	Dk 4708	$967,642	$0.0024	$0.0024	$0.0024
5	Pension Adjustment Factor (PAF)	Dk 4708	($4,679,974)	($0.0118)	($0.0118)	($0.0118)
6	On-System Margin Credits (MC)	Dk 4708		$0.0000	$0.0000	$0.0000
7	Reconciliation Factor (R)	Dk 4708	($100,990)	$0.0000	($0.0011)	$0.0000
8	Service Quality Factor (SQP)	Dk 4708	$0	$0.0000	$0.0000	$0.0000
9	Earnings Sharing Mechanism (ESM)	Dk 4708	$0	$0.0000	$0.0000	$0.0000
10	Subtotal	Sum ([1]:[9])	$3,890,871	$0.0104	$0.0093	($0.0015)
11	Uncollectible Percentage	Schedule MAL-22 Pg 7 Line 15	1.91%	1.91%	1.91%	1.91%
12	DAC factors grossed up for uncollectible	[10]/(1-[11])	$3,966,633	$0.0106	$0.0094	($0.0015)
13	Revenue Decoupling Adjustment (RDA)	Dk 4708	$177,598	$0.0006	$0.0000	$0.0006
14	Revenue Decoupling Adjustment Reconciliation	Dk 4708	$298,047	$0.0010	$0.0000	$0.0010
15	DAC factor	[12]+[13]+[14]	$4,442,277	**$0.0122**	**$0.0094**	**$0.0001**

Section 2: DAC factors including annual ISR component

Line No.		ISR Reconciliation w/o uncollectible[1] (therms)	Uncollectible Percentage[2]	ISR Reconciliation* (therms) (A)	Base DAC Component*[3] (therms) (B)	DAC Component Subtotal Rates* (therms) (C) =(A) + (B)	ISR Component* (therms) (D)	Sep 1 2018 DAC Rates* (therms) (E) = (C)+(D)
16	Res-NH	$0.0465	1.91%	$0.0474	$0.0122	$0.0596		$0.0596
17	Res-NH-LI	$0.0465	1.91%	$0.0474	$0.0001	$0.0475		$0.0475
18	Res-H	$0.0202	1.91%	$0.0205	$0.0122	$0.0327		$0.0327
19	Res-H-LI	$0.0202	1.91%	$0.0205	$0.0001	$0.0206		$0.0206
20	Small	$0.0299	1.91%	$0.0304	$0.0122	$0.0426		$0.0426
21	Medium	$0.0195	1.91%	$0.0198	$0.0122	$0.0320		$0.0320
22	Large LL	$0.0161	1.91%	$0.0164	$0.0094	$0.0258		$0.0258
23	Large HL	$0.0120	1.91%	$0.0122	$0.0094	$0.0216		$0.0216
24	XL-LL	$0.0021	1.91%	$0.0021	$0.0094	$0.0115		$0.0115
25	XL-HL	$0.0006	1.91%	$0.0006	$0.0094	$0.0100		$0.0100

***Factors Include Uncollectible Allowance**

[1] Docket 4708
[2] Attachment 2 Schedule 22 Pg 7 Line 15
[3] Section 1, Line 15

	Current Energy Efficiency Factors				
		Reference	Residential	Commercial & Industrial	
1	Energy Efficiency Factor	Docket No. 4654	0.8600	0.7030	$/Dktherm
2	Uncollectible	Docket No. 4654	3.18%	3.18%	
3	Total Energy Efficiency Fact	Ln 1/(1-Ln 2)/10	$0.0888	$0.0726	$/Therm

	Proposed Energy Efficiency Factors				
			Res	C&I	
4	Energy Efficiency Factor	Ln 1	0.8600	0.7030	$/Dktherm
5	Uncollectible	Attachment 2 Schedule 22 Pg 7 Line 15	1.91%	1.91%	
6	Total Energy Efficiency Fact	Ln 4/(1-Ln 5)/10	$0.0876	$0.0716	$/Therm

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Compliance Attachment 19

Narragansett Gas Redlined Tariff

Marked to show changes from the tariff currently in effect

THE NARRAGANSETT ELECTRIC COMPANY

d/b/a NATIONAL GRID

Rhode Island Public Utilities Commission Tariff

RIPUC NG-GAS No. 101

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GENERAL TERMS AND CONDITIONS

1.0 APPLICABILITY:

The following terms and conditions shall apply to and be a part of each Rate Classification now or hereafter in effect except as they may be expressly modified or superseded by Rhode Island Public Utilities Commission order.

2.0 RATES AND TARIFFS:

The Company furnishes natural gas service under rates and/or special contracts (Schedule of Rates) promulgated in accordance with the provisions of the Rhode Island General Laws and the regulations of the Rhode Island Public Utilities Commission ("PUC") and the Rhode Island Division of Public Utilities and Carriers ("Division"), all as may be in effect from time to time. Such Schedule of Rates, which includes these Terms and Conditions, is available for public inspection during normal business hours at the administrative offices of the Company and at the offices of the PUC and the Division or on the Company's website.

The Schedule of Rates may be revised, amended, supplemented or supplanted in whole or in part from time to time according to the procedures provided in the General Laws and the PUC regulations. When effective, all such revisions, amendments, supplements or replacements will appropriately supersede the present Schedule of Rates. In case of conflict between these Terms and Conditions and any orders or regulations of the PUC or the Division, said orders or regulations shall govern.

The provisions of these Terms and Conditions apply on a non-discriminatory and non-preferential basis to all persons, partnerships, corporations or others (hereinafter ~~customers~~ Customers or the ~~customer~~Customer) who obtain natural gas distribution service from the Company pursuant to the Schedule of Rates.

No representative of the Company has the authority to modify orally any provision or rate contained in the Schedule of Rates or to bind the Company to any promise or representation contrary thereto. Any such modification to the Schedule of Rates or these Terms and Conditions shall be in writing and made in accordance with the provisions of the General Laws and pursuant to regulations of the PUC and Division.

The Company will advise all new residential customers as to the least expensive rate available for the service based on the information in our records. Non-residential customers will be advised of the applicable rate based on a review of the available information in ~~our~~ the existing records or as a result of a field inspection by the Company when the customer provides information which is inconsistent with Company records. The Customer is responsible for accurately describing its gas burning equipment and updating the Company as changes occur.

GENERAL TERMS AND CONDITIONS

A Customer is entitled to change its customer account from one rate classification to another upon written application to the Company; provided, however that the customer account's use complies with the conditions specified in the requested rate classification. Once an election to change rate classifications has been made by the Customer, the customer account must remain on that rate for a period of not less than twelve months. In cases where the Customer requests a rate reclassification, no rebate will be granted for service rendered during the period the customer account was served under the previous rate classification, except in instances where the previous rate classification was due to an error by the Company.

3.0 OBTAINING SERVICE FROM THE COMPANY:

The Company shall furnish service to applicants under the filed rates and in accordance with these Terms and Conditions and the rules and regulations of the PUC and the Division. The furnishing of service and acceptance by the ~~customer~~ Customer constitutes a contract under these provisions. The Company may require at least one person on behalf of all parties who will receive service to sign an application or contract. Application for gas service within the territory served by the Company will be received through any duly authorized representative of the Company.

The Company may accept oral or written application for residential service. Residential service may commence upon receipt by the Company of oral application, except that the Company reserves the right to require residential customers to show identification and proof of residency before commencing service. If residential service is commenced upon the receipt of oral application, then all residents at that address who have attained the age of majority may choose to execute a written application, thereby becoming parties to the contract. Non-residential service may commence upon oral application for an interim period pending the receipt of a duly executed written application and security deposit.

The Company reserves the right to refuse service, at any location, to an individual who is indebted to the Company for any service not in dispute before the Division, furnished to such individual at any location, or to such applicant or customer under another name. The Company will commence service if a reasonable payment plan for said indebtedness made in accordance with PUC and Division regulations is agreed to by the Customer and the Company. The Company reserves the right to refuse service to any non-residential applicant who has not paid a deposit as required by the Company.

A Customer shall be and remains the customer of record and shall be liable for service taken until such time as the Customer requests termination of service and a final meter reading is recorded by the Company. The bill rendered by the Company based on such final meter reading shall be payable upon receipt. Such meter reading and final bill shall not be unduly delayed by the Company. In the event that the Customer of record fails to give notice of

GENERAL TERMS AND CONDITIONS

termination of service to the Company or fails to provide access to the meter, the customer of record shall continue to be liable for service taken until the Company either disconnects the meter or a new party becomes a customer of the Company by taking service at such service location. Failure to make application for service shall not relieve a party from the obligation to apply and/or pay for service previously used.

The Company shall undertake to furnish service to the Customer for use only for his/her own purposes and only on the premises occupied through ownership or lease by the Customer, except as provided below. In cases where the Customer is a condominium association or the owner or manager of a commercial or residential rental property with over six (6) units, the Customer may allocate the Company charges for gas service to other gas users on the premises through any reasonable means, including properly installed submetering. In such situations where the Customer is allocating the Company charges for service to others, the burden is on the Customer, when requested by the Company, to demonstrate that the allocated charges are no greater than the Customer's bill from the Company. When allocating such charges, the Customer may separately include reasonable administrative fees. Natural gas sold by the Company to authorized natural gas vehicle filling stations may be re-metered or submetered by the Customer for resale to another or others.

On an annual basis the Company may notify all customers that if they are the owners of property and their tenants move out, the owner must provide written notification in advance that he/she wants gas left on at that premises in his/her name. If the Company does not receive advance written notice, the service may be terminated, and the Company will not be liable for any damages to the premises resulting from the termination of gas service.

3.1 BILLING TERMINATION ("Soft-Off"):

~~The Company and the Division have agreed to participate in a one-year pilot program (the "Pilot") with respect to the Company's "Soft-Off" termination policy, pursuant to a Settlement Agreement between the Company and the Division, as approved by the PUC on May 4, 2012. During the Pilot, w~~Where a customer has requested termination of service and an estimated or actual final meter reading is recorded, and the account is not subject to a shut-off order or request, the Company may choose to utilize a ~~"~~Soft-Off~~"~~ termination.

In the event of a termination of an account for which there is no unbilled consumption, a landlord may initiate an application for service in the landlord's name at that premises by either oral or written request in accordance with Section 1, Schedule A, Paragraph 3.0 of this tariff; provided however, that in the event of a termination of an account for which there is any unbilled consumption, a landlord may initiate an application for service in the landlord's name only upon providing the Company with a signed authorization. In addition, where the

GENERAL TERMS AND CONDITIONS

landlord has previously provided the Company a signed agreement, the Company may record the landlord as the customer of record for that account without further authorization.

When gas consumption at a premises where a Soft Off termination has been implemented exceeds 13 ccf in a month the Company will send a notification to the premises indicating that service will be terminated pursuant to the PUC's and Division's rules and regulations governing the termination of service if an account is not established.

Once metered gas consumption at that premises exceeds an aggregate of 35 ccf or the account is still in a "Soft-Off" status for a consecutive period of 90 days, whichever occurs first, the Company will commence a termination action for the account, provided however that where such a termination action would affect the statutory and/or termination rights of other gas customers at that location, service will be terminated at the Soft Off premises as soon as the Company is able to accomplish the termination so as not to conflict with the rights provided under the PUC's and the Division's rules and regulations governing the termination of service for the other customers.

4.0 SECURITY DEPOSITS:

Security deposits, letters of credit or bonds may be required and taken in accordance with rules and procedures promulgated by the PUC or other body having authority to regulate the Company. The Company reserves the right to refuse service to an applicant who has not paid a deposit as required by the Company. The rate of interest paid on deposits shall be adjusted annually on March l. The interest rate in effect in any year shall be based on the average rate over the prior calendar year for 10-year constant maturity Treasury Bonds as reported by the Federal Reserve Board.

5.0 SERVICE SUPPLIED:

The Company shall take reasonable care in providing regular and uninterrupted service to its firm customers, but whenever the Company deems that the situation warrants any interruption or limitation in the service to be rendered, such interruption or limitation shall not constitute a breach of the contract, and shall not render the Company liable for any damages suffered thereby by any person, or excuse the customer from further fulfillment of the contract.

The Company may refuse to supply service to loads of unusual characteristics which, in its sole judgment, might adversely affect the quality of service supplied to other customers, the public safety, or the safety of the Company's personnel. In lieu of such refusal, the Company may require a customer to install any necessary regulating and protective equipment in accordance with the requirements and specifications of the Company.

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Whenever the estimated expenditures necessary to supply gas to a customer(s) or to resume service to a customer following relocation of Company equipment for reasons other than the needs of the Company shall be of such an amount that the income to be derived from gas service at the applicable rates will, in the opinion of the Company, be insufficient to warrant such expenditure, the Company will require the ~~customer~~Customer(s) to pay a Contribution in Aid of Construction ("CIAC") for meter relocation or for main and service extension. See Section 8, Service and Main Extension Policies. The level of the CIAC will be based on an economic analysis looking at appropriate impacts associated with the capital expenditures. A detailed written cost estimate will be provided to the Customer upon request.

The Company shall make application in a reasonable time for any necessary locations or other street permits required by public bodies for its pipes, mains, and other apparatus, and shall not be required to supply service until a reasonable time after such approvals are obtained. The applicant for service shall obtain all other permits, certificates, licenses, easements and the like necessary to give the Company access to the applicant's equipment and to enable its pipes to be connected thereto.

The Customer shall notify the Company in writing before making any significant change in the Customer's gas equipment which would affect the capacity or other characteristics of the Company's facilities required to serve the Customer. The Customer shall be liable for any damage to the Company's property caused by Customer's additional or changed installation if made without prior notification to the Company.

All piping, equipment, and apparatus on the premises of the Customer, excep~~ting~~t meters, underground service pipe, and governors, shall be furnished and put in place by the Customer, and shall conform to the requirements and regulations of the Company, and the Company shall not be required to supply gas unless such piping, equipment, and apparatus at all times conform to the requirements and regulations of the State, City, and Town ordinances and laws and policies of the Company. The Company shall be under no obligation to make any inspection to ascertain whether the foregoing condition has been conformed with and shall be under no liability for any damages occasioned by any defect in such piping, equipment, or apparatus or other property on the premises.

If temporary service is rendered, the ~~customer~~ Customer shall pay the cost of service under the rate plus the cost of installing and removing all equipment and connections.

6.0 INSTALLATION OF METERS:

The Company will furnish, install, connect, and maintain such meter(s) as are necessary for metering gas service for Company billing purposes.

GENERAL TERMS AND CONDITIONS

All gas service to be provided under a single service classification to a customer in a building will be rendered through a single meter except in the instances described in (1) and (2) below:

(1) The Company may elect to install more than one meter for gas service provided under a single service classification:

i. when the use of more than one meter is necessary to provide safe gas service;

ii. when the use of more than one meter is required by a municipal ordinance;

iii. when one meter cannot correctly measure the total gas service rendered;

iv. when the characteristics of gas service of the ~~customer~~ Customer are such that at the time the service line was installed there was no single meter commercially available to measure the gas service correctly;

v. when more than one meter is required in order to render proper and reliable gas service without interruption; or

vi. in other comparable circumstances where service cannot practically be rendered through a single meter.

Pursuant to (i) through (vi), when more than one meter is installed to measure the gas service of a single customer at a premise~~s~~ or building under a single service classification under the above listed circumstances, the registrations of the meters will be combined under one customer account and the bill computed as if all service had been rendered through a single meter.

(2) At the Customer's written request and at the Customer's expense, the Company will install more than one meter for a building or premise~~s~~ under a single service classification, in which case the quantity of gas supplied through each meter will be measured separately and the bills for each computed separately under the appropriate service classification(s).

Gas service provided to commercial and industrial customers for use by emergency back-up natural gas generators of more than 12 kW shall be separately metered subject to the Company's technical determination that more than one meter is required to correctly measure the total gas service rendered. Should the Company determine that this service be separately metered, the Company will issue a separate

GENERAL TERMS AND CONDITIONS

bill pursuant to a rate schedule applicable for the usage on the separate meter. Otherwise, if so determined by the Company to be technically feasible, the Company shall allow gas usage for emergency back-up natural gas generators to be measured by the Customer's existing meter.

~~(B)~~ For residential gas services provided pursuant to prior tariff provisions that required that gas service for use by emergency back-up natural gas generators be separately metered and billed, when both meters are served under a single residential service classification, the registrations of the meters will be combined under one customer account and the bill computed as if all service had been rendered through a single meter. Should a residential customer request the removal of one of the meters, the Customer shall bear the cost of removing the meter and the cost of piping through the remaining meter. If the Company, at its sole discretion, decides to remove the additional meter, the Company will bear the cost of the removal of the meter and any piping cost.

7.0 BILLING AND READING OF METERS:

Bills are calculated and rendered on the basis of a customer account which shall have a unique identification number established for the billing of service provided through an individual meter, except for multiple metered customer accounts established pursuant to section (1) of Item 6.0 above, or aggregation pools established pursuant to the Company's Transportation Terms and Conditions, Section 6, Schedule C of the tariff. A single Customer may have more than one customer account.

All bills are due within 25 days from the date of the bill. A late payment charge shall accrue on non-residential bills after 25 days in accordance with regulations of the PUC and the Division.

Customers receiving bills may elect to receive their bill electronically. Customers electing to receive their bills electronically will receive a paperless billing credit as identified in Section 1, Schedule A, Item 12.0.

Whenever a check or draft presented for payment of service is not accepted by the institution on which it is written, the Customer shall be charged a returned check fee,~~charge of $15 applies~~ as identified in Item 12.0, per check or draft written. Such returned check charge shall be waived for customers ~~eligible for low-income assistance programs~~receiving gas service on low income rate classes Rate 11 and Rate 13.

The Customer shall be responsible for all charges for distribution and gas service furnished by the Company under the applicable rates as filed from time to time with the PUC, from the

GENERAL TERMS AND CONDITIONS

time service is commenced until it is terminated.

Annually in August, the Company will review the gas consumption of each non-residential firm customer account for the just ended September through August period to determine if any customer account qualifies for a different rate class. If any such customer account does qualify for a different rate class based on this billing information, then commencing with the September billing month, that customer account will be billed under that new rate class.

Properly authorized representatives of the Company shall have the right to access the Customer's premises at all reasonable times and intervals for the purpose of reading, installing, examining, repairing, replacing, or removing the Company's meters, meter reading devices, pipes, and other gas equipment and appliances, in accordance with the General Laws, public regulations, and Company policy in effect from time to time. The Customer shall be responsible for providing accessibility to the above metering and other equipment belonging to the Company.

Readings taken by an ~~automated~~ Automated ~~meter~~ Meter ~~reading~~ Reading ("AMR") ~~device~~ technology will be considered actual readings for billing purposes.

The Company shall maintain the accuracy of all metering equipment installed pursuant hereto by regular testing and calibration in comparison to recognized standards and in accordance with PUC and Division regulations. A meter shall be deemed to be registering correctly if it appears from examination or test that it does not vary more than two percent (2%) from the standard approved by the Division.

In the event that the Company obtains inaccurate meter readings for any reason or in case any meter shall for any reason fail to register the full amount of gas supplied or the maximum demand of any customer account for any period of time, the amount of the bill of such customer account shall be estimated by the Company from available data. Such estimated bills shall be payable as rendered unless a customer disputes such estimate in accordance with procedures established by the Division.

The Company will notify the Customer whenever it obtains information indicating that gas is being diverted from the ~~customer's~~ Customer's service or that the meter has been tampered with. The Customer will be held responsible to the Company for any leakage or other use of gas which may occur beyond the point of the meter installation.

Unless otherwise determined by the Company, all residential premises shall be equipped with a meter that employs ~~Automatic Meter Reading ("~~AMR~~")~~ technology utilizing radio frequency transmitters to allow the Company to obtain meter readings remotely. However,

GENERAL TERMS AND CONDITIONS

residential customers may choose to "opt-out" by having their AMR meter replaced with a non-AMR meter.

Customers who choose to opt-out will be charged an initial fee, as identified in Item 12.0, ~~of $74.00~~ for the removal of the existing AMR gas meter and the installation of the non-AMR gas meter.

Customers who choose to opt-out will also be charged a monthly meter reading fee ~~of $13.00~~ for the non-AMR gas meter, as identified in Item 12.0. The meter reading fee is applicable to Customers who receive gas and electric service, or receive gas-only service, from the Company. The Company, at its option, may choose to read the non-AMR meter less frequently than once per month. In that case, or if the Company is unable for any reason to read the meter on the regularly scheduled monthly read date, the Company shall make a reasonable estimate of the consumption of gas during those months when the meter is not read, based on available data, and such estimated bills shall be payable as rendered.

A Customer will not be assessed the initial or monthly fee until after the Company has installed the non-AMR gas meter.

Any opt-out Customer who subsequently wishes to have an AMR gas meter re-installed will be charged a "re-installation fee" ~~of $74.00~~as identified in Item 12.0. The re-installation fee will be charged for the removal of the non-AMR gas meter and the installation of the AMR gas meter.

Any Customer electing re-installation will no longer be assessed the special monthly gas meter reading fee after the AMR meter has been re-installed.

8.0 DISCONTINUANCE OF SERVICE:

Subject to the applicable regulations of the PUC and the Division, the Company shall have the right to discontinue gas service to the Customer and to remove or disconnect its meters and piping for nonpayment of bills for gas service. The customer shall be responsible for paying the cost of reconnecting gas service if the service is disconnected for nonpayment of bills or an ~~$25~~ account restoration charge, as identified in Item 12.0, in the case of a turn-on after a shut-off for nonpayment of bills. Such account restoration charge shall be waived for Customers ~~eligible for low-income assistance programs~~receiving service on low income rate classes Rate 11 and Rate 13.

The Company reserves the right to disconnect its service at any time without notice or to refuse to connect its service if, to its knowledge and in its judgment, the Customer's

GENERAL TERMS AND CONDITIONS

installation has become or is unsafe, defective, or in violation of the Company's policies or any ordinances, laws, codes, or regulations.

In the event that any action by the Customer or others shall cause a condition in the premises occupied by any customer whereby life or property is endangered, the Company may discontinue service to said premises regardless of the number of occupants or tenants of said premises.

Whenever the Company shall have proof that any customer is diverting and/or stealing service, the Company may discontinue its service to such customer and remove the meter.

9.0 COMPANY INSTALLATION AND PROPERTY:

All meters, services, and other gas equipment owned by the Company shall be and will remain the property of the Company and no one other than an employee or authorized agent of the Company shall be permitted to remove, operate, or maintain such property. The Customer shall be responsible for all damage to, or loss of, such property unless occasioned by circumstances beyond the Customer's control. Such property shall be installed at points most convenient for the Company's access and service and in conformance with public regulations in force from time to time. The costs of relocating such property shall be borne by the Customer when done at the Customer's request, or for his convenience, or if necessary to remedy any violation of public law or regulation caused by the Customer.

The Company shall provide and maintain the necessary housing, fencing, barriers, and foundations for the protection of the equipment to be installed upon the ~~customer's~~ Customer's premises. Such space, housing, fencing, barriers, and foundations shall be in conformity with applicable laws and regulations and subject to the Company's specifications and approval.

10.0 SUPPLY OF GAS:

The Company shall make every reasonable effort to maintain an uninterrupted supply of gas for all firm customers, but it shall not be liable for loss or damage caused by reason of any interruption or reduction of the supply, or by reason of any abnormal pressure or quality of the gas, whether as a result of accident, labor difficulties, condition of fuel supply, the actions of any public authority, failure to receive any gas for which in any manner it has contracted, the implementation in accordance with good utility practice of an emergency load reduction program by the Company or one with whom it has contracted for a supply of gas, or inability for any other reason beyond the Company's control to maintain normal pressure or quality, or uninterrupted and continuous service.

GENERAL TERMS AND CONDITIONS

Whenever the integrity of the Company's system or the supply of gas is believed to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in its sole judgment, curtail or interrupt gas service or reduce pressure and such action shall not be construed to constitute a default nor shall the Company be liable therefore in any respect. The Company will use reasonable efforts under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

The Company shall be excused from performing under the Schedule of Rates and shall not be liable in damages or otherwise if and to the extent that it shall be unable to do so or prevented from doing so by statute or regulation or by action of any court or public authority having or purporting to have jurisdiction in the premises; or by loss, diminution, or impairment of gas supply from its suppliers or the systems of others with which it is interconnected; or by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, act of God or public enemy, failure of any supplier to perform, restraint by any court or regulatory agency, or any other intervening cause, whether or not similar thereto; the Company shall use reasonable efforts under the circumstances to overcome such cause and to resume full performance.

The foregoing shall not alter the Company's liability under applicable legal standards for damages in the case of its negligent or intentionally wrongful conduct with respect to any act or failure to act by the Company.

11.0 COMPANY LIABILITY:

The Company shall not be liable for any loss or damage resulting from the use of gas or the presence of the Company's appliances and equipment on the ~~customer's~~ Customer's premises unless such loss or damage results directly and solely from the Company's negligence.

The Company shall not, in any event except that of its own negligent acts or omissions, be liable to any party for any direct, consequential, indirect, or special damages, whether arising in tort, contract or otherwise, by reason of any services performed, or undertaken to be performed, or actions taken by the Company, or its agents or employees, under the Schedule of Rates or in accordance with or required by law, including, without limitation, termination of the customer's service.

The ~~customer~~ Customer assumes full responsibility for the proper use of gas furnished by the Company and for the condition, suitability, and safety of any and all equipment on the Customer's premises, or owned or controlled by the Customer which is not the Company's property. The Customer shall indemnify and save harmless the Company from and against

GENERAL TERMS AND CONDITIONS

any and all claims, expenses, legal fees, losses, suits, awards, or judgments for injuries to or deaths of persons or damage of any kind, whether to property or otherwise, arising directly or indirectly by reason of (1) the routine presence in or use of gas from pipes owned or controlled by the Customer; or (2) the failure of the Customer to perform any of his or her duties and obligations as set forth in the Schedule of Rates where such failure creates safety hazards; or (3) the Customer's improper use of gas or gas appliances. Except as otherwise provided by law, the Company shall be liable for damages claimed to have resulted from the Company's conduct of its business only when the Company, its employees, or agents have acted in a negligent or intentionally wrongful manner.

12.0 SCHEDULE OF AMINISTRATIVE FEES AND CHARGES:

Account Restoration Charge: $96.00

Paperless Billing Credit: $0.37/bill/month

Return Check Charge: $8.00

Daily Metered Equipment Fee: A customer will be charged for the cost of equipment installed by the Company to provide FT-1 Distribution Service through wireless readings of the Company's meter pursuant to Section 7, Schedule C, Item 2.02.0. The initial lump sum charge is $1,239.00

Daily Metered Data Plan Fee: A customer will be charged annually for the data plan associated with FT-1 Distribution Service pursuant to Section 7, Schedule C, Item 2.02.0. The annual data plan fee is $17.00

AMR Opt-Out Fees:

Removal of AMR Meter/Installation of Non-AMR Meter: $74.00

Monthly Meter Reading Fee: $13.00

Reinstallation of AMR Meter: $74.00

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DEFINITIONS

Actual Base Revenue Per Customer:	The actual base revenue for a rate class for a month divided by the actual number of customers billed for each rate class in the month.
Actual Transportation Quantity:	The quantity of gas actually received during the Gas Day as measured by the metering equipment at the Point(s) of Receipt, adjusted for the applicable Company Fuel Allowance.
Aggregation Pool:	One or more transportation Customer accounts whose gas usage is aggregated into a Marketer's account for operational purposes, including but not limited to nominating, scheduling and balancing gas deliveries to specified Point(s) of Receipt.
AGT Costs:	Advanced Gas Technology program costs as approved by the PUC.
Average Normalized Winter Day Usage:	A Customer's average normal winter day's usage, based on their actual gas usage during the most recent November through March period, adjusted for normal degree days, as approved in the most recent general rate case ~~proceeding~~.
Base Revenue:	Base Revenue is the sum of the customer charge, variable distribution charges and demand charges for firm service rate classes. Base Revenue is net of Gross Earnings Tax (GET).
BTU content factor:	One British thermal unit (i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60°) Fahrenheit). A Therm is one hundred thousand Btus. The BTU content factor for a given volume shall be calculated by the Company on a seasonal basis at the end of October and the end of April based upon an average of the Transporting Pipeline's prior six-month experience of recorded BTU factors.
Capacity Release Revenues:	Revenues derived from the sale of capacity upstream of the city-gate.
Capacity Exempt Customer:	Any Customer who is the customer of record at a location having a Capacity Exemption.

DEFINITIONS

Capacity Exemption: A location having Gas Usage that is not subject to a mandatory pipeline capacity assignment from the Company. Customers are capacity exempt if they (1) elected to retain their Capacity Exemption at a specific location as part of the 1999 revisions to the Company's Business Choice program in Docket RIPUC 2902, (2) receive delivery service on the Company's Non-Firm Sales or Non-Firm Transportation rate schedules, or (3) elected capacity exemption as a New Customer in accordance with Section 6, Transportation Terms and Conditions, Schedule C, Part 1.07.1.

Company Fuel Allowance**:** The quantity in Therms (as calculated on a percentage basis) by which the gross amount of gas received for Customer's account at the Point(s) of Receipt is reduced in kind in order to compensate the Company for gas loss and unaccounted for, Company use or similar quantity-based adjustment.

Consumption Algorithm**:** A mathematical formula used to calculate a Customer's daily consumption based on the Customer's historical base load and heat use per heating degree day factor.

Critical Day: Defined as any day where supply resource constraints are expected to adversely impact the operation of the Company's distribution system. A Critical Day may occur under conditions, such as severe cold temperatures, pipeline emergencies, malfunctions or unusual, out-of-season weather conditions.

Customer: Any party(s) that has obtained service from the Company pursuant to the General Terms and Conditions or pursuant to the Transportation Terms and Conditions.

Daily Index: The mid-point of the range of prices for the respective New England Citygates as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Algonquin Citygates" and "Daily Price Survey, Midpoint, Citygates Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)." In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of gas as the basis for this calculation until such time that PUC approves a suitable replacement.

DEFINITIONS

Deferred Balance:	The difference between incurred costs and revenues received.
Deferred Gas Cost Balance:	The difference between gas costs incurred and gas revenues received.
Dekatherm (Dt):	Ten Therms or one million Btu's (MMBtu).
Design Winter Sales Sendout:	Sales sendout of Residential Non-Heating, Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I during November through March based on design winter temperatures.
Division	The Rhode Island Division of Public Utilities and Carriers.
Electronic Bulletin Board (EBB):	An internet web site which allows both the Company and Marketers to electronically post nominations and other transportation-related information.
EDI	Electronic Data Interchange, the system by which the Company and Marketers initiate transactions and share information.
Environmental Response Costs:	All reasonable and prudently incurred costs associated with evaluation, remediation, clean-up, litigation, claims, judgments, insurance recovery (net of proceeds), and settlements arising out of the Company's utility-related ownership, operation, or use of: (1) manufactured gas production and storage facilities and disposal sites where wastes and materials from such facilities were deposited; (2) mercury regulators; and (3) meter disposal. Also included are the reasonable and prudently incurred costs for acquiring plant, property and equipment to facilitate remediation and other appropriate environmental management objectives in connection with the above sites, properties, and activities. The Company will use its best efforts to minimize Environmental Response Costs consistent with applicable regulatory requirements and sound environmental management policies and practices.
Forecasted Daily Usage (FDU):	Customer's estimated daily consumption for the next gas day as

DEFINITIONS

calculated by the Company based upon a forecast of heating degree days and the consumption algorithm.

Gas Day:	A period of twenty-four (24) consecutive hours beginning at 10:00 am (EST) and ending at 10:00 am (EST) the next calendar day.
Gas Usage:	The actual quantity of gas used by the Customer as measured by the Company's metering equipment at the Point of Delivery and converted to Therms.
Hedge Collateral:	Funds the Company is required to put up as collateral on hedge positions by an ~~Exchange~~ exchange or counterparty, or funds it receives from an Exchange or counterparty as collateral.
Hedge Collateral Carrying Costs:	For the month being calculated, carrying costs equal the total of the following: (1) For each ~~Exchange~~ exchange or counterparty holding the Company's collateral, the monthly short term borrowing rate defined as the Company's money pool rate, times the average hedge collateral daily balance for the month divided by 12, ~~Less~~ less (2) for each ~~Exchange~~ exchange or counterparty where the Company holds their collateral, the monthly short term borrowing rate times the average hedge collateral daily balance for the month divided by 12, ~~Less~~ less (3) any interest paid to the Company by the ~~Exchange~~ exchange or counterparty on the collateral funds it holds. The Company will recover carrying costs from customers or credit customers for carrying costs through the Gas Adjustment. In the event the Company chooses to meet its collateral obligations by posting a letter of credit or other non-cash instrument, the carrying cost will be the direct costs of the letter of credit or alternative non-cash instrument.
Imbalance:	The difference between the Actual Transportation Quantity and Gas Usage.
Interest on Deferred Balance:	Interest revenue/expense required to finance the deferred balance based on the Bank of America Prime Rate less 200 basis points (2%) as in effect from time to time.

DEFINITIONS

Inventory Finance Charge:	Finance charges associated with the storage of natural gas as calculated using a working capital calculation.
Local Storage Costs:	Costs associated with the investment, operations, and maintenance of natural gas storage downstream of the city-gate.
~~Low Income Assistance Programs:~~	~~Programs for assisting low income customers with their energy bills including, but not limited to, Low Income Heating Assistance (LIHEAP) and Low Income Weatherization, as in effect from time to time.~~
Marginal Gas Cost:	The variable cost of the Company's marginal source of supply for the Gas Day. Incremental Cost is a synonymous term.
Marketer:	An entity meeting the eligibility requirements of Section 6, Schedule C, Item 5.03, that is designated in a Transportation Service Application by the Customer to act on its behalf for nomination, notification, scheduling, balancing, and receipt of communications, and which has executed a Marketer Aggregation Pool Service Agreement. A Customer may designate itself as the Marketer provided that they have an executed service agreement with the Transporting Pipeline or provide proof of contract to purchase the gas at the Company's city gate.
Maximum Daily Quantity:	The maximum quantity of gas a customer is authorized to use during the gas day.
Monthly Index:	The simple average of the Daily Indices for the applicable month.
Net Insurance Recoveries:	Proceeds recovered from insurance providers and third parties for Environmental Response Costs, less the cost of obtaining such proceeds through claims, settlements, and litigation.
New Customer:	A Customer taking a supply of gas at a new Point of Delivery that has not been previously served by the Company.
Non-Firm Customer:	A customer who receives service under the Company's Non-Firm rate ~~service~~class.

Non-Firm Transportation

DEFINITIONS

Margin:	Margins derived from the transportation of natural gas to non-firm customers downstream of the city gate.
Off-System Sales Margins:	Margins derived from the sale of natural gas upstream of the city-gate.
Operational Flow Order:	The Company's instruction to Marketers and/or Customers to take such action as conditions require, including, but not limited to, diverting gas to or from the Company's distribution system pursuant to Section 6, the Transportation Terms and Conditions, Schedule C, Item 1.04.2.
Peak Day Use:	The estimated use of a customer on the forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage. It is calculated by estimating the customer's average use on a day when heat is not required (the baseload use) and the average use per degree day (the heating use) based on the customer's historical usage history. In the event the customer's historical usage is unavailable or not representative of expected future use, the Company will evaluate the customer's gas equipment and its projected utilization in order to calculate the customer's estimated use. The Peak Day Use equals the baseload use plus the product of the use per degree day times the design degree day value as approved by the PUC.
Pipeline Costs:	Costs associated with the entitlement and transmission of natural gas on the interstate pipeline system.
Pipeline Shipper(s):	The party(s) from whom a Marketer has purchased gas to be delivered to and transported by the Company.
Point of Delivery:	A location at which the Company's distribution facilities are interconnected with the Customer's facility.
Point(s) of Receipt:	Outlet side of the measuring station at the interconnection between the Transporting Pipeline and the Company's distribution facilities where gas will be received by the Company for transportation service in its service territory.
PUC	The Rhode Island Public Utilities Commission.
Purchased Gas Working Capital:	The working capital required to finance the Company's purchased gas.

DEFINITIONS

Refunds:	Refunds from pipeline, storage, and suppliers.
Scheduled Transportation Quantity:	The quantity of gas scheduled by the Marketer to be received by the Company for Customer's account during the Gas Day at the Point of Receipt, including the applicable Company Fuel Allowance.
Service Quality Performance Fund:	Deferred account containing accumulated Service Quality adjustments.
Soft-Off	The termination of an account by the Company for billing purposes where there is no new customer of record and the actual flow of gas to the premises is not disconnected.
Supplier Costs:	Costs associated with the entitlement and purchase of natural gas.
Target Revenue Per Customer:	~~For the period through January 31, 2013, the target revenue per customer established in Docket 4206, thereafter a target average revenue per~~For the period through August 2018, the target revenue per customer amount is that established in Docket 4323. For the period beginning September 2018, it shall be the target revenue per customer establish in Docket 4770.~~the most recent general rate case.~~
Therm:	An amount of gas having a thermal content of 100,000 Btus.
Transportation Imbalance Revenues:	Revenues associated with daily and monthly imbalances for transportation customers, as included in the Company's Terms and Conditions of Firm Transportation.
Transporting Pipeline:	The party(s) engaged in the business of rendering transportation service of natural gas in interstate commerce subject to the jurisdiction of the Federal Energy Regulatory Commission, which are transporting gas for Marketer to a Point of Receipt of the Company.
Upstream Storage	

DEFINITIONS

Costs:	Costs associated with the entitlement, injection, withdrawal, and storage of natural gas upstream of the city-gate.
Working Capital:	The dollar amounts required to support the Company's activities prior to the receipt of revenue.

TAXES AND SURCHARGES

1.0 RHODE ISLAND GROSS EARNINGS TAX:

Unless otherwise indicated, all rates exclude an amount necessary for the payment of Rhode Island Gross Earnings Tax. An amount necessary for the payment of Rhode Island Gross Earnings Tax will be separately identified on bills rendered to customers.

2.0 GROSS EARNINGS TAX REDUCTION FOR MANUFACTURERS:

Consistent with the gross earnings tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will be billed the applicable Rhode Island Gross Earnings Tax (GET). The Customer is responsible for providing to the Company in writing its tax exemption number and other appropriate documentation. If the Company collected any taxes or assessments from the Customer and is later informed by the Customer that the Customer is exempt from such taxes, it shall be the Customer's responsibility to obtain any refund from the appropriate governmental taxing agency.

Eligible manufacturing customers are those Customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30 (7) of Rhode Island General Laws) indicating the Customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a Customer, the Customer will be required to reimburse the Company in the amount of the credits provided to such Customer which were disallowed, including any interest required to be paid by the Company to such authority.

The Division of Taxation has indicated that it will generally deem 95% of manufacturer's volumes to be for "manufacturing use" eligible for the reduced manufacturer's Gross Earnings Tax rate. Thus, unless usage is separately metered for manufacturing only, 95% of billed amounts for qualified customers will be deemed to be for manufacturing purposes and eligible for the manufacturer's GET credit, whereas the remaining 5% of the billed amount will be subject to the standard GET rate. If usage is separately metered for manufacturing use only, the entire amount will be subject to the reduced manufacturing GET rate.

No other use of gas will be included in this rate for billing purposes.

3.0 OTHER RHODE ISLAND TAXES:

Where applicable at rate or rates in effect from time to time.

TAXES AND SURCHARGES

4.0 ENERGY EFFICIENCY SURCHARGE:

As provided for in Section 39-1-27.7 and Section 39-2-1.2 of Rhode Island General Laws, a charge per dekatherm (Dt) designed to recover the costs of the Company's gas Energy Efficiency Program ("EEP").

With the filing of the Company's EEP plan for the upcoming calendar year, the Company will file its EEP per Dt charge on or before October 15 of each year. In any year in which the Company is required to file a triennial Energy Efficiency Procurement plan, the Company will file the EEP Charge by November 1. The EEP Charge shall be effective on the following January 1. The EEP charge will be designed to collect the estimated costs of the Company's EEP plan for the upcoming calendar year plus a full reconciliation of all costs and revenues for the current year including a reconciliation of forecasted revenue and costs for months of the current year for which actual data is not available at the time of the filing. Any projected amounts included in the EEP charge filing are subject to reconciliation to actual amounts and any difference will be reflected in a future EEP charge filing. Upon approval by the PUC, such a charge (adjusted for the uncollectible percentage approved in the most recent general rate case ~~proceeding~~) shall become effective with usage on or after the effective date.

The Company may file to change the EEP charge at any time should significant over- or under-recoveries occur.

GAS COST RECOVERY CLAUSE

1.0 GENERAL:

1.1 Purpose:

The purpose of this clause is to establish procedures that allow the Company, subject to the jurisdiction of the PUC, to annually adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity in order to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, purchased gas working capital, and to credit supplier refunds, capacity credits from off-system sales and revenues from capacity release transactions.

The Gas Cost Recovery Clause shall include all costs of firm gas, including, but not limited to, commodity costs, demand charges, hedging and hedging related costs, local production and storage costs and other gas supply expense incurred to procure and transport supplies, transportation fees, inventory finance costs, requirements for purchased gas working capital, all applicable credits, taxes, and deferred gas costs. Any costs recovered through the application of the Gas Charge shall be identified and explained fully in the annual filing.

1.2 Applicability:

The Gas Charge shall be calculated separately for the following rate groups:

(1) Residential Non-Heating, Low Income Residential Non-Heating, Large C&I High Load Factor, Extra Large C&I High Load Factor;
(2) Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large C&I Low Load Factor, and Extra Large C&I Low Load Factor; and
(3) FT-2 Firm Transportation – Marketers.

The Company will make annual Gas Charge filings based on forecasts of applicable costs and volumes and annual Reconciliation filings based on actual costs and volumes. The Gas Charge shall become effective with consumption on or after November 1 as designated by the Company. In the event of any change subsequent to the November effective date which would cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than five percent (5%) of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate that non-zero balance.

Unless otherwise notified by the PUC, the Company shall submit the Gas Charge filings no later than sixty (60) days before they are scheduled to take effect. The Annual Reconciliation filing will be made by July 1 of each year containing actual data for the twelve months ending March 31 of that year.

GAS COST RECOVERY CLAUSE

2.0 GAS CHARGE FACTORS

2.1 Gas Charges to Sales Customers:

The Gas Charge consists of two (2) components: (1) Fixed Costs and (2) Variable Costs. These components shall be computed using a forecast of applicable costs and volumes for each firm rate schedule based on the following formula:

$$GC_S = FC_S + VC_S$$

Where:

GC_S Gas Charge applicable to High Load Factor sales rates (Residential Non-Heating, Low Income Residential Non-Heating, Large and Extra Large High Load C&I) and Low Load Factor sales rates (Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large and Extra Large Low Load C&I).

FC_S Fixed Cost Component for a rate classification. See Item 3.1 for calculation.

VC_S Variable Cost Component for a rate classification. See Item 3.2 for calculation.

This calculation will be adjusted for the uncollectible percentage approved in the most recent general rate case ~~proceeding~~ and the Gas Charges to Sales Customers are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

2.2 Gas Charge to FT-2 Marketers:

The FT-2 Demand Rate (SDC_M) recovers fixed costs associated with storage and peaking resources including pipeline supplies designated by the Company for peaking purposes. See item 3.3 for calculation.

The FT-2 Variable Charges for underground storage components consist of the following:

SLF The Company's weighted average loss factor on storage withdrawals across all storage contracts.

WWCC The Company's weighted average commodity cost of storage withdrawals under all storage contracts.

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PLF The Company's weighted average loss factor on pipeline contracts used to deliver storage withdrawals to the system.

PCC The Company's weighted average commodity cost on pipeline contracts used to deliver storage withdrawals to the system

This calculation will be adjusted for the uncollectible percentage approved in the most recent general rate case ~~proceeding~~ and the Gas Charges to Sales Customers are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

3.0 GAS CHARGE CALCULATIONS

3.1 Supply Fixed Cost Component:

The Supply Fixed Cost Component shall include all fixed costs related to the purchase, storage, or delivery of firm gas, including, but not limited to, pipeline and supplier fixed reservation costs, demand charges, operation and maintenance costs for storage facilities and other fixed gas supply expense incurred to transport or store supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Fixed Cost Component shall be identified and explained fully in the annual filing.

The Supply Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$FC_S = \frac{DWS_S \text{ x } (TC_{FC} - TR_{FC} + WC_{FC} + R_{FC} - (SDC_M \text{ x } MDQ_{SM} \text{ x } 12))}{Dt_S}$$

Where:

FC_S Supply Fixed Cost Component for High Load Factor rates (Residential Non-Heating, Low Income Residential Non-Heating, Large High Load C&I and Extra-Large High Load C&I) and Low Load factor rates (Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low C&I and Extra Large Low Load C&I).

DWS_S Percent of Design Winter Sales Sendout (November - March) for High Load Factor rates (Residential Non-Heating, Low Income Residential Non-Heating, Large High Load C&I and Extra-Large High Load C&I) and Low Load factor rates (Residential Heating, Low Income

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Residential Heating, Small C&I, Medium C&I, Large Low C&I and Extra Large Low Load C&I).

TC_{FC} — Total Fixed Costs, including, but not limited to pipeline, storage, and supplier reservation and supply related local production and storage costs. The level of supply-related local production and storage costs shall be ~~as~~ determined annually as estimated by the Company~~in the Company's most recent rate case proceeding~~.

TR_{FC} — Credits to Fixed Costs relating to supply services, including, but not limited to Marketer capacity release revenues, ~~and~~ the amount forecasted to customers under the Natural Gas Portfolio Management Plan ("NGPMP") for the November to October period, and forecasted gas costs relating to supplies required to maintain system pressures on the Company's distribution system, as defined in Section 3, Item 3.1.

WC_{FC} — Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.

R_{FC} — Deferred Fixed Cost Account Balance as of October 31, as derived in Item 6.0 less the amount guaranteed to customers under the NGPMP and, following approval by the PUC, the net positive revenue from optimization transactions reduced by the guaranteed amount and the Company incentive under the Plan.

SDC_M — FT-2 Storage Demand Charge rate charged to Marketers based on their Maximum Daily Quantity of storage gas. See Item 3.3 for calculation.

MDQ_{SM} — Storage Forecast of Maximum Daily Quantity to be billed to Marketers.

Dt_S — Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I.

3.2 Supply Variable Cost Component:

The Supply Variable Cost Component shall include all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expense incurred to transport supplies, transportation fees, and requirements for purchased gas working capital, storage commodity costs, taxes on storage

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commodity and other gas storage expense incurred to transport supplies, transportation fees, inventory commodity costs, and inventory financing costs. Any costs recovered through the application of the Supply Variable Cost Component shall be identified and explained fully in the annual filing.

The Supply Variable Cost Component is calculated for each applicable rate schedule as follows:

$$VC = \frac{TC_{VC} - TR_{VC} + WC_{VC} + R_V + IF_s}{Dt_{VC}}$$

Where:

VC	Supply Variable Cost Component for High Load Factor rates (Residential Non-Heating, Low Income Residential Non-Heating, Large and Extra Large High Load C&I) and Low Load Factor rates (Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large and Extra Large Low Load C&I).
TC_{VC}	Total Supply Variable Costs, including, but not limited to pipeline, supplier, storage, commodity-billed pipeline transition costs, and any hedge, hedging related cost or the carrying cost on hedge collateral.
TR_{VC}	Total Credits to Supply Variable Costs, including, but not limited to balancing commodity charge revenues and transportation imbalance charges.
WC_{VC}	Working Capital requirements associated with Total Supply Variable Costs. See ~~item~~ Item 5.0 for calculation.
R_V	Deferred Cost Account Balance as of October 31, as derived in Item 6.0 plus the net of any Gas Procurement Incentives/Penalties associated with the Gas Procurement Incentive Plan.
Dt_{VC}	Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I.
IF_S	Inventory Finance Cost as calculated in Item 4.0 below.

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3.3 FT-2 Storage Demand Charge:

The FT-2 Storage Demand Charge (SDC_M) shall include all fixed costs related to the operations, maintenance, and delivery of storage, including, but not limited to, the supply-related portion of local production and storage costs ~~as determined in the most recent rate case proceeding~~, delivery of storage gas to the Company's Distribution System, Storage Inventory Financing Charges and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Demand Charge shall be identified and explained fully in the annual filing.

The Storage Demand Charge Component is calculated for the FT-2 rate schedule as follows:

$$SDC_M = \frac{TFC_S + IF_S + WC_S}{MDQ_S \times 12}$$

Where:

SDC_M FT-2 Storage Demand Charge in \$/per Maximum Daily Quantity of Storage gas to be charged to Marketers.

TFC_S Total Storage Fixed Costs, equals all fixed costs of storage, including, but not limited to, the supply related portion of local production and storage costs, taxes on storage, any demand or fixed charges associated with storage or delivery of storage gas to the Company's Distribution System, and any demand or fixed pipeline reservation charges designated by the Company as a peaking resource. The level of supply-related local production and storage costs shall be ~~as~~ determined annually as estimated by the Company~~in the most recent rate case proceeding~~.

IF_S Inventory Finance Cost as calculated in Item 4.0 below.

MDQ_S The total maximum daily quantity of storage gas in Dekatherms deliverable to the Company's Distribution System using the LNG facilities, storage resources, and pipeline contracts related to storage delivery.

WC_{FC} Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.

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4.0 INVENTORY FINANCING:

IFs = $(ASB_U + ASB_L)$ x COC

Where:

IF_S — Inventory Finance Charges for storage

ASB_U — Average underground storage balance

ASB_L — Average LNG storage balance

COC — Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent general rate case ~~proceeding~~. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended March as presented in the Company's annual Distribution Adjustment Clause Filing.

5.0 WORKING CAPITAL REQUIREMENT:

WC_M = WCA_M x [DL ÷ 365] x COC

Where:

WC_M — Working Capital requirements of Supply Fixed (WC_{FC}) and, Storage Fixed (WC_{SFC}), Supply Variable (WC_{SV}), Storage Variable Product (WC_{SVC}) or Storage Variable Non-product (WC_{SVNC}) Cost Components.

WCA_M — Working Capital Allowed in the Supply Fixed, Storage Fixed, and Supply Variable, Storage Variable Product, or Storage Variable Non-product Cost component calculations.

DL — Days Lag approved in the most recent general rate case ~~proceeding~~.

COC — Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent general rate case ~~proceeding~~. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended March as presented in the Company's annual Distribution Adjustment Clause

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(DAC) filing in support of the Earnings Sharing Mechanism (ESM). The long-term debt component will be based on the Company's actual long-term borrowing rate as presented in the Company's annual DAC filing.

6.0 DEFERRED GAS COST ACCOUNTS:

The Company shall maintain two (2) separate Deferred Gas Cost Accounts: (1) Fixed Costs and revenues and (2) Supply Variable Costs and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

An amount equal to the allowable costs incurred less:

1. Gas Revenues collected adjusted for the RIGET and uncollectible percentage approved in the most recent general rate case ~~proceeding~~;

2. Credits to costs, including but not limited to GCR Deferred Responsibility surcharge/credits and Transitional Sales Service (TSS) surcharge revenues,

   and including

3. Monthly interest based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning-of-the-month balance and the balance after entries 1. and 2. above.

7.0 REFUNDS:

Any refund associated with the Company's total gas cost for Sales customers shall be credited to the Deferred Cost Account.

8.0 WEIGHTED AVERAGE UPSTREAM PIPELINE TRANSPORTATION COST:

At the request of a marketer or the Division, the Company will provide within 21 days an estimate of the pipeline path costs for the next GCR year beginning November 1. The estimate will be based on the most recent GCR filing updated for current commodity pricing and other known changes which would significantly affect the factor. Concurrent with the annual GCR filing, the Company shall calculate the final weighted average cost of upstream pipeline transportation capacity. The cost shall be applicable to capacity release under the Transportation Terms and Conditions effective November 1 of each year or at such time as the PUC approves the rates.

GAS COST RECOVERY CLAUSE

9.0 DEFERRED GAS COST RESPONSIBILITY:

Under the Transportation Terms and Conditions, Section 6, Schedule C, Item 1.0, if a Customer who has been receiving firm sales service and elects to transfer to transportation service to purchase gas from a Marketer, the Customer is responsible for their portion of the deferred gas cost balance. The calculation of any under-recovered or over-recovered gas cost attributable to the Customer's prior service will be charged or credited to the Customer's account at the time transportation service is initiated.

9.1 Factor Calculations:

The calculation of the Customer's deferred gas cost balance consists of: (1) the prior period deferred gas cost reconciliation amount reflected in the Company's current Gas Charge; and (2) any incremental under-recovery or over-recovery of actual costs versus projected costs that accrue while the current Gas Charge is in effect.

The first component is calculated on the basis of the Company's Gas Charge filing with the PUC in accordance with the following formula:

$$PPF = \frac{DAB_B}{Dt_S}$$

Where:

PPF Prior Period Factor as a $/Dt.

DAB_B Deferred Gas Cost Account Beginning Balance for the first month covered under the Gas Charge filing.

Dt_S Forecast of sales volumes for the period covered by GCC filing.

The second component is calculated on a quarterly basis and represents the additional deferral balance since the balance determined in the Company's last Gas Charge filing. The factor is calculated as follows:

$$IDF = \frac{DQB_E - PDAB_B}{Dt_a}$$

Where:

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IDF Incremental Deferred Gas Cost Balance Factor as a $/Dt.

DQB_E Actual Deferred Gas Cost Account Ending Balance for a quarter subsequent to the PPF.

$PDAB_B$ Projected Deferred Gas Cost Account Ending Balance for the quarter subsequent to the PPF.

Dt_a Actual sales volumes for the quarter(s) subsequent to the PPF.

9.2 Application of Factors:

The customer's total Deferred Gas Cost Responsibility will equal the sum of the following:

(1) The PPF times: (a) the Customer's prior GCR year's total Dt minus (b) the Customer's current year's Dt where the current GCR year's Dt reflects the period the customer has been billed the current Gas Charge; and

(2) The IDF times the Customer's Dt during the period covered by the IDF.

DISTRIBUTION ADJUSTMENT CLAUSE

1.0 GENERAL

1.1 Purpose:

The purpose of the Distribution Adjustment Clause ("DAC") is to establish procedures that allow the Company, subject to the jurisdiction of the PUC, to annually adjust its rates for firm sales and transportation in order to recover, credit, or reconcile the following:

~~(1)~~ (1) the system pressure costs;
(2) the difference between the approved AGT factor revenue collections and actual AGT factor revenue collections;
~~(3) the difference between the approved LIAP revenue collected through base rates for Large and Extra Large C&I customers and actual LIAP revenue collections for Large and Extra Large C&I customers;~~
(~~4~~3) the costs of the Infrastructure, Safety, and Reliability Plan;
(~~5~~4) the amortization of the most recent ten years of Environmental Response costs;
(~~6~~5) Pension costs and Post-retirement Benefits Other than Pensions expenses;
~~(7) the margins from on-system non-firm sales and non-firm transportation services that are above or below an established dollar amount;~~
(~~8~~6) to credit any Service Quality Performance penalties;
(~~9~~7) any over or under collections of revenue under the Revenue Decoupling mechanism;
(~~10~~8) the previous year DAC items;
(~~11~~9) any Earnings Sharing; and
(~~12~~10) any ~~Arrearage Management~~Residential Assistance costs.

Any costs recovered through the application of the Distribution Adjustment Charge shall be identified and explained fully in the annual Distribution Adjustment Charge filing.

1.2 Applicability:

The Distribution Adjustment Charge will be applied to sales and transportation volumes under each of the Company's firm rate schedules.

The Company will make annual DAC filings and its annual Reconciliation filings based on actual costs and volumes available at the time of filing as well as forecasts of applicable costs and volumes through October of that year. With the exception of the Infrastructure, Safety and Reliability component described in ~~section~~ Item 3.~~4~~3.2, the Distribution Adjustment Charge shall become effective with consumption as of

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November 1 each year.

Unless otherwise notified by the PUC, the Company shall submit the Distribution Adjustment Charge filings no later than 90 days before they are scheduled to take effect, provided however that the Revenue Decoupling Adjustment component of the Distribution Adjustment Charge filing will be made July 1 annually. The Annual Reconciliation filing will be made by August 1 of each year.

2.0 DISTRIBUTION ADJUSTMENT CHARGE:

The Distribution Adjustment Charge will consist of an annual System Pressure factor, an Advanced Gas Technology factor, ~~a Low Income Assistance Programs factor,~~ an Infrastructure, Safety, and Reliability factor, an Environmental Response Cost factor, a Pension Adjustment Mechanism factor, ~~a Non-firm On-System Margin Credit factor,~~ a Service Quality Performance factor, a Revenue Decoupling Adjustment factor, and a Reconciliation of deferred account balance factor, an Earnings Sharing Mechanism factor, a Low Income Discount Recovery Factor, and an Arrearage Management Adjustment Factor ~~(“AMAF”)~~. The Distribution Adjustment Charge is calculated as follows:

DAC = SP+AGT~~+LIAP~~+ISR+ERCF+PAF~~+MC~~+SQP+RDA+AMAF+R+ESM+LIDRF

Where:

DAC	Distribution Adjustment Charge applicable to all firm throughput.
SP	System Pressure factor. See Item 3.1 for calculation.
AGT	Advanced Gas Technology factor. See Item 3.2 for calculation.
~~LIAP~~	~~Low Income Assistance Programs factor. See Item 3.3 for calculation.~~
ISR	Infrastructure, Safety, and Reliability factor. See Item 3.3 ~~4~~for calculation.
ERCF	Environmental Response Cost Factor. See Item 3.4~~5~~ for calculation.
PAF	Pension Adjustment Factor. See Item 3.5~~6~~ for calculation.
~~MC~~	~~On-system Margin Credits related to Non-Firm Dual-Fuel customer margins. See Item 3.7 for calculation.~~
SQP	Service Quality Performance Factor. See Item 3.6~~8~~ for calculation.
RDA	Revenue Decoupling Adjustment factor. See Item 3.7~~9~~ for calculation.

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AMAF Arrearage Management Adjustment Factor. See Item 3.8 for calculation.

LIDRF Low Income Discount Recovery Factor. See Item 3.9 for calculation.

R Reconciliation of deferred account balances as of October 31. See Item 4.0 for calculation.

ESM Earnings Sharing Mechanism Factor. See Item 5.0 for calculation.

~~AMAF Arrearage Management Adjustment Factor. See Item 3.10 for calculation.~~
The Distribution Adjustment Charge, excluding the RDA, shall be increased by the uncollectible expense percentage approved in the most recent general rate case ~~proceeding~~.

3.0 DISTRIBUTION ADJUSTMENT CALCULATIONS

3.1 System Pressure Factor:

The System Pressure factor shall be computed in a manner that identifies and includes all fixed and variable gas supply costs required on an annual basis to maintain pressure within the Company's distribution system and shall identify and consider all gas supply costs that are required to maintain pressure for all portions of the Company's distribution system~~utilizing a forecast of Liquefied Natural Gas (LNG) sendout comprised of the projected withdrawal of commodity costs, the projected inventory cost of LNG, demand costs and the average LNG inventory finance costs from the GCR filing for the November to October period based on the following formula~~:

$$SP = \frac{GCSP\ \cancel{(WTC_{LNG} + INV_{LNG} + DM_{LNG} + INF_{LNG})}\ x\ SP\%}{Dt_T}$$

Where:

SP System Pressure Amount.
~~WTC_{LNG} Forecasted withdrawal commodity costs.~~
~~INV_{LNG} Forecasted inventory cost of LNG.~~
~~DM_{LNG} Forecasted demand costs.~~~~INF_{LNG} Forecasted inventory finance costs.~~

GCSP Forecasted Gas Costs associated with supply used to maintain system pressures, including both demand and commodity costs.

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SP% — Percent of ~~local storage~~ supply used to maintain system pressures, as established in the most recent general rate case or DAC proceeding.

Dt_T — Forecasted annual firm throughput.

3.2 AGT Factor:

The Advanced Gas Technology factor ~~will be computed on an~~shall be determined annually, or as otherwise approved by the PUC, based on an estimate of AGT grants to be disbursed during the upcoming year, adjusted by any AGT grants from the prior year in excess of available funding or available funding in excess of AGT grants from the prior year,~~is utilizing the approved amount for~~ the total of which is the eligible AGT Costs to be approved for recovery by the PUC~~for the prior twelve month period ended March 31, except for the first reconciliation period after the approval of Docket RIPUC 4323 which will be based on a stub period~~. The formula will be as follows:

$$AGT = \frac{AGT_B \cancel{- AGT_{EMB}}}{Dt_T}$$

Where:

AGT — AGT Factor

$AGT_{\cancel{B}}$ — ~~Approved~~ AGT Costs~~budget~~

Dt_T — Forecasted annual firm throughput in dekatherms

~~AGT_{EMB} — AGT funding embedded in base rates, \$300,000~~

~~3.3 LIAP Factor:~~

~~The Low Income Assistance factor shall be computed on an annual basis utilizing the approved funding for low income programs, such as Low Income Heating Assistance and Low Income Weatherization, for the prior twelve month period ended March 31 except for the first reconciliation period after the approval of Docket RIPUC 4323 which will be based on a stub period. The formula will be as follows:~~

$$\cancel{LIAP = \frac{LIAP_B - LIAP_{EMB}}{Dt_T}}$$

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~~**Where:**~~

~~LIAP LIAP Factor~~

~~$LIAP_B$ Approved low income program funding(s)~~
~~Dt_T Forecasted annual firm throughput~~

~~$LIAP_{EMB}$ LIAP funding embedded in base rates, $1,785,000; Consisting of $1,585,000 of Low Income Heating Assistance and $200,000 of Low Income Weatherization~~**3.3**

Infrastructure, Safety and Reliability Plan:

~~**3.4.1**~~**3.3.1** Gas Infrastructure, Safety, and Reliability Plan Filing:

In compliance with R.I.G.L. Section 39-1-27.7.1, no later than January 1 of each year, the Company shall submit to the PUC a Gas Infrastructure, Safety, and Reliability Plan (Gas ISR Plan) for the upcoming fiscal year (April to March) for review and approval within 90 days. The Gas ISR Plan shall include the upcoming fiscal year's forecasted capital investment on its gas distribution system infrastructure and may include any other costs relating to maintaining safety and reliability that have been mutually agreed upon by the Division and the Company.

~~**3.4.2**~~**3.3.2** Infrastructure, Safety and Reliability Factor:

Effective each April 1, the Company shall recover through a change in Distribution Adjustment Charge rates the Cumulative Revenue Requirement on the Adjusted Cumulative Non-growth Capital spending as approved by the ~~Commission~~ PUC in the Company's annual gas infrastructure, safety, and reliability filings less the amount included in rate base for base rate purposes. For purposes of this section, non-growth capital shall exclude general plant (FERC Accts 389 through 399). The Cumulative Revenue Requirement shall mean the return and taxes on year-end Adjusted Cumulative Non-growth Capital Spending, at a rate equal to the pre-tax weighted average cost of capital as approved by the ~~Commission~~ PUC in the most recent ~~distribution base~~general rate case~~proceeding~~, plus the annual depreciation net of depreciation expense attributable to general plant that was approved by the ~~Commission~~ PUC in the Company's most recent ~~distribution~~ general~~base~~ rate ~~proceeding~~ case adjusted, if appropriate, by later proceedings related to capital, plus the annual municipal property tax recovery mechanism.

~~as approved in the Settlement Agreement in Docket RIPUC 4323~~The Adjusted Cumulative Non-growth Capital Spending shall mean the cumulative actual non-growth capital investment recorded since ~~January 31, 2014~~the end of the Company's

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rate year in its most recent general rate case, ~~and~~ reflecting any difference between Actual Non-Growth Investment and Forecasted Non-Growth Investment~~,~~, for any period during which Forecasted Non-Growth Investment has not been reconciled to Actual Non-Growth Investment including ~~included in rate base for base rate purposes, for the period April 1, 2011~~ through ~~January 31, 2014,~~the end of the Company's rate year in its last general rate case ~~in docket RIPUC 4323~~. Cumulative Revenue Requirements will reflect Adjusted Cumulative Non-Growth Capital Spending as defined above plus the associated retirements, cost of removal, accumulated depreciation, and accumulated deferred taxes.

All accumulated Gas ISR investments will be eligible for inclusion in rate base recovery through new rates set in the next general ~~base~~ rate case.

The Company shall allocate the Cumulative Revenue Requirements to its rate classes based on the rate base allocation approved by the PUC in the Company's most recent ~~base distribution~~general rate ~~proceeding~~case. Any other costs, including Operation and Maintenance expenses mutually agreed upon by the Division and the Company shall be allocated on a per unit basis.

~~3.4.3~~3.3.3 Infrastructure, Safety and Reliability Factor: Reconciliation Mechanism:

The Company shall include an annual reconciliation mechanism associated with the ISR Factor designed to reconcile the actual Cumulative Revenue Requirements and any associated costs approved for recovery through this mechanism to the actual billed revenue for the prior fiscal year. As part of its annual DAC filing, the Company shall submit by August 1 a reconciliation factor (either positive or negative) related to the ISR Factor recoveries and actual Cumulative Revenue Requirements and any associated costs approved for recovery through this mechanism to take effect annually for the twelve months beginning November 1 each year.

~~3.5~~3.4 Environmental Response Cost Factor (ERCF):

$$ERCF = \frac{\frac{\sum ERCyr_x}{10} - ERC_{EMB}}{Dt_T}$$

Where:

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ERC — Environmental Response Costs as defined in Section 1, Schedule B Definitions

$\sum ERCyr_{x}$ — The sum of Environmental Response Costs, incurred in the most recent twelve month period ended March 31. ~~except for the first reconciliation period after the approval of Docket RIPUC 4323 which will be based on a stub period and in the prior nine years.~~

ERC_{EMB} — Environmental Response Costs funding embedded in base rates, $1,310,000.

Dt_{T} — Forecasted annual firm throughput

In order to limit the bill impacts that could potentially result from the incurrence of environmental remediation costs, the ERC factor, calculated as described above, shall be limited to an increase of no more than $0.10 per dekatherm in any annual DAC filing. If this limitation results in the Company recovering less than the amount that would otherwise be eligible for recovery in a particular year, then beginning on the date that the proposed ERC factor becomes effective, carrying costs shall accrue to the Company on the portion of the environmental remediation costs not included in the ERC factor as a result of this limitation. Such carrying costs shall accrue through the year in which such amount, together with accumulated carrying costs, are recovered from ratepayers. Any amounts so deferred shall be incorporated into the ERC factor in succeeding years consistent with the $0.10 per dekatherm ERC factor annual increase limitation. Such carrying charges shall accrue at the Interest on Deferred Balance rate specified in Section 1, Schedule B of the Company's Definition section above.

~~3.6~~3.5 Pension Adjustment Factor:

The Pension Adjustment Factor shall recover or refund the prior fiscal year's reconciliation of the Company's actual Pension and Post-retirement Benefits Other Than Pension (PBOP) expenses to the Company's Pension and PBOP expense allowance included in distribution base rates, including interest at the rate of interest paid on customer deposits. The recoverable actual Pension and PBOP shall reflect expense recorded on the Company's books of account pursuant to the Financial Accounting Standards Board ("FASB") Accounting Standards Codification Topic 715, Compensation—Retirement Benefits, as amended in March 2017 in a FASB Accounting Standards Update (formerly Statement of Financial Accounting Standards ("SFAS") 87 and SFAS 106) associated with pension and PBOP. The PAF will be computed on an annual basis for the ~~nine month period ending March 31, 2013 and thereafter for each~~ twelve months ended March 31 and will be based on the difference

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in the Company's actual Pension and PBOP expense for the prior twelve month period ended March 31 and the distribution base rate allowance, plus carrying charges at the weighted average cost of capital on the cumulative five quarter average underfunding of the Pension and PBOP Minimum Funding Obligation for the fiscal year ended March 31. The Minimum Funding Obligation will be equal to the amount of Pension and PBOP costs collected from customers during the fiscal year, plus the amounts of Pension and PBOP costs capitalized during the year. The amount collected from customers during the fiscal year would include (1) Pension and PBOP allowance included in base rates, and (2) amounts collected or refunded through the PAF. For the purpose of determining its Minimum Funding Obligation and the carrying costs that apply to that obligation, the Company shall be permitted to combine the funding of pensions and PBOPs, thereby offsetting, any deficiencies in PBOPs funding with any excess pension funding, or conversely offsetting any deficiencies in pension funding with any excess PBOP funding. The Company will be required to accrue and defer carrying charges on only the net unfunded pension/PBOP amount.

~~3.7 On-System Margin Credits:~~

~~Each year, the Company will calculate the total non-firm customer margins, exclusive of Rhode Island Gross Earnings Tax for the twelve month period ending each March 31 beginning March 31, 2014. If that total exceeds a target revenue of $1,800,000, the On-System Margin Credit shall be positive. If the total non-firm margins, exclusive of Rhode Island Gross Earnings Tax, for the twelve-month period ending March 31 are less than the target revenue of $1,800,000, the On-System Margin Credit shall be negative. For the twelve month period ending March 31, 2013, the target will be prorated for the seven month period ending January 31, 2013 for the On-System Margin target in effect during that period ($2,816,000) and actual firm and non-firm dual fuel Customer margins, (exclusive of Rhode Island Gross Earnings Tax) during that period and for the two month period ending March 31, 2013 during which the $1.8 million target is in effect and actual non-firm customer margins, exclusive of Rhode Island Gross Earning Tax, during that period.~~

~~The On System Margin Credit is calculated as follows:~~

$$\cancel{MC = \frac{NFCM - \$1,800,000}{Dt_T}}$$

~~Where:~~

~~MC On-System Margin Credit factor~~

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~~NFCM The non-firm customer margins exclusive of Rhode Island Gross Earnings Tax (GET) for the 12 months ending March 31.~~

~~Dt_T Forecasted annual firm throughput~~

~~If in any year the Company is required to calculate the total Non-Firm Customer margins, exclusive of GET, for a period less than a twelve month period, then the Company will prorate the target threshold based upon the monthly 2011 non-firm revenue distribution and if the total exceeds that prorated target threshold the Non-Firm On-System Margin credit will be positive and if it is less than the prorated target the credit will be negative. In addition, if a non-firm customer who was active customer during calendar year 2011 migrates to firm service, the Company will reduce the margin threshold by the non-firm customer's actual 2011 calendar year usage multiplied by the applicable non-firm rate approved in RIPUC Docket 4323. Conversely, the Company will increase the margin threshold for firm customers who migrate to non-firm service based upon the customers most recent historical usage multiplied by the applicable non-firm service rate.~~

~~3.8~~3.6 Service Quality Performance Factor:

The Service Quality Performance (SQP) Factor will be used for crediting to customers any penalties reflected in the Company's annual Service Quality Report.

~~3.9~~3.7 Revenue Decoupling Adjustment Factor:

The Revenue Decoupling Adjustment (RDA) Factor shall be a credit or surcharge determined for all Residential rate classes and Small and Medium C&I rate classes as the sum of the March 31 ~~Revenue Per Customer~~ deferral ending balances for each rate class divided by the forecasted total annual firm throughput for those rate classes. The March deferral ending balance for each rate class shall result from the monthly calculation of the ~~variance~~ difference between ~~a~~the Target Revenue-per-Customer and the Actual Revenue-Per-Customer for ~~the following periods: (1) the ten month period ending January 31, 2013, (2) the fourteen month period February 1, 2013 – March 31, 2014 and (3)~~ each twelve months ~~period~~ ending March 31 ~~thereafter~~. The deferral balance will be calculated as follows:

$$RDAF = \frac{\sum_{RC}(AEB_{M-1} + DIFF_M + INT_M)}{Dt_{RC}}$$

Where:

DISTRIBUTION ADJUSTMENT CLAUSE

RDAF — Revenue Decoupling Adjustment Factor

$\sum_{RC}$ — The sum of the March 31 ~~Revenue per Customer~~ deferral ending balances for each of the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I.

AEB_{M-1} — Account Ending Balance for prior month

~~VR_M~~ $DIFF_M$ — Current month ~~Variance~~ Difference

$$= (RPC_{TM} - RPC_{AM}) \times CUST_M$$

RPC_{TM} — ~~For the period ending January 31, 2013, the Target Revenue per Customer will be based on targets established in Docket RIPUC 4206. Thereafter,~~ Target Revenue-per-Customer ~~will be~~ based on class specific revenue per customer targets established in the most recent general rate case. The ~~Target~~ target ~~Revenue~~ for Low-Income classes will reflect non-discounted revenue. Low-income class revenue and customers will be included with non-discounted revenue and customers for the purposes of setting the target.

RPC_{AM} — Actual Revenue-per-Customer for current month calculated as actual base revenue~~s~~ divided by number of customers in the current month. Revenue for Low-Income classes will reflect non-discounted revenue~~s~~.

$CUST_M$ — Number of customers in current month~~.~~

INT_M — Interest on average monthly balance based on the Bank of America Prime minus 200 basis points.

$$= \frac{(AEB_{M-1} + VR_M) \times BA_M}{2}$$

~~BA_M — Bank of America Prime minus 200 basis points~~

DISTRIBUTION ADJUSTMENT CLAUSE

Dt_{RC} Forecasted annual firm throughput for the following rate classes: Residential Non-heat (including Low Income Residential Non-heat), Residential Heat (including Low Income Residential Heat), Small C&I, and Medium C&I.

~~3.10~~3.8 Arrearage Management Adjustment Factor (AMAF):

In compliance with R.I.G.L. §39-2-1(d)(2), the Company shall surcharge customers allowable amounts forgiven through the Arrearage Management Plan (AMP) over the prior calendar year as described in Section 7, Schedule C, Item 9.0 through the AMAF ~~factor~~.

$$AMAF = \frac{AMPC}{Dt_T}$$

Where:

AMPC Allowable arrearage management plan costs the Company may recover from firm ~~sales~~ customers in accordance with R.I.G.L. § 39-2-1(d)(2) and described in Section 7, Schedule C, Item 9.0.

Dt_T Forecasted annual firm throughput

3.9 Low Income Discount Recovery Factor (LIDRF):

The Low Income Discount Recovery Factor shall be determined annually based upon the total amount of low income discount applied to eligible customer bills. The low income discount percentages are as follows:

- Residential Assistance Non-Heating, Rate 11: 25% with an additional 5% for a total of 30% for those customers receiving benefits through Medicaid, General Public Assistance, and/or the Family Independence Program.
- Residential Assistance Heating, Rate 13: 25% with an additional 5% for a total discount of 30% for those customers receiving benefits through Medicaid, General Public Assistance, and/or the Family Independence Program.

$$LIDRF = \frac{LIDC}{Dt_T}$$

DISTRIBUTION ADJUSTMENT CLAUSE

Where:

LIDC Annual low income discounts provided to eligible low income customers which the Company may recover from firm customers.

Dt_T Forecasted annual firm throughput excluding Rate 11 and Rate 13 forecasted annual throughput.

4.0 DEFERRED DISTRIBUTION ADJUSTMENT COST ACCOUNT:

The Distribution Adjustment Cost Account shall include annual reconciliation for the twelve month period for the revenues and costs for the System Pressure factor, Advanced Gas Technology factor, ~~LIAP factor,~~ ISR factor, Environmental Response Costs factor, Pension Adjustment ~~Factor~~factor, ~~On-System Margin Credit factor,~~ SQP factor, RDA factor, ESM factor, ~~Arrearage Management Adjustment Factor~~AMAF, LIDRF and a Previous Reconciliation factor, including a true-up for any prior year's forecasted revenues and costs. Base rate related items (~~LIAP factor,~~ Advanced Gas Technology factor, Pension Adjustment factor and Environmental Response ~~cost~~ Cost factor) will be ~~only be~~ reconciled only for those non-Revenue Decoupling rate classes (Large and Extra Large high load and low load factor rate classes). For each reconciliation component, a monthly rate based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning and ending balance shall also apply.

5.0 EARNINGS SHARING MECHANISM:

~~The annual Earnings Sharing Mechanism ("ESM") established in Docket No. 3401 will remain in place.~~ The Earnings Sharing Mechanism Credit ("ESMC") for FY 18 will be included with the September 1 DAC filing based on financial information for ~~the 9-month period ending March 31, 2013 and for each~~ the 12 month~~s~~ period ending March 31 ~~thereafter~~. All subsequent ESMC will be filed on May 1 and will reflect a 12 month period ending December 31. For purposes of calculating earnings to be shared, the Company will be allowed to include its 50% share of net merger synergies resulting from the National Grid/KeySpan transactions, or $2,450,000. Calculation of the ESMC is as follows:

$$ESMC = \frac{ESMF}{Dt_T}$$

Where:

DISTRIBUTION ADJUSTMENT CLAUSE

ESMF — Earnings Sharing Mechanism Fund is defined as ~~the~~ customers' share of earnings subject to sharing and will be based ~~on a return on equity of 10.5% for the seven month period ending January 31, 2013 and 9.5% for 2 month period ending March 31, 2013. Thereafter earnings subject to sharing will be based~~ on ~~a~~the return on equity authorized by the PUC in a general rate case or as otherwise authorized by the PUC~~of 9.50%~~. For FY 18, the a~~A~~nnual earnings over ~~this~~ 9.5% return on equity, up to and including 100 basis points, being shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of ~~this~~ 9.5% return on equity shall be shared 75% to customers and 25% to the Company. For all subsequent ESMC, the annual earnings over 9.275% return on equity, and up to and including 100 basis points (i.e., 10.275%), will be shared 50% to customers and 50% to the Company. Any earnings more than 100 basis points in excess of 9.275% return on equity (i.e., exceeding 10.275%) shall be shared 75% to customers and 25% to the Company. The Company's share of any shared earnings will be retained by Company and not reflected in any earnings report.

Dt_T — Forecasted annual firm throughput

RESIDENTIAL NON-HEATING
RATE 10

1.0 AVAILABILITY:

Sales service is available under this rate for all domestic non-heating purposes in individual private residential dwellings with six (6) or ~~less~~ fewer units or in connection with condominium associations with gas supplied through one meter.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 RATES:

September 1, 2018
Customer Charge: $~~13.00~~14.00 per month
Distribution Charge: $~~0.4386~~ 0.5456 per Therm

September 1, 2019
Customer Charge: $14.00 per month
Distribution Charge: $0.5922 per Therm

September 1, 2020
Customer Charge: $14.00 per month
Distribution Charge: $0.6162 per Therm

4.0 MINIMUM CHARGE:

Customer Charge per month.

5.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

6.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

RESIDENTIAL NON-HEATING
RATE 10

7.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

8.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

9.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

10.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

LOW INCOME RESIDENTIAL NON-HEATING
RATE 11

1.0 AVAILABILITY:

Sales service is available under this rate for all domestic non-heating purposes in individual private residential dwellings with six (6) or ~~less~~ fewer units or in connection with condominium associations with gas supplied through one meter. Eligible customers must meet both of the following criteria: ~~A Customer will be eligible for this rate upon verification of the Customer's participation in the low income home energy assistance program or its successor program~~.

1. Must be the head of a household or principal wage earner.
~~1.~~2. Must be presently receiving supplemental Security Income from the Social Security Administration, be eligible for the low-income home energy assistance program, or one of the following from the appropriate Rhode Island agencies: Medicaid, Food Stamps, General Public Assistance, or Family Independence Program.

It is the responsibility of the customer to annually certify, by forms provided by the Company, the continued compliance with the foregoing provisions. ~~Compliance with the foregoing qualifications will be verified annually with the State Office of Energy Resources.~~

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 RATES:

September 1, 2018
Customer Charge: $~~11.70~~14.00 per month
Distribution Charge: $~~0.39470~~0.5456 per Therm

September 1, 2019
Customer Charge: $14.00 per month
Distribution Charge: $0.5922 per Therm

September 1, 2020
Customer Charge: $14.00 per month
Distribution Charge: $0.6162 per Therm

4.0 MINIMUM CHARGE:

Customer Charge per month.

LOW INCOME RESIDENTIAL NON-HEATING
RATE 11

5.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

6.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

7.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

8.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

9.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

10.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

11.0 LOW INCOME DISCOUNT:

The Customer's total bill for service as determined based upon the provisions above will be discounted by twenty-five (25) percent. Customers receiving benefits through the following programs will receive an additional discount of five (5) percent, totaling a total bill discount of thirty (30) percent: Medicaid, General Public Assistance, or Family Independence Program.

RESIDENTIAL HEATING
RATE 12

1.0 AVAILABILITY:

Sales service is available under this rate for all domestic purposes in individual private residential dwellings with six (6) or ~~less~~ fewer units or in connection with condominium associations with gas supplied through one meter where natural gas is the primary fuel used for space and/or central heating equipment.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 RATES:

September 1, 2018

Customer Charge:	$~~13.00~~14.00 per month
Peak Distribution Charge:	$0.5534 per Therm
Off Peak Distribution Charge:	$0.4960 per Therm

September 1, 2019

Customer Charge:	$14.00 per month
Peak Distribution Charge:	$0.5803 per Therm
Off Peak Distribution Charge:	$0.5201 per Therm

September 1, 2020

Customer Charge:	$14.00 per month
Peak Distribution Charge:	$0.5943 per Therm
Off Peak Distribution Charge:	$0.5327 per Therm

~~On-Peak Period (November – April)~~

~~First 125 Therms~~	~~$0.4672 per Therm~~
~~Over 125 Therms~~	~~$0.3010 per Therm~~

~~Off-Peak Period (May – October)~~

~~First 30 Therms~~	~~$0.4672 per Therm~~
~~Over 30 Therms~~	~~$0.3010 per Therm~~

4.0 MINIMUM CHARGE:

Customer Charge per month.

5.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

RESIDENTIAL HEATING
RATE 12

6.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

7.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

8.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

9.0 ENERGY EFFICIENCY:

This application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

10.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

LOW INCOME RESIDENTIAL HEATING
RATE 13

1.0 AVAILABILITY:

Sales service is available under this rate for all domestic purposes in individual private residential dwellings with six (6) or less units or in connection with condominium associations with gas supplied through one meter where natural gas is the primary fuel used for space and/or central heating equipment. Eligible customers must meet both of the following criteria: ~~A Customer will be eligible for this rate upon verification of the Customer's participation in the low income home energy assistance program or its successor program.~~

1. Must be head of a household or principal wage earner.
~~1.~~2. Must be presently receiving Supplemental Security Income from the Social Security Administration, be eligible for the low-income home energy assistance program, or one of the following form the appropriate Rhode Island agencies: Medicaid, Food Stamps, General Public Assistance, or Family Independence Program.

It is the responsibility of the customer ~~ot~~to ~~annualy~~annually certify, by form provided by the Company, the continued ~~compliane~~compliance with the foregoing provisions. ~~Compliance with the foregoing qualifications will be verified annually with the State Office of Energy Resources.~~

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 RATES:

September 1, 2018

Customer Charge:	$~~11.70~~14.00 per month
Peak Distribution Charge:	$0.5534 per Therm
Off Peak Distribution Charge:	$0.4960 per Therm

September 1, 2019

Customer Charge:	$14.00 per month
Peak Distribution Charge:	$0.5803 per Therm
Off Peak Distribution Charge:	$0.5201 per Therm

September 1, 2020

Customer Charge:	$14.00 per month
Peak Distribution Charge:	$0.5943 per Therm
Off Peak Distribution Charge:	$0.5327 per Therm

~~On-Peak Period (November – April)~~
~~First 125 Therms $0.4205 per Therm~~

LOW INCOME RESIDENTIAL HEATING
RATE 13

~~Over 125 Therms $0.2709 per Therm~~

~~Off-Peak Period (May – October)~~
~~First 30 Therms $0.4205 per Therm~~
~~Over 30 Therms $0.2709 per Therm~~

4.0 MINIMUM CHARGE:

Customer Charge per month.

5.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

6.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

7.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

8.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

9.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

10.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

11.0 LOW INCOME DISCOUNT:

LOW INCOME RESIDENTIAL HEATING
RATE 13

The Customer's total bill for service as determined based upon the provisions above will be discounted by twenty-five (25) percent. Customers receiving benefits through the following programs will receive an additional discount of five (5) percent, totaling a total bill discount of thirty (30) percent: Medicaid, General Public Assistance, or Family Independence Program.

C&I SMALL
RATE 21

1.0 AVAILABILITY:

Transportation or Sales service is available under this rate at single locations to Commercial and Industrial customers whose annual gas usage is equal to or less than 5,000 Therms as determined by Company records and procedures. In the case of a New Customer, or an existing Customer with new gas applications, the annual gas usage for the first year shall be that agreed upon by the Company and the Customer.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 TRANSPORTATION SERVICE PROVISIONS:

For Customers selecting transportation service under this Schedule, the Transportation Service provisions found in Section 6 are applicable as in effect from time to time. Customers receiving service under this Schedule are only eligible for FT-2 transportation service.

4.0 RATES:

September 1, 2018

Customer Charge:	$~~22.00~~25.00 per month
Peak Distribution Charge:	$0.4852 per Therm
Off Peak Distribution Charge:	$0.4284 per Therm

September 1, 2019

Customer Charge:	$25.00 per month
Peak Distribution Charge:	$0.5109 per Therm
Off Peak Distribution Charge:	$0.4510 per Therm

September 1, 2020

Customer Charge:	$25.00 per month
Peak Distribution Charge:	$0.5241 per Therm
Off Peak Distribution Charge:	$0.4627 per Therm

~~On-Peak Period (November - April)~~

~~First 135 Therms $0.5431 per Therm~~
~~Over 135 Therms $0.2242 per Therm~~

~~Off-Peak Period (May - October)~~

~~First 20 Therms $0.5431 per Therm~~
~~Over 20 Therms $0.2242 per Therm~~ **MINIMUM CHARGE:**

C&I SMALL
RATE 21

Customer Charge per month.

6.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

7.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

8.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

9.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

10.0 ENERGY EFFICIENCY:

This application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

11.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

C&I MEDIUM
RATE 22

1.0 AVAILABILITY:

Transportation or Sales service is available under this rate at single locations to Commercial and Industrial customers whose annual gas usage is greater than 5,000 Therms, but less than or equal to 35,000 Therms as determined by Company records and procedures. In the case of a New Customer, or an existing Customer with new gas applications, the annual gas usage for the first year shall be that agreed upon by the Company and the ~~customer~~Customer.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 TRANSPORTATION SERVICE PROVISIONS:

For Customers selecting transportation service under this Schedule, the Transportation Service provisions found in Section 6 are applicable as in effect from time to time. Customers receiving service under this Schedule are only eligible for FT-2 transportation service.

4.0 RATES:

September 1, 2018

Customer Charge:	$~~70.00~~85.00 per month
Demand Charge:	$~~1.3000~~1.5000 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the ~~customer~~Customer.
Distribution Charge:	$~~0.1865~~0.2484 per Therm

September 1, 2019

Customer Charge:	$85.00 per month
Demand Charge:	$1.5000 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.
Distribution Charge:	$0.2647 per Therm

C&I MEDIUM
RATE 22

September 1, 2020

Customer Charge:	$85.00 per month
Demand Charge:	$1.5000 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.
Distribution Charge:	$0.2731 per Therm

5.0 MINIMUM CHARGE:

Customer Charge and Demand Charge per month.

6.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

7.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

8.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

9.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

10.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

C&I MEDIUM
RATE 22

11.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

C&I LARGE HIGH LOAD FACTOR USE
RATE 23

1.0 AVAILABILITY:

Transportation or Sales service is available under this rate at single locations to Commercial and Industrial customers whose annual gas usage is greater than 35,000 Therms, but less than 150,000 Therms and whose off-peak (May through October) gas usage is equal to or greater than 31% of the annual gas usage for the most recent September through August period, as determined by Company records and procedures. In the case of a New Customer, or an existing Customer with new gas applications, the annual gas usage for the first year shall be that agreed upon by the Company and the Customer.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 TRANSPORTATION SERVICE PROVISIONS:

For Customers selecting transportation service under this Schedule, the Transportation Service provisions found in Section 6 are applicable as in effect from time to time. Customers receiving service under this Schedule may receive either FT-1 or FT-2 transportation service.

4.0 RATES:

September 1, 2018

Customer Charge:	$~~175.00~~200.00 per month
Demand Charge:	$~~1.8000~~2.0500 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the ~~customer~~Customer.
Distribution Charge:	$~~0.1007~~0.1617 per Therm

September 1, 2019

Customer Charge:	$200.00 per month
Demand Charge:	$2.0500 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.

C&I LARGE HIGH LOAD FACTOR USE
RATE 23

Distribution Charge: $0.1719 per Therm

September 1, 2020

Customer Charge: $200.00 per month

Demand Charge: $2.0500 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.

Distribution Charge: $0.1771 per Therm

5.0 MINIMUM CHARGE:

Customer Charge and Demand Charge per month.

6.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

7.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

8.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

9.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

10.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

C&I LARGE HIGH LOAD FACTOR USE
RATE 23

11.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

C&I EXTRA LARGE HIGH LOAD FACTOR USE
RATE 24

1.0 AVAILABILITY:

Transportation or Sales service is available under this rate at single locations to Commercial and Industrial customers whose annual gas usage is equal to or greater than 150,000 Therms and whose off-peak (May through October) gas usage is equal to or greater than 31% of the annual gas usage for the most recent September through August period, as determined by Company records and procedures. In the case of a New Customer, or an existing Customer with new gas applications, the annual gas usage for the first year shall be that agreed upon by the Company and the Customer.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 TRANSPORTATION SERVICE PROVISIONS:

For Customers selecting transportation service under this Schedule, the Transportation Service provisions found in Section 6 are applicable as in effect from time to time. Customers receiving service under this Schedule may receive either FT-1 or FT-2 transportation service.

4.0 RATES:

September 1, 2018

Customer Charge:	$~~425.00~~500.00 per month
Demand Charge:	$~~1.8000~~2.0500 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the ~~customer~~Customer.
Distribution Charge:	$~~0.0256~~0.0369 per Therm

September 1, 2019

Customer Charge:	$500.00 per month
Demand Charge:	$2.0500 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.

C&I EXTRA LARGE HIGH LOAD FACTOR USE
RATE 24

Distribution Charge: $0.0413 per Therm

September 1, 2020

Customer Charge: $500.00 per month

Demand Charge: $2.0500 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.

Distribution Charge: $0.0435 per Therm

5.0 MINIMUM CHARGE:

Customer Charge plus Demand Charge per month.

6.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

7.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

8.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

9.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

10.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

C&I EXTRA LARGE HIGH LOAD FACTOR USE
RATE 24

11.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

C&I LARGE LOW LOAD FACTOR USE
RATE 33

1.0 AVAILABILITY:

Transportation or Sales service is available under this rate at single locations to Commercial and Industrial customers whose annual gas usage is greater than 35,000 Therms, but less than 150,000 Therms and whose off-peak (May through October) gas usage is equal to or less than 30% of the annual gas usage for the most recent September through August period, as determined by Company records and procedures. In the case of a New Customer, or an existing Customer with new gas applications, the off-peak and annual gas usage for the first year shall be that agreed upon by the Company and the Customer.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 TRANSPORTATION SERVICE PROVISIONS:

For Customers selecting transportation service under this Schedule, the Transportation Service provisions found in Section 6 are applicable as in effect from time to time. Customers receiving service under this Schedule may receive either FT-1 or FT-2 transportation service.

4.0 RATES:

September 1, 2018

Customer Charge:	$~~175.00~~200.00 per month
Demand Charge:	$~~1.3000~~1.5000 per Therms of customer's highest average daily consumption from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the ~~customer~~Customer.
Distribution Charge:	$~~0.1727~~0.2429 per Therm

September 1, 2019

Customer Charge:	$200.00 per month
Demand Charge:	$1.5000 per Therms of customer's highest average daily consumption from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.

C&I LARGE LOW LOAD FACTOR USE
RATE 33

Distribution Charge: $0.2574 per Therm

September 1, 2020
Customer Charge: $200.00 per month
Demand Charge: $1.5000 per Therms of customer's highest average daily consumption from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.
Distribution Charge: $0.2649 per Therm

5.0 MINIMUM CHARGE:

Customer Charge and Demand Charge per month.

6.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

7.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

8.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

9.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

10.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

C&I LARGE LOW LOAD FACTOR USE
RATE 33

11.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

C&I EXTRA LARGE LOW LOAD FACTOR USE
RATE 34

1.0 AVAILABILITY:

Transportation or Sales service is available under this rate at single locations to Commercial and Industrial customers whose annual gas usage is equal to or greater than 150,000 Therms and whose off-peak (May through October) gas usage is equal to or less than 30% of the annual gas usage for the most recent September through August period, as determined by Company records and procedures. In the case of a New Customer, or an existing Customer with new gas applications, the annual gas usage for the first year shall be that agreed upon by the Company and the Customer.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 TRANSPORTATION SERVICE PROVISIONS:

For Customers selecting transportation service under this Schedule, the Transportation Service provisions found in Section 6 are applicable as in effect from time to time. Customers receiving service under this Schedule may receive either FT-1 or FT-2 transportation service.

4.0 RATES:

September 1, 2018

Customer Charge:	$~~425.00~~500.00 per month
Demand Charge:	$~~1.3000~~1.5000 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the ~~customer~~Customer.
Distribution Charge:	$~~0.0328~~0.0421 per Therm

September 1, 2019

Customer Charge:	$500.00 per month
Demand Charge:	$1.5000 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November

C&I EXTRA LARGE LOW LOAD FACTOR USE
RATE 34

	through April gas consumption shall be that agreed upon by the Company and the Customer.
Distribution Charge:	$0.0479 per Therm

September 1, 2020

Customer Charge:	$500.00 per month
Demand Charge:	$1.5000 per Therm of customer's maximum average daily quantity (MADQ) from the most recent November through April period based on historical billing data. In the case of a new customer or a customer with new gas applications, the November through April gas consumption shall be that agreed upon by the Company and the Customer.
Distribution Charge:	$0.0509 per Therm

5.0 MINIMUM CHARGE:

Customer Charge plus Demand Charge per month.

6.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

7.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

8.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

9.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is subject to the Distribution Adjustment Clause in Section 3, Schedule A.

C&I EXTRA LARGE LOW LOAD FACTOR USE
RATE 34

10.0 ENERGY EFFICIENCY:

The application of the above rate is subject to Energy Efficiency provisions in Section 1, Schedule C.

11.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

NON-FIRM SALES (NFS) SERVICE
RATE 60

1.0 AVAILABILITY:

Non-firm sales service is grandfathered as of July 1, 2009 and will no longer be offered to any customer, except that any non-firm sales customer as of that date will be able to continue the service until such time that the non-firm sales customer decides to change to firm service or obtain non-firm transportation service and purchase natural gas from a ~~third-party~~ Marketer. Such customers are non-residential customers with dual-fuel capability: (1) whose premises are located adjacent to the Company's gas distribution mains having adequate capacity to supply the customer's prospective gas requirements in addition to the requirements of other customers already receiving service from such distribution mains; (2) who use~~s~~ gas for boiler load, process load, or cogeneration with a minimum combined hourly input of 100 Ccf/hour; and (3) who maintain~~s~~ adequate standby facilities for the use of an alternate fuel which may be substituted for gas when gas is not available under this ~~Tariff~~Schedule.

2.0 RATES:

Non-firm Sales (NFS) service rates shall be set for the upcoming month, no later than 10:30 a.m. ten (10) business days prior to the commencement of that month. The Customer must notify the Company by 9:00 a.m. two (2) business days prior to the commencement of that month of the intention to take NFS service, and must provide a reasonable estimate of natural gas expected to be used for the month.

Customer ~~charge~~Charges will be determined as follows:

1. For those Customers who can potentially consume more than 150,000 Therms per month:

    - $625 per month, per customer

2. For those Customers who can potentially consume more than 35,000 Therms, but less than 150,000 Therms per month:

    - $405 per month, per customer

3. For those Customers whose potential monthly consumption is less than 35,000 Therms per month:

    - $185 per month, per customer

The Distribution Charge applicable to all gas delivered to a ~~non-firm sales~~ NFS service customer shall be based on the Customer's annual usage in accordance with the following:

NON-FIRM SALES (NFS) SERVICE
RATE 60

≤ 35,000 therms	$~~0.2206~~0.2236 per therm
35,001 to 150,000 therms and:	
Off-peak usage ≤ 31%	$~~0.2147~~0.2177 per therm
Off-peak usage > 31%	$~~0.1436~~0.1456 per therm
> 150,000 therms and:	
Off-peak usage ≤ 31%	$~~0.0912~~0.0919 per therm
Off-peak usage > 31%	$~~0.0733~~0.0738 per therm

The reference to 31% is ~~to~~ the percentage of gas usage from May through October compared to annual usage from September through August. In the case of an existing Customer with new gas applications, the annual gas usage for the first year shall be that agreed upon by the Company and the Customer. The classification will be based on the higher of the most recent 12-months usage or the 12-months previous to that. This classification will be reviewed annually after the August billing period and any change will be reflected with the September bill.

The Company will provide the ~~customer~~ Customer with an initial mid-month estimate of the ~~Commodity~~ commodity ~~Charge~~ charge based on 110% of the sum of the NYMEX closing price on the eleventh business day prior to the start of the month and a publicly available forward basis for gas supply delivered to the Northeastern US. The forward basis will be the Transco Zone 6 Basis Swap (based on the Platts IFERC basis swap obtained from the NYMEX), or a publicly traded forward basis for supply delivered to the Company's city gate (should one become available), or such other publicly available traded basis for supply delivered to the Northeastern U.S. should the Transco Zone 6 Basis Swap become unavailable. The Company will recalculate the ~~Commodity~~ commodity ~~Charge~~ charge based upon the NYMEX settled price and a publicly available forward basis for gas supply delivered to the Northeastern US. The Customer shall be charged the higher of the recalculated rate or the initial mid-month estimate.

3.0 MINIMUM CHARGE:

For delivery service, the minimum charge is the Customer Charge per month. Under no circumstances shall the NFS Commodity Charge be less than the cost of the incremental supply available to the Company for the month, adjusted for the Company's Fuel Allowance.

4.0 GENERAL RULES AND REGULATIONS:

NON-FIRM SALES (NFS) SERVICE
RATE 60

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

5~~4~~.0 NOTIFICATION OF INTERRUPTION/CURTAILMENT:

The Customer will curtail or discontinue service when, in the sole opinion of the Company, such curtailment or interruption is necessary in order for ~~it~~ the Company to continue to supply the gas requirements of its firm customers at such time. The Company will attempt to give the Customer three (3) working days' notice of such curtailment, except in emergency situations, when at least one hour's notice shall be given.

6~~5~~.0 FAILURE TO CURTAIL:

For any period that ~~a~~ the Customer fails to curtail the use of gas as requested by the Company, the charge for gas commodity delivered to the Customer will be equal to the Gas Usage at a penalty of five (5) times the Daily Index. Such use of gas under these circumstances shall be considered an "unauthorized use" of gas.

In the event where the Company, in its sole discretion, grants the Customer an exemption from the curtailment, the use of gas under these circumstances shall be referred to as an "authorized use of gas." Authorized use of gas during a curtailment will be for a limited time period. The charge for gas commodity delivered to the Customer under these conditions will be the highest cost gas required to meet demand during the applicable curtailment period. Payments for this use, whether authorized or unauthorized, shall not preclude the Company from turning off the ~~customer's~~ Customer's supply of gas in the event of the failure to interrupt, or curtail, the use thereof when requested to do so.

All gas delivered to the Customer during a curtailment, either "unauthorized" or "authorized," shall be subject to the Distribution Charges and Energy Efficiency Program Charge in effect at the time of such Gas Usage.

7.0 METER TEST:

~~Users~~ Customers will receive the results of periodic calibration tests performed by the Company on the meters installed on their premises. Meters will be deemed unacceptable if these tests show an error greater than +/-1%. Meters will also be deemed unacceptable, no matter what their error, if the results of three successive tests are consistently high or low. Meters will measure gas flow rates corrected to 60^{o} F gas.

8.0 TELEMETERING:

NON-FIRM SALES (NFS) SERVICE
RATE 60

Wireless communications or ~~Telemetering~~ telemetering equipment is required for those customers who wish to avail themselves of this service, as identified in Section 1, Schedule A, Item 12.0.

9~~8~~.0 NON-FIRM TRANSPORTATION SERVICE OPTION:

The Company will also offer, during the winter months, limited NFS and non-firm transportation (NFT) service for customers on a "best efforts" basis. If a Customer buying gas under this rate schedule opts to directly arrange for the acquisition of wellhead gas supplies, and the transportation of those wellhead gas supplies to the Company's gate stations, then the Company will transport, subject to available capacity, such directly acquired gas to the Customer's facilities. Rates and conditions for such transportation service are included in the Company's Non-Firm Transportation (NFT) Service in Section 6, Schedule A of RIPUC NG 101.

10~~9~~.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

11~~0~~.0 ENERGY EFFICIENCY:

The application of the above rate to all gas delivered is subject to Energy Efficiency provisions in Section1, Schedule C.

12~~1~~.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

13.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is not subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

14.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is not subject to the Distribution Adjustment Clause in Section 3, Schedule A.

TRANSITION SALES SERVICE
TSS

1.0 AVAILABILITY:

Transitional Sales Service (TSS) shall apply to Customers subject to the Transportation Terms and Conditions. The Company's General Terms and Conditions will govern this Service to the extent not consistent herewith.

TSS is not available to Capacity Exempt Customers.

The Company reserves the right to restrict the availability of this service if the Company determines that the integrity of the distribution system is at risk.

2.0 GENERAL CONDITIONS:

TSS is provided by the Company to Customers switching from ~~supplier~~ transportation service to firm sales service. TSS is available to Customers who meet the requirements ~~of Section 5, Schedule H, Item 1.0~~above, and (a) who terminate ~~supplier~~ transportation service, (b) who receive a termination notice from a designated ~~supplier~~Marketer, or (c) for whom a designated ~~supplier~~ Marketer becomes ineligible to serve the Customer.

All Customers transferring to firm sales service from firm transportation service, either from FT-1 service or FT-2 service, and who have received an assignment of the Company's interstate pipeline capacity while on firm transportation service immediately prior to their transfer back to firm sales service, will be subject to the provisions of this rate schedule in addition to the provisions of the Company's applicable firm sales service rate schedules.

3.0 TERM:

For each Customer who transfers to firm sales service from FT-1 transportation service, TSS will be applicable to firm sales service provided to the Customer through the next April 30 after the Customer starts taking firm sales service or until the Customer enters into a contractual commitment with the Company to take firm sales service continuously for a period of not less than one year. After April 30, the Customer will receive firm sales service and will not be subject to the TSS surcharge defined below.

For each Customer transferring to firm sales service from FT-2 transportation service, TSS will be applicable to firm sales service provided to the Customer through the end of the Customer's first billing cycle subsequent to the next April 30 after the Customer starts taking firm sales service or until the Customer enters into a contractual commitment with the Company to take firm sales service continuously for a period of not less than one year. After the end of the first billing cycle after April 30, the Customer will receive firm sales service and will not be subject to the TSS surcharge defined below.

TRANSITION SALES SERVICE
TSS

4.0 SURCHARGE:

Each Customer receiving TSS will be subject to a monthly surcharge during the term the Customer receives TSS, unless a Customer, prior to their return to the Company for gas supply, enters into a contractual commitment with the Company to take firm sales service continuously for a period of not less than one year. If such an agreement is executed, the Customer will not be subject to the TSS surcharge. The TSS surcharge is designed to charge a market-based price reflecting the cost of gas supplies in the marketplace at the time consumption is occurring for the incremental amount of gas that the Company must purchase over and above the quantities of gas procured for firm sales customers under the provisions of the Company's Gas Procurement Incentive Plan ("GPIP"). The surcharge will reflect any positive difference between the GPIP cost of gas for the month in which gas is supplied and a market-based gas price for the same month. This surcharge shall apply to all firm sales service consumption of Customers switching from firm transportation service subsequent to April 30 of each year, with the exception of those Customers committing to remain on firm sales service for a period of at least 12 months as described above.

4.1 Calculation:

The surcharge for Customers who switch to firm sales service from firm transportation service shall be computed as follows:

IF
$\{ [(NYMEX_M – GPIP_M) (GPIP_{QM} \div Dt_M)] \} - R_{GCR}$ is > 0,

THEN:
$TSS = \{ [(NYMEX_M – GPIP_M) (GPIP_{QM} \div Dt_M)] \} - R_{GCR}$

OTHERWISE:

$TSS = 0$

Where:

TSS	Transitional Sales Service monthly surcharge.
$NYMEX_M$	The NYMEX closing price for month M.
$GPIP_M$	Average cost of gas purchased under the GPIP for month M.

TRANSITION SALES SERVICE
TSS

$GPIP_{QM}$	The Total Quantity of GPIP purchases for month M.
Dt_M	Total forecasted sales for month M underlying the GPIP.
R_{GCR}	The per Dt Deferred Gas Cost Reconciliation reflected in the current GCR charge.

TSS surcharges will be calculated monthly. Supporting calculations for all components of the applicable surcharges will be posted on the Company's website by the second business day of each month. In addition, supporting workpapers shall be submitted to the PUC and the Division simultaneously with the posting on the Company's website.

5.0 STORAGE AND PEAKING:

FT-1 firm transportation service Customers eligible for TSS who transfer to firm sales service will be subject to a Storage and Peaking charge for recovery of Storage and Peaking costs. Such charge will be calculated at the time the FT-1 ~~customer~~ Customer transfers to firm sales service based on the ~~customer's~~ Customer's actual consumption as a FT-1 ~~transportation~~ ~~customer~~ Customer since the most recent April 1, multiplied by the currently effective FT-2 Demand Charge provided in the Company's most recently approved GCR filing.

NON-FIRM TRANSPORTATION (NFT) SERVICE
RATE 61

1.0 AVAILABILITY:

For any non-residential customer with dual-fuel capability: (1) whose premises are located adjacent to the Company's gas distribution mains having adequate capacity to supply the Customer's prospective gas requirements in addition to the requirements of other customers already receiving service from such distribution mains; (2) who uses gas for boiler load, process load, or cogeneration with a minimum combined hourly input of 100 Ccf/hour; and (3) who maintains adequate standby facilities for the use of an alternate fuel which may be substituted for gas when gas transportation is not available under this ~~Tariff~~Schedule.

This rate is available to any Customer who has, without the assistance of the Company or the use of its facilities or dedicated pipeline capacity, arranged for the acquisition and transportation of gas supplies to the Company's gate stations, has executed a Transportation Service Application, has designated on such Application a Marketer as required under the Transportation Terms and Conditions in Section 6, Schedule C, and who meets the following additional criteria:

A. The Customer must have telemetering equipment in place.

B. The Customer agrees to discontinue service, when in the sole discretion of the Company, such discontinuance is necessary in order to continue to serve the needs of firm customers at such time. The Company will attempt to give three (3) working days' notice of such action except in the event of emergency, when at least one hour's notice will be given.

Any gas consumed during a requested discontinuance, whether authorized or unauthorized, shall be provided by the Company and not a third party supplier or Marketer of record.

2.0 RATE:

The Customer must notify the Company by 9:00 a.m. two (2) business days prior to the commencement of that month of any change in gas marketer.

Customer Charge will be determined as follows:

1. For those Customers who can potentially consume more than 150,000 Therms per month:
   - $~~715~~ 625 per month, per customer.

2. For those Customers who can potentially consume more than 35,000 Therms, but less than 150,000 Therms per month:

NON-FIRM TRANSPORTATION (NFT) SERVICE
RATE 61

- $~~485~~ 405 per month, per customer

3. For those Customers whose potential monthly consumption is less than 35,000 Therms per month:

- $~~275~~ 185 per month, per customer

Distribution Charge:

The Distribution Charge applicable to all gas delivered to a ~~non-firm transportation~~NFT service Customer shall be based on the Customer's annual usage in accordance with the following:

≤ 35,000 therms	$~~0.2206~~0.2236 per therm
35,001 to 150,000 therms and:	
Off-peak usage ≤ 31%	$~~0.2147~~0.2177 per therm
Off-peak usage > 31%	$~~0.1436~~0.1456 per therm
> 150,000 therms and:	
Off-peak usage ≤ 31%	$~~0.0912~~0.0919 per therm
Off-peak usage > 31%	$~~0.0733~~0.0738 per therm

The reference to 31% is ~~to~~ the percentage of gas usage from May through October compared to annual usage from September through August. In the case of a New Customer, or an existing Customer with new gas applications, the annual gas usage for the first year shall be that agreed upon by the Company and the Customer. The classification will be based on the higher of the most recent 12-months usage or the 12-months previous to that. This classification will be reviewed annually after the August billing period and any change will be reflected with the September bill.

3.0 MINIMUM CHARGE:

For delivery service, the minimum charge is the Customer Charge per month.

4.0 TRANSPORTATION TERMS AND CONDITIONS:

The Company's Transportation Terms and Conditions, Section 6, Schedule C, as in effect from time to time and where not inconsistent with any provisions hereof, are a part of this Schedule.

NON-FIRM TRANSPORTATION (NFT) SERVICE
RATE 61

5.0 GENERAL RULES AND REGULATIONS:

The Company's General Terms and Conditions, Section 1, Schedule A, as in effect from time to time and where not inconsistent with any provisions hereof, are a part of this Schedule.

6.0 TELEMETERING EQUIPMENT:

Telemetering equipment is required. The customer may have access to the telemetering equipment for data gathering and transmission, as identified in Section 1, Schedule A, Item 12.0.

7.0 ~~NON-FIRM~~NFT CUSTOMER USE OF GAS:

A ~~Non-Firm~~NFT customer that elects to use gas from the Company for any reason shall receive Default Transportation Service and be charged the rate applicable to such service as set forth in the Transportation Terms and Conditions, Section 6, Schedule C, Item 2.04~~.0~~, for the first month of service and shall pay the Non-Firm unauthorized use rate as forth in the Transportation Terms and Conditions, Section 6, Schedule C, Item 1.05~~.0~~, for all additional months.

8.0 NOTIFICATION OF INTERRUPTION/CURTAILMENT:

The Customer will curtail or discontinue service when, in the sole opinion of the Company, such curtailment or interruption is necessary in order for it to continue to supply the gas requirements of its firm customers at such time. The Company will attempt to give the Customer three (3) working days' notice of such curtailment, except in emergency situations, when at least one hour's notice shall be given.

9.0 FAILURE TO CURTAIL:

For any period that a Customer fails to curtail the use of gas as requested by the Company, the charge for gas commodity delivered to the Customer will be equal to the Gas Usage at a penalty of five (5) times the Daily Index. Such use of gas under these circumstances shall be considered an "unauthorized use" of gas.

In the event where the Company, in its sole discretion, grants the Customer an exemption from the curtailment, the use of gas under these circumstances shall be referred to as an "authorized use of gas." Authorized use of gas during a curtailment will be for a limited time period. The charge for gas commodity delivered to the Customer under these conditions will be the highest cost gas required to meet demand during the applicable curtailment period. Payments for this use, whether authorized or unauthorized, shall not preclude the Company

NON-FIRM TRANSPORTATION (NFT) SERVICE
RATE 61

from turning off the ~~customer's~~ Customer's supply of gas in the event of the failure to interrupt, or curtail, the use thereof when requested to do so.

All gas delivered to the Customer during a curtailment, either "unauthorized" or "authorized", shall be subject to the Distribution Charges and Energy Efficiency Program Charge in effect at the time of such Gas Usage.

10.0 GAS BALANCING NOMINATION/AGGREGATION:

Refer to the Transportation Terms and Conditions, Section 6, Schedule C.

11.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

12.0 ENERGY EFFICIENCY:

The application of the above rate to all gas delivered is subject to Energy Efficiency provisions in Section 1, Schedule C.

13.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

14.0 GAS COST RECOVERY CLAUSE:

The application of the above rate is not subject to the Gas Cost Recovery Clause in Section 2, Schedule A.

15.0 DISTRIBUTION ADJUSTMENT CLAUSE:

The application of the above rate is not subject to the Distribution Adjustment Clause in Section 3, Schedule A.

FIRM TRANSPORTATION SERVICE

1.0 AVAILABILITY:

Firm Transportation Service is available to any Commercial and Industrial customer account who:

(1) is classified as Small, Medium, Large, or Extra Large pursuant to Section 5, Schedule A, B, C, D, E, and F; and,

(2) elects to purchase gas supplies from a ~~supplier other than the Company~~Marketer through the execution of a Transportation Service Application pursuant to the Transportation Terms and Conditions, Section 6, Schedule C.

2.0 CHARACTER OF SERVICE:

Firm Transportation Service provides for the transportation of gas supplies purchased ~~on~~ by a customer~~'s behalf~~ from a ~~supplier other than the Company~~Marketer on a firm 365 days per year basis. Service is classified as either Firm Transportation Service FT-1 or Firm Transportation Service FT-2 as follows:

FT-1 This service provides firm transportation of customer-purchased gas supplies to customers electing to have Gas Usage recorded on a daily basis at the ~~customer's~~ Customer's Point of Delivery. This service is available only to Large and Extra Large Commercial and Industrial customers.

FT-2 This service provides firm transportation of customer-purchased gas supplies to customers without the requirement for recording daily Gas Usage at the ~~customer's~~ Customer's Point of Delivery. This service is available to all Commercial and Industrial customers.

Also refer to the Transportation Terms and Conditions, Section 6, Schedule C, Items 2.0 and 3.0 for additional information.

3.0 RATES:

Specific rates billable by the Company to the ~~customer~~ Customer are those applicable under the ~~customer's~~ Customer's service classification as provided for in Section 5, Schedules A, B, C, D, E, or F. For customers electing FT-1 Service, a one-time charge associated with the installation of telemetering equipment may also apply as provided for under the Transportation Terms and Conditions, Section 6, Schedule C, Item 2.02.0.

Rates associated with Firm Transportation Service which is billable to Marketers are those applicable under the Transportation Terms and Conditions, Section 6, Schedule C, as in effect from time to time.

FIRM TRANSPORTATION SERVICE

4.0 TRANSPORTATION TERMS AND CONDITIONS:

The Transportation Terms and Conditions in Section 6, Schedule C, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of the Schedule.

5.0 GENERAL RULES AND REGULATIONS:

Firm Transportation Service will also be governed by the Company's General Terms and Conditions ~~of Service~~ to the extent not inconsistent herewith.

TRANSPORTATION TERMS AND CONDITIONS

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TRANSPORTATION TERMS AND CONDITIONS

TRANSPORTATION TERMS AND CONDITIONS

1.0 GENERAL:

These terms and conditions apply to those Commercial and Industrial customers classified as Small, Medium, Large, Extra Large, or Non-firm who purchase gas supplies from sources other than the Company for transportation service by the Company pursuant to Section 5, Schedule A, B, C, D, E, and F, and Section 6, Schedule A, as well as to any Marketers designated to act on the customer's behalf pursuant to a Transportation Service Application and executing a Marketer Aggregation Pool Service Agreement. Any FT-1 customers classified as Medium at the time the access to FT-1 service for Medium customers was discontinued or any Customers reclassified as Medium based on their reduction in load will be grandfathered and allowed to continue receiving service under the FT-1 rate schedule. Transportation service will also be governed by the Company's General Terms and Conditions of Service to the extent not inconsistent herewith.

The Company reserves the right to restrict the availability of Transportation Service should the number of customers exceed the capability of the Company to reliably administer the service or if the integrity of the distribution system is put at risk.

If a Customer requesting service hereunder has been a sales service customer of the Company at the same service location within the preceding twelve month period, any under-recovered or over-recovered gas costs attributable to such prior service under the Gas Cost Recovery Clause in Section 2, Schedule A, Section 9.0 shall be determined and charged by the Customer or credited to the Customer's account.

1.01.0 TERM OF SERVICE:

1.01.1 FT-1 Transportation Service:

FT-1 Transportation Service will commence on the first day of a calendar month subject to satisfying the Company's Transportation Terms and Conditions and be for an initial term of up to one year to reflect a common anniversary of November 1. Service shall continue thereafter on a year-to-year basis, unless terminated by the Customer, Marketer or the Company, effective with the Customer's next billing cycle, upon at least thirty (30) days advance notice, either by written notice or the appropriate EDI transmission, to the Company. The Marketer shall be responsible for providing the Company with an executed Transportation Service Application for each new FT-1 customer account being added to its FT-1 Aggregation Pool no less than thirty (30) days prior to commencement of service. The Company's receipt of the Transportation Service Application initiates the thirty (30) day notice period. Existing FT-1 service customers may be switched to another Marketer by using an EDI enrollment transaction.

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1.01.2 FT-2 Transportation Service:

FT-2 Transportation Service will commence on the first day of a Customer's billing cycle subject to satisfying the Company's Transportation Terms and Conditions. Service shall continue thereafter on a year-to-year basis unless terminated by the Customer, Marketer, or the Company, effective with the Customer's next billing cycle, upon at least fifteen (15) days advance written notice to the Company. The Marketer shall be responsible for providing the Company with an EDI enrollment for each Customer being added to its FT-2 Aggregation Pool no less than fifteen (15) days prior to commencement of service.

1.01.3 Non-Firm Transportation (NFT) Service:

Customers classified as Non-Firm Transportation (NFT) will be able to commence transportation as of the first (1^{st}) of any calendar month subject to meeting the nomination requirements established in Item 1.03 following and having submitted to the Company an executed Transportation Service Application.

A Customer's designation as NFS or NFT shall remain in effect until the Company is notified of a further change. Such notice is required by 9 a.m. two (2) business days before the start of the calendar month when such change is to take effect. Switching to or initiating transportation service mid-month is generally not allowed.

1.02.0 Designation Of Marketer:

1.02.1 Firm Transportation:

Customers wishing to switch Marketers will be allowed to do so at the start of a calendar month in the case of FT-1 Service, or at the start of a Customer's billing cycle in the case of FT-2 Service. For new FT-1 Service, the Customer and the new Marketer shall execute a new Transportation Service Application listing the new Marketer as their designated Marketer and forward that document to the Company for processing. For FT-2 Service, the Marketer will contact the Company through electronic data interchange (EDI) to initiate service with the customer account number being the validation. In the event of a dispute over the enrollment of a customer, the Marketer will be required to provide proof of authorization by the customer. This can be in the form of a signed agreement with the customer, audio recording of the customer's agreement/or authorization or an electronically recorded authorization. The Marketer is required to retain such proof for a minimum of two years or for the length of the service agreement, whichever is longer. The Company must receive the new Transportation Service Application or EDI transmittal at least thirty (30) days prior to the change in the case of FT-1 Service, and at least fifteen (15) days prior to the customer's meter read in the case of FT-2 Service. For an FT-

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1 Service customer without a capacity assignment from the Company, see Item 1.07 below, the Company must be notified of such change by 9 a.m. at least two (2) business days before the start of the calendar month The Company will not accept a Transportation Service Application which designates a Marketer that has not executed an Aggregation Pool Service Agreement.

If the Company receives more than one Transportation Service Application for the same FT-1 customer account with different designations of Marketer, the Company will contact the Customer for clarification and confirmation.

The Company will notify the Marketer of record via an EDI drop transaction in the event that a customer account assigned to the Marketer's Aggregation Pool is terminated.

Marketer must provide the Company with (30) days' advance notice in the event that the Marketer terminates service to a Customer in its Aggregation Pool.

Customers not subject to Default Transportation Service in Item 2.04 below, may return to sales service with at least thirty (30) days' advance notice, subject to availability, in the Company's sole discretion, of adequate gas transmission, gas supply and/or gas storage capability, and subject to the Company's Transitional Sales Service Rate, Section 5 Schedule H, of the Commercial and Industrial Services.

These provisions for switching Marketers or returning to Sales Service do not excuse the performance of any contractual obligations between the customer and a Marketer, including the potential requirement of paying damages to the Marketer for a breach of any such contractual obligation.

1.02.2 Non-Firm Transportation:

Switching Marketers is allowed at the start of any calendar month with the provision that the Company receive the Customer's Transportation Service Application designating the effective Marketer by 9 a.m. at least two (2) business days before the start of the month for which the switch is effective.

These provisions for switching Marketers do not excuse the performance of any contractual obligations between the customer and a Marketer, including the potential requirement of paying damages to the Marketer for a breach of any such contractual obligation.

If the Company receives more than one Transportation Service Application for the same customer account with different designations of Marketer, the Company will

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contact the Customer for clarification and confirmation.

1.03.0 Nominations:

1.03.1 General:

Marketer shall provide notice via the Company's Electronic Bulletin Board (EBB) the required information relative to Shipper and Transporting Pipeline names and contract number(s) on which deliveries will be made and the specified quantity of gas that Marketer will deliver to the Point(s) of Receipt on each day of the calendar month. Marketer is required to have separate nomination names and contract numbers for each of Marketer's Aggregation Pools. Additional information may be required by the Company. The Company will host an annual post-winter meeting with all Suppliers to discuss any proposed changes to the transportation program and the related requirements.

1.03.2 Dispatch Communication:

All nomination information shall be communicated to the Company's Gas Control Supply Operations Department via the Company's EBB. Marketer shall be responsible for monitoring the EBB 24 hours per day, seven days per week for dispatch purposes. In the event that the Company is unable to contact a Marketer regarding any nomination or dispatch, the Company may take any action it deems necessary to maintain system integrity as otherwise outlined in the General Terms and Conditions.

1.03.3 Initial Nominations:

The Nomination terms for FT-1 and NFT Service for deliveries to commence service on the first day of any calendar month will be submitted to the Company not later than the initial nomination deadline of the upstream Transporting Pipeline(s) transporting gas for Marketer. Such nominations will specify the quantity to be scheduled on each day of the month. The nomination requirements for FT-2 Service are described in Item 3.03 below.

As a condition of confirming any nomination, Company may direct Marketer to have gas delivered to an alternate Point of Receipt on the same Transporting Pipeline. Upon receipt of such directions, Marketer will arrange with the Transporting Pipeline to have gas delivered to the Point of Receipt designated by Company. Such alternate point of Receipt will remain the Point of Receipt for Marketer's gas for the period stated by the Company in its instructions until Company directs Marketer otherwise.

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1.03.4 Subsequent Nominations:

After the first day of the calendar month, Marketer may alter its nomination, provided that the revised nomination for delivery on any day is submitted to Company's EBB in accordance with the NAESB inter-day nomination schedule. The Company will accept on a best-efforts basis, an intra-day nomination submitted to the company's EBB up until 8:00 AM of the end of the gas day.

1.03.5 Intra-Day Nominations:

For daily metered Aggregation Pools, the Company will accept and implement, on a best-efforts basis, an intra-day nomination submitted to the Company's EBB following NAESB time lines.

One (1) such nomination per gas day shall be accepted subject to confirmation by the Transporting Pipeline.

1.03.6 Scheduling of Service:

Company will attempt to confirm with Transporting Pipeline(s) that the nominated quantities equal the Scheduled Transportation Quantity. If such nomination is confirmed, the Company will schedule said quantities to the Marketer at the designated Point of Receipt(s).

If Marketer is purchasing gas at the Company's city gate, they are responsible for identifying the original delivering contract number, Shipper and any additional title transfers.

If Marketer's nominations on the Company's Electronic Bulletin Board are not consistent with nominations on Transporting Pipeline, then the smaller of the two nominations shall prevail, and all associated balancing and penalty assessments shall be based on the smaller nomination.

1.04.0 Protection Of System Operations:

1.04.1 Company Operational Flow Order (OFO):

Service hereunder may be limited as provided in the Company's General Terms and Conditions. Further, in the event that the Company determines in its sole judgment that it must take prompt action in order to maintain system integrity or to ensure Company's continued ability to provide service to its firm customers, the Company may declare a Critical Day or issue an OFO. In addition to the OFOs listed below, the Company shall have the right to issue any other OFO reasonably intended to

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serve the above stated purpose. The Company may take any one or more of the following actions:

(1) declare a Critical Day which would require Marketer to fully utilize upstream capacity that it received from Company through Capacity Release; and require Marketer to fully schedule storage resources allocated as part of FT-2 Service, i.e., up to the MDQ-U, prior to relying on peaking resources to the extent they are needed to meet their customer's demands;

(2) take any actions that are within Company's operational capability to reduce or eliminate Marketer or Aggregation Pool excess receipts; and

(3) take any actions that are within Company's operational capability to reduce or eliminate Marketer or Aggregation Pool excess takes.

When the Company issues an Operational Flow Order it will issue a notice to Marketers and state in the notice the balancing tolerances that will be in effect and, to the extent practicable, provide information on the cause and expected duration of the OFO. In addition, where the Company's need to issue an OFO is the result of its receipt of a notice of any kind from any of its pipeline transportation, storage, or peaking service providers, the Company will include that information in the notice and, to the extent possible, coordinate the duration and terms of its OFO with those of the service provider. Such an attempt to coordinate its OFO with those of its service providers will be based on the Company's sole discretion and such coordination will not limit the Company's ability to impose different terms or to continue or terminate its OFO at a time different from its service provider(s).

1.04.2 Pipeline Operational Flow Order:

If, at any time, an immediate upstream pipeline issues an order changing the requirements at the Point(s) of Receipt, then Company may so notify Marketer and direct Marketer to modify requirements at the Point(s) of Receipt to the extent necessary for Company to comply with the pipeline's order. Marketer will be responsible for coordinating with their customers regarding any necessary change to Customer's quantity of Gas Usage.

1.04.3 Marketer Responsibility:

In the event Company takes action to alleviate excess imbalances it will nonetheless remain the obligation of Marketer to make such further adjustments to nominations, both to Company, Shipper, and to Transporting Pipeline, during the remainder of the month to resolve accumulated imbalances or to account for subsequent changes in actual deliveries. Company's exercise of its authority under this section will have no

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effect on Marketer's liability for unauthorized overrun or imbalance penalties that apply to Marketer under this tariff or any similar charge, including scheduling penalties, imposed by any upstream Transporting Pipeline(s).

An operational flow order may be issued by the Company as a blanket order to all transportation customers, or to individual Marketer's Aggregation Pools, whose actions are determined by the Company to jeopardize system integrity.

For Critical Days or OFO's aggravated by under-delivery, the Marketer will be charged a penalty of 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceed 102% of the Marketer's aggregate actual receipts on the Transporting Pipeline at the Point of Receipt. The Marketer will be charged a penalty of 0.1 times the Daily Index for the differences between said receipts and said usage that exceed 20% of said receipts [(Receipts – Usage) > (20% x Receipts)].

For Critical Days or OFO's aggravated by over-delivery, the Marketer will be charged a penalty of 0.1 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceed 120% of the Marketer's aggregate actual receipts on the Transporting Pipeline at the Point of Receipt. The Marketer will be charged a penalty of 5 times the Daily Index for the differences between said receipts and said usage that exceed 2% of said receipts [(Receipts – Usage) > (2% x Receipts)].

1.05.0 Unauthorized Use:

In the event the Company provides a Marketer with as much notice as Company deems practicable of an Operational Flow Order per Item 1.04.0 or other curtailment of service and thereby reduces the Scheduled Transportation Quantity for delivery, the total Gas Usage by the Customer may not exceed the revised Scheduled Transportation Quantity. If, on any Gas Day, after notice of curtailment, the quantity of gas taken by Marketer's Customers in an Aggregation Pool, exclusive of NFT customers whose use under a curtailment is covered in Item 4.04 below, exceeds Marketer's Scheduled Transportation Quantity as so revised for the Aggregation Pool, and the Company has not authorized such excess quantity, then all such Gas Usage constitutes Unauthorized Use and is subject to an overrun penalty for each Dekatherm not delivered of five (5) times the Daily Index. Such charges will be billed to the Marketer's account.

1.06.0 Shipper And Transporting Pipeline Requirements:

Marketers must deliver a minimum of forty percent (40%) of total daily pipeline receipts (including all of the Marketer's Aggregation Pools serving both FT-1 and FT-2 customers) on each of the upstream pipelines: Algonquin Gas Transmission ("Algonquin") and

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Tennessee Gas Pipeline ("Tennessee"). The remaining twenty percent (20%) of total daily pipeline receipts (including all of the Marketer's Aggregation Pools serving both FT-1 and FT-2 customers) may be delivered on either or both Algonquin or Tennessee.

Marketer warrants with respect to each Aggregation Pool that it has entered into the necessary agreements for the purchase and delivery of a gas supply to the Point of Receipt which it wants Company to transport and that it has entered into the necessary transportation agreements for the delivery of gas supply to the Point of Receipt. Marketer acknowledges that it must arrange for the delivery of Actual Transportation Quantities to the Company sufficient to include both the Scheduled Transportation Quantities and the applicable Company Fuel Adjustments.

In addition, Marketer warrants that at the time of delivery of its gas supply to the Point of Receipt, Marketer shall have good title to such gas, free of all liens, encumbrances and claims whatsoever. Marketer shall indemnify the Company and save it harmless from all suits, actions, debts, accounts, damage, costs, losses and expenses arising from or out of any adverse legal claims of third parties to or against said gas supply.

1.07.0 Capacity Release:

Each Marketer serving any Customer migrating from (i) Firm Sales Service to FT-1 or FT-2 Transportation Service or (ii) another Marketer's Aggregation Pool where they were previously assigned pipeline capacity by the Company, will be required to accept, for each such Customer account, an assignment of a portion of Company's firm interstate pipeline transportation capacity at maximum rates for an initial term of up to one year.

The Company shall determine the quantity to be released based on the customer's calculated Peak Day Use and load factor rate class. The Company will separately calculate assignment percentages for high load factor rate classes and low load factor rate classes eligible for transportation for pipeline, storage and peaking. It will then multiply the pipeline percentage applicable to the Customer's rate class times the Customer's Peak Day Use to determine the amount of capacity to be assigned to the Marketer. The pipeline, storage and peaking allocation percentages will then be provided in the Company's annual Gas Cost Recovery filing.

The Company will provide Marketers with the calculated base and thermal factors used to estimate each customer's peak day use. The factors are provided based on the results of the Company's application of the specific methodology in this tariff and certain historical data. Marketers may not assume that use of the factors will yield correct estimates of any customer's use for any future period or that the capacity provided as a result of the calculation will meet the customer's requirements under all conditions.

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The quantity of capacity shall be set forth in the confirmation materials provided to the Marketer. For all Customers classified as Small, Medium, Large, or Extra-Large, this quantity will be reviewed annually against the Customer's most recent usage patterns. Any change in Customer's required capacity will be reflected in a revised capacity release with the Marketer for effect on the following November 1. In the event that a Marketer stops delivering gas on behalf of an existing capacity exempt customer, the customer will be prohibited from taking firm Company sales service. Such customers will receive Default Transportation Service as described in Item 2.04.0 below.

Marketer shall be required to execute a Capacity Assignment Agreement at the time a Marketer establishes an Aggregation Pool or any other instruments reasonably required by Company or interstate pipeline necessary to effectuate such assignment. Marketer is responsible for utilizing and paying for the assigned capacity consistent with the terms and conditions of the interstate pipeline's tariffs and this tariff. Marketer is responsible for payment of all upstream pipeline charges associated with the assigned firm transportation capacity, including but not limited to demand and commodity charges, shrinkage, GRI charges, cash outs, transition costs, pipeline overrun charges, annual change adjustments and all other applicable charges. These charges will be billed directly to the Marketer by the interstate pipeline.

All Capacity Assignments for FT-1 Transportation Service will be effective with the commencement of service. Capacity Assignments for FT-2 Customers will be effective the first of the upcoming month for Transportation Service Applications received prior to the tenth. For FT-2 Service, EDI enrollments received on or after the tenth of the month, the capacity release will not be effective until the first of the month subsequent to the upcoming month.

Capacity Assignments will be effective for an initial term of up to one year through the following November 1. Capacity Assignments shall be reviewed each November 1 and be subject to annual adjustment as described above. The new capacity assignment percentages, along with the storage maximum daily quantities and maximum storage quantities in section 3.02.2, will be available on the Company's EBB. All releases hereunder will be subject to recall under the following conditions: (1) when required to preserve the integrity of the Company's facilities and service; (2) at the Company's option, whenever the Marketer fails to deliver gas in an amount equal to the Scheduled Transportation Quantity; and (3) any other conditions set forth in the capacity release transaction between the Marketer and the Company.

The Company shall assess a surcharge/credit to Marketers based on the difference between the charges of the upstream pipeline transportation capacity and the weighted average of the Company's upstream pipeline transportation capacity charges as calculated by the Company. To the extent that the charges of such released pipeline capacity are greater than the weighted average charges, the Marketer shall receive credit for such difference in charges

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based on the total quantity of capacity released by the Company to the Marketer. The per Dt charge is calculated by subtracting the charge per Dt for the released pipeline capacity from the Company's weighted average Upstream Transportation charges as identified in the Company's annual Gas Cost Recovery Filing. To the extent that the cost of such released pipeline capacity is less than the weighted average cost, the Marketer shall be surcharged for such difference.

During the calendar month of September, each Marketer will be required to submit a new Capacity Assignment Agreement indicating pipeline capacity path preferences based on the available paths identified in the Company's annual Gas Cost Recovery Filing. Any changes from the Marketer's previous election will be effective November 1 in conjunction with the updating of customer capacity quantities described above.

Each Marketer's capacity assignment associated with Customers in an aggregation pool shall be reviewed on a monthly basis prior to the tenth (10th) calendar day of the month, and adjusted to reflect any net changes resulting from the addition and deletion of customers to the pool.

1.07.1 Capacity Exemption for New Firm Loads:

New Customers requesting firm service that are classified as Large or Extra-Large and electing FT-1 transportation service will not be required to take assignment of the Company's capacity resources as described in 1.07.0 above and must notify the Company in writing of its intent to be Capacity Exempt. The New Customer must also initiate gas supply service from a Marketer within 60 days after the start of distribution service. In the event that the New Customer does not obtain a Marketer within 60 days of the commencement of distribution service, the Customer will be prohibited from receiving Company-supplied firm sales service and will receive and be billed for Default Transportation Service as described below in Item 2.04.0. The consumption of such Customers may be subject to annual review and confirmation by the Company. Customers who fail to meet the minimum requirement for the Large classification shall be required to take assignment of the Company's capacity resources after no less than 60 days' notice. Marketers for such customers may be responsible for obtaining citygate capacity at a specific citygate on the Company's system as determined by the Company. Such determination will be based on the customer's location, load characteristics and distribution system requirements.

In the event that a Marketer stops delivering gas on behalf of a customer without Company assigned pipeline capacity, the customer will be prohibited from taking firm Company sales service. Such customers shall receive and be billed for Default Transportation Service as described in Item 2.04.0 below.

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1.07.2 Capacity Exemption for Non-Firm Customers Converting to Firm Service:

Non-Firm Sales and Non-Firm Transportation Customers classified as Large or Extra-Large who have been approved by the Company to receive firm distribution service and have elected FT-1 transportation service must, no later than 90 days' notice before the commencement of distribution service, either (i) request in writing a Capacity Assignment from the Company, or (ii) notify the Company in writing of its intent to retain its Capacity Exempt status. In the event that a Customer who has requested to retain its Capacity Exempt status but does not have a Marketer at the time the Customer begins receiving firm distribution service, the Customer will be prohibited from taking Company-supplied firm sales service and will receive and be billed for Default Transportation Service as described below in Item 2.04.0. The consumption of such Customers may be subject to annual review and confirmation by the Company. To qualify for Capacity Exempt status, Marketers for such Customers may be responsible for obtaining citygate capacity at a specific citygate on the Company's system as determined by the Company. Such determination will be based on the Customer's location, load characteristics, and distribution system requirements. For those Non-Firm Customers converting to firm distribution service and requesting an assignment of the Company's pipeline capacity, the Company must respond in writing within 30 days regarding the availability of pipeline capacity. If the Company is not able to provide a capacity assignment, the Customer will retain its Capacity Exempt status and will be prohibited from taking Company-supplied firm sales service and will receive and be billed for Default Transportation Service as described below in Item 2.04.0.

In the event that a Marketer stops delivering gas on behalf of a Customer who does not have an assignment of the Company's pipeline capacity, the Customer will be prohibited from taking Company-supplied firm sales service. If the Customer is unable to secure a gas supply from a Marketer, the customer will receive and be billed for Default Transportation Service as described below in Item 2.04.0.

1.08.0 Facilities:

The Company shall own, operate and maintain, at its expense, its gas distribution facilities to the Point of Delivery. The Customer shall furnish, maintain and operate the facilities required between Company's Point of Delivery and the Customer's equipment.

1.9.0 Quality:

Marketer is responsible for insuring that all gas received, transported and delivered hereunder to the Point of Receipt meets the quality specifications and standards outlined in the General Terms and Conditions of the Transporting Pipeline's FERC Gas Tariff.

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1.10.0 Possession of Gas:

Company shall be deemed to be in control and possession of transportation gas to be delivered in accordance with this service from receipt at the Point(s) of Receipt until it shall have been delivered to Customer at the Point of Delivery. Marketer shall be deemed to be in possession and control of the gas prior to such receipt by the Company and Customer shall be deemed to be in control and possession of transportation gas after such delivery by the Company to the Point of Delivery. Company shall have no responsibility with respect to such gas before it passes the Point of Receipt or after it passes such Point of Delivery or on account of anything which may be done, happen or arise with respect to such gas after Point of Delivery.

1.11.0 Provision of Future Taxes, Surcharges Fees, Etc.:

In the event a tax of any kind is imposed or removed by any government authority upon the sale or transportation of gas or upon the gross revenues derived therefrom (exclusive, however, of taxes based on Company's net income), the rate for service to Customer and/or Marketer, as the Company deems appropriate, shall be adjusted by an amount equal to or otherwise properly reflecting said tax. Similarly, the effective rate for service hereunder shall be adjusted to reflect any refund or imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental authority.

1.12.0 Retention of Pipeline Fuel Adjustment:

The Company shall retain in kind, from the quantities of gas actually delivered to the Point(s) of Receipt for Marketers' accounts, the amount thereof equal to the applicable Company Fuel Allowance. Such Company Fuel Allowance shall be calculated by the Company based upon an average of the Company's most recent five (5) years' experience, fuel loss and unaccounted for or similar quantity based adjustments.

1.13.0 Limitations of Liability:

The liability of the Company shall be limited in accordance with the provisions of the Company's General Terms and Conditions.

1.14.0 Force Majeure:

Neither Company nor Marketer shall be liable to the other or to Customer for delays or interruptions in performing their respective obligations hereunder arising from any acts, delays or failure to act on the part of, or compliance by Marketer or Company with any operating standard imposed by any governmental authority, or by reason of an act of God,

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accident or disruption, including without limit, strikes or equipment failures, or any other reason beyond Marketer’s or Company's control, provided, however, in the event of an occurrence of one or more of the foregoing events, reasonable diligence shall be used to overcome such event. The party claiming force majeure shall, on request, provide the other party with a detailed written explanation thereof, and of the remedy being undertaken.

1.15.0 Electronic Data Interchange (EDI):

The Company will require use of EDI for all transactions associated with account administration, usage and billing, and payments for the FT-2 service. The transactions requiring EDI communication are enrollments, drops, adjustments and historical usage. EDI will also be available for requesting historical usage, switching and drops for FT-1 accounts. The detail information on EDI processing is available to Marketers on request. All Marketer EDI transaction sets will be tested prior to operational implementation.

2.0 FT-1 TRANSPORTATION SERVICE:

2.01.0 Character of Service:

This service provides firm, 365 day transportation of Customer purchased gas supplies to customers electing to have Gas Usage recorded on a daily basis at the Point of Delivery. The Customer shall identify on the Transportation Service Application a Marketer that it has designated to perform initial and subsequent nominations, to receive scheduling and other notices from the Company, and to do balancing. Such Marketer shall assign Customer to an Aggregation Pool with other Customers electing FT-1 or NFT service or establish a one-customer Aggregation Pool and execute an appropriate Marketer Aggregation Pool Service Agreement. Specific Marketer requirements and obligations are described in Item 5.0 below.

2.02.0 Telemetering:

For purposes of FT-1 transportation service and NFT service, the Company will provide equipment at the Customer’s facility which will allow for daily wireless readings for the purpose of the measuring Gas Usage at the Customer’s Delivery Point. The Company will install, own, and maintain the equipment in service and the Customer shall be responsible for the initial lump sum fee as identified in Section 1, Schedule A, Item 12.0. The Company will attempt to read the meters daily unless the delay is caused by the wireless service provider. This service requires a data plan from a telecommunications provider, which will be under the Company’s name, with the Customer being responsible for the cost as identified in Section 1, Schedule A, Item 12.0. The Company will waive the initial lump sum fee if the Company requests an existing FT-1 Customer and NFT customer who are currently being served with telemetering equipment to switch to a wireless service. The Company will provide new requests for FT-1 transportation service and NFT service using

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wireless readings. At the Company's discretion in situations where wireless readings are not feasible due to technical or other logistical reason, ~~The~~ the Company will provide at the Customer's expense, at the Point of Delivery to the Customer, a device that the Company will attach to its metering equipment for the purpose of monitoring the Gas Usage. The Customer shall be responsible to supply a dedicated electrical supply and a telephone line at a location acceptable to Company and capable of transmitting information collected from the monitoring device to the Company's computer system. The Customer shall be responsible for the maintenance and service of the telephone line. Should a dedicated phone line be required, it is the responsibility of the Customer to schedule the installation, to notify Company when such installation has been completed, and the Customer is responsible for any associated charges. FT-1 and NFT transportation service shall not commence until the telemetering equipment is in place and operational.

2.03.0 Balancing:

FT-1 and NFT Service is subject to both Daily and Monthly balancing provisions. It will be the Marketer's responsibility to provide accurate and timely nominations of quantities proposed to be received and delivered by Company under this service and to maintain as nearly as possible, equality between the Gas Usage and the Actual Transportation Quantity. Marketer shall be solely responsible for securing faithful performance by Shipper and Transporting Pipeline, and the Company shall not be responsible as a result of any failure of Shipper or Transporting Pipeline to perform. Charges and Penalties associated with FT-1 and NFT balancing are billed to the Marketer.

2.03.1 Daily Imbalances:

The Marketer must maintain a balance between daily receipts and daily usage within the following tolerances:

Off-Peak Season:	The difference between the Marketer's Aggregation Pool actual receipts and the aggregated gas usage of customers in the Aggregation Pool shall be within 15% of said receipts. The Marketer shall be charged a penalty of 0.1 times the Daily Index for all differences not within the 15% tolerance.
Peak Season:	The difference between the Marketer's Aggregation Pool actual receipts and the aggregated gas usage of customers in the Aggregation Pool shall be within 10% of said receipts. The Marketer shall be charged a penalty of 0.5 times the Daily Index for all differences not within the 10% tolerance.
Critical Day(s):	The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so

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notify the Marketer when a Critical Day is declared pursuant to Item 1.05 above.

If the Marketer does not deliver gas on the transporting pipelines as required in Item 1.06.0 above, the Company may charge the Marketer a penalty of 0.5 times the Daily Index for all differences less than the forty (40) percent minimum requirement on each transporting pipeline.

If the Marketer has an accumulated imbalance within a month, the Marketer may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

2.03.2 Monthly Imbalances:

For each Aggregation Pool, the Marketer must maintain total Actual Transportation Quantities within a reasonable tolerance of total monthly Gas Usage. Any differences between total Monthly Transportation Quantities for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a percentage of total Monthly Transportation Quantities will be cashed out according to the following schedule:

Imbalance Tier	Over-deliveries	Under-deliveries
0% ≤ 5%	The average of the Daily Indices for the relevant Month relevant Month	The highest average of seven consecutive Daily Indices for the
> 5% ≤ 10%	0.85 times the above stated rate	1.15 times the above stated rate
> 10% ≤ 15%	0.60 times the above stated rate	1.4 times the above stated rate
> 15%	0.25 times the above stated rate	1.75 times the above stated rate

For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% Under-delivery on a Delivering Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven consecutive Daily Indices.

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All cash-out charges or credits, as determined above, will be applied to the Marketer's monthly invoice for the Aggregation Pool.

Designated Marketers may arrange with another of Company's Marketers providing service to the same Point of Receipt to exchange, purchase or sell daily or monthly imbalance gas. The Company will notify each Marketer of its monthly imbalance following the close of the billing month in which the imbalance occurs. Marketers will have three business days following such notification to notify Company of any imbalance exchange or sale and to confirm such transaction.

2.03.3 Pass-Through of Upstream Imbalance Charges:

In addition to other charges provided for in this Section, Marketer will be responsible for any imbalance charge or penalty imposed on Company by an upstream pipeline as a direct result of an imbalance, scheduling error, unauthorized overrun or other similar charges caused by Marketer. The Company shall assign imbalance penalties assessed to the Company by upstream pipelines to sales and transportation customers based on the extent that each group caused such penalties, as determined by the Company. The portion of any such penalty assigned to transportation service shall be further assigned to individual Marketers based on the extent to which each Marketer's Aggregation caused such penalties, as determined by the Company.

2.04.0 Default Transportation Service:

Default Transportation Service is available to any Commercial or Industrial customer account classified as Large or Extra Large that subscribes to FT-1 Transportation Service and that does not have pipeline capacity assignment from the Company. Customers will receive this service as a result of their marketer no longer delivering gas on their behalf. Such service will continue in effect until either service is established with a new marketer through the execution of a new Transportation Application per Item 1.03.1 above or service is terminated.

This service provides for a continuous supply of gas of not less than 1,000 Btu per cubic foot, and is provided on a best efforts basis with as little as 24 hours advance notice. Where notification is at least 24 hours in advance but less than three business days before the start of a calendar month, the service provided will be Short-Notice Default Transportation Service. Where notice is provided at least three business days prior to the start of a calendar month, the service provided will be Advance-Notice Default Transportation Service. Short-Notice Default Transportation Service will be switched to Advance-Notice Default Transportation Service at the start of a subsequent month once the service has been in effect for the three business day period before the start of such month.

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Default Transportation Service is a temporary surrogate for provision of gas to a customer that would otherwise be provided by a marketer, hence it includes nominating and balancing. Customer must maintain an operational telemetering device as required in Item 2.02.0 above.

2.04.1 Rates:

As indicated in Item 2.04.0 of Section 6, Schedule C of the Company's Transportation Terms and Conditions, two Default Transportation Services are available in the event that a marketer stops delivering gas on behalf of Large and Extra Large FT-1 customers who have elected to forgo the Company's assignment of pipeline capacity:

Short-Notice Service:

The commodity charge for Short-Notice service shall be the higher of:

a. The Company's applicable firm sales rate

OR

b. Winter (November – March) – 135% of the Daily Algonquin Citygates average price or 135% of the Daily Tennessee Zone 6 (delivered) average price published in Gas Daily. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

Summer (April – October) – 115% of the Daily Algonquin Citygates average price or 115% of the Daily Tennessee Zone 6 (delivered) average price published in Gas Daily. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

Advance-Notice Service:

The commodity charge for Advance-Notice service shall be the higher of:

a. The Company's applicable firm sales rate

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OR

b. Winter (November – March) – 135% of the Algonquin Citygates Monthly Contract Index price or 135% of the Tennessee Zone 6 (delivered) Monthly Contract Index price published in the Gas Daily Price Guide. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

Summer (April – October) – 115% of the Algonquin Citygates Monthly Contract Index price or 115% of the Tennessee Zone 6 (delivered) Monthly Contract Index price published in the Gas Daily Price Guide. The citygate (Algonquin or Tennessee) used for pricing shall be based on the customer's location, load characteristics and distribution system requirements in accordance with Item 1.08.1 of the Company's Transportation Terms and Conditions. The published price will be adjusted for Company Fuel Allowance and GET as appropriate.

3.0 FT-2 TRANSPORTATION SERVICE:

3.01.0 Character of Service:

This service provides firm, 365 day transportation of Customer purchased gas supplies to customers without the requirement for recording daily Gas Usage at the Customer's Point of Delivery. Daily Nominations are calculated by the Company on the basis of a consumption algorithm, and the Marketer is obligated to deliver to the city gate and/or nominate the purchase of underground storage and peaking supplies at the city gate sufficient to meet the forecasted daily usage of its FT-2 pool customers.

The Customer's designated Marketer shall be allocated a quantity of Company contracted underground storage and peaking resources which, when combined with the pipeline capacity released, will be sufficient to meet the Customer's calculated Peak Day Use. The Marketer may purchase supplies delivered to the Company's city gate based on the Company's storage and peaking supply capabilities and costs. The ability to purchase supplies is made available to the Marketer pursuant to a written agreement with the Company, for the purpose of meeting the Company forecasted daily usage under the operational parameters described below. Additional Marketer requirements and obligations are described in Item 5.0 below.

3.02.0 Storage And Peaking Resources:

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As described in Section 6, Schedule C. 1.07.0 above, the Company will annually calculate a Customer's total storage and peaking resource requirements based on the Customer's calculated Peak Day Use. It will then multiply the storage and peaking percentage applicable to the Customer's rate class times the Customer's Peak Day Use to determine the amount of capacity to be assigned to the Marketer for storage and peaking, respectively.

3.02.1 Maximum Daily Quantity (MDQ):

The result of the calculations above will establish the Customer's Maximum Daily Quantity (MDQ-P) and (MDQ-U). These parameters represent the maximum storage and peaking quantities available to the Marketer each day for meeting the Customer's Gas Usage needs.

3.02.2 Maximum Storage Quantity (MSQ):

The Customer's Maximum Underground Storage Quantity (MSQ-U) is calculated as the maximum storage quantity from underground storage over the course of the November to March withdrawal season and is calculated by the Company by multiplying the Customer's MDQ-U times the weighted average number of days of service available to the Company under its various underground storage agreements.

The Customer's Maximum Peaking Storage Quantity (MSQ-P) is calculated as the maximum amount of peaking storage over the course of the November to March withdrawal season and is calculated by multiplying the MDQ-P times the number of days that the Company's available LNG, net of amounts required for pressure support, boil-off and any heel quantities, could be used at 100% output. These quantities serve to define the maximum quantities that can be nominated for purchase by a Marketer and are a component of the operational parameters for the service.

3.02.3 Operational Parameters:

The available for the Underground Storage and Peaking accounts shall be tracked by the Company and made available to the Marketers via electronic means. These balances will be updated each Gas Day to reflect Marketer nominations for purchase.

The Company will establish monthly maximum purchase levels reflective of the Company's available resources and the Marketers Maximum Storage Quantities, MSQ-U and MSQ-P. There will be separate purchase levels for each month for both Underground Storage and Peaking Resources. Such levels will be as provided in the annual Gas Cost Recovery Filing.

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In addition to operational parameters for monthly purchase levels, there are daily maximums established for the quantities which the Marketer can nominate for purchase. These factors vary by month and as the Marketer's entitlement level changes. Such factors will be based on the Marketer's total MDQ, the Company's storage contracts and peaking supply capabilities and will be as provided in conjunction with the annual Gas Cost Recovery Filing.

3.02.4 Purchases:

The Company will update an FT-2 aggregation pool's MSQ-U, MSQ-P, MDQ-U and MDQ-P assignments in total and for each month concurrent with the Customer's initiation of transportation service with the designated Marketer.

Marketer will then be entitled to purchase from the Company the available amount of underground storage for the month on any day up to its allowed MDQ for the month until the cumulative purchases for the month equal the monthly limit. The purchases will be at a rate calculated as indicated below. The estimated rate will be provided to the marketers by the second business day of the month in which the purchase is being made.

The Company shall develop a price for the purchases based on the Company's underground storage inventory price at the beginning of the month and for the variable costs associated with the withdrawal of the gas from storage and the transportation of the gas to the system.

The price per Dt at the Company's city gate shall be calculated using the following formula:

$\$/Dt = (((IP \div (1-SLF) + WWCC) \div (1-PLF)) + PCC)$

Where:

$/Dt	cost per Dekatherm charged to Marketers for underground storage inventory at the Company's city gate
IP	Underground Storage Inventory Price at Beginning of the month
SLF	Weighted Average Loss Factor on Storage Withdrawals
WWCC	Weighted Average Withdrawal Commodity Charges
PLF	Weighted Average Pipeline Loss Factor

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PCC Weighted Average Pipeline Commodity Charge.

The rate components SLF, WWCC, PLF and PCC are as calculated in the Company's most recent Gas Cost Recovery Filing.

Marketers will be entitled to purchase peaking inventory at the Company's cost of LNG inventory and Weighted Average commodity charge of pipeline supplies designated by Company as peaking resource.

3.02.5 Demand Rates:

The FT-2 Demand Rate is designed to recover the fixed costs and other miscellaneous costs associated with the provision of the underground storage and peaking resources and is billed to the Marketer:

$/DT cost per Dekatherm charged to Marketers per unit of MDQ where MDQ = MDQ-U plus MDQ-P.

The FT-2 demand rate is as calculated in the Company's most recent Gas Cost Recovery Filing. The calculation is in Section 2, Gas Charge, Schedule A, Item 3.3.

3.03.0 Nominations:

The Company shall calculate the Forecasted Daily Usage (FDU) of the aggregation pool using a Consumption Algorithm for each of the customers in the aggregation pool. The Company shall have sole responsibility for such Consumption Algorithm and by selecting FT-2 service, Marketer agrees to abide by the results of such algorithm. The algorithm is:

FDU = Base Load + (HU factor x FDD)

Where:

FDU an individual customer account's forecasted daily usage for the next gas day

Base Load average daily consumption for the most recent July and August billing cycles

HU Factor most recent billing cycle consumption, minus the base load, divided by the heating degree days for the billing cycle

FDD forecasted heating degree days for the gas day starting at 10:00 AM the next day

FDU will be adjusted for any Company fuel allowance.

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The Company will provide to the Marketer no later than 9:30 AM each day using an electronic posting or via facsimile the FDU for the next gas day which would start at 10:00 AM the next day. If the Company is unable to provide to the Marketer the FDU using an electronic posting or via facsimile before 9:30 AM, the default FDU will be the prior day's FDU. The Marketer shall be obligated to nominate any combination of pipeline, underground storage or peaking equal to the FDU for the next gas day. Such nomination is to be posted on the Company's Electronic Bulletin Board in the timely cycle before the start of the next gas day. The Company shall not accept or confirm any nominations that are greater than the FDU of the aggregation pool and any nominations for storage and peaking resources must be in accordance with the applicable operational parameters. When the Marketer's cumulative storage or peaking use for the month reaches the Marketer's maximum storage or peaking use for the month, the Marketer will not be able to nominate storage or peaking quantities to satisfy the FDU nomination requirement.

3.03.1 Critical Days:

To satisfy the FDU nomination requirement on Critical Days, the Marketer is required to fully utilize upstream capacity that it received from Company through Capacity Release so as to help avoid restricting the Company's ability to provide efficient and reliable firm transportation and sales service. Notice of Critical Days will be posted on the EBB no later than concurrent with the posting of the FDU nomination requirement.

3.03.2 Over- and Under-deliveries:

If the Company declares an OFO or critical day condition reducing the tolerance for under-deliveries, any under-deliveries of the aggregation pool's gas requirements, up to the FDU, will be treated as Unauthorized Use and subject to penalty charges as provided in Item 1.05.0 above. Under-deliveries at times when an OFO or critical day have not been declared will be cashed out at 120% of daily index.

If the Company declares an OFO or critical day condition reducing the tolerance for over-deliveries, any over-deliveries of the aggregation pool's gas requirements, above the FDU, will be cashed out at 40% of the daily index. In addition, the Company reserves the right to reject such a nomination. Over-deliveries at other times will be cashed out at 80% of Daily Index.

3.03.3 FDU Weather True-up Cash Out:

Each month, the forecasted daily use (FDU) for each day will be recalculated and the change in consumption attributable to differences between the original forecasted

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degree days and actual degree days will be calculated. Each day's change in consumption will be cashed out at that day's published Daily Index.

3.04.0 Billing Imbalances:

Imbalances between customer Gas Usage and the Forecasted Daily Usage (FDU), adjusted for actual weather, will be cashed out at the average of the Algonquin and Tennessee city gate delivered monthly indexes. The Company will prorate the imbalance amount between the months billed based on the customer's base load and heating use factors and apply the average monthly index to the corresponding month's imbalance quantity, calculated as follows:

MU = (Base Load x Number of billed days in month) + (HU Factor x ADDM)

Where:

MU	Usage attributable to that individual month
Base Load	average daily consumption for the most recent July and August billing cycles
HU Factor	most recent billing cycle consumption, minus the base load, divided by the heating degree days for the billing cycle
ADDM	actual degree days for the billing period

The imbalance amount will be a credit if deliveries exceed the customer's use and a debit if deliveries are less than the customer's use. The billed imbalance amount for any billing will be the sum of the imbalance charges or credits attributable to each individual month included in the bill. The charges or credits for the individual months will be calculated as follows:

IBM = (MU – FDUM) x (AGTI + TGPI) ÷ 2

Where:

IBM	Individual Billing Month charge/credit
AGTI	Algonquin Pipeline published price Index for the month
TGPI	Tennessee Pipeline published price Index for the month

All quantities will be adjusted for Company Fuel Allowance.

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4.0 NFT SERVICE:

4.01.0 Character Of Service:

This service provides interruptible transportation of Customer purchased gas supplies to customers with telemetering equipment and that are eligible to be classified under Section 6, Schedule A of the Company's Tariff. The Customer shall identify on the Transportation Service Application a Marketer that it has designated to perform initial and subsequent nominations, to receive scheduling and other notices from the Company, and to do balancing. Such Marketer may assign Customer to an Aggregation Pool with other Customers electing NFT or FT-1 transportation service or establish a one-customer Aggregation Pool. Specific Marketer requirements and obligations are described in Item 5.0 below. A Customer receiving NFT service does not have pipeline capacity assignment from the Company.

4.02.0 Nominations:

The nomination requirements in Item 1.04.0 above apply to the provision of NFT Service.

4.03.0 Imbalances:

The Daily and Monthly Imbalance provisions in Items 2.03 above apply equally here.

4.04.0 Curtailments:

The notification of interruption or curtailment and the provisions of failure to curtail are described in Section 6, Schedule A, Item 8.0 and Item 9.0.

5.00 MARKETER AGGREGATION SERVICE:

5.01.0 Character of Service:

This service allows Marketers to aggregate customer accounts and form Aggregation Pools for the purpose of making initial and subsequent nominations, making delivery to a designated Point of Receipt, and for balancing of Actual Transportation Quantity with Gas Usage on Customer's behalf. The Company will transport gas, owned by the Customers of the Aggregation Pool, to the Point(s) of Delivery for each Customer included in such pool. A Marketer shall be designated by each Customer on the Transportation Service Application, and each such customer must be assigned by the Marketer to an Aggregation Pool of one or more customers. Changing the designated Marketer is allowed under the conditions in Item 1.02 above and is accomplished through the execution of a new Transportation Service Application. Once so designated, the Company will rely on information provided by the Customer's Marketer for nomination, balancing and scheduling

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purposes and all notices provided by the Company to Customer's Marketer shall be deemed to have been provided to the Customer.

5.02.0 Aggregation Pools:

The aggregation of Customer accounts into an aggregation pool is limited by the transportation service of the respective Customers.

The Customer's transportation service restriction requires that Customers subscribing to non-daily metered FT-2 Service must be aggregated in a separate pool from Customers subscribing to daily metered FT-1 or NFT Service. Customers subscribing to FT-1 or NFT can be combined in a single Aggregation Pool. A separate Marketer Account will be established for each Marketer Aggregation Pool.

The Marketer Aggregation Pool Service Agreement have an initial term through the following November 1. Thereafter, the Pool Service Agreement shall be automatically renewed for successive one year terms, unless notice of termination is provided by the Marketer on or before October 1 or if the Company has terminated the agreement under its collection procedures. Marketers may assign their Aggregation Pool Service Agreements to another certified Marketer with the Company's consent.

5.03.0 Marketer Qualifications:

In order to be designated hereunder as a Marketer, the Marketer must meet the following qualifications:

(1) The Marketer must be authorized by the PUC in accordance with PUC Regulations for Utility Interaction with Gas Marketers;
(2) The Marketer must demonstrate to the Company that it meets the following creditworthiness standards:

A. The Marketer, or a guarantor, maintains a minimum rating from one of the rating agencies and no rating below the minimum from one of the other two rating agencies. For the purposes of this Section, minimum rating shall mean "BBB" from Standard & Poor's, "Baa2" from Moody's Investor Service, or "BBB" from Fitch Ratings (minimum rating)

B. If a Marketer or a guarantor, is not rated by Standard & Poor's, Moody's Investor Service or Fitch Ratings, it shall satisfy the Company's creditworthiness requirements if the Marketer, or a guarantor maintains a minimum "1A2" rating from Dun & Bradstreet (Dun and Bradstreet minimum rating) and the Marketer maintains 24 months good payment history with the Company

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C. In the event that the Marketer has not met the credit standards above, then the Marketer must so notify the Company and the Marketer will be required to use one of the financial vehicles specified in 5.03.3 to satisfy the Company's credit standards.

(3) Marketers must have an executed Marketer Aggregation Pool Service Agreement with the Company and accepted its designation as the marketer for each customer by countersigning the applicable Transportation Service Application.

(4) Marketers must provide the Company with a copy of their GET exemption certificate, state sales tax exemption certificate or other appropriate exemption certificate(s) in order to be exempt from the applicable taxes.

5.03.1 Marketer Disqualification:

A Marketer may be disqualified from participating in the transportation program for any of the following conditions:

(1) Failure to continue to meet all the conditions set forth in Section 5.03.0 with respect to authorization by the PUC and the credit standards set out in 5.03.0, and abide by the terms and conditions of the Marketer Aggregation Pool Service Agreement set forth in Section 6.0.

(2) Failure to pay an invoice from the Company on the due date or maintain sufficient credit. If Marketer fails to pay an invoice on the due date or the Marketer's credit limit or security is insufficient to cover the unpaid amount, the Company may discontinue participation in the customer transportation program; provided however, that at the Marketer's request, the Company will allow up to 10 business days for the Marketer to cure any failure to pay or any shortfall provided such action, as determined solely by the Company, will not result in harm to its customers or the gas system.

(3) If a Marketer, through its actions, causes a significant risk or condition that compromises safety, system security or operational reliability and fails to eliminate that risk or condition when notified, the Company may immediately discontinue the Marketer's participation in the customer transportation program.

(4) If the Marketer fails to provide supply at a level that reasonably matches its customers' daily requirements for its daily balanced pool or, when directed by the Company to deliver a certain quantity under the FT-2 service it fails to deliver the required amount, the Company may discontinue the Marketer's participation in the customer transportation program.

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5.03.2 Calculation of Credit Risk and Security for Natural Gas Imbalance Risk:

The Company may require a Marketer to provide security equal to three times the highest month's gas usage of the Marketer's Aggregation Pool at the firm sales rate applicable to the upcoming peak period. This amount may be updated at the Company's discretion

5.03.3 Security Instruments:

The following financial arrangements are acceptable methods of providing security:

(1) Deposit or prepayment, which shall accumulate interest at the applicable rate per annum approved by the Rhode Island Public Utilities Commission;
(2) Standby irrevocable letter of credit or surety bond issued by a bank, insurance company or other financial institution with at least an "A" bond rating;
(3) Security interest in collateral; or,
(4) Guarantee by another party or entity with a credit rating of at least "BBB" by S&P, "Baa2" by Moody's, or "BBB" by Fitch; or
(5) Other means of providing or establishing adequate security.

The Company may refuse to accept any of these methods for just cause provided that its policy is applied in a nondiscriminatory manner to any Marketer.

If the credit rating of a bank, insurance company, or other financial institution that issues a letter of credit or surety bond to a Marketer falls below an "A" rating, the Company shall allow a minimum of five business days for a Marketer to obtain a substitute letter of credit or surety bond from an "A" rated bank, insurance company, or other financial institution.
The Marketer agrees that the Company has the right to access and apply the deposit, letter of credit or other financial vehicle to any payment obligations, not in dispute, which are deemed by the Company to be late. The Company may review and determine the status of a Marketer's creditworthiness at its sole discretion. If Marketer is unable to maintain the Company's credit approval or otherwise ceases to meet the Marketer Qualifications, the Company may terminate the Marketer Aggregation Pool Agreement as of the first day of the month following written notice to Marketer.

5.04 Intentionally Left Blank

5.05 Billing:

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Billing for monthly customer charges and transportation charges for quantities actually delivered shall be based on the readings at each individual meter for the Customer and billed on a billing cycle basis to the Customer. The Customers and Marketers shall be liable for all rates, charges and surcharges allowed for in the Company's Rate Schedules related to transportation services provided to each customer individually.

Calculation of charges applicable to the Aggregation Pool will be based on aggregated Gas Usage, MDQ's, etc. of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, e.g., imbalance charges, credits or penalties, and FT-2 Throughput charges shall be billed to the Marketer on a calendar month basis.

All bills rendered to the Marketer are due within ten (10) days from the date of the invoice. A late payment charge, in accordance with regulations of the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers, shall accrue after ten (10) days.

6.0 SERVICE AGREEMENTS: (See Attached Sheets)

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The Narragansett Electric Company, Transportation Service Application

This Transportation Service Application ("Application") must be completed by the customer and the marketer prior to the commencement of the requested Transportation Service.

NG:	The Narragansett Electric Company d/b/a National Grid 175 East Old Country Road Hicksville, NY 11801 Attn: Supplier Services	Customer:	____ ____ ____ ( )
Notice to:	Customer Contact Center: 1-800-870-1664	Notice to:	____ ( )

The Customer hereby requests Transportation Service subject to the NG General Terms and Conditions, Section 1 of RIPUC NG-GAS No. 101, its Transportation Terms and Conditions, Section 6, Schedule C and, under the terms and conditions set forth herein. NG shall review this Application and notify the Customer of its approval or rejection by way of a Confirmation Letter that shall set forth the terms and conditions of the Customer's Transportation Service. Upon Customer's and Marketer's fulfillment of all conditions set forth in the Confirmation Letter, such Confirmation shall represent an Agreement by NG to provide Transportation Service consistent with this Application and the Transportation Terms and Conditions set forth in Section 6, Schedule C of RIPUC NG-GAS No. 101.

Account Number	Meter Number	Service Address	FT-1	NFT
1)				
2)				
3)				

1. Transportation Service shall commence in accordance with Item 1.02, Section 6, Schedule C of RIPUC NG-GAS No. 101
2. FT-1 and NFT Services require telemetry. A telemetering device and related equipment installed by NG shall remain NG property at all times. The Customer shall provide NG with access to a phone line that meets NG specifications for telemetering purposes. The customer is financially obligated for the costs to acquire, install and operate the telemetering device and related equipment.
3. Provision of transportation service based on this Application shall have an initial term through the following November 1st, unless sooner terminated in accordance with the terms and conditions of NG's Tariff, and shall continue thereafter from year to year unless terminated by customer, Marketer, or NG upon not less than 30 days prior written notice.

Public Regulation

The Narragansett Electric Company is a public utility subject to regulation by the Rhode Island Public Utilities Commission ("Commission"). The provision of transportation service as a result of this Application is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to this Application. Compliance by NG with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the commencement of transportation service, shall relieve NG of its obligations hereunder as a result of such compliance. In the event of the issuance of any order of the Commission which materially modifies the provisions of such service, either NG, the customer, or the Marketer shall have the option to terminate transportation service by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

Customer Signature ____ Title ____

Print or Type Name ____ Date ____ Phone # ____

Contact in event of telecommunications issue : Print or Type Name ____ Phone # ____

This section to be filled out by the Marketer

By signing below and pursuant to its separate Marketer Aggregation Pool Service Agreement, the Marketer (i) accepts the designation as the customer's marketer and (ii) agrees to pay all applicable Marketer charges in accordance with NG's tariff, including its Transportation Terms and Conditions

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Marketer	Marketer Signature	Title
Phone #	Print or Type Name	Date

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THE NARRAGANSETT ELECTRIC COMPANY
MARKETER AGGREGATION POOL SERVICE AGREEMENT

This Agreement ("Agreement") is entered into this _______ day of ____________, 20__, by and between The Narragansett Electric Company, d/b/a National Grid, a subsidiary of National Grid USA with a principal place of business in the State of Rhode Island at 280 Melrose Street, Providence, Rhode Island (herein called "NG" or the "Company") and ____ (herein called "Marketer.")

WITNESSETH THAT:

WHEREAS, the Company's tariff, RIPUC NG-GAS No. 101, Section 6, Schedule C, provides for and establishes terms and conditions for a Marketer Aggregation Pool; and

WHEREAS; Marketer desires to establish an Aggregation Pool and desires Company to provide pool aggregation services pursuant to such Schedule C and to transport quantities of gas delivered by Marketer for use at the locations of customers belonging to the Aggregation Pool (hereafter called "Points of Delivery"); and

WHEREAS: Company, is willing to provide such service to Marketer.

NOW, THEREFORE, Company and Marketer agree that Company, subject to the Company's General Terms and Conditions, Transportation Terms and Conditions, limitations and provisions hereof, commencing __________________ 1, 20__, will transport and deliver to customers of Marketer's Aggregation Pool such quantities of Marketer's gas delivered by Transporting Pipeline to Company's distribution facilities (hereafter called "Point of Receipt").

1.0 AGGREGATION POOL:

1.1 Marketer is establishing a single Aggregation Pool as indicated by an X:

Daily Metered _____
Non-daily Metered _____

1.2 Marketer hereby subscribes to Company's Marketer Aggregation Service pursuant to Item 5.00 of the Company's Transportation Terms and Conditions, Section 6, Schedule C.

1.3 Marketer represents and warrants that Marketer has met and will continue to meet the Marketer qualifications in Item 5.03 of Company's Transportation Terms and Conditions, Section 6, Schedule C.

1.4 Marketer agrees to provide to Company no later than 30 days before the above identified commencement date Transportation Service Applications for all end user customers in Marketer's

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Aggregation Pool identified in 1.1 above. Such list is to include: Customer Name; Billing Address; NG account #; and, name and telephone number of customer contact person.

1.5 Marketer agrees to notify Company in writing of any changes in the makeup of an Aggregation Pool as provided in the Company's Transportation Terms and Conditions.

1.6 Marketer represents and warrants that it has accepted the designation as the Marketer of each customer of the Aggregation Pool and agrees in each case to be bound by, perform, and pay all charges applicable to transportation service to the Customer's account in accordance with the provisions of the Company's tariff.

2.0 PIPELINE CAPACITY RELEASE:

2.1 Company agrees to provide to Marketer no later than 15 days before the above identified commencement date, the quantity of interstate pipeline capacity allocated for Marketer's FT-1 and FT-2 Aggregation Pool(s) broken down by individual customer.

2.2 Marketer agrees to accept assignment of such firm interstate pipeline capacity in accordance with the Company's Transportation Terms and Conditions, Schedule C, Item 1.07.

2.3 Company agrees to update the calculation of the quantity of interstate pipeline capacity annually based on customers' most recent historical usage in accordance with the Company's Transportation Terms and Conditions, Schedule C, Item 1.07.

3.0 PUBLIC REGULATION:

3.1 Company is a public utility subject to regulation by Rhode Island Public Utilities Commission ("Commission"). This Agreement is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to the Agreement. Compliance by Company with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the effective date of this Agreement, shall relieve Company of any liability for its failure to perform any of its obligations hereunder as a result of such compliance. In the event of the issuance of any order of the Commission which materially modifies the provisions of this Agreement, either Company or Marketer shall have the option to terminate this Agreement by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

3.2 This Agreement shall be subject to Company's General Terms and Conditions and Transportation Terms and Conditions on file with the Commission to the extent those Terms and Conditions are not inconsistent with the provisions of this Agreement.

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4.0 GOVERNING LAW:

This Agreement is entered into and shall be construed in accordance with the laws of the State of Rhode Island and any actions hereunder shall be brought in the appropriate forum within the State of Rhode Island.

IN WITNESS WHEREOF, the parties hereto have signed and sealed this Agreement by their duly authorized officers:

By ____________________________

Signature: ____________________________

Name: ____________________________

Title: ____________________________

Date: ____________________________

____
Witness

By The Narragansett Electric Company

Signature: ____________________________

Name: ____________________________

Title: ____________________________

Date: ____________________________

____
Witness

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THE NARRAGANSETT ELECTRIC COMPANY
STORAGE AND PEAKING RESOURCE AGREEMENT

This Agreement ("Agreement") is entered into this _______ day of ____________, 20__, by and between the Narragansett Electric Company, d/b/a National Grid, a subsidiary of National Grid USA with a principal place of business in the State of Rhode Island at 280 Melrose Street, Providence, Rhode Island (herein called "NG" or the "Company") and ____ (herein called "Marketer.")

WITNESSETH THAT:

WHEREAS, Marketer seeks to obtain service respecting a quantity of the Company's contracted underground storage and peaking resources pursuant to the terms and conditions for FT-2 Transportation Service in the Company's tariff, RIPUC NG-GAS No. 101, Section 6, Schedule C; and

WHEREAS; Marketer desires that the Company transport quantities of gas delivered by Marketer for use at the locations of customers belonging to an FT-2 Aggregation Pool (hereafter called "Points of Delivery"); and

WHEREAS: Company, is willing to provide such storage and transportation service to Marketer.

NOW, THEREFORE, Company and Marketer agree that Company, subject to the Company's General Terms and Conditions, Transportation Terms and Conditions, limitations and provisions hereof, commencing __________________ 1, 20__, will provide to Marketer storage and peaking services in association with Marketer account number ______________ under the terms and conditions set forth below.

1.0 SCOPE OF AGREEMENT:

1.1 The Company will calculate the Maximum Storage Quantities for both Underground Storage and for Peaking services ("MSQ-U" and "MSQ-P" respectively) as well as the Maximum Daily Quantities for both Underground Storage and Peaking services ("MDQ-U" and "MDQ-P" respectively) in accordance with Item 3.02 in Section 6, Schedule C of the Company's tariff. Such calculated quantities can change during the term of the agreement to the extent that the makeup of the Marketer's FT-2 Aggregation Pool changes.

1.2 Marketer hereby agrees to utilize and manage such services and inventories attributed to its account in accordance with the Operational Parameters described in Item 3.02.3 of the Company's Transportation Terms and Conditions, Section 6, Schedule C and as on file with the Public Utilities Commission as part of the Company's annual Gas Cost Recovery filing.

TRANSPORTATION TERMS AND CONDITIONS

2.0 INVENTORY SERVICES:

2.1 All nominations for purchases from storage will take place at the Company's city gate.

2.2 Purchases of inventory service from the Company will be as stated in the Company's currently effective tariff.

2.3 Purchase of any storage inventory service from the Company will require payment via electronic transfer of funds within ten days of the invoice date.

2.4 Marketer acknowledges that it shall bear no ownership interest in any other storage or peaking assets or inventory of the Company.

3.0 SUCCESSORS AND ASSIGNS:

3.1 This Agreement shall be binding on the parties hereto and their respective successors and assigns. This Agreement may not be assigned by Marketer without the prior written consent of the Company.

4.0 PUBLIC REGULATION:

4.1 Company is a public utility subject to regulation by Rhode Island Public Utilities Commission ("Commission"). This Agreement is subject to any limitations, modifications or amendments ordered by the Commission, regardless of whether said order resulted from a petition, request or other solicitation directed to the Commission by a party to the Agreement. Compliance by Company with any order, rule, regulation or policy statement of the Commission, or of any other federal, state or local governmental authority, whether issued before or after the effective date of this Agreement, shall relieve Company of any liability for its failure to perform any of its obligations hereunder as a result of such compliance. In the event of the issuance of any order of the Commission which materially modifies the provisions of this Agreement, either Company or Marketer shall have the option to terminate this Agreement by giving written notice of termination to the other party at any time within thirty (30) days after the issuance of said order.

4.2 This Agreement shall be subject to Company's General Terms and Conditions and Transportation Terms and Conditions on file with the Commission, including provision thereof limiting the Company's liability, to the extent those Terms and Conditions are not inconsistent with the provisions of this Agreement. Upon request of the Marketer, Company shall provide the Marketer with a copy of Company's complete filed Tariff and Terms and Conditions.

5.0 GOVERNING LAW:

This Agreement is entered into and shall be construed in accordance with the laws of the State of Rhode Island and any actions hereunder shall be brought in the appropriate forum within the State of Rhode Island.

TRANSPORTATION TERMS AND CONDITIONS

IN WITNESS WHEREOF, the parties hereto have signed and sealed this Agreement by their duly authorized officers:

By ____________________________

Signature: ____________________________

Name: ____________________________

Title: ____________________________

Witness ______________________ Date: ____________________________

By The Narragansett Electric Company

Signature: ____________________________

Name: ____________________________

Title: ____________________________

Witness ________________________ Date: ____________________________

~~NATURAL GAS VEHICLE SERVICE~~
~~RATE 70~~

~~This service has been eliminated as of May 7, 2012 in pursuant of Docket 4271 that was approved by the PUC.~~

GAS LAMPS
RATE 80

1.0 AVAILABILITY:

This service is available for gas lamps, without meters, to customers of record on July 1, 2002 throughout the Company's service territory and is not available to new commercial accounts.

2.0 CHARACTER OF SERVICE:

A continuous supply of gas of not less than 1,000 Btu per cubic foot.

3.0 RATES: On a monthly basis: $9.52 per lamp

4.0 GENERAL RULES AND REGULATIONS:

The Company's General Rules and Regulations, in Section 1 of RIPUC NG-GAS No. 101, as in effect from time to time and where not inconsistent with any specific provisions hereof, are a part of this Schedule.

5.0 RHODE ISLAND GROSS EARNINGS TAX:

The application of the above rates is subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

6.0 LIHEAP ENHANCEMENT:

The application of the above rate is subject to the Low Income Home Energy Assistance Enhancement Plan (LIHEAP) provisions in Section 7, Schedule C.

OTHER MISCELLANEOUS CHARGES

~~OPTIONAL CREDIT CARD PAYMENT PROVISION~~

~~OPTIONAL CREDIT CARD PAYMENT PROVISION~~

~~**1.0 AVAILABILITY:**~~

~~Customers of National Grid (National Grid or Company) have the option of paying their bills issued by National Grid through the use of a payment-processing agent (Third Party Vendor). Residential and non-residential customers, as determined by the Company's rate schedule designations, have the option to make payments by telephone or web page. The availability of this option will be subject to the Company's ability to arrange for such an option. This payment option is available to all of the Company's customers choosing to make payments to the Company through use of the Third Party Vendor-sponsored telephone or web page system. If there is a conflict between the PUC's Rules Governing the Acceptance of Credit Card Payments (the Rules) and this provision, the Rules shall govern.~~

~~**2.0 PAYMENT TYPES:**~~

~~The following payment methods shall be accepted under this provision:~~

1. ~~Visa;~~
2. ~~Mastercard;~~
3. ~~American Express;~~
4. ~~Discover;~~
5. ~~Debit Cards issued by a financial institution which include a card association symbol such as Visa or MasterCard; and~~
6. ~~Electronic Checks~~

~~**3.0 FEES:**~~

~~Customers choosing to make payments under this option will be assessed a fee directly by the Third Party Vendor for each payment the customer initiates. The fee to be charged by the Third Party Vendor, as identified in Section 1, Schedule A, Sheet 12, is based on whether the customer making the payment is a residential customer or a non-residential customer and the number of payment transactions made. The customer must initiate each payment transaction. Initiating one payment transaction does not establish future payment transactions for a customer.~~

~~**4.0 PAYMENT AMOUNT:**~~

~~Customers who choose to make payments under this provision shall have the ability to make partial payments. Additionally, the Company shall not deny a customer's use of these payment options because the customer's account with the Company is past due.~~

OTHER MISCELLANEOUS CHARGES

OPTIONAL CREDIT CARD PAYMENT PROVISION

~~**5.0 COMPANY OBLIGATION:**~~

~~The payment transaction shall occur between the customer and the Third Party Vendor. The Company shall provide information regarding the Third Party Vendor's payment systems to assist its customers who choose to make payments by telephone or web page. The Company shall assist its customers in the resolution of any disputes between customers and the Third Party Vendor involving the credits posted by the Company to customers' accounts as a result of the processing of customer payments under this provision. The Company has no obligation, however, to participate in any dispute involving matters strictly between the customer and the Third Party Vendor or the customer's bank or card issuer.~~

~~**6.0 TERMS & CONDITIONS:**~~

~~The Company's Terms & Conditions, as may be amended from time to time, where not inconsistent with any specific provisions hereof, are a part of this provision.~~

OTHER MISCELLANEOUS CHARGES

LOW INCOME HOME ENERGY ASSISTANCE PROGRAM ~~ENHANCEMENT~~ PLAN ENHANCEMENT CHARGE

7.0 LOW INCOME HOME ENERGY ASSISTANCE ~~ENHANCEMENT~~ PLAN (LIHEAP) ENHANCEMENT CHARGE:

In accordance with R.I.G.L. § 39-1-27.12, the Company shall bill monthly to all customers a Low Income Home Energy Assistance ~~Enhancement~~ Plan enhancement charge ("LIHEAP Charge") approved by the PUC, provided however that the annual charge shall not exceed $10 per customer, per year. For purposes of this section a "customer" is defined as any person taking service at a single point of gas delivery or gas meter.

The monthly rate for the LIHEAP Charge is $0.81 per customer and shall appear as a separate line item on a customer's bill.

7.1 LIHEAP Enhancement Fund:

The Company shall establish a LIHEAP Enhancement ~~Plan~~ fund that shall be used to account for the combined funds collected through the LIHEAP Charge from both gas and electric service customers. The Rhode Island Department of Human Services ("DHS") shall designate to the Company the qualifying customer accounts and the amounts to be credited from the LIHEAP Enhancement ~~Plan~~ fund. The cumulative amount of credits applied to customer bills will be limited to an amount no greater than the cumulative aggregate projected LIHEAP Charges billed through the end of the current calendar year. Once the aggregate credits applied to customer bills equals the aggregate projected LIHEAP Charges billed through the end of the current calendar year, including interest as defined below, the application of the LIHEAP Enhancement ~~Plan~~ credits would cease. Any difference in aggregate cumulative actual LIHEAP Charges billed and aggregate cumulative credits applied to customer bills, will accrue interest at the customer deposit interest rate.

The projected annual revenue in the LIHEAP Enhancement ~~Plan~~ fund ~~collected~~ billed through the gas and electric service LIHEAP ~~Enhancement Plan charges~~ Charges shall not exceed seven million five hundred thousand dollars ($7,500,000) and shall not be less than six million five hundred thousand dollars ($6,500,000).

Beginning on September 1, 2016 and monthly thereafter between April 15 and September 30 of each year, the Company will set aside a minimum of 5 percent of the funds ~~collected~~ billed through the LIHEAP ~~Enhancement Plan~~Charge, to be allocated to provide assistance to customers seeking LIHEAP certification for the sole purpose of entering into the Arrearage Management Program ("AMP") as described in R.I.G.L. § 39-2-1(d)(2). This fund is designated for homeless families or individuals who are transitioning from a shelter into

OTHER MISCELLANEOUS CHARGES

LOW INCOME HOME ENERGY ASSISTANCE PROGRAM ~~ENHANCEMENT~~ PLAN ENHANCEMENT CHARGE

housing who provide acceptable documentation to DHS. Remaining funds available after September 30 of each year will be eligible for use in the upcoming winter season.

7.2 LIHEAP Eligible Customer:

For purposes of receiving funds from the LIHEAP Enhancement fund in subpart 7.1 above, a qualifying LIHEAP eligible customer shall be a household with a combined gross income equal to or less than 60 percent of the state median household income as calculated by the U.S. Bureau of Census and as adjusted for family or group size by the U.S. Department of Health and Human Services regulation 45 CFR § 96.85 or its successor regulation.

OTHER MISCELLANEOUS CHARGES

RESIDENTIAL ASSISTANCE PROVISION

The DAC contained in all of the Company's firm rate classes except for the Low Income Rates 11 and 13 shall include a Low Income Discount Recovery Factor ("LIDRF") to recover the cost of bill discounts provided to customers receiving service on Rates 11 and 13. In addition, the DAC contained in all of the Company's firm rate classes shall include an Arrearage Management Adjustment Factor ("AMAF") to recover the cost associated with the operation of the Arrearage Management Program ("AMP").

LOW INCOME BILL DISCOUNTS

On an annual basis, the Company shall estimate the discount to be provided to Rates11 and 13 customers. The estimated discount will be twenty-five (25) percent of the forecasted Rates 11 and 13 annual billing units multiplied by the Rates 11 and 13 customer charge and the sum of the Base Distribution Charges, the Distribution Adjustment Charges, the Energy Efficiency Charges, and the Gas Charges in effect during the period. For those customers who are receiving benefits through Medicaid, General Public Assistance, and/or the Family Independence Program, the estimated discount will be an additional five (5) percent for a total discount of thirty (30) percent of the forecasted Rates 11 and 13 annual billing units multiplied by the Rates 11 and 13 customer charge and the sum of the Base Distribution Charges, the Distribution Adjustment Charges, the Energy Efficiency Charges, and the Gas Charges in effect during the period. This estimate of the discount shall be used to determine the amount to be reflected in the Distribution Adjustment Charge on prospective basis. The amount shall be divided by the estimated therms to be delivered by the Company to all customers excluding customers on Rates 11 and 13. Such per therm charge is referred to as the LIDRF.

The revenue billed through the LIDRF shall be subject to reconciliation against the actual bill discounts provided during the twelve month reconciliation period for which the LIDRF is in effect, and any over- or under-recovery of the actual discount provided shall be reflected in the Reconciliation Factor.

For purposed of the above reconciliation, the Company shall accumulate the actual discounts provided to Rates 11 and 13 customers and the revenue billed through the LIDRF and shall accrue interest on the difference between these amounts at the interest rate paid on customer deposits on a monthly basis.

Should any balance remain subsequent to the recovery of the over- or under-recovery balance as described above, the Company shall reflect, as an adjustment in the then-current reconciliation period, the amount of the remaining balance.

OTHER MISCELLANEOUS CHARGES

ARREARAGE MANAGEMENT PROGRAM PROVISION

8.0 ARREARAGE MANAGEMENT PROGRAM:

In accordance with R.I.G.L. § 39-2-1(d)(2), commencing on September 1, 2016, the Company shall implement an ~~Arrearage Management Program ("~~AMP~~")~~ pursuant to this tariff provision.

I. PROGRAM ELIGIBILITY

In order to be considered eligible for enrollment in the AMP, a customer who has been terminated from gas service or is recognized, pursuant to a rule or decision by the Division ~~of Public Utilities and Carriers~~, as being scheduled for actual shut-off of service on a specific date, shall meet all of the following criteria:

- The applicant must be the customer of record, although the customer of record may authorize someone else to communicate with the Company to help enroll the customer of record in the AMP;
- The applicant must be eligible for the federal low-income home energy assistance program ("LIHEAP");
- The account must be receiving retail delivery service on the Company's Residential Low-Income Rates 11 and 13;
- The customer's account must have a minimum balance of $300.00 that is more than 60 days past due;
- If service to the account has been terminated, the customer must make an initial payment of 25% of the total unpaid balance (current and past due), unless otherwise directed by the ~~Public Utilities Commission ("~~PUC ~~")~~ as a result of an emergency regulation;
- The customer must agree to a payment plan, as further described in Section III;
- The customer must agree to remain current with payments. "Remaining current" means that the customer:
  1) misses no more than two (2) payments in the 12-month term of the payment plan; and
  2) pays the amount due under the payment plan in full by the conclusion of the payment plan's 12-month term;
- The customer must agree to participate in the Company's Energy Efficiency programs; and
- The customer must apply for other available energy assistance programs, such as fuel assistance and weatherization

OTHER MISCELLANEOUS CHARGES

ARREARAGE MANAGEMENT ADJUSTMENT PROVISION

II. ENROLLMENT

To participate, the customer must affirmatively apply to participate in the AMP.

The Company shall administer the AMP enrollment process in compliance with the eligibility qualifications outlined in Section I. By applying to participate in the AMP, the customer agrees to comply with the terms of the AMP, including the customer's specific payment plan. After a customer has applied to the AMP, the Company shall determine whether the customer has met all of the AMP eligibility criteria set forth in Section I, based on the Company's records. The Company will coordinate with the Community Action Program ("CAP") agencies to validate customer eligibility when appropriate.

III. PAYMENT PLAN

AMP participants shall enroll in a 12-month payment plan, paid in equal monthly installments, ~~that~~which will cover new charges based upon their current estimated annual usage ("Payment Plan").

The current component of the Payment Plan shall be based on the customer's average monthly usage for the previous year less the customer's actual or anticipated fuel assistance commitments, and shall be converted to a fixed monthly payment.

IV. ARREARS FORGIVENESS

AMP participants will be eligible for forgiveness of their account balance that is past due at the time of the first bill under their Payment Plan, up to an annual maximum of $1,500. With each payment under the Payment Plan, a portion of the participant's outstanding past due account balance as described above is forgiven in an amount equal to the total past due account balance or $1,500, whichever is less, divided by 12; provided, however, that the annual arrearage forgiveness amount shall not exceed $1,500.

If an AMP participant's past due account balance at the time their Payment Plan takes effect exceeds $1,500, the AMP participant may request an extension of the Payment Plan beyond the initial 12-month term to establish a new Payment Plan to accommodate the additional account balance in excess of $1,500. To be eligible for an extension, the AMP participant must be current with their Payment Plan at the conclusion of the initial 12-month term. Such AMP participant's Payment Plan will be extended upon the AMP participant's timely request for an extension.

OTHER MISCELLANEOUS CHARGES

ARREARAGE MANAGEMENT ADJUSTMENT PROVISION

PAYMENT PLAN REVIEW

Customers applying to participate in the AMP will be advised that the amount of their required monthly payment under their Payment Plan may change over the lifetime of the Payment Plan.

The Company shall review the Payment Plans of active AMP participants every three months and may adjust the installment payments based on the following:

- A fuel assistance commitment is made subsequent to enrollment;
- There is a change in fuel assistance, such as a change in the amount, from what was understood at enrollment;
- The customer moves to a new address with a different average monthly usage for the previous year;
- Actual usage patterns differ from what was estimated as annual usage at enrollment; or
- There is a significant change in the Company's rates from what was anticipated at enrollment.

V. DEFAULT

The Company shall consider the AMP participant's billing account in default if either of the following occurs:

- The AMP participant misses more than two (2) payments in the 12-month Payment Plan term; or
- If the amount due under the Payment Plan is not paid in full by the conclusion of the 12-month Payment Plan term.

Upon default, the Company shall terminate an AMP participant from the AMP and the customer's unpaid balance will be due and payable in full. However, any arrearage forgiven under the AMP prior to termination of participation in the AMP will remain forgiven.

Customers shall have the option to opt out of continued participation in the AMP at any time, with the understanding that any unpaid balance will be due and payable in full. Customers who voluntarily opt out of the AMP will receive the same treatment as those customers who default on their Payment Plans under the AMP, as set forth in Section X (Subsequent Eligibility).

OTHER MISCELLANEOUS CHARGES

ARREARAGE MANAGEMENT ADJUSTMENT PROVISION

VI. TERMINATION

In addition to termination upon default, a customer's participation in the AMP shall terminate if either of the following occurs:

- The AMP participant moves outside of the Company's service territory; or
- The AMP participant moves from one service location to another service location.

If a customer is terminated from AMP participation, the customer's unpaid balance will be due and payable in full. However, any arrearage forgiven under the AMP prior to termination of participation in the AMP will remain forgiven.

VII. COLLECTION ACTIVITY

AMP participants shall not be subject to the Company's normal collections activities while actively participating in the AMP. The Company shall resume normal collections activities if an AMP participant defaults while participating in the AMP or terminates the AMP.

VIII. AMP BILLING AND ACTIVE PLAN NOTICING

The Company shall remove the amount of an AMP participant's arrears balance up to $1,500 from the "current amount due" field on certain views of AMP participant accounts in the Company's billing system. However, the arrears balance up to $1,500 shall remain on the customer's bill.

Customers who are enrolled in the AMP will receive an AMP "Enrollment Letter" outlining the terms and conditions of their participation in the AMP.

Customers in danger of defaulting from the AMP will receive a default letter advising them of the need to make all required payments or risk default, termination from the AMP, and a return to the Company's normal collections activities.

IX. SUBSEQUENT ELIGIBILITY

A customer is eligible for subsequent enrollment in the AMP provided two years have passed since either (a) the date of the customer's successful completion of the AMP, or (b) the date on which the customer's participation in the AMP was terminated as a result of default or because the customer voluntarily opted out of the AMP, so long as a CAP agency has provided a recommendation to allow eligibility notwithstanding the customer's default or voluntary opt out of the AMP. The Company shall review requests for re-enrollment on a case-by-case basis to determine that the foregoing criteria are met.

OTHER MISCELLANEOUS CHARGES

ARREARAGE MANAGEMENT ADJUSTMENT PROVISION

X. REPORTING METRICS

The Company shall report monthly and annually the metrics below to allow for the evaluation of the effectiveness of the AMP. The monthly and annual reports shall be submitted to the PUC in Docket No. 4290.

- Number of customers enrolled in the program at the end of the reporting period;
- Number of customers added to the program during the reporting period;
- Number of customers terminated from the program (by choice or default) during the reporting period;
- Number of customers who successfully completed the program during the reporting period;
- Total customer payments during the reporting period;
- Total amount to be forgiven for all participating customers at the end of the reporting period;
- Average amount to be forgiven for all participating customers at the end of the reporting period;
- Total amount to be paid under a payment plan for all participating customers at the end of the reporting period;
- Average arrears balance not yet forgiven of all participating customers at the end of the reporting period;
- Average arrears balance as a percentage of the total balance due for all participating customers at the end of the reporting period;
- Total amount of arrears outstanding for all participants at the end of the reporting period;
- Total amount of forgiveness credits (allowances) given during the reporting period;
- Number of forgiveness credits (allowances) given during the reporting period;
- Average amount of forgiveness credits (allowances) given during the reporting period;
- Number of participants receiving LIHEAP at the end of the reporting period;
- Percentage of participants receiving LIHEAP at the end of the reporting period; and
- Total LIHEAP payments received during the reporting period.

OTHER MISCELLANEOUS CHARGES

ARREARAGE MANAGEMENT ADJUSTMENT PROVISION

The Company shall also provide a schedule with the number of customers enrolled in the AMP, by month, together with the number of defaults and program terminations.

XI. COST RECOVERY

The ~~prices for Delivery Charges contained in~~DAC applicable to all the firm rates of the Company are ~~subject to adjustment to reflect~~shall contain an Arrearage Management Adjustment Factor ("AMAF") designed to recover incremental costs incurred associated with the AMP. Incremental costs include the amount of arrearage forgiven. The recovery of the arrearage amounts forgiven by the Company through the AMP is dependent on the following criteria:

i. If a customer does not satisfy the conditions of R.I.G.L. § 39-2-1(d)(2), the amount of arrearage forgiven by the Company to that point shall remain forgiven and be written off by the Company. However, the amount of arrearage forgiven by the Company is recoverable in full.

ii. If a customer does satisfy the conditions of R.I.G.L. § 39-2-1(d)(2), all arrearage amounts forgiven will be treated as bad debt. At the end of each calendar year, the Company will perform a test to determine if the amount of bad debt for the year exceeds the adjusted allowable bad debt from the Company's most recent general rate case. This adjusted allowable bad debt will be calculated using the distribution uncollectible amount determined in the last general rate case, updated for the current calendar year Gas Cost Recovery, ~~Distribution Adjustment Clause ("~~DAC~~")~~, commodity, and energy efficiency-related bad debt. Should the actual amount of bad debt incurred by the Company for the year exceed this adjusted allowable bad debt amount, the Company will be entitled to recover, in the following year, all amounts of arrearage forgiven under R.I. Gen. Laws § 39-2-1(d)(2)(xiv) in the prior year in excess of the allowable bad debt. If, however, the amount of the arrearage forgiven under § 39-2-1(d)(2)(xiv) in excess of the adjusted allowable bad debt for a given year is not significant enough to calculate an annual reconciling factor for that year, the Company may reflect such amount in its next Revenue Decoupling Mechanism reconciliation filing.

The AMAF shall be a uniform per therm factor based on the estimated therms to be delivered by the Company to its gas customers over a 12-month period. For billing purposes, the AMAF will be included with the DAC charge on customers' bills. Should any balance remain outstanding subsequent to the recovery of costs associated with the AMP as described above, the Company shall reflect this balance as an adjustment in the subsequent period.

OTHER MISCELLANEOUS CHARGES

ARREARAGE MANAGEMENT ADJUSTMENT PROVISION

XII. ADJUSTMENT TO RATES

Adjustments to rates pursuant to the Arrears Management Program Provision are subject to review and approval by the PUC. Modifications to the factor contained in this Provision shall be made in accordance with a notice filed with the PUC pursuant to R.I.G.L. § 39-3-11(a) setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

SERVICE AND MAIN EXTENSION POLICIES

THE NARRAGANSETT ELECTRIC COMPANY
POLICY 1
NATURAL GAS SERVICE AND MAIN EXTENSION POLICY
FOR NEW INDIVIDUAL RESIDENTIAL CUSTOMERS

When an individual residential customer or a group of individual residential ~~customer(s)~~customers[1] ("Customer") request installation of a new service or a relocation of or upgrade to an existing service for the purpose of receiving natural gas service ("Request"), this policy shall apply. This policy applies to the installation and relocation of natural gas facilities by The Narragansett Electric Company ("Company"). This policy shall apply to firm service customers.

1. Installation of Service Line

The Company will install a "Service Line," which may include, but is not limited to: piping, associated metering, and pressure reducing appurtenances, that transports gas below grade to the first accessible fitting of a Customer's building. The location of the service line, the metering equipment, and the service entrance shall be designated by the Company in accordance with Rhode Island law and accepted industry practices. The Customer may be required to pay a "Contribution in Aid of Construction (CIAC)" as described in ~~Section~~Item 6~~.~~ below.

2. Main Extension

The Company will install a "Main," if necessary, to provide natural gas distribution service. A ~~"~~Main~~"~~ includes, but is not limited to, a pipeline owned by the Company located on a public and/or private right-of-way which is available or used to transport gas to one or ~~moreService~~more Service Lines. The Customer may be required to pay a CIAC, as described in ~~Section~~Item 6 below.

3. System Reinforcement(s)

System Reinforcements such as new main or main replacements (increased pipe-size) may be installed when the Company deems such to be necessary to provide adequate service. The Company reserves the right to recover costs for system reinforcements that are designed solely for the Customer's benefit.

4. Estimated Revenue

[1] A group of residential customers may include a residential subdivision, all or a portion of residential homes along a public way, or a multiple unit building with individually metered residential dwellings.

SERVICE AND MAIN EXTENSION POLICIES

Before undertaking the construction of new facilities to serve the Customer, the Company will estimate the annual incremental revenue to be derived by the Company under the ~~local~~ distribution ~~service rates~~charges from the installation of the new facilities. Any revenue from the Distribution Adjustment Clause factors, Cost of Gas Recovery factors, and Energy Efficiency Program Charges shall be excluded from this calculation.

5. Estimated Expenditures

5.1 Service Line and Main Extension

Service Line and Main Extension installation costs are estimated based on the pipe size, pipe composition, pipe length, and estimated trenching cost.

Plastic piping of diameter 8 inches or less will be estimated on a per foot basis, coupled with a callout fee, absent extenuating circumstances. Costs associated with service line ~~piping of diameter larger than 8 inches or composition other than plastic will be estimated using an engineering estimate.~~

~~5.2 Main Extension~~

~~Main extension installation costs are estimated based on the pipe size, pipe composition, pipe length, and estimated trenching cost.~~

~~Plastic piping of diameter 8 inches or less will be estimated on a per foot basis, absent extenuating circumstances. Costs associated with~~and main extension piping of diameter larger than 8 inches or composition other than plastic will be estimated using an engineering estimate.

~~5.3~~5.2 System Reinforcements

System reinforcement costs will be estimated using an engineering estimate.

~~5.4~~5.3 Extenuating Circumstances

Projects with extenuating circumstances will be estimated using an engineering estimate.

Examples of extenuating circumstances include but are not limited to: excessive ledge, bridge and railroad crossings, ~~DEM~~Department of Environmental Management ("DEM") permits and permit restrictions, state roads, restoration requirements, state road permits and any additional municipal requirements, concrete base roadways, new roadways or newly paved roadways and unusual landscaping, culverts, or upgrading of an existing service for added load.

SERVICE AND MAIN EXTENSION POLICIES

6. Customer Payments

6.1 Contribution in Aid of Construction

Whenever the estimated expenditures necessary to supply gas to the Customer, or for relocation or upgrade of Company equipment for reasons other than the needs of the Company, shall be such an amount that the estimated revenue derived from gas service at the applicable rates will be insufficient to warrant such expenditures, the Company will require the Customer to pay the whole or part of such expenditures. The Company will use a cash flow and a net present value (NPV) analysis~~)~~ to determine the appropriate customer contribution, ~~referred at~~or CIAC, which includes a tax contribution factor based on the cash contribution and/or value of ~~the~~ donated property ~~and/or any such cash contribution~~. The resulting CIAC represents the amount that is owed to the Company from the Customer(s) prior to ~~project implementation~~the Company commencing construction.

6.2 Additional Payment

When, in the Company's opinion, ~~significant~~an engineering study is required to determine the method of service or prepare construction estimates, the Company will estimate the cost of such engineering study. The Company may charge the Customer this cost before engineering begins. If construction is undertaken, this payment will be applied to any required CIAC. If no CIAC is required, the entire additional advance payment will be refunded. If construction is not undertaken, the Company will retain the appropriate portion of this additional advanced payment as reimbursement of costs incurred by the Company, and if any amount remains, will refund the remaining balance to the Customer.

6.3 Payment Terms

For CIAC charges up to $6,000 per Customer, each Customer will be required to pay the entire amount before the start of construction. If an individual Customer's CIAC is greater than $6,000, the Customer will have the option to either pay the entire amount before the start of construction, or pay $6,000 before the start of construction and pay the amount in excess of $6,000 under a payment plan. The terms of the payment plan will be based on equal payments of at least $75 per month until the amount in excess of $6,000 is paid in its entirety. The term of the payment plan is not to exceed a period of five (5) years or sixty (60) months. The amount collected under the payment plan will include interest at the rate ~~of interest applicable to the Company's~~paid on customer ~~deposit accounts~~deposits. The Customer can choose to pay the remaining balance at any time within the five-year period without penalty.

6.4 Change of Customer

The Customer must agree, as a condition of the monthly payment terms, that if he/she sells, leases, or otherwise transfers control and use of the property to anther individual ("New

SERVICE AND MAIN EXTENSION POLICIES

Occupant"), and such New Occupant opens a new account with the Company, the Customer will obtain an agreement from such New Occupant to pay the remaining balance that would have been owed by the Customer at that location. Otherwise, the Customer will remain personally liable for the balance owed.
The Company reserves the right to place a lien on the property until such time that the obligation is fulfilled.

6.5 Reconciliation

Whenever the Company collects a CIAC, the Customer has the option to request reconciliation in accordance with the following:

6.5.1 Per-Foot Basis

In instances where the Customer has paid a CIAC derived using per-foot rates, ~~and~~ the final actual footage for the project exceeds 125 feet~~;~~, and the difference between the final actual footage and estimated footage exceeds 25 feet then~~,~~ the Company will calculate the difference between the estimated and actual feet ~~times~~multiplied by the per-foot cost. The ~~resultant~~resulting difference will be refunded to the Customer~~, if the difference between the final actual and estimated footage is in excess of 25 feet.~~.

6.5.2 Engineering Estimate Basis

In instances where the estimated expenditure was derived using an engineering estimate and the Customer has paid a CIAC, once installation is complete and the actual expenditures ~~recorded~~determined, the Company will ~~compare~~determine the difference between the engineering estimate and the actual cost of installation. If the difference exceeds the greater of (a) $1,000, or (b) 10% of the engineering estimate, the Company will ~~and refund the difference to the Customer,~~ recalculate the Customer's CIAC based on actual cost and refund to the Customer the difference between the initial CIAC and the lower recalculated CIAC. ~~if the difference is greater than 10% of the estimated expenditure or $1,000, whichever is greater.~~ In no case shall the reconciliation result in additional payments from the Customer, nor will the Company refund more than the Customer actually paid.

7. More Than One Customer

When natural gas service is requested by more than one Customer for the same main extension line, the CIAC will be reasonably allocated among those Customers.

8. Customer Added After Initial Construction

If a new Customer (or group of Customers) is supplied from facilities constructed under this policy, and if such service begins within five (5) years from the date of the first payment

SERVICE AND MAIN EXTENSION POLICIES

received by the Company from the original Customer or group of Customers, the Company will recalculate the charges associated with installation of the main extension and adjust ~~charges~~CIACs or initiate refunds as appropriate.

9. Gas Service Agreement

The Company will require the Customer to sign a gas service agreement setting forth the terms of this policy and any other terms that the Company deems are reasonably necessary in connection with the installation, relocation, and/or upgrade of natural gas distribution line(s) to the Customer's property, provided that such terms are not inconsistent with the terms expressed in this policy.

10. Seasonal ~~limitations~~Limitations on Underground Construction

The Company may decline, in its sole discretion, to install any underground facilities due to weather or other seasonal concerns.

11. Easements

If necessary in the Company's determination, the Company will, as a condition on the installation of the service, require the Customer(s) to provide the Company with an executed easement (drafted by the Company) for all facilities located on private property. The Customer will provide the easement prior to the start of the Company's construction and at no cost to the Company. In the event that third party rights are required for the Customer's installation, the Customer will be responsible for obtaining all third party rights or crossings at the Customer's expense.

12. Changes in Policy and Procedures

The policies, procedures, and charges set forth herein are subject to periodic review and may be expanded, updated, revised, and/or modified from time to time at the Company's discretion and with the Division's approval.

~~**Narragansett Electric Company**~~
~~**For Individual Residential Customers**~~
~~**CIAC THRESHOLD FOOTAGES PER RESIDENTIAL GAS HEATING CUSTOMER**~~

13. Thresholds for CIAC Waivers

This matrix below shows, by Customer Subcategory, the service length and or service & main installation combinations that would result in no charge to the Customer. Any variation from what is shown here may result in a cost to the Customer based on length of service line and main, type of service (residential, C&I, etc~~)~~.) and pipe size. Please contact the Company

SERVICE AND MAIN EXTENSION POLICIES

directly for further information regarding costs related to jobs that ~~exceedthe~~exceed the thresholds shown below.

SERVICE AND MAIN EXTENSION POLICIES

Pipe Size	Service / Main	Under 2" / 2"	Under 2" / 2"	Under 2" / 2"	Under 2" / 2"
Customer Subcategory		Conversion	New Homes XXLarge	New Homes XLarge	New Homes Large
Approximate Square Footage			4500	3500	2400
Annual Load (ADTh)		123	255	201	142
	Service Footage	Service Footage	Service Footage	Service Footage	Service Footage
	Service Line Only	81	177	139	96
	Main Footage	Service Footage	Service Footage	Service Footage	Service Footage
	10	60	157	119	76
	15	51	146	109	66
	20	41	137	99	56
	25	31	127	89	46
	30	21	117	78	36
	35	11	107	69	26
	40	N/A	97	58	16
	45	N/A	86	48	5
	50	N/A	76	38	N/A
	55	N/A	67	28	N/A
	60	N/A	57	17	N/A
	65	N/A	47	8	N/A
	70	N/A	37	N/A	N/A

Pipe Size	Service / Main	Under 2" / 2"	Under 2" / 2"	Under 2" / 2"	Under 2" / 2"
Customer Subcategory		New Homes Med	New Homes Small	Apartment/Condo Small	Apartment/Condo Large
Approximate Square Footage		1800	1200		
Annual Load (ADTh)		123	108	59	83
	Service Footage	Service Footage	Service Footage	Service Footage	Service Footage
	Service Line Only	81	69	22	48
	Main Footage	Service Footage	Service Footage	Service Footage	Service Footage
	10	60	48	N/A	28
	15	51	39	N/A	18
	20	41	29	N/A	7
	25	31	19	N/A	N/A
	30	21	9	N/A	N/A
	35	11	N/A	N/A	N/A
	40	N/A	N/A	N/A	N/A
	45	N/A	N/A	N/A	N/A
	50	N/A	N/A	N/A	N/A
	55	N/A	N/A	N/A	N/A
	60	N/A	N/A	N/A	N/A
	65	N/A	N/A	N/A	N/A
	70	N/A	N/A	N/A	N/A

SERVICE AND MAIN EXTENSION POLICIES

THE NARRAGANSETT ELECTRIC COMPANY
POLICY 2
NATURAL GAS SERVICE AND MAIN EXTENSION POLICY FOR RESIDENTIAL DEVELOPMENTS

When a developer, contractor, builder or other customer ("Developer") proposing to construct a residential development or individual homes requests installation of a new service or a relocation of or upgrade to an existing service for the purpose of receiving natural gas service ("Request"), this policy shall apply. This policy applies to the installation and relocation of natural gas facilities by The Narragansett Electric Company ("Company").

1. Installation of Service Line

The Company will install a "Service Line," which may include, but is not limited to: piping, associated metering, and pressure reducing appurtenances, that transports gas below grade to the first accessible fitting of a Customer's building. The location of the service line, the metering equipment, and the service entrance shall be designated by the Company in accordance with Rhode Island law and accepted industry practices. The ~~Customer~~ Developer may be required to pay a "Contribution in Aid of Construction (CIAC)" as described in Item 6 below.

2. Main Extension

The Company will install a "Main" if necessary, to provide natural gas distribution service. A "Main" includes, but is not limited to, a pipeline owned by the Company located on a public and/or private right-of-way which is available or used to transport gas to one or more Service Lines. The ~~Customer~~ Developer may be required to pay a CIAC, as described in ~~Section 7.~~Item 6 below.

3. System Reinforcement(s)

System Reinforcements such as new main or main replacements (increased pipe-size) may be installed when the Company deems such to be necessary to provide adequate service. The Company reserves the right to recover costs for system reinforcements that are designed solely for the Customer's benefit.

4. Estimated Revenue

Before undertaking the construction of new facilities to serve the ~~Customer~~development, the Company will estimate the annual incremental revenue to be derived by the Company under the local distribution service rates from the installation of the new facilities. Any revenue

SERVICE AND MAIN EXTENSION POLICIES

from the Distribution Adjustment Clause factors, Cost of Gas Recovery factors, and Energy Efficiency Charges shall be excluded from this calculation.

5. Estimated Expenditures

5.1 Service Line and Main Extension

Service line and main extension installation costs are estimated based on the pipe size, pipe composition, pipe length, and estimated trenching cost.

Plastic piping of diameter 8 inches or less will be estimated on a per foot basis, coupled with a call out fee, absent extenuating circumstances. Costs associated with service line ~~piping of diameter larger than 8 inches or composition other than plastic will be estimated using an engineering estimate.~~

~~11.1 Main Extension~~

~~Main extension installation costs are estimated based on the pipe size, pipe composition, pipe length, and estimated trenching cost.~~

~~Plastic piping of diameter 8 inches or less will be estimated on a per foot basis, absent extenuating circumstances. Costs associated with~~and main extension piping of diameter larger than 8 inches or composition other than plastic will be estimated using an engineering estimate.

5.2 System Reinforcements

System reinforcement costs will be estimated using an engineering estimate.

5.3 Extenuating Circumstances

Projects with extenuating circumstances will be estimated using an engineering estimate.

Examples of extenuating circumstances include but are not limited to: excessive ledge, bridge and railroad crossings, DEM permits and permit restrictions, state roads, restoration requirements, state road permits and any additional municipal requirements, concrete base roadways, new roadways or newly paved roadways and unusual landscaping, culverts or upgrading of an existing service for added load.

6. Developer Obligations

SERVICE AND MAIN EXTENSION POLICIES

The Developer will be responsible for removal of ledge, trenching and backfilling in accordance with the Company's construction standards. In addition, the Developer will be responsible for:

i. providing, prior to the start of the Company's construction, all applicable documents required for the Company to prepare design drawings and easements for its facilities to be installed on private property;

ii. supplying copies of all invoices, when requested, indicating manufacturer and part number for all such equipment listed/referred to above; equipment that is not approved shall not be used without the prior written consent of the Company; and

iii. turning over ownership of the local gas distribution system to the Company upon inspection and acceptance of such system by the Company.

7. ~~Customer~~ Developer Payments

a. Contribution in Aid of Construction

Whenever the estimated expenditures necessary to supply gas to the Customer, or for relocation or upgrade of Company equipment for reasons other than the needs of the Company, shall be such an amount that the estimated revenue derived from gas service at the applicable rates will be insufficient to warrant such expenditures, the Company will require the ~~Customer~~ Developer to pay the whole or part of such expenditures. The Company will use a cash flow and a net present value (NPV analysis) to determine the appropriate customer contribution, referred at CIAC, which includes a tax contribution factor based on the value of the donated property and/or any such cash contribution. The resulting CIAC represents the amount that is owed to the Company from the ~~Customer(s)~~Developer prior to project implementation. Cost to the ~~Customer~~ Developer will vary depending upon job scope, and will be provided during the application process, once job specifications have been determined.

b. Additional Payment

When, in the Company's opinion, significant engineering is required to determine the method of service or prepare construction estimates, the Company will estimate the cost of such engineering study. The Company may charge the Customer this cost before engineering begins. If construction is undertaken, this payment will be applied to any required CIAC. If no CIAC is required, the entire additional advance payment will be refunded. If construction is not undertaken, the Company will retain the appropriate portion of this

SERVICE AND MAIN EXTENSION POLICIES

additional advanced payment as reimbursement of costs incurred by the Company, and if any amount remains, will refund the remaining balance to the ~~Customer~~Developer.

c. Reconciliation

Whenever the Company collects a CIAC, the Customer has the option to request a reconciliation in accordance with the following:

i. Per Foot Basis

In instances where the ~~Customer~~ Developer has paid a CIAC derived using per foot rates, and the final actual footage for the project exceeds 125 feet; then, the Company will calculate the difference between the estimated and actual feet times the per foot cost. The resultant difference will be refunded to the Customer, if the difference between the final actual and estimated footage is in excess of 25 feet.

ii. Engineering Estimate Basis

In instances where the estimated expenditure was derived using an engineering estimate and the ~~Customer~~ Developer has paid a CIAC, once installation is complete and the actual expenditures ~~recorded~~determined, the Company will determine the difference between~~compare~~ the engineering estimate and the actual cost of installation. If the difference exceeds the greater of (a) $1,000 or (b) 10% of the engineering estimate, the Company will ~~and refund the difference to the Customer~~ recalculate the Developer's CIAC based on actual cost and refund to the customer the difference between the initial CIAC and the lower recalculated CIAC.~~, if the difference is greater than 10% of the estimated expenditure or greater than $1,000, whichever is greater.~~ In no case shall the reconciliation result in additional payments from the Customer, nor will the Company refund more than the ~~Customer~~ Developer actually paid.

8. More Than One Customer

When natural gas service is requested by more than one Customer for the same main extension line, the CIAC will be reasonably allocated among those Customers.

9. Customer Added After Initial Construction

If a new Customer (or group of Customers) is supplied from facilities constructed under this policy, and if such service begins within five (5) years from the date of the first payment received by the Company from the original Customer or group of Customers, the Company will recalculate the charges associated with installation of the main extension and adjust charges or initiate refunds as appropriate.

SERVICE AND MAIN EXTENSION POLICIES

10. Developer Provides Plans and Documentation

The total number of house lots proposed to be constructed ("House Lots") will be provided in advance to the Company by the Developer (prior to the Company building the distribution line), along with an electronic copy (in a format acceptable to the Company) of the subdivision plan approved by the planning board in the applicable community.

The Company may require the Developer to provide, in advance, the following:

(A) a copy of the approval of the planning board for the subdivision;

(B) a copy of all permits and approvals that have been obtained for constructing the development;

(C) the name and address of the bank or credit union providing financing for the development, including a contact person and phone number;

(D) a schedule or Developer's best estimate for the construction of homes in the development; and

(E) if requested by the Company, such other reasonable information that may be required to confirm the viability of the development.

11. Building the Distribution Line in Segments

The Company may, in its own discretion, construct the distribution in segments, rather than all at once in the proposed development.

12. Gas Service Agreement

The Company will require the ~~Customer~~ Developer to sign a gas service agreement setting forth the terms of this policy and any other terms that the Company deems are reasonably necessary in connection with the installation, relocation, and/or upgrade of natural gas distribution line(s) to the ~~Customer's property~~development, provided that such terms are not inconsistent with the terms expressed in this policy.

~~12.~~13. Seasonal limitations on Underground Construction

The Company may decline, in its sole discretion, to install any underground facilities due to weather or other seasonal concerns.

SERVICE AND MAIN EXTENSION POLICIES

~~13.~~14. Easements

If necessary in the Company's determination, the Company will, as a condition on the installation of the service, require the ~~Customer(s)~~Developer to provide the Company with an executed easement (drafted by the Company) for all facilities located on private property. The Developer will provide the easement prior to the start of the Company's construction and at no cost to the Company. In the event that third party rights are required for the Developer's installation, the Developer will be responsible for obtaining all third party rights or crossings at the Developer's expense.

~~12. Changes in Policy and Procedures~~

~~The policies, procedures, and charges set forth herein are subject to periodic review and may be expanded, updated, revised, and/or modified from time to time at the Company's discretion, and with the Division's approval.~~

SERVICE AND MAIN EXTENSION POLICIES

THE NARRAGANSETT ELECTRIC COMPANY
POLICY 3
NATURAL GAS SERVICE AND MAIN EXTENSION POLICY

FOR COMMERCIAL, INDUSTRIAL AND EXISTING RESIDENTIAL CUSTOMERS

The terms of this policy shall apply when a commercial, industrial or non-residential (a real estate development which is not an approved subdivision of single-family homes) customer ("Customer") requests installation of a new service or a relocation of or upgrade to an existing service for the purpose of receiving natural gas service ("Request"). This policy applies to the installation and relocation of natural gas facilities by The Narragansett Electric Company ("Company").

1. Installation of Service Line

The Company will install a "Service Line," which may include, but is not limited to: piping, associated metering, and pressure reducing appurtenances, that transports gas below grade to the first accessible fitting of a Customer's building. The location of the service line, the metering equipment, and the service entrance shall be designated by the Company in accordance with Rhode Island law and accepted industry practices. The Customer may be required to pay a "Contribution in Aid of Construction (CIAC)" as described below.

2. Main Extension

The Company will install a "Main," if necessary, to provide natural gas distribution service. A "Main" includes, but is not limited to, a pipeline owned by the Company located on a public and/or private right-of-way which is available or used to transport gas to one or more Service Lines. The Customer may be required to pay a CIAC, as described below.

3. System Reinforcement(s)

System Reinforcements such as new main or main replacements (increased pipe-size) may be installed when the Company deems such to be necessary to provide adequate service. The Company reserves the right to recover costs for system reinforcements that are designed solely for the Customer's benefit.

4. Estimated Revenue

Before undertaking the construction of new facilities to serve the Customer, the Company will estimate the annual incremental revenue to be derived by the Company under the local distribution service rates from the installation of the new facilities. Any revenue from the

SERVICE AND MAIN EXTENSION POLICIES

Distribution Adjustment Clause factors, Cost of Gas Recovery factors, and Energy Efficiency Charges shall be excluded from this calculation.

5. Estimated Expenditures

a. Service Line and Main Extension

Service line and main extension installation costs are estimated based on the pipe size, pipe composition, pipe length, and estimated trenching cost.

Plastic piping of diameter 8 inches or less will be estimated on a per foot basis, coupled with a call out fee, absent extenuating circumstances. Costs associated with service line ~~piping of diameter larger than 8 inches or composition other than plastic will be estimated using an engineering estimate.~~

~~12.1 Main Extension~~

~~Main extension installation costs are estimated based on the pipe size, pipe composition, pipe length, and estimated trenching cost.~~

~~Plastic piping of diameter 8 inches or less will be estimated on a per foot basis, absent extenuating circumstances. Costs associated with~~and main extension piping of diameter larger than 8 inches or composition other than plastic will be estimated using an engineering estimate.

b. System Reinforcements

System reinforcement costs will be estimated using an engineering estimate.

c. Extenuating Circumstances

Projects with extenuating circumstances will be estimated using an engineering estimate.

Examples of extenuating circumstances include but are not limited to: excessive ledge, bridge and railroad crossings, DEM permits and permit restrictions, state roads, restoration requirements, state road permits and any additional municipal requirements, concrete base roadways, new roadways or newly paved roadways and unusual landscaping, culverts or upgrading of an existing service for added load.

6. Customer Obligations

SERVICE AND MAIN EXTENSION POLICIES

The Customer, at no cost to the Company, will be responsible for blasting and tree trimming and removal on private property, including roadways not accepted as public ways by the municipality, in accordance with the Company's specifications and subject to the Company's inspection.

7. Customer Payments

a. Contribution in Aid of Construction

Whenever the estimated expenditures necessary to supply gas to the Customer, or for relocation or upgrade of Company equipment for reasons other than the needs of the Company, shall be such an amount that the estimated revenue derived from gas service at the applicable rates will be insufficient to warrant such expenditures, the Company will require the Customer to pay the whole or part of such expenditures. The Company will use a cash flow and a net present value (NPV analysis) to determine the appropriate customer contribution, referred at CIAC, which includes a tax contribution factor based on the value of the donated property and/or any such cash contribution. The resulting CIAC represents the amount that is owed to the Company from the Customer(s) prior to project implementation. Cost to the Customer will vary depending upon job scope, and will be provided during the application process, once job specifications have been determined.

b. Additional Payment

When, in the Company's opinion, significant engineering is required to determine the method of service or prepare construction estimates, the Company will estimate the cost of such engineering. The Company may charge the Customer this cost before engineering begins. If construction is undertaken, this payment will be applied to any required CIAC. If no CIAC is required, the entire additional advance payment will be refunded. If construction is not undertaken, the Company will retain the appropriate portion of this additional advanced payment as reimbursement of costs incurred by the Company, and if any amount remains, will refund the remaining balance to the Customer

c. Reconciliation

Whenever the Company collects a CIAC, the Customer has the option to request a reconciliation in accordance with the following:

i. Per Foot Basis

In instances where the Customer has paid a CIAC derived using per foot rates, and the final actual footage for the project exceeds 125 feet; then, the Company will calculate the difference between the estimated and actual feet times the per foot cost.

SERVICE AND MAIN EXTENSION POLICIES

The resultant difference will be refunded to the Customer, if the difference between the final actual and estimated footage is in excess of 25 feet.

ii. Engineering Estimate Basis

In instances where the estimated expenditure was derived using an engineering estimate and the Customer has paid a CIAC, once installation is complete and the actual expenditures ~~recorded~~determined, the Company will ~~compare~~determine the difference between the engineering estimate and the actual cost of installation. If the difference exceeds the greater of (a) $1,000, or (b) 10% of the engineering estimate, the Company will recalculate the Customer's CIAC based on actual cost and refund to the Customer the difference between the initial CIAC and the lower recalculated CIAC. ~~and refund the difference to the Customer, if the difference is greater than 10% of the estimated expenditure or greater than $1,000, whichever is greater.~~ In no case shall the reconciliation result in additional payments from the Customer, nor will the Company refund more than the Customer actually paid.

8. More Than One Customer

When natural gas service is requested by more than one Customer for the same main extension line, the CIAC will be reasonably allocated among those Customers.

9. Customer Added After Initial Construction

If a new Customer (or group of Customers) is supplied from facilities constructed under this policy, and if such service begins within five (5) years from the date of the first payment received by the Company from the original Customer or group of Customers, the Company will recalculate the charges associated with installation of the main extension and adjust charges or initiate refunds as appropriate.

10. Building the Distribution Line in Segments

The Company may, in its own discretion, construct the distribution in segments, rather than all at once in the proposed development.

11. Gas Service Agreement

The Company will require the Customer to sign a gas service agreement setting forth the terms of this policy and any other terms that the Company deems are reasonably necessary in connection with the installation, relocation, and/or upgrade of natural gas distribution line(s) to the Customer's property, provided that such terms are not inconsistent with the terms expressed in this policy.

12. Seasonal limitations on Underground Construction

SERVICE AND MAIN EXTENSION POLICIES

The Company may decline, in its sole discretion, to install any underground facilities due to weather or other seasonal concerns.

13. Easements

If necessary in the Company's determination, the Company will, as a condition on the installation of the service, require the Customer(s) to provide the Company with an executed easement (drafted by the Company) for all facilities located on private property. The Customer will provide the easement prior to the start of the Company's construction and at no cost to the Company. In the event that third party rights are required for the Customer's installation, the Customer will be responsible for obtaining all third party rights or crossings at the Customer's expense.

~~13. Changes in Policy and Procedures~~

~~The policies, procedures, and charges set forth herein are subject to periodic review and may be expanded, updated, revised, and/or modified from time to time at the Company's discretion, and with the Division's approval.~~

Compliance Attachment 20

Compliance Attachment 20

Narragansett Electric and Narragansett Gas Calculation of the

Proposed Low Income Discount Recovery Factor

Narragansett Electric
Calculation of Estimated Rate Year Electric Low Income Discount and Low Income Discount Recovery Factor (LIDRF)

Section 1 - Calculation of Low Income Discount

		Rate Year Rate A-60 Units	Rate A-60 Rate	Charges	Proposed Discount	Low Income Discount
		(a)	(b)	(c)	(d)	(e)
(1)	Customer Charge	437,171	$2.00	$874,342		
(2)	RE Growth Factor	437,171	$0.78	$340,993		
(3)	LIHEAP Enhancement Surcharge	437,171	$0.81	$354,109		
(4)	Distribution kWh Charge	223,496,800	$0.04298	$9,605,892		
(5)	ISR CapEx Factor	223,496,800	$0.00000	$0		
(6)	ISR CapEx Reconciliation Factor	223,496,800	($0.00135)	($301,721)		
(7)	ISR O&M Factor	223,496,800	$0.00175	$391,119		
(8)	ISR O&M Reconciliation Factor	223,496,800	($0.00001)	($2,235)		
(9)	Pension/PBOP Factor	223,496,800	($0.00085)	($189,972)		
(10)	Revenue Decoupling Mechanism Adjustment Factor	223,496,800	$0.00184	$411,234		
(11)	Storm Fund Replenishment Factor	223,496,800	$0.00288	$643,671		
(12)	Arrears Management Adjustment Factor	223,496,800	$0.00002	$4,470		
(13)	Low Income Discount Recovery Factor	223,496,800	$0.00000	$0		
(14)	Subtotal Distribution Energy Charge			$10,562,459		
(15)	Transmission Charge	223,496,800	$0.03271	$7,310,580		
(16)	Transition Charge	223,496,800	($0.00087)	($194,442)		
(17)	Energy Efficiency Program Charge	223,496,800	$0.01002	$2,239,438		
(18)	Renewable Energy Distribution Charge	223,496,800	$0.00690	$1,542,128		
(19)	Total Delivery Service Charges			$23,029,607		
(20)	Winter Commodity Charge	108,217,729	$0.09515	$10,296,917		
(21)	Summer Commodity Charge	115,279,071	$0.08486	$9,782,582		
(22)	Total Commodity Charges	223,496,800		$20,079,499		
(23)	Total			$43,109,106		
(24)	Low Income Discount				25.0%	$10,777,276
(25)	Value of Exemption from Low Income Discount Recovery Factor					$328,540
(26)	Total Low Income Benefit				25.6%	$11,105,816

(a) Compliance Attachment 9, Schedule 4-A
(b) (1), (4) Compliance Attachment 9, Schedule 4-A
(2), (3), (6) - (12), (15) - (17) per RIPUC 2095, Effective Date July 1, 2018
(20) per RIPUC 2096, Effective January 1, 2018
(21) per RIPUC 2096, Effective Date April 1, 2018
(c) Column (a) x Column (b)
(d) Proposed Discount off of total amount billed
(e) Line (23) x Line (24), Column (d)

(13) Proposing that all A-60 customers are exempt from Low Income Discount Recovery Factor
(14) Sum of Lines (4) through (13)
(19) Sum of Lines (1) through (3) + Line (14) + Sum of Lines (15) through (18)
(22) Line (20) + Line (21)
(23) Line (19) + Line (22)
(24) Column (c), Line (23) x Column (d), Line (24)
(25) Column (a) kWh x Section 2, Line (1) ÷ Total Company kWh Delivery Forecast including low income rate classes
(26) Line (24) + Line (25); Column (d) = Column (e) ÷ Line (23) Column (c)

Section 2 - Calculation of Proposed Low Income Discount Recovery Factor

(1)	Estimated Discount Provided, Rate Year	$10,777,276
(2)	Forecasted kWh Deliveries, Rate Year	7,072,229,805
(3)	Proposed Low Income Discount Recovery Factor for September 1, 2018	$0.00152

(1) Section 1, Line (24), Column (e)
(2) Rate Year Forecast excluding Rate A-60 kWh
(3) Line (1) ÷ Line (2), truncated to five decimal places

Narragansett Gas
Calculation of Estimated Rate Year Gas Low Income Discount and Low Income Discount Recovery Factor (LIDRF)

Section 1 - Calculation of Low Income Discount

		Rate Year Rate 11 Units	Rate 10 Rate	Charges	Rate Year Rate 13 Units	Rate 12 Rate	Charges	Total Charges
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	Customer Charge	2,492	$14.00	$34,888	204,901	$14.00	$2,868,614	$2,903,502
(2)	LIHEAP Enhancement Surcharge	2,492	$0.81	$2,019	204,901	$0.81	$165,970	$167,989
(3)	Distribution Charge Peak	101,774	$0.5456	$55,528	11,536,022	$0.5534	$6,384,035	$6,439,562
	Distribution Charge Off Peak				2,725,461	$0.4960	$1,351,829	$1,351,829
(4)	DAC	101,774	$0.0475	$4,834	11,536,022	$0.0206	$237,642	$242,476
(5)	Low Income Discount Recovery Factor	101,774	$0.0000	$0	11,536,022	$0.0000	$0	$0
(6)	Energy Efficiency Program Charge	101,774	$0.0876	$8,915	11,536,022	$0.0876	$1,010,556	$1,019,471
(7)	Total Delivery Service Charges			$106,185			$12,018,645	$12,124,829
(8)	Commodity Charge	101,774	$0.4797	$48,821	11,536,022	$0.5226	$6,028,725	$6,077,546
(9)	Total			$155,006			$18,047,370	$18,202,376
(10)	Low Income Discount Percentage			25%			25%	
(11)	Low Income Discount			$38,751			$4,511,842	$4,550,593
(12)	Low Income Discount Recovery Factor			$1,167			$132,318	$133,485
(13)	Total Low Income Benefit			$39,918			$4,644,160	$4,684,078
(14)	Effective Low Income Discount			25.6%			25.5%	25.5%

(a), (d) Workpaper NG-PP-1(a)-GAS, Pages 24 and 27
(b), (e) Line (1), (3): Compliance Attachment 16, page 1
(c) Column (a) x Column (b)
(f) Column (d) x Column (e)
(g) Column (c) + Column (f)

(7) Sum of Lines (1) through (6)
(9) Line (7) + Line (8)
(10) Proposed Discount off of total amount billed
(11) Line (9) x Line (10)
(12) Column (c) and (f) = Column (a) and (d) therms x Section 2, Line (1) ÷ Total Company Therm Forecast including low income rate classes
(13) Line (11) + Line (12)
(14) Line (13) ÷ [Line (9) + Line (12)]

Section 2 - Calculation of Proposed Low Income Discount Recovery Factor

(1)	Estimated Discount Provided, Rate Year	$4,550,593
(2)	Forecasted Therms, Rate Year	382,361,343
(3)	Proposed Low Income Discount Recovery Factor for September 1, 2018	$0.0119

(1) Section 1, Line (10), Column (h)
(2) Rate Year Forecast excluding Rates 11 and 13
(3) Line (1) ÷ Line (2), truncated to four decimal places

Compliance Attachment 21

Compliance Attachment 21

Narragansett Electric and Narragansett Gas Calculation of Miscellaneous Fees

Narragansett Gas

Proposed Fee for Account Restoration

(1)	Labor Costs for Meter Off Due to Non Payment	$19.79
(2)	Labor Burdens	$13.74
(3)	Transportation Costs for Meter Off Due to Non Payment	$4.93
(4)	Labor Costs for Meter On Due to Customer Payment	$29.69
(5)	Labor Burdens	$20.62
(6)	Transportation Costs for Meter On Due to Customer Payment	$7.40
(7)	Total Cost of Restoring Service	$96.17
(8)	Proposed Account Restoration Fee	$96.00
(9)	Current Account Restoration Fee	$25.00
(10)	Proposed Increase in Account Restoration Fee	$71.00
(11)	Test Year Count of Account Restoration Fees Billed	3,274
(12)	Proposed Incremental Account Restoration Fee Revenue	$232,454

(1) 0.6 hours of labor time x average hourly rate of $32.98
(2) Line (1) x labor OH %, excluding pension and OPEB, of 69.44%
(3) 0.6 hours of labor time x average hourly rate of $8.22
(4) 0.9 hours of labor time x average hourly rate of $32.98
(5) Line (4) x labor OH %, excluding pension and OPEB, of 69.44%
(6) 0.9 hours of labor time x average hourly rate of $8.22
(7) Sum of Lines (1) through (6)
(8) Line (7), truncated to 0 decimal places
(9) Per Company Tariff, RIPUC NG-GAS 101, Section 1, Schedule A, Sheet 9
(10) Line (8) - Line (9)
(11) Per Company Billing Report
(12) Line (10) x Line (11)

Narragansett Electric

Proposed Fee for Account Restoration

(1)	Labor Costs for Meter Off Due to Non Payment	$8.13
(2)	Labor Burdens	$5.65
(3)	Transportation Costs for Meter Off Due to Non Payment	$2.47
(4)	Labor Costs for Meter On Due to Customer Payment	$8.13
(5)	Labor Burdens	$5.65
(6)	Transportation Costs for Meter On Due to Customer Payment	$2.47
(7)	Total Cost of Restoring Service	$32.50
(8)	Proposed Account Restoration Fee	$32.00
(9)	Current Account Restoration Fee	$38.00
(10)	Proposed Increase in Account Restoration Fee	($6.00)
(11)	Test Year Count of Account Restoration Fees Billed	11,900
(12)	Proposed Incremental Account Restoration Fee Revenue	($71,400)

(1) 0.3 hours of labor time x average hourly rate of $27.11
(2) Line (1) x labor OH %, excluding pension and OPEB, of 69.44%
(3) 0.3 hours of labor time x average hourly rate of $8.22
(4) 0.3 hours of labor time x average hourly rate of $27.11
(5) Line (4) x labor OH %, excluding pension and OPEB, of 69.44%
(6) 0.3 hours of labor time x average hourly rate of $8.22
(7) Sum of Lines (1) through (6)
(8) Line (7), truncated to 0 decimal places
(9) Per Company Tariff, RIPUC No. 2130, Section 21
(10) Line (8) - Line (9)
(11) Per Company Billing Report
(12) Line (10) x Line (11)

Narragansett Gas

Proposed Fee for IP Wireless Device

	Plant Investment		
(1)	Incremental Cost of Meter Equipped with a Wireless Module		$1,035
	Labor Cost		
(2)	Average Travel Time	1.0	
(3)	Average Time to Install	2.0	
(4)	Total Time	3.0	
(5)	Hourly Rate	$42.60	
(6)	Base Labor	$127.80	
(7)	Labor Overheads	95.88%	
(8)	Labor Costs		$250
(9)	Lump Sum Fee, Equipment Cost		$1,285
(10)	Annual Fee, Data Plan		$17
(11)	Monthly Weighted Cost of Data Plan		Weighting
(12)	Monthly Cost, Low End	$0.83	85%
(13)	Monthly Cost, High End	$5.00	15%
(14)	Weighted Average Monthly Cost	$1.46	
(15)	x 12	12	
(16)	Annual Cost	$17	

(2) Average Estimate
(3) Average Estimate
(4) Line (2) + Line (3)
(6) Line (4) x Line (5)
(7) Test Year Average
(8) Line (6) x [1 + Line (7)]
(9) Line (1) + Line (8)
(10) Line (16)

Narragansett Electric
Proposed Fee for IP Wireless Device

	Plant Investment			
(1)	Incremental Cost of Meter Equipped with a Wireless Module			$583
	Labor Cost			
(2)	Average Travel Time	0.2		
(3)	Average Time to Install	1.0		
(4)	Total Time	1.2		
(5)	Hourly Rate	$39.62		
(6)	Base Labor	$48.86		
(7)	Labor Overheads	95.88%		
(8)	Labor Costs			$96
(9)	Lump Sum Fee, Equipment Cost			$679
(10)	Annual Fee, Data Plan			$17
(11)	Monthly Weighted Cost of Data Plan		Weighting	
(12)	Monthly Cost, Low End	$0.83	85%	
(13)	Monthly Cost, High End	$5.00	15%	
(14)	Weighted Average Monthly Cost	$1.46		
(15)	x 12	12		
(16)	Annual Cost	$17		

(2) Average Estimate
(3) Average Estimate
(4) Line (2) + Line (3)
(6) Line (4) x Line (5)
(7) Test Year Average
(8) Line (6) x [1 + Line (7)]
(9) Line (1) + Line (8)
(10) Line (16)

Narragansett Gas
Proposed Fee for Returned Checks

	Service Description	Service Charges	Reference
	Test Year External Costs		
	JPCM Charges		
(1)	Return Item	$17,504	
(2)	Return Multiple Locations	$1,445	
(3)	Return Image	$4,504	
(4)	Return Detail Reporting	$1,351	
(5)	Return Item Redeposit	$9,264	
(6)	ARC Zero Admin Return Process	$6,000	
(7)	Return Item Redeposit	$25,809	
(8)	eLockbox Return - Electronic	$203	
(9)	Return Notification - Online	$218	
(10)	Return Notification - Transmission	$23,793	
(11)	Total	$90,091	Total JPCM Charges per Invoices
	TransCentra Charges		
(12)	Return Corr. Various Types	$1,192	Per TransCentra Invoices
(13)	Data Capture - Return / NSF Item	$832	Per TransCentra Invoices
(14)	Total	$2,024	Total TransCentra Costs
(15)	Total External Costs	$92,115	Line (11) + Line (14)
	Test Year Internal Costs		
		Wages	
	Internal Labor		
(16)	Base Labor	$6,948	Per Company Estimate
(17)	Labor Overheads	$4,896	Per Company Estimate
(18)	Total	$11,844	Line (16) + Line (17)
	Proposed Returned Check Fee		
(19)	Total External Costs	$92,115	Line (15)
(20)	Total Internal Costs	$11,844	Line (18)
(21)	Total Costs	$103,958	Line (19) + Line (20)
(22)	Test Year Returned Items	13,072	Per General Ledger
(23)	Proposed Returned Check Fee	$8.00	Line (21) ÷ Line (22), rounded to 0 decimal places
	Incremental Revenue		
(24)	Proposed Returned Check Fee	$8.00	Line (23)
(25)	Current Returned Check Fee	$15.00	R.I.P.U.C. 2130
(26)	Proposed Decrease in Returned Check Fee	($7.00)	Line (24) - Line(25)
(27)	Test Year Returned Items- Gas	4,248	Per General Ledger
(28)	Decrease in Returned Check Fee Revenue - Gas	($29,736)	Line (26) x Line (27)

Narragansett Electric
Proposed Fee for Returned Checks

	Service Description	Service Charges	Reference
	Test Year External Costs		
	JPCM Charges		
(1)	Return Item	$17,504	
(2)	Return Multiple Locations	$1,445	
(3)	Return Image	$4,504	
(4)	Return Detail Reporting	$1,351	
(5)	Return Item Redeposit	$9,264	
(6)	ARC Zero Admin Return Process	$6,000	
(7)	Return Item Redeposit	$25,809	
(8)	eLockbox Return - Electronic	$203	
(9)	Return Notification - Online	$218	
(10)	Return Notification - Transmission	$23,793	
(11)	Total	$90,091	Total JPCM Charges per Invoices
	TransCentra Charges		
(12)	Return Corr. Various Types	$1,192	Per TransCentra Invoices
(13)	Data Capture - Return / NSF Item	$832	Per TransCentra Invoices
(14)	Total	$2,024	Total TransCentra Costs
(15)	Total External Costs	$92,115	Line (11) + Line (14)
	Test Year Internal Costs		
		Wages	
	Internal Labor		
(16)	Base Labor	$6,948	Per Company Estimate
(17)	Labor Overheads	$4,896	Per Company Estimate
(18)	Total	$11,844	Line (16) + Line (17)
	Proposed Returned Check Fee		
(19)	Total External Costs	$92,115	Line (15)
(20)	Total Internal Costs	$11,844	Line (18)
(21)	Total Costs	$103,958	Line (19) + Line (20)
(22)	Test Year Returned Items	13,072	Per General Ledger
(23)	Proposed Returned Check Fee	$8.00	Line (21) ÷ Line (22), rounded to 0 decimal places
	Incremental Revenue		
(24)	Proposed Returned Check Fee	$8.00	Line (23)
(25)	Current Returned Check Fee	$15.00	R.I.P.U.C. 2130
(26)	Proposed Decrease in Returned Check Fee	($7.00)	Line (24) - Line(25)
(27)	Test Year Returned Items- Electric	8,824	Per General Ledger
(28)	Decrease in Returned Check Fee Revenue - Electric	($61,768)	Line (26) x Line (28)

Narragansett Electric
Lighting Service Charge

Service Charge - Labor and Equipment Costs for Initial Analysis

Service Charge Cost Development

	Description		Service Response to Customer Requested Task Other Than General O&M Functions		
	Labor				
(1)	Trouble Shooter - Hourly Rate		$47.12		Labor Rate per Negotiated Union Agreement
(2)	Installation & Travel Time (Minutes)		45		Average Estimate (Travel/Set-up/Work/ Breakdown)
(3)		SubTotal Direct Labor		$35.34	Line (1) x [Line (2) ÷ 60]
	Labor Overhead				
(4)	Overhead Labor Cost		112.17%		Test Year Labor Allocation Rates
(5)		SubTotal Labor Overhead		$39.64	Line (3) x Line (4)
(6)		Total Labor		$74.98	Line (3) + Line (5)
	Equipment				
(7)	Truck-Light Duty		$46.58		NG Fleet Category Cost Assessment
(8)	Installation & Travel Time (Minutes)		45		Average Estimate (Travel/Set-up/Work/ Breakdown)
(9)		Total Equipment		$34.94	Line (7) x [Line (8) ÷ 60]
	Material				
(10)	Red Cap PE, Connect/Disconnect, Fuse, Etc.		$5.00		Average of Purchase Agreement Pricing
(11)		SubTotal Material		$5.00	Line (10)
	Material Overhead				
(12)	Stores Handling		23.25%	$1.16	Test Year Allocation Rates
(13)	Imprest Stock (connectors/tape/etc.)		3.00%	$0.15	Estimate for non-specified required materials
(14)		SubTotal Material Overhead		$1.31	Line (12) + Line (13)
(15)		Total Material		$6.31	Line (11) + Line (14)
(16)	Total Labor, Equipment Material & Misc. Costs			$116.00	Line (6) + Line (9) + Line (15), Truncated to 0 decimal places

Narragansett Electric
Off Cycle Meter Read for Switch of Supplier

Interval Data Meters With Remote Interrogation (Telemetered)

(1)	Cost of Labor for Contact Center NE	$25.93
(2)	Estimated Time Required to Receive Call and Notify Others	0.25
(3)	Cost of Labor to Process Request	$6.48
(4)	Labor-Related Overheads	$4.50
(5)	Total Contact Center NE Cost of Processing Request	$10.98
(6)	Cost of Labor per Hour for Supplier Services to Process Request	$35.22
(7)	Estimated Time Required to Process Drop Request (which produces a CME) and notify the Energy Supply Company	0.50
(8)	Cost of Labor to Process Request	$17.61
(9)	Labor-Related Overheads	$12.23
(10)	Total Supplier Services Cost of Processing Request	$29.84
(11)	Cost of Labor per Hour for Accounts Processing	$25.02
(12)	Estimated Time Required to to Build a Daily List of WFMs and Process the CME	0.25
(13)	Cost of Labor to Process Switch	$6.26
(14)	Labor-Related Overheads	$4.34
(15)	Total Accounts Processing Cost of Processing Request	$10.60
(16)	Total Transaction Costs for Off Cycle Meter Read for Switch to Competitive Supplier	$51.42
(17)	Proposed Off Cycle Meter Read Fee - Telemetered	$51.00
(18)	Current Off Cycle Meter Read Fee - Telemetered	$84.19
(19)	Decrease in Off Cycle Meter Read Fee	($33.19)
(20)	Test Year Count of Off Cycle Meter Read Fees Billed	0
(21)	Decrease in Off Cycle Meter Read Fee Revenue	$0.00

(1) Estimated average hourly wage per position based on employee complement.
(2) Estimated time required to complete transaction per department manager.
(4) test year average labor overheads
(6) Estimated average hourly wage per position based on employee complement.
(7) Estimated time required to complete transaction per department manager.
(9) test year average labor overheads
(11) Estimated average hourly wage per position based on employee complement.
(12) Estimated time required to complete transaction per department manager.
(14) test year average labor overheads
(16) Line (5) + Line (10) + Line (15)
(17) Line (16) truncated to zero decimal places
(18) Optional Off Cycle Meter Read for Switch of Supplier provision, RIPUC No. 2019-A
(19) Line (17) - Line (18)
(20) Per Company billing records
(21) Line (19) x Line (20)

Narragansett Electric
Off Cycle Meter Read for Switch of Supplier

Interval Data Meters Without Remote Interrogation (Non-Telemetered)

(1)	Cost of Labor for Contact Center NE	$25.93
(2)	Estimated Time Required to Receive Call and Notify Others	0.25
(3)	Cost of Labor to Process Request	$6.48
(4)	Labor-Related Overheads	$4.50
(5)	Total Contact Center NE Cost of Processing Request	$10.98
(6)	Cost of Labor per Hour for Supplier Services to Process Request	$35.22
(7)	Estimated Time Required to Process Drop Request (which produces a CME) and notify the Energy Supply Company	0.50
(8)	Cost of Labor to Process Request	$17.61
(9)	Labor-Related Overheads	$12.23
(10)	Total Supplier Services Cost of Processing Request	$29.84
(11)	Cost of Labor per Hour for Accounts Processing	$25.02
(12)	Estimated Time Required to to Build a Daily List of WFMs and Process the CME	0.25
(13)	Cost of Labor to Process Switch	$6.26
(14)	Labor-Related Overheads	$4.34
(15)	Total Accounts Processing Cost of Processing Request	$10.60
(16)	Cost of Labor per Hour for Customer Meter Services	$33.75
(17)	Estimated Time Required to Probe Meter	0.50
(18)	Cost of Labor to Probe Meter	$16.88
(19)	Labor-Related Overheads	$11.72
(20)	Total Customer Meter Services Cost to Read Meter	$28.59
(21)	Total Transaction Costs for off cycle read for switch to competitive supplier	$80.01
(22)	Proposed Off Cycle Meter Read Fee - Non-Telemetered	$80.00
(23)	Current Off Cycle Meter Read Fee - Non-Telemetered	$114.52
(24)	Decrease in Off Cycle Meter Read Fee	($34.52)
(25)	Test Year Count of Off Cycle Meter Read Fees Billed	0
(26)	Decrease in Off Cycle Meter Read Fee Revenue	$0

(1) Estimated average hourly wage per position based on employee complement.
(2) Estimated time required to complete transaction per department manager
(4) test year average labor overheads
(6) Estimated average hourly wage per position based on employee complement.
(7) Estimated time required to complete transaction per department manager
(9) test year average labor overheads
(11) Estimated average hourly wage per position based on employee complement.
(12) Estimated time required to complete transaction per department manager
(14) test year average labor overheads
(16) Estimated average hourly wage per position based on employee complement.
(17) Estimated time required to complete transaction per department manager
(19) test year average labor overheads
(21) Line (5) + Line (10) + Line (15) + Line (20)
(22) Line (21) truncated to zero decimal places
(23) Optional Off Cycle Meter Read for Switch of Supplier provision, RIPUC No. 2019-A
(24) Line (22) - Line (23)
(25) Per Company billing records
(26) Line (24) x Line (25)

Narragansett Electric
Commercial Enhanced Metering Options
One-time and Annual Fee Calculations

(1)	**Option One - Commercial:**	
(2)	Hourly Reporting Equipment - Wireless Interface - Company Owned Equipment	
(3)	Incremental Cost of Commercial Meter with Wireless Modem Installed	
(4)	Lump Sum Fee, Equipment Cost	$679.00
(5)	Annual Fee, Data Plan	$17.00
(6)	**Option Two - Commercial:**	
(7)	Hourly Reporting Equipment - Pulse Interface - Company Owned Equipment	
(8)	Incremental Cost of Commercial Meter with Internal Modem Installed	
(9)	Meter (Capitalized)	$177.00
(10)	Cost of Labor (based upon time to prepare meter and perform exchange)	$79.24
(11)	Labor - Related Overheads	$55.02
(12)	Transportation	$4.32
(13)	Estimated Materials (Telephone line surge suppresser, gel connectors, misc. wire, tape, etc.)	$35.00
(14)	**One Time Fee for Commercial Option Two**	$350.58
(15)	**Option Three - Commercial:**	
(16)	Hourly Reporting Equipment - Pulse Interface - Customer Owned Equipment	
(17)	Incremental Cost of Pulse Interface Box Installed	
(18)	Pulse Interface Box (Capitalized)	$30.00
(19)	Cost of Labor (based upon time to perform meter exchange, install pulse interface box, install pulses in meter and test)	$79.24
(20)	Labor - Related Overheads	$55.02
(21)	Transportation	$4.32
(22)	Material - Pulse Initiator (Estimated)	$5.00
(23)	**One Time Fee for Commercial Option Three**	$173.58

(4) Per Schedule 3(b), Page 2, line (9)
(5) Per Schedule 3(b), Page 2, line (10)
(10) Labor cost reflects estimate of 2.0 hours of meter worker time required to install meter with internal modem and complete meter exchange. This time estimate is based upon historic business practices. Labor cost is based upon the hourly wage of a meter worker.
(11) Average overhead accural rates for year ended June 30, 2017
(12) Reflects estimated transportation charges
(19) Labor cost reflects estimate of 2.0 hours of meter worker time required to install program and connect pulses in meter, complete meter exchange and test. This time estimate is based upon historical business practices. Labor cost is based upon the hourly wage of a meter worker per union labor agreement.
(20) Average overhead accural rates for year ended June 30, 2017
(21) Reflects estimated transportation charges

Narragansett Electric
Calculation of Monthly Charge for Enhanced Metering

(1)	**Service Option Two**	
(2)	Total Installation Cost of Enhanced Metering	
(3)	Equipment for this Option	$350.58
(4)	Proposed Annual Carrying Charge	18.96%
(5)	Annual Enhanced Metering Charge	$66.46
(6)	**Monthly Enhanced Metering Charge**	$5.54
(7)	**Service Option Three**	
(8)	Total Installation Cost of Enhanced Metering	
(9)	Equipment for this Option per	$173.58
(10)	Proposed Annual Carrying Charge	18.96%
(11)	Annual Enhanced Metering Charge	$32.91
(12)	**Monthly Enhanced Metering Charge**	$2.74

(2) Page 1, Line (14)
(4) Annual Carrying Charge
(5) Line (3) x Line (4).
(6) Line (5) ÷ 12
(9) Page 1, Line (23)
(11) Line (9) x Line (10)
(12) Line (11) ÷ 12

Narragansett Electric
Proposed Centerline Footage Rates forLine Extension Policy 1 and Policy 2
Overhead and Underground Costs

	(a) Year	(b) Number of Jobs	(c) Total Cost	(d) CFL	(e) Proposed Cost/Foot
(1)	**Overhead**	5	$80,637	2,140	$37.68
(2)	**Underground**	12	$395,729	10,610	$37.30

(e) Column (c) / Column (d)

(1)(b) Page 2, count of overhead jobs
(1)(c) Page 2, sum of 1(h) through 5(h)
(1)(d) Page 2, sum of 1(d) through 5(d)
(2)(b) Page 2, count of underground jobs
(2)(c) Page 2, sum of 7(h) through 18(h)
(2)(d) Page 2, sum of 7(d) through 18(d)

Narragansett Electric

Overhead Costs

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line #	**SAP Work Order**	**Year**	**Total Costs (Excludes Payments)**	**CLF**	**Payment**	**JO Pole Debits/Credits**	**NGrid Job Cost**	**Inflated (*) Actual Job Cost**	**$/FT**	**Town**
(1)	10021177863	2016	$16,112.76	305	$83.73	($2,000.00)	$14,112.76	$13,953.46	$45.75	SOUTH KINGSTOWN
(2)	10022387136	2016	$17,243.69	410	$1,842.11	($1,500.00)	$15,743.69	$15,565.97	$37.97	COVENTRY
(3)	10020108779	2016	$14,684.00	400	$1,846.29	($1,500.00)	$13,184.00	$13,035.18	$32.59	COVENTRY
(4)	10021358535	2016	$18,402.32	425	$2,093.30	($2,000.00)	$16,402.32	$16,217.17	$38.16	SOUTH KINGSTOWN
(5)	10019832990	2016	$21,614.70	600	$5,538.86	$500.00	$22,114.70	$21,865.07	$36.44	NORTH KINGSTOWN
(6)	**Total**		**$88,057.47**	**2,140**	**$11,404.28**	**($6,500.00)**	**$81,557.47**	**$80,636.85**	**$37.68**	

Underground Costs

Line #	SAP Work Order	Year	Total Costs (Excludes Payments)	CLF	Payment	JO Pole Debits/Credits	Actual Job Cost	Inflated (*) Actual Job Cost	$/FT	Town
(7)	10019656014	2016	$12,687.50	300	$3,992.70	$0.00	$12,687.50	$12,544.28	$41.81	RICHMOND
(8)	10016697079	2016	$41,821.05	350	$4,537.99	$0.00	$41,821.05	$41,348.97	$118.14	PORTSMOUTH
(9)	10020259518	2016	$39,995.89	410	$4,668.55	$0.00	$39,995.89	$39,544.42	$96.45	LINCOLN
(10)	10017552335	2016	$14,963.57	560	$6,072.48	$0.00	$14,963.57	$14,794.66	$26.42	EXETER
(11)	10016573223	2016	$13,468.39	600	$6,459.75	$0.00	$13,468.39	$13,316.35	$22.19	TIVERTON
(12)	10019968521	2016	$33,107.71	675	$9,755.26	$0.00	$33,107.71	$32,733.99	$48.49	SMITHFIELD
(13)	10018411966	2016	$36,021.26	775	$12,322.77	$0.00	$36,021.26	$35,614.65	$45.95	NORTH KINGSTOWN
(14)	10020765736	2016	$34,546.50	1,100	$14,068.64	$0.00	$34,546.50	$34,156.54	$31.05	GLOCESTER
(15)	10019388775	2016	$35,987.54	1,200	$15,256.92	$0.00	$35,987.54	$35,581.31	$29.65	CUMBERLAND
(16)	10017043617	2016	$33,584.07	1,310	$17,658.19	$0.00	$33,584.07	$33,204.97	$25.35	CHARLESTOWN
(17)	10017834906	2016	$77,102.28	1,370	$19,843.74	$0.00	$77,102.28	$76,231.95	$55.64	CRANSTON
(18)	10018781379	2016	$26,960.82	1,960	$26,818.98	$0.00	$26,960.82	$26,656.49	$13.60	COVENTRY
(19)	**Total**		**$400,246.58**	**10,610**	**$141,455.97**	**$0.00**	**$400,246.58**	**$395,728.58**	**$37.30**	

(*) The Handy Whitman electric utility inflation tables were used to escalate historical actual job costs to 2017 dollars.

Handy Whitman Electric Inflation Table	**2016**	**98.9%**

Compliance Attachment 22

Compliance Attachment 22

Narragansett Electric and Narragansett Gas

Existing Cost Recovery and Reconciling Mechanisms

The Narragansett Electric Company
Existing Electric and Gas Cost Recovery and Reconciling Mechanisms

The following is the Company's currently effective cost recovery and reconciling mechanisms. For those having individual tariff provisions governing their operation, the tariff provision is reflected.

Electric:

- Energy Efficiency Program Provision
- Infrastructure, Safety, and Reliability Provision
- LIHEAP Enhancement Plan Provision
- Long Term Contracting for Renewable Energy Recovery Provision
- Long Term Contracting for Renewable Energy Recovery Reconciliation Provision
- Net Metering Provision
- Pension Adjustment Mechanism Provision, as revised by the Settlement Agreement
- Qualifying Facilities Power Purchase Rate
- Renewable Energy Growth Program Cost Recovery Provision
- Revenue Decoupling Mechanism Provision, as revised by the Settlement Agreement
- Standard Offer Service Adjustment Provision
- Storm Fund Replenishment Provision
- Street Light Metering Pilot Cost Recovery Provision
- Transition Cost Adjustment Provision
- Transmission Service Cost Adjustment Provision
- Arrearage Management Plan Provision (proposed to be renamed Residential Assistance Provision as revised by the Settlement Agreement)
- Customer Credit Provision
- Environmental Response Fund
- Service Quality Plan

Gas:

- Distribution Adjustment Clause:
  - Infrastructure, Safety, and Reliability Plan Provision
  - Pension Adjustment Provision, as Revised by the Settlement Agreement
  - Revenue Decoupling Mechanism Provision
  - System Pressure Provision
  - Advanced Gas Technology Provision
  - Environmental Response Cost Provision
  - Service Quality Performance Provision
  - Earning Sharing Mechanism, as revised by the Settlement Agreement
  - Arrearage Management Plan Provision (proposed to be renamed Residential Assistance Provision as revised by the Settlement Agreement)

- Gas Cost Recovery Clause, as revised by the Settlement Agreement
- Energy Efficiency Surcharge Provision
- LIHEAP Enhancement Plan Provision

Compliance Attachment 23

Storm Contingency Fund

THE NARRAGANSETT ELECTRIC COMPANY
STORM CONTINGENCY FUND

The Storm Contingency Fund (Storm Fund) is subject to the provisions of the Joint Proposal and Settlement between the Company and the Division filed with the PUC on September 25, 2017 in Docket No. 4686 and approved by the PUC on April 27, 2018 (Docket 4686 Settlement Agreement). The interest rate on the Storm Fund balance is set at the customer deposit rate and shall be adjusted on March 1 annually, as approved by the PUC in Docket No. 2509.[1]

In addition to the base distribution rate contributions to the Storm Fund, the Company will also credit additional revenue to the Storm Fund as follows:

(1) 50 percent of all revenue received by the Company from attachment and other telecommunication company fees for use of distribution plant in excess of $850,000 annually are credited to the Storm Fund on an annual basis;[2]

(2) For major storm events occurring after April 27, 2018, the Company will credit the Storm Fund 75 percent of the Net Revenue (as hereinafter defined) received by Narragansett Electric or Narragansett Gas, as appropriate, for performing storm response services in other jurisdictions. The term "Net Revenue" is defined as the proceeds received or cost reductions achieved for base labor and non-incremental labor overhead costs on all labor (*i.e.*, not just base labor) charged for storm restoration services provided to other utilities, whether affiliated or non-affiliated, less an amount equal to 53.20 percent for Narragansett Electric and

[1] See also Docket No. 4686 Settlement Agreement, Paragraph (12)(a), at 3.
[2] See Joint Proposal and Settlement between the Company and the Division filed with the PUC on September 25, 2017 in Docket No. 4686 and approved by the PUC on April 27, 2018 (Docket No. 4686 Settlement Agreement), Paragraph (12)(d); see also Report and Order No. 18037, at 3 in Docket No. 3617.

THE NARRAGANSETT ELECTRIC COMPANY
STORM CONTINGENCY FUND

55.18 percent for gas, which are the labor capitalization rates set in this proceeding. The labor capitalization rate will be reset in each general rate case for Narragansett Electric. The Company will credit the Net Revenue received for Narragansett Electric storm response services performed in other jurisdictions, including those outside of National Grid USA operating companies' service territories, to the Storm Fund. The Company will credit the Net Revenue received for Narragansett Gas storm response services performed in other jurisdictions, including those outside of National Grid USA operating companies' service territories, back to customers through the Distribution Adjustment Charge, applicable.

In addition, the following provisions apply to the Storm Fund effective with the implementation of new base distribution rates in this proceeding:

(1) In the Docket No. 4686 Settlement Agreement approved by the PUC, the Company agreed to make an adjustment to charges to the Storm Fund to remove base labor and overheads of Service Company employees to the extent those charges are already being recovered through Narragansett Electric's base distribution rates. For major storms that occur after the effective date of new base distribution rates in the Company's most recently completed general rate case, this percentage will be based on the percentage of base labor of New England-based Service Company employees who charge Narragansett Electric during the test year in that rate case. This will be the percentage of New England-based

THE NARRAGANSETT ELECTRIC COMPANY
STORM CONTINGENCY FUND

Service Company costs that are effectively recovered in base distribution rates. For major storms, that percentage of Service Company base labor and overheads will be excluded from the Storm Fund.

For major storms that occur after the effective date of new base distribution rates in this proceeding, the percentage of base labor of New England-based Service Company employees who charged Narragansett Electric during the Test Year in this proceeding was 6.82 percent. This represents the percentage of New England Service Company costs that are effectively recovered in base distribution rates and will be excluded from the Storm Fund. This percentage will be reset in each general rate case for Narragansett Electric;

(2) The Storm Fund threshold amount will be increased to $1.1 million for storm events that occur on or after September 1, 2018. The threshold amount will escalate automatically each January 1 using a 50/50 weighting of the change in the Gross Domestic Product Chain-type Index (GDP-CTI) and All Urban Consumer Price Index (CPI-U).[3] The first escalation of this threshold amount will occur on January 1, 2020; and

(3) The Storm Fund will no longer be subject to a deductible, and no provision for deductibles will be included in base distribution rates.[4]

[3] This is the same method used to calculate inflation in this proceeding.
[4] See Docket No. 4686 Settlement Agreement, Paragraph (8), at 3.

Compliance Attachment 24

Compliance Attachment 24

Company's Response to PUC 4-1 (Supplemental)

PUC 4-1 SUPPLEMENTAL

Request:

Please recalculate the revenue requirement for each Narragansett Electric and Narragansett Gas that results from the changes to the tax code made in H.R.-1 The Tax Cuts & Jobs Act. If the companies are still working through all of the Act to determine all of the impacts, at a minimum, please recalculate the revenue requirement to reflect the change in the corporate tax rate from 35% to 21% and supplement the response after full analysis has been completed.

Response:

As suggested by the question, adjustments to the Company's proposed revenue requirements for Narragansett Electric and Narragansett Gas are appropriate to account for revisions to the corporate tax rate modified by the federal Tax Cuts and Jobs Act (Tax Act). There are several ramifications that flow from the change in the corporate tax rate and some of these ramifications will take time to evaluate and quantify. National Grid is fully engaged in the process of identifying the cost reductions that will flow to customers of all of its regulated utility operations. It is clear that the change in tax rate will have an impact on both annual income-tax expense and balances of Accumulated Deferred Income Tax and Excess Deferred Federal Income Tax. Also, it is clear that it will be necessary to align the Company's proposed revenue requirements with the specifications of the Tax Act by the time that rates go into effect for this proceeding.

The Company has not yet had sufficient time to rerun all of the revenue requirement models to determine the precise reduction that would flow through the Company's entire revenue requirement proposals for this proceeding as a result of the change in corporate tax rate. Although it is a relatively straightforward calculation for the first year revenue requirement, flowing the change through the future years is a more involved exercise. For the first year impact, the Company estimates a reduction to the revenue requirements of approximately $19.3 million in total for Rhode Island customers, which is a $9.7 million reduction for Narragansett Electric and a $9.6 million reduction for Narragansett Gas. Please refer to Attachment PUC 4-1 for summary revenue requirement schedules reflecting this reduction.

The Company will supplement this response as soon as reasonably possible to provide a more detailed analysis.

Supplemental Response:

On March 2, 2018, the Company submitted revised revenue requirements for Narragansett Electric and Narragansett Gas with the Public Utilities Commission (PUC) reflecting the reduction in the federal income tax rate from 35 percent to 21 percent, and also recalculated the projected deferred income tax components of rate base to reflect a provision of the Tax Act that

Prepared by or under the supervision of: Melissa Little and Pamela Bushmich

ceases bonus depreciation on capital investment after September 27, 2017. As a consequence of the reduction in the federal income tax rate, the Company restated all of its net deferred tax liability balances based on the new 21 percent federal income tax rate because the Company will be paying income taxes as the book/tax timing differences reverse at that 21 percent federal income tax rate. The Company's net deferred tax liability is a liability for income taxes to be paid in the future to the federal government. The 14 percent decrease to the federal income tax rate and aforementioned restatement of the Company's net deferred tax liability balances reflects the fact that the Company's liability to the federal government has been reduced. Deferred taxes for the Company are primarily the result of differences in the timing of when a cost is expensed (*i.e.*, deducted) on its federal income tax return, and when it is expensed on the Company's books. These are referred to as "book-to-tax return differences" or "book/tax timing differences". In general, costs are expensed on an accelerated basis for tax return purposes than they are on the Company's books. The most prevalent book/tax timing difference relates to plant which is expensed for tax purposes faster than it is depreciated on the Company's books.

With the limited exception of the change in deferred income taxes associated with non-recoverable expenses, the Company has recorded an excess deferred tax liability to offset the net reduction to its net deferred tax liability balances. This excess deferred tax liability is a regulatory liability account representing an amount ultimately owed entirely to customers. Certain property related excess deferred taxes are referred to as "protected" excess deferred taxes. Pursuant to the Tax Act, the timing of the pass back of protected excess deferred taxes must align with the timing of when the Company will receive the benefit from the federal government of the reduction in the tax rate. This will occur when the underlying book/tax timing differences reverse and the Company ultimately pays income tax at a 21 percent tax rate for a cost that it deducted prior to the Tax Act at the 35 percent tax rate then in effect. Until that time, the Company has no benefit to return to customers. The Company would violate the normalization rules under the Tax Act if it were to provide customers with the benefit of protected excess deferred taxes prior to the time that it earned that benefit. Protected excess deferred income taxes will be passed back to customers beginning September 1, 2018 when new base distribution rates go into effect, through the end of the depreciable book life of the last fully depreciated asset that was placed into service prior to January 1, 2018.

Certain plant-related excess deferred taxes and all non-plant related excess deferred taxes are considered to be "non-protected". The plant-related non-protected excess deferred taxes include those associated with deferred income taxes generated by the "capital repairs" tax deduction for certain plant assets recorded on the Company's books that were eligible for immediate deduction as an expense on the Company's federal income tax return. There are no restrictions on the timing in which non-protected excess deferred income taxes are returned to customers; however, it would be prudent to align the timing of non-protected amounts within a reasonable period of time in which the Company will earn the benefit. Should federal income tax rates increase in the future, in addition to increased customers' bills attributable to the increase in the income tax rates, customers would also be required to return any non-protected excess deferred taxes that were prematurely provided to them.

At this time, the Company estimates that total protected and non-protected excess deferred taxes to be approximately $116 million and $51 million for Narragansett Electric distribution and Narragansett Gas, respectively. Please see the components of the Company's estimated excess deferred income taxes in the Company's responses to Division 31-1 and Division 31-2, Attachment DIV 31-1, and Attachment DIV 31-2. These estimates are based on the temporary differences in effect on December 31, 2017 adjusted by an estimate of the temporary difference movement between December and March 31, 2018.

Attachment DIV 31-1 and Attachment DIV 31-2 present the data categorized by property related and non-property related amounts. The Net Operating Loss (NOL) deferred taxes are included with the property related deferred taxes as the NOL is caused by the plant deductions for repairs and bonus depreciation and is currently included in rate base calculations. The Company has also estimated the split of deferred taxes between the transmission and distribution operations. Approximately $98 million of the Narragansett Electric distribution excess deferred taxes of $116 million is property-related and the remaining $18 million is non-property related. Approximately $47 million of the Narragansett Gas excess deferred taxes of $51 million is property-related and the remaining $4 million is non-property related. The Company is unable to provide the amounts for protected and unprotected property related deferred taxes at this time. The Company currently keeps all tax related depreciation and the tax basis of its plant assets in its PowerTax system. At present, the PowerTax system calculates book-to-tax depreciation timing differences for the current fiscal year only. To identify and to calculate protected and unprotected property balances, the Company needs to implement a deferred tax module in PowerTax to match up the historic book depreciation amounts, by vintage year of investment and by asset type. The new deferred tax model is also needed to accurately determine the timing of the reversal of the underlying plant related book/tax timing differences, which will establish the timing for the pass back to customers of the protected excess deferred federal income taxes. The project is currently under bid and is expected to commence in May 2018.

The Company has recorded the $116 million and $51 million estimates of customer related excess deferred federal income tax to a tax regulatory liability account as described above in recognition that customers will be refunded those excess deferred taxes. The Company will be able to calculate more accurately excess deferred taxes when its fiscal year ended March 31, 2018 audited financial statements are completed during the late summer. These estimates will become final with the filing of the fiscal year ended March 31, 2018 federal income tax return in December 2018, and the excess deferred tax regulatory liability will be adjusted to reflect that final balance.

At this time, the Company is proposing to reduce its Narragansett Electric and Narragansett Gas revenue requirements by a high level estimate of excess deferred income tax amortization of $4.1

million and $1.8 million, respectively. The Company would propose to true up these estimates in a supplemental compliance filing to be filed with the PUC in Docket No. 4770 after the Company files its Fiscal Year 2018 federal income tax return in December 2018. The true-up would reconcile the impact of the actual excess deferred tax amortization with the estimated amounts identified above, and would determine the final revenue requirements for Narragansett Electric and Narragansett Gas effective September 1, 2018. From these supplemental revenue requirements, the Company will calculate the difference between the revenue requirements it began recovering September 1, 2018 and the revenue requirements in the supplemental compliance filing in Docket No. 4770, and proposes to reflect the supplemental compliance revenue requirements, annual target revenue (for Narragansett Electric) and target revenue per customer (for Narragansett Gas) in the next electric and gas Revenue Decoupling Mechanism (RDM) reconciliation filings. In addition, the Company will also evaluate the appropriateness of proposing supplemental compliance rate design schedules based upon the amount of the true-up to the revenue requirements or whether to provide annual adjustments in the Narragansett Electric and Narragansett Gas RDM reconciliation filings if the differences are determined to be relatively small such that adjusting base distribution rates would not be needed.

In developing the high level estimate of excess deferred income tax amortization, the Company must be careful not to violate the normalization rules of the Tax Act and amortize more protected excess deferred taxes than allowed. Also, as described above, the Company needs to implement a deferred tax module in PowerTax before it can determine the protected and non-protected portions of its property related excess deferred taxes. For this high level estimate, the Company proposes to amortize all property related excess deferred taxes over an approximate 30 year average service life of its assets. The composite depreciation rate currently in effect is 3.40 percent and 3.38 percent for Narragansett Electric distribution plant and Narragansett Gas plant, respectively, both of which equate to average service lives of just under 30 years. The Company expects that the majority of its non-protected excess deferred taxes will be property related; consequently, the Company proposes to amortize all non-protected excess deferred taxes over the average remaining service lives of 22 years and 25 years for Narragansett Electric distribution and Narragansett Gas property, respectively. The calculation of these lives was provided in the Company's response to Division 31-4, Attachment DIV 31-4. The high level estimate of excess deferred tax amortization is calculated as follows:

Narragansett Electric:	
Property related excess deferred taxes	$98 million/30 years=$3.3 million
Non-property excess deferred taxes	$18 million/22 years=$0.8 million
Narragansett Gas:	
Property related excess deferred taxes	$47 million/30 years=$1.6 million
Non-property excess deferred taxes	$ 4 million/25 years=$0.2 million

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Prior to the commencement of hearings in this docket, the Company will update its Narragansett Electric and Narragansett Gas revenue requirements reflecting the excess deferred tax amortization of $4.1 million and $1.8 million for Narragansett Electric distribution and Narragansett Gas, respectively. The overall combined benefits of the Tax Act reflecting the change in the federal income tax rates from 35 percent to 21 percent, the changes to the bonus depreciation rules, and the proposed return of excess deferred income taxes total $13.8 million for Narragansett Electric and $11.4 million for Narragansett Gas.

It is important to note that this does not reflect an allocation of net excess deferred taxes of National Grid USA Service Company, Inc. (Service Company). All Service Company net excess deferred tax amounts are unprotected. The Company is still determining the timing of the reversal of the underlying deferred taxes as well as the Company's allocated share. Certain excess deferred tax amounts are in an asset position and could result in an increase in amortization expense. The Company will supplement this response as soon as reasonably possible once an estimate of Service Company amortization can be determined.

Prepared by or under the supervision of: Melissa Little and Pamela Bushmich

Compliance Attachment 25

Compliance Attachment 25

Illustrative Calculation of Gas Growth

Narragansett Gas
d/b/a National Grid
Computation of Class RDM Revenue per Customer - Illustrative
Rate Year Ending August 31, 2019

Line No.		Col A Settled rate Designed Class Rev Requirement	Col B Settled Growth Capital Rev Requirement	Col C Illustrative Actual Growth Capital Rev Requirement	Col D = A - B + C Actual Rate Year Rev Target	Col E Illustrative Actual Avg. Rate Year No. Customers	Col G = D/E Actual RDM Target
	RDM Classes						
1	Res Non Ht(incl Low Income)	$4,984,876	$83,446	$113,788	$5,015,217	24,346	$206.00
2	Res HT (incl Low Income)	$144,104,491	$2,412,298	$2,856,144	$144,548,336	203,649	$709.79
3	C&I Small	$17,730,128	$296,801	$358,574	$17,791,901	18,328	$970.75
4	C&I Medium	$25,676,399	$429,821	$545,438	$25,792,016	4,599	$5,608.18
5							
6	Sub-Total RDM	$192,495,894	$3,222,367	$3,873,943	$193,147,471	250,922	

Column Notes

Column A - Per Settlement Rate Design
Column B - RDM Class related Growth Capital revenue requirement per Settlement
Column C - Column C - Illustrative Actual RDM Class related Growth Capital revenue requirement for the Rate Year ending 8/31/19. Will reflect Actual RDM Class related growth Capital revenue requirement for the Rate Year when known.
Column C - Illustrative Actual Average number of customers for the Rate Year ending 8/31/19. Will reflect Actual Average number of customers for the Rate Year when known.

Narragansett Gas
d/b/a National Grid
Forecasted Growth Capital Data July 2017-August 2019 as Filed

Line No.		Final Rate Design	**Initial Filing** Rate Base With Growth	Final Rate Design Alloc	Fcst Growth Capital Revenue Requirement	Fcst Growth Capital Revenue Requirement	Fcst. No. Customers
		Col A	Col B	Col C = B/Total B	Col D	Col E = D*C	Col F
1	Res Non Ht(incl Low Income)	$4,984,876	$19,445,726	2%		83,446	17,003
2	Res HT (incl Low Income)	$144,104,491	$488,099,847	66%		2,412,298	227,099
3	Total	$149,089,367	$507,545,573	68%		$2,495,745	244,102
4							
5	C&I Small	$17,730,128	$61,278,442	8%		296,801	19,276
6	C&I Medium	$25,676,399	$93,212,447	12%		429,821	5,201
7	Sub-Total	$43,406,527	$154,490,889	20%		$726,622	24,477
8							
9	C&I Large LLF	$10,944,175	$42,474,377	5%		183,205	
10	C&I Large HLF	$3,818,416	$17,136,732	2%		63,920	
11							
12	C&I XLarge LLF	$2,037,431	$7,429,139	1%		34,106	
13	C&I XLarge HLF	$8,719,040	$33,165,069	4%		145,956	
14							
15	Sub-Total	$25,519,062	$100,205,317	12%		$427,187	268,579
16							
17	Sub-Total C&I	$68,925,589	$254,696,206	32%		$1,153,809	
18							
19	Total	$218,014,956	$762,241,779	100%	3,649,554	$3,649,554	
20							
21							
22	RDM	$192,495,894	$662,036,462				
23	NON RDM	$25,519,062	$100,205,317				
24	Total	$218,014,956	$762,241,779				
25							

Narragansett Gas
d/b/a National Grid
Illustrative Actual Growth Capital Data July 2017-August 2019

Line No.		Final Rate Design	**Initial Filing** Rate Base With Growth	Final Rate Design Alloc	Actual Growth Capital Revenue Requirement *	Actual Growth Capital Revenue Requirement	Actual No. Customers
		Col A	Col B	Col C = B/Total B	Col D	Col E= D*C	Col F
	RDM Classes ONLY						
1	Res Non Ht(incl Low Income)	$4,984,876	$19,445,726	3%		113,788	24,346
2	Res HT (incl Low Income)	$144,104,491	$488,099,847	74%		2,856,144	203,649
3	Total	$149,089,367	$507,545,573	77%		$2,969,931	227,995
4							
5	C&I Small	$17,730,128	$61,278,442	9%		358,574	18,328
6	C&I Medium	$25,676,399	$93,212,447	14%		545,438	4,599
7	Sub-Total	$43,406,527	$154,490,889	23%		$904,012	22,927
8							
9	Total	$192,495,894	$662,036,462	100%	3,873,943	$3,873,943	250,922
10							
11							

** Includes Revenue Requirement associated with Actual growth capital related to RDM rate classes and an allocation of Growth related System Reinforcements.

Narragansett Gas
d/b/a National Grid
Computation of Growth Capital Investment Revenue Requirement as Filed
Rate Year Ending August 31, 2019

Line No		Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment	$20,364,203	$3,325,333	$19,952,000
2	Cumulative Growth Capital	$20,364,203	$23,689,536	$43,641,536
3				
4	Deferred Tax Calculation:			
5	Composite Book Depreciation Rate			
6	Tax Depreciation Rate			
7				
8	Tax Depreciation	$1,375,602	$1,594,792	$2,347,974
9	Cumulative Tax Depreciation	$1,375,602	$2,970,394	$5,318,367
10				
11	Book Depreciation	$344,155	$692,993	$980,313
12	Cumulative Book Depreciation	$344,155	$1,037,148	$2,017,462
13				
14	Cumulative Book / Tax Timer	$1,031,447	$1,933,245	$3,300,906
15	Effective Tax Rate	28.00%	21.00%	21.00%
16	Deferred Tax Reserve	$288,805	$405,982	$693,190
17				
18	Rate Base Calculation:			
19	Cumulative Incremental Capital Included in Rate Base	20,364,203	23,689,536	43,641,536
20	Accumulated Depreciation	($344,155)	($1,037,148)	($2,017,462)
21	Deferred Tax Reserve	($288,805)	($405,982)	($693,190)
22	Year End Rate Base	**$19,731,243**	**$22,246,407**	**$40,930,884**
23				
24	Revenue Requirement Calculation:			
25	Average Rate Base			$31,588,645
26	Pre-Tax ROR			8.45%
27	Return and Taxes			$2,669,241
28	Book Depreciation			$980,313
29				
30	**Annual Revenue Requirement**			**$3,649,554**

1/ Weighted Average Cost of Capital per Settlement RIPUS Docket Nos. 4770/4780

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	47.85%	5.10%	2.44%		2.44%
Short Term Debt	1.11%	1.76%	0.02%		0.02%
Preferred Stock	0.09%	4.50%	0.00%		0.00%
Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
	100.00%		7.19%	1.26%	8.45%

Narragansett Gas
d/b/a National Grid
Computation of Growth Capital Rate Base as Filed
Rate Year Ending August 31, 2019

Line No		Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment			$19,952,000
2	Cumulative Growth Capital	$0	$0	$19,952,000
3				
4	Deferred Tax Calculation:			
5	Composite Book Depreciation Rate			3.05%
6	Tax Depreciation			3.75%
7				
8	Tax Depreciation			$748,200
9	Cumulative Tax Depreciation			$748,200
10				
11	Book Depreciation			$304,268
12	Cumulative Book Depreciation			$304,268
13				
14	Cumulative Book / Tax Timer			$443,932
15	Effective Tax Rate			21.00%
16	Deferred Tax Reserve			$93,226
17				
18	Rate Base Calculation:			
19	Cumulative Incremental Capital Included in Rate Base			$19,952,000
20	Accumulated Depreciation			($304,268)
21	Deferred Tax Reserve			($93,226)
22	Year End Rate Base			**$19,554,506**

Narragansett Gas
d/b/a National Grid
Computation of Growth Capital Rate Base as Filed
12 Months Ended June 30, 2018

Line No			Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment		$20,364,203	$0	$0
2	Cumulative Growth Capital		$20,364,203	$20,364,203	$20,364,203
3					
4	Deferred Tax Calculation:				
5	Composite Book Depreciation Rate		3.38%	3.38%	3.05%
6	Tax Depreciation Rate	1/	6.76%	7.22%	6.68%
7					
8	Tax Depreciation		$1,375,602	$1,470,092	$1,359,718
9	Cumulative Tax Depreciation		$1,375,602	$2,845,694	$4,205,412
10					
11	Book Depreciation		$344,155	$688,310	$621,108
12	Cumulative Book Depreciation		$344,155	$1,032,465	$1,653,573
13					
14	Cumulative Book / Tax Timer		$1,031,447	$1,813,229	$2,551,838
15	Effective Tax Rate		28.00%	21.00%	21.00%
16	Deferred Tax Reserve		$288,805	$380,778	$535,886
17					
18	Rate Base Calculation:				
19	Cumulative Incremental Capital Included in Rate Base		$20,364,203	20,364,203	20,364,203
20	Accumulated Depreciation		($344,155)	($1,032,465)	($1,653,573)
21	Deferred Tax Reserve		($288,805)	($380,778)	($535,886)
22	Year End Rate Base		**$19,731,243**	**$18,950,960**	**$18,174,744**

1/ From FY 2019 Gas Infrastructure, Safety, and Reliability Plan Proposal Filing, Section 3, Attachment 1-Supp2

		FY18, Page 5	FY19, Page 3	
a	Bonus Depreciation, Line 12	$7,236,739	$0	
b	Remaining Tax Depreciation, Line 18	$814,133	$1,077,379	
c	a + b	$8,050,872	$1,077,379	
d	Plant Additions, Line 1	$93,077,000	$100,772,000	
e	Tax Depreciation Rate (c / d)	8.65%	1.07%	
f	Proration to 12 months ended June 30, 2018	75%	25%	
g	Blended Tax Depreciation	6.49%	0.27%	6.76%

Narragansett Gas
d/b/a National Grid
Computation of Growth Capital Rate Base as Filed
Two Months Ended August 31, 2018

Line No		Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment	$0	$3,325,333	$0
2	Cumulative Growth Capital	$0	$3,325,333	$3,325,333
3				
4	Deferred Tax Calculation:			
5	Composite Book Depreciation Rate		3.38%	3.05%
6	Tax Depreciation		3.75%	7.22%
7				
8	Tax Depreciation		$124,700	$240,056
9	Cumulative Tax Depreciation		$124,700	$364,756
10				
11	Book Depreciation		$4,683	$54,937
12	Cumulative Book Depreciation		$4,683	$59,620
13				
14	Cumulative Book / Tax Timer		$120,017	$305,135
15	Effective Tax Rate		21.00%	21.00%
16	Deferred Tax Reserve		$25,204	$64,078
17				
18	Rate Base Calculation:			
19	Cumulative Incremental Capital Included in Rate Base		$3,325,333	3,325,333
20	Accumulated Depreciation		($4,683)	($59,620)
21	Deferred Tax Reserve		($25,204)	($64,078)
22	Year End Rate Base		**$3,295,447**	**$3,201,634**

Narragansett Gas
d/b/a National Grid
Ilustrative Computation of Actual Growth RDM-Related Capital Investment Revenue Requirement
Rate Year Ending August 31, 2019

Line No		Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment	$21,000,000	$3,166,667	$23,000,000
2	Cumulative Growth Capital	$21,000,000	$24,166,667	$47,166,667
3				
4	Deferred Tax Calculation:			
5	Composite Book Depreciation Rate			
6	Tax Depreciation Rate			
7				
8	Tax Depreciation	$1,472,100	$1,634,740	$2,493,272
9	Cumulative Tax Depreciation	$1,472,100	$3,106,840	$5,600,112
10				
11	Book Depreciation	$354,900	$714,260	$1,043,566
12	Cumulative Book Depreciation	$354,900	$1,069,160	$2,112,726
13				
14	Cumulative Book / Tax Timer	$1,117,200	$2,037,680	$3,487,386
15	Effective Tax Rate	28.00%	21.00%	21.00%
16	Deferred Tax Reserve	$312,816	$427,913	$732,351
17				
18	Rate Base Calculation:			
19	Cumulative Incremental Capital Included in Rate Base	$21,000,000	$24,166,667	$47,166,667
20	Accumulated Depreciation	($354,900)	($1,069,160)	($2,112,726)
21	Deferred Tax Reserve	($312,816)	($427,913)	($732,351)
22	Year End Rate Base	**$20,332,284**	**$22,669,594**	**$44,321,590**
23				
24	Revenue Requirement Calculation:			
25	Average Rate Base			$33,495,592
26	Pre-Tax ROR			8.45%
27	Return and Taxes			$2,830,378
28	Book Depreciation			$1,043,566
29				
30	**Annual Revenue Requirement**			**$3,873,943**

1/ Weighted Average Cost of Capital per Settlement RIPUS Docket Nos. 4770/4780

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	47.85%	5.10%	2.44%		2.44%
Short Term Debt	1.11%	1.76%	0.02%		0.02%
Preferred Stock	0.09%	4.50%	0.00%		0.00%
Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
	100.00%		7.19%	1.26%	8.45%

Narragansett Gas
d/b/a National Grid
Illustrative Computation of Actual RDM-Related Growth Capital Rate Base
Rate Year Ending August 31, 2019

Line No		Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment			$23,000,000
2	Cumulative Growth Capital	-	-	$23,000,000
3				
4	Deferred Tax Calculation:			
5	Composite Book Depreciation Rate			3.05%
6	Tax Depreciation			3.75%
7				
8	Tax Depreciation			$862,500
9	Cumulative Tax Depreciation			$862,500
10				
11	Book Depreciation			$350,750
12	Cumulative Book Depreciation			$350,750
13				
14	Cumulative Book / Tax Timer			$511,750
15	Effective Tax Rate			21.00%
16	Deferred Tax Reserve			$107,468
17				
18	Rate Base Calculation:			
19	Cumulative Incremental Capital Included in Rate Base			$23,000,000
20	Accumulated Depreciation			($350,750)
21	Deferred Tax Reserve			($107,468)
22	Year End Rate Base			**$22,541,783**

Narragansett Gas
d/b/a National Grid
Illustrative Computation of Actual RDM-Related Growth Capital Rate Base
12 Months Ended June 30, 2018

Line No		Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment	$21,000,000	$0	$0
2	Cumulative Growth Capital	$21,000,000	$21,000,000	$21,000,000
3				
4	Deferred Tax Calculation:			
5	Composite Book Depreciation Rate	3.38%	3.38%	3.05%
6	Tax Depreciation Rate	7.01%	7.22%	6.68%
7				
8	Tax Depreciation	$1,472,100	$1,515,990	$1,402,170
9	Cumulative Tax Depreciation	$1,472,100	$2,988,090	$4,390,260
10				
11	Book Depreciation	$354,900	$709,800	$640,500
12	Cumulative Book Depreciation	$354,900	$1,064,700	$1,705,200
13				
14	Cumulative Book / Tax Timer	$1,117,200	$1,923,390	$2,685,060
15	Effective Tax Rate	28.00%	21.00%	21.000%
16	Deferred Tax Reserve	$312,816	$403,912	$563,863
17				
18	Rate Base Calculation:			
19	Cumulative Incremental Capital Included in Rate Base	$21,000,000	21,000,000	21,000,000
20	Accumulated Depreciation	($354,900)	($1,064,700)	($1,705,200)
21	Deferred Tax Reserve	($312,816)	($403,912)	($563,863)
22	Year End Rate Base	**$20,332,284**	**$19,531,388**	**$18,730,937**

Narragansett Gas
d/b/a National Grid
Illustrative Computation of Actual RDM-Related Growth Capital Rate Base
Two Months Ended August 31, 2018

Line No		Twelve Months Ended June 30, 2018 (a)	Two Months Ended August 31, 2018 (b)	Rate Year Ending August 31, 2019 (c)
1	Annual Growth Capital Investment	$0	$3,166,667	$0
2	Cumulative Growth Capital	$0	$3,166,667	$3,166,667
3				
4	Deferred Tax Calculation:			
5	Composite Book Depreciation Rate		3.38%	3.05%
6	Tax Depreciation		3.75%	7.22%
7				
8	Tax Depreciation		$118,750	$228,602
9	Cumulative Tax Depreciation		$118,750	$347,352
10				
11	Book Depreciation		$4,460	$52,316
12	Cumulative Book Depreciation		$4,460	$56,776
13				
14	Cumulative Book / Tax Timer		$114,290	$290,576
15	Effective Tax Rate		21.00%	21.00%
16	Deferred Tax Reserve		$24,001	$61,021
17				
18	Rate Base Calculation:			
19	Cumulative Incremental Capital Included in Rate Base		$3,166,667	3,166,667
20	Accumulated Depreciation		($4,460)	($56,776)
21	Deferred Tax Reserve		($24,001)	($61,021)
22	Year End Rate Base		**$3,138,206**	**$3,048,870**

Compliance Attachment 26

List of Charitable Organizations

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Compliance Attachment 27

Address for Notices to the Settling Parties

NOTICE ADDRESS FOR SETTLING PARTIES

The Notice Address for the Settling Parties is as follows:

If to The Narragansett Electric Company d/b/a National Grid: Bill Malee Celia O'Brien, Esq. National Grid 40 Sylvan Road Waltham, MA 02451 bill.malee@nationalgrid.com celia.obrien@nationalgrid.com	If to the Rhode Island Division of Public Utilities and Carriers: Jonathan Schrag Deputy Administrator Rhode Island Division of Public Utilities and Carriers 89 Jefferson Blvd. Warwick, RI 02888 jonathan.schrag@dpuc.ri.gov
If to the Rhode Island Office of Energy Resources: Andrew Marcaccio Rhode Island Office of Energy Resources 1 Capitol Hill Providence, RI 02908 andrew.marcaccio@doa.ri.gov	If to Conservation Law Foundation: Jerry Elmer Conservation Law Foundation 235 Promenade Street, Suite 560, Mailbox 28 Providence, RI 02908 jelmer@clf.org

NOTICE ADDRESS FOR SETTLING PARTIES

If to the Department of the Navy and the Federal Executive Agencies: Kelsey A. Harrer, Esq. Assistant Counsel NAVFAC LANT, Code 09C7 6506 Hampton Blvd. Bldg. A Norfolk, VA 23508-1278 kelsey.a.harrer@navy.mil Kay Davoodi Director, Utilities Rates and Studies Office NAVFAC HQ, Department of the Navy 1322 Patterson Avenue SE Suite 1000 Washington Navy Yard, D.C. 20374 khojasteh.davoodi@navy.mil	If to Energy Consumers Alliance of New England d/b/a People's Power & Light, Sierra Club, & Natural Resources Defense Council: James G. Rhodes, Esq. Rhodes Consulting 860 West Shore Road Warwick, RI 02889 james@jrhodeslegal.com Sierra Club Josh Berman, Staff Attorney Sierra Club Environmental Law Program 50 F St. NW, 8th Floor Washington, DC 20001 Josh.Berman@sierraclub.org; Aaron Isherwood Coordinating Attorney Sierra Club Environmental Law Program 2101 Webster St., Suite 1300 Oakland, CA 94612 aaron.isherwood@sierraclub.org
If to Northeast Clean Energy Council: Janet Gail Besser Executive Vice President Northeast Clean Energy Council 250 Summer Street, 5th Floor Boston, MA 02210 jbesser@necec.org Joseph A. Keough Jr., Esq. Keough + Sweeney, Ltd. 41 Mendon Avenue Pawtucket, RI 02861 jkeoughjr@keoughsweeney.com;	If to Wal-Mart Stores, L.P. and Sam's East, Inc.: Melissa M. Horne, Esq. Of Counsel Higgins, Cavanagh & Cooney, LLP 10 Dorrance Street, Suite 400 Providence, RI 02903 mhorne@hcc-law.com

NOTICE ADDRESS FOR SETTLING PARTIES

If to The George Wiley Center: Jennifer L. Wood, Esq. Executive Director John Willumsen-Friedman, Esq. Deputy Director Rhode Island Center for Justice 1 Empire Plaza, Suite 410 Providence, RI 02903 jwood@centerforjustice.org jwillumsen@centerforjustice.org	If to Direct Energy Business, LLC, Direct Energy Services, LLC and Direct Energy Solar: Marc A. Hanks Senior Manager Corporate and Regulatory Affairs Direct Energy 24 Gary Drive Westfield, MA 01085 marc.hanks@directenergy.com Craig Waksler Counsel Eckert Seamans Cherin & Mellott, LLC Two International Place, 16th Floor Boston, MA 02130 cwaksler@eckertseamans.com
If to ChargePoint, Inc.: Jesse S. Reyes, Esq. Brown Rudnick, LLP One Financial Center Boston, MA 02111 jreyes@brownrudnick.com	If to Acadia Center: Amy E. Boyd Senior Attorney Acadia Center 31 Milk St., Suite 501 Boston, MA 02109 aboyd@acadiacenter.org Erika Niedowski Policy Advocate Acadia Center 144 Westminster Street, Suite 203 Providence, RI 02903 eniedowski@acadiacenter.org

NOTICE ADDRESS FOR SETTLING PARTIES

If to New Energy Rhode Island:	If to National Railroad Passenger Corporation (Amtrak):
Seth Handy, Esq. Handy Law, LLC 42 Weybosset Street Providence, RI 02903 seth@handylawllc.com	Robert A. Weishaar, Jr., Esq. McNees Wallace & Nurick LLC 1200 G Street NW, Suite 800 Washington, DC 20005 bweishaar@mcneeslaw.com

Compliance Attachment 28

Compliance Attachment 28

Benefit Cost Analysis and Supporting Inputs for Performance Incentive Mechanisms

Including New Program BCA Summaries for EVs and Heat

SUMMARY
Amended SETTLEMENT AGREEMENT

						Targets									Quantified Net Benefits ($1000) (before incentive)									Unquantified Benefits	Additional Bps for Unquantified Benefits										
						2019			2020			2021			2019			2020			2021				2019			2020			2021			2019	
Performance Incentive Mechanism	**Bps or Shared Savings**	**% to Company**	**Assumed Costs as % of Benefits**	**BCR**	**Target Units**	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High		Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)
System Efficiency																																			
FCM Peak Demand Reduction	bps	45%	70%	1.43	MW below baseline	14	17	20	17	21	25	21	24	29	$ 563	$ 684	$ 805	$ 940	$ 1,162	$ 1,383	$ 1,519	$ 1,736	$ 2,098	Reliability; Mkt Trnsf	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5	7
Total PIMs															$563	$684	$805	$940	$1,162	$1,383	$1,519	$1,736	$2,098		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5	7

SUMMARY
Amended SETTLEMENT AGREEMENT

						Incentives (Basis Points)							Incentives ($1000)								
							2020			2021			2019			2020			2021		
Performance Incentive Mechanism	**Bps or Shared Savings**	**% to Company**	**Assumed Costs as % of Benefits**	**BCR**	**Target Units**	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low ($1,000)	Medium ($1,000)	High ($1,000)	Low ($1,000)	Medium ($1,000)	High ($1,000)	Low ($1.000)	Medium ($1,000)	High ($1,000)
System Efficiency																					
FCM Peak Demand Reduction	bps	45%	70%	1.43	MW below baseline	8	9	11	13	14	16	20	$ 253	$ 308	$ 362	$ 423	$ 523	$ 622	$ 684	$ 781	$ 944
Total PIMs						8	9	11	13	14	16	20	$253	$308	$362	$423	$523	$622	$684	$781	$944

OUTCOMES
Amended Settlement Agreement

		FCM Savings (MW-yr)									Transmission Savings (MW-yr)									Distribution Savings (MW-yr)								
		2019	2019	2019	2020	2020	2020	2021	2021	2021	2019	2019	2019	2020	2020	2020	2021	2021	2021	2019	2019	2019	2020	2020	2020	2021	2021	2021
Performance Incentive Mechanism	**Target Units**	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency																												
FCM Peak Demand Reduction	MW below baseline	14	17	20	17	21	25	21	24	29	14	17	20	17	21	25	21	24	29	7	9	10	9	11	13	11	12	15
Total PIMs	-	**14**	**17**	**20**	**17**	**21**	**25**	**21**	**24**	**29**	**14**	**17**	**20**	**17**	**21**	**25**	**21**	**24**	**29**	**7**	**9**	**10**	**9**	**11**	**13**	**11**	**12**	**15**

OUTCOMES
Amended Settlement Agreement

		Energy Peak (MWh)									GHG (Tons)								
		2019	2019	2019	2020	2020	2020	2021	2021	2021	2019	2019	2019	2020	2020	2020	2021	2021	2021
Performance Incentive Mechanism	**Target Units**	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency																			
FCM Peak Demand Reduction	MW below baseline	14	17	20	17	21	25	21	24	29	0	0	0		0	0	0	0	0
Total PIMs	-	**14**	**17**	**20**	**17**	**21**	**25**	**21**	**24**	**29**	-	-	-	-	-	-	-	-	-

INCENTIVES
Amended Settlement Agreement

						Incentive for Quantified Net Benefits									Unquantified Benefits	Additional Bps for Unquantified Benefits								
						2019			2020			2021				2019			2020			2021		
Performance Incentive Mechanism	Bps or Shared Savings	% to Company	Assumed Costs as % of Benefits	BCR	Target Units	Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)		Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)
System Efficiency																								
FCM Peak Demand Reduction	bps	45%	70%	1.43	MW below baseline	5.39	6.55	7.70	8.98	11.09	13.20	15	17	20	Reliability; Mkt Trnsf	-	-	-	-	-	-	-	-	-
Total PIMs						5	7	8	9	11	13	15	17	20		0	0	0	0	0	0	0	0	0

INCENTIVES
Amended Settlement Agreement

Performance Incentive Mechanism	Bps or Shared Savings	% to Company	Assumed Costs as % of Benefits	BCR	Target Units	Incentives (Basis Points)									Incentives ($1000)								
						2019			2020			2021			2019			2020			2021		
						Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low (bps)	Medium (bps)	High (bps)	Low ($1,000)	Medium ($1,000)	High ($1,000)	Low ($1,000)	Medium ($1,000)	High ($1,000)	Low ($1,000)	Medium ($1,000)	High ($1,000)
System Efficiency																							
FCM Peak Demand Reduction	bps	45%	70%	1.43	MW below baseline	5.4	6.5	7.7	9.0	11.1	13.2	15	17	20	$253	$308	$362	$423	$523	$622	$684	$781	$944
Total PIMs						5.4	6.5	7.7	9.0	11.1	13.2	14.5	16.6	19.9	$253	$308	$362	$423	$523	$622	$684	$781	$944

THE NARRAGANSETT ELECTRIC COMPANY
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THE NARRAGANSETT ELECTRIC COMPANY
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Benefits of Amended Settlement Agreement PIMs

						FCM Benefits ($/MW-yr)										
						2019	2019	2019	2020	2020	2020	2021	2021	2021	2019	2019
Performance Incentive Mechanism	**Assumed Measure Life (yrs)**					Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium
System Efficiency																
FCM Peak Demand Reduction	4					$43,429	$43,429	$43,429	$91,907	$91,907	$91,907	$146,807	$146,807	$146,807	$22,683	$22,683

Outcomes

						FCM Savings (MW-yr)										
						2019	2019	2019	2019	2020	2020	2021	2021	2021	2019	2019
Performance Incentive Mechanism	**Target Units**	**Convert Tx Months of Savings to Years**	**FCM Peak Coincidence**	**Transmission Peak Coincidence**	**Distribution Peak Coincidence**	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium
System Efficiency																
FCM Peak Demand Reduction	MW below baseline	100%	100%	100%	50%	14	17	20	17	21	25	21	24	29	14	17
Total PIMs						**14**	**17**	**20**	**17**	**21**	**25**	**21**	**24**	**29**	**14**	**17**

Calculate $ Value of Outcomes

						FCM Benefits ($)										
						2019	2019	2019	2020	2020	2020	2021	2021	2021	2019	2019
Performance Incentive Mechanism						Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium
System Efficiency																
FCM Peak Demand Reduction						$608,007	$738,295	$868,582	$1,562,416	$1,930,044	$2,297,671	$3,082,957	$3,523,379	$4,257,416	$317,566	$385,615
Total PIMS						**$ 608,007**	**$ 738,295**	**$ 868,582**	**$ 1,562,416**	**$ 1,930,044**	**$ 2,297,671**	**$ 3,082,957**	**$ 3,523,379**	**$ 4,257,416**	**$ 317,566**	**$ 385,615**

Benefits of Amended Settlement Agreement PIMs

						Transmission Peak Benefits ($/MW-yr)							Distri			
						2019	2020	2020	2020	2021	2021	2021	2019	2019	2019	2020
Performance Incentive Mechanism	Assumed Measure Life (yrs)					High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low
System Efficiency																
FCM Peak Demand Reduction	4					$22,683	$23,137	$23,137	$23,137	$23,600	$23,600	$23,600	$135,726	$135,726	$135,726	$138,441

Outcomes

						Transmission Savings (MW-yr)							Dist			
						2019	2019	2020	2020	2021	2021	2021	2019	2019	2019	2019
Performance Incentive Mechanism	Target Units	Convert Tx Months of Savings to Years	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence	High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low
System Efficiency																
FCM Peak Demand Reduction	MW below baseline	100%	100%	100%	50%	20	17	21	25	21	24	29	7	8.5	10	8.5
Total PIMs						**20**	**17**	**21**	**25**	**21**	**24**	**29**	**7**	**9**	**10**	**9**

Calculate $ Value of Outcomes

						Transmission Benefits ($)							D			
						2019	2020	2020	2020	2021	2021	2021	2019	2019	2019	2020
Performance Incentive Mechanism						High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low
System Efficiency																
FCM Peak Demand Reduction						$453,665	$393,328	$485,875	$578,423	$495,593	$566,392	$684,390	$950,082	$1,153,671	$1,357,260	$1,176,745
Total PIMS						**$ 453,665**	**$ 393,328**	**$ 485,875**	**$ 578,423**	**$ 495,593**	**$ 566,392**	**$ 684,390**	**$ 950,082**	**$ 1,153,671**	**$ 1,357,260**	**$ 1,176,745**

THE NARRAGANSETT ELECTRIC COMPANY
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Benefits of Amended Settlement Agreement PIMs

						bution Benefits ($/MW-yr)					Energy Peak Benefits ($/MW)					
						2020	2020	2021	2021	2021	2019	2019	2019	2020	2020	2020
Performance Incentive Mechanism	Assumed Measure Life (yrs)					Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency																
FCM Peak Demand Reduction	4					$138,441	$138,441	$141,209	$141,209	$141,209	$130	$130	$130	$142	$142	$142

Outcomes

						ribution Savings (MW-yr)					Energy Peak (MWh)					
						2020	2020	2021	2021	2021	2019	2019	2019	2020	2020	2020
Performance Incentive Mechanism	Target Units	Convert Tx Months of Savings to Years	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency																
FCM Peak Demand Reduction	MW below baseline	100%	100%	100%	50%	10.5	12.5	10.5	12	14.5	14	17	20	17	21	25
Total PIMs						11	13	11	12	15	14	17	20	17	21	25

Calculate $ Value of Outcomes

						istribution Benefits ($)					Energy Peak ($)					
						2020	2020	2021	2021	2021	2019	2019	2019	2020	2020	2020
Performance Incentive Mechanism						Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency																
FCM Peak Demand Reduction						$1,453,626	$1,730,507	$1,482,698	$1,694,512	$2,047,536	$1,823	$2,214	$2,605	$2,412	$2,979	$3,547
Total PIMS						$ 1,453,626	$ 1,730,507	$ 1,482,698	$ 1,694,512	$ 2,047,536	$ 1,823	$ 2,214	$ 2,605	$ 2,412	$ 2,979	$ 3,547

Benefits of Amended Settlement Agreement PIMs

									GHG ($/Tonne)								
						2021	2021	2021	2029	2019	2019	2020	2020	2020	2021	2021
Performance Incentive Mechanism	**Assumed Measure Life (yrs)**					Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium
System Efficiency																
FCM Peak Demand Reduction	4					$148	$148	$148	$270	$267	$267	$267	$267	$267	$264	$264

Outcomes

									GHG (Tonnes)							
						2021	2021	2021	2019	2019	2019	2020	2020	2020	2021	2021
Performance Incentive Mechanism	**Target Units**	**Convert Tx Months of Savings to Years**	**FCM Peak Coincidence**	**Transmission Peak Coincidence**	**Distribution Peak Coincidence**	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium
System Efficiency																
FCM Peak Demand Reduction	MW below baseline	100%	100%	100%	50%	21	24	29								
Total PIMs						**21**	**24**	**29**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Calculate $ Value of Outcomes

									GHG Benefits ($)							
						2021	2021	2021	2019	2019	2019	2020	2020	2020	2021	2021
Performance Incentive Mechanism						Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium
System Efficiency																
FCM Peak Demand Reduction						$3,109	$3,553	$4,294	$0	$0	$0	$0	$0	$0	$0	$0
Total PIMS						**$ 3,109**	**$ 3,553**	**$ 4,294**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Benefits of Amended Settlement Agreement PIMs

							Initiative Net Benefits ($/tonne over study period)									
						2021	2029	2019	2019	2020	2020	2020	2021	2021	2021
Performance Incentive Mechanism	Assumed Measure Life (yrs)					High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency															
FCM Peak Demand Reduction	4					$264									

Outcomes

							Initiative (tonnes)								
						2021	2019	2019	2019	2020	2020	2020	2021	2021	2021
Performance Incentive Mechanism	Target Units	Convert Tx Months of Savings to Years	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency															
FCM Peak Demand Reduction	MW below baseline	100%	100%	100%	50%										
Total PIMs						0	0	0	0	0	0	0	0	0	0

Calculate $ Value of Outcomes

							Initiative Net Benefits ($)									
						2021	2019	2019	2019	2020	2020	2020	2021	2021	2021	2019
Performance Incentive Mechanism						High	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low
System Efficiency																
FCM Peak Demand Reduction						$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,877,479
Total PIMS						$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,877,479**

Note -- GHG tonne be

Benefits of Amended Settlement Agreement PIMs

Performance Incentive Mechanism	Assumed Measure Life (yrs)				
System Efficiency					
FCM Peak Demand Reduction	4				

Outcomes

Performance Incentive Mechanism	Target Units	Convert Tx Months of Savings to Years	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence
System Efficiency					
FCM Peak Demand Reduction	MW below baseline	100%	100%	100%	50%
Total PIMs					

Calculate $ Value of Outcomes

	Benefits										
	2019	2019	2020	2020	2020	2021	2021	2021	2019-21 Cumulative		
Performance Incentive Mechanism	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
System Efficiency											
FCM Peak Demand Reduction	$2,279,795	$2,682,112	$3,134,900	$3,872,524	$4,610,148	$5,064,357	$5,787,837	$6,993,636	$10,076,736	$11,940,156	$14,285,896
Total PIMS	$ 2,279,795	$ 2,682,112	$ 3,134,900	$ 3,872,524	$ 4,610,148	$ 5,064,357	$ 5,787,837	$ 6,993,636	$10,076,736	$11,940,156	$14,285,896

nefits not counted because EV and Heat total initiative benefits are counted

Key Assumptions and Inputs

Company WACC	7.50%
Inflation	2.00%

Outcomes		Incremental Outcomes										
											2019Low	2019Medium
		2019	2019	2019	2020	2020	2020	2021	2021	2021	2019	2019
Performance Incentive Mechanism	Outcome Units	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium
System Efficiency												
FCM Peak Demand Reduction	MW reduced	14	17	20	17	21	25	21	24	29	14	17

FCM			Source/Notes	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	($/MW-yr)	Ngrid BCA	I-3; Attachment DIV 8-6; AESC 2015 Update - Appendix	$0	$0	$0	$151,748	$145,443	$154,497	$173,685	$193,939	$214,296	$235,795	$259,373
		Division	Daymark Email Rec'd 3/16/18	$0	$0	$0	$55,042	$55,936	$62,393	$64,297	$69,950	$75,749	$84,529	$102,516
		Ngrid EE Screening Tool												
		NG Settlement	AESC 2018	$0	$0	$0	$62,348	$64,920	$68,921	$75,469	$83,422	$91,903	$100,567	$109,541

Transmission				2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	($/MW-yr)	Ngrid BCA	Attachment DIV 1-36-1	$114,808	$117,104	$119,446								
		Division	Daymark Email Rec'd 3/16/18	$124,913	$133,170	$141,612	$150,390	$159,312	$168,380	$177,593	$186,950	$196,453	$206,100	$215,893
		Ngrid EE Screening Tool		$14,157	$14,440	$14,728	$15,023	$15,323	$15,630	$15,943	$16,261	$16,587	$16,918	$17,257
		NG Settlement	50% of EE values	$7,078	$7,220	$7,364	$7,512	$7,662	$7,815	$7,971	$8,131	$8,293	$8,459	$8,628

Distribution				2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	($/MW-yr)	Ngrid BCA												
		Division		$84,706	$86,400	$88,128	$89,891	$91,688	$93,522	$95,393	$97,301	$99,247	$101,232	$103,256
		Ngrid EE Screening Tool		$84,706	$86,400	$88,128	$89,891	$91,688	$93,522	$95,393	$97,301	$99,247	$101,232	$103,256
		NG Settlement	50% of EE values	$42,353	$43,200	$44,064	$44,945	$45,844	$46,761	$47,696	$48,650	$49,623	$50,616	$51,628

Note:. Ngrid EE Screenting Tool values for Transmission and Distribution for 2019 reflect a 2% inflation rate applied to the original 2016 estimates used in EE screeing

Energy Peak				2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	($/MWh)	Ngrid BCA												
		Division	Daymark Email Rec'd 3/16/18	$80	$82	$74	$76	$77	$83	$87	$94	$96	$101	$110
		Ngrid EE Screening Tool												
		NG Settlement	AESC 2018	$33	$40	$49	$48	$46	$46	$50	$55	$54	$60	$60

GHG MWh				2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	($/MWh)	Ngrid BCA		$49	$49	$49	$48	$48	$47	$47	$46	$46	$45	$45
		Division		$49	$49	$49	$48	$48	$47	$47	$46	$46	$45	$45
		Ngrid EE Screening Tool		---										
		NG Settlement		$49	$49	$49	$48	$48	$47	$47	$46	$46	$45	$45

GHG tons				2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$/metric tonne	Ngrid BCA		$86	$86	$86	$85	$84	$84	$83	$82	$81	$80	$79
		Division		$86	$86	$86	$85	$84	$84	$83	$82	$81	$80	$79
		Ngrid EE Screening Tool		---										
		NG Settlement		$86	$86	$86	$85	$84	$84	$83	$82	$81	$80	$79

			Basis Points 2019	Basis Points 2020	Basis Points 2021
			2019	2020	2021
Basis Points	Bps	Ngrid	$47,010	$47,145	$47,356

Key Assumptions and Inputs

Company WACC	7.50%
Inflation	2.00%

Outcomes

		Cumulative Outcomes						
		2019High	2020Low	2020Medium	2020High	2021Low	2021Medium	2021High
		2019	2020	2020	2020	2021	2021	2021
Performance Incentive Mechanism	**Outcome Units**	High	Low	Medium	High	Low	Medium	High
System Efficiency								
FCM Peak Demand Reduction	MW reduced	20	17	21	25	21	24	29

FCM			**Source/Notes**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	($/MW-yr)	**Ngrid BCA**	1-3; Attachment DIV 8-6; AESC 2015 Update - Appendix	$290,551	$308,170	$314,333	$320,620	$327,032	$333,573	$340,244	$347,049	$353,990
		Division	Daymark Email Rec'd 3/16/18	$97,070	$108,661	$111,185	$114,424	$117,749	$121,160	$124,661	$128,254	$131,940
		Ngrid EE Screening Tool										
		NG Settlement	AESC 2018	$106,405	$106,723	$116,246	$112,918	$113,255	$123,361	$127,971	$132,715	$137,599

Transmission				**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	($/MW-yr)	**Ngrid BCA**	Attachment DIV 1-36-1									
		Division	Daymark Email Rec'd 3/16/18	$225,830	$235,913	$246,141	$256,513	$267,031	$277,693	$288,501	$299,454	$310,551
		Ngrid EE Screening Tool		$17,602	$17,954	$18,313	$18,679	$19,053	$19,434	$19,823	$20,219	$20,623
		NG Settlement	50% of EE values	$8,801	$8,977	$9,156	$9,340	$9,526	$9,717	$9,911	$10,109	$10,312

Distribution				**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
	($/MW-yr)	**Ngrid BCA**															
		Division		$105,321	$107,428	$109,576	$111,768	$114,003	$116,283	$118,609	$120,981	$123,401	$125,869	$128,386	$130,954	$133,573	$136,244
		Ngrid EE Screening Tool		$105,321	$107,428	$109,576	$111,768	$114,003	$116,283	$118,609	$120,981	$123,401	$125,869	$128,386	$130,954	$133,573	$136,244
		NG Settlement	50% of EE values	$52,661	$53,714	$54,788	$55,884	$57,002	$58,142	$59,304	$60,491	$61,700	$62,934	$64,193	$65,477	$66,786	$68,122

Note:. Ngrid EE Screenting Tool values for Transmission and Distribution for 2019 reflect a 2% inflation rate applied to the ori

Energy Peak				**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**					
	($/MWh)	**Ngrid BCA**															
		Division	Daymark Email Rec'd 3/16/18	$116	$121	$128	$136	$142	$151	$156	$166	$174					
		Ngrid EE Screening Tool															
		NG Settlement	AESC 2018	$64	$60	$62	$64	$69	$79	$84	$90	$97	$104	$111	$119	$128	$137

GHG MWh				**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
	($/MWh)	**Ngrid BCA**		$44	$54	$55	$56	$58	$59	$60	$61	$62	$63	$65	$66	$67	$69
		Division		$44	$54	$55	$56	$58	$59	$60	$61	$62	$63	$65	$66	$67	$69
		Ngrid EE Screening Tool															
		NG Settlement		$44	$54	$55	$56	$58	$59	$60	$61	$62	$63	$65	$66	$67	$69

GHG tons				**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
	$/metric tonne	**Ngrid BCA**		$78	$96	$98	$99	$101	$103	$106	$108	$110	$112	$114	$116	$119	$121
		Division		$78	$96	$98	$99	$101	$103	$106	$108	$110	$112	$114	$116	$119	$121
		Ngrid EE Screening Tool															
		NG Settlement		$78	$96	$98	$99	$101	$103	$106	$108	$110	$112	$114	$116	$119	$121

Basis Points	Bps	**Ngrid**

Key Assumptions and Inputs

Company WACC	7.50%
Inflation	2.00%

Outcomes

Performance Incentive Mechanism	Outcome Units
System Efficiency	
FCM Peak Demand Reduction	MW reduced

FCM			Source/Notes
	($/MW-yr)	**Ngrid BCA**	I-3; Attachment DIV 8-6; AESC 2015 Update - Appendix
		Division	Daymark Email Rec'd 3/16/18
		Ngrid EE Screening Tool	
		NG Settlement	AESC 2018

Transmission			
	($/MW-yr)	**Ngrid BCA**	Attachment DIV 1-36-1
		Division	Daymark Email Rec'd 3/16/18
		Ngrid EE Screening Tool	
		NG Settlement	50% of EE values

Distribution				2044	2045	2046	2047	2048
	($/MW-yr)	**Ngrid BCA**						
		Division		$138,969	$141,749	$144,584	$147,475	$150,425
		Ngrid EE Screening Tool		$138,969	$141,749	$144,584	$147,475	$150,425
		NG Settlement	50% of EE values	$69,485	$70,874	$72,292	$73,738	$75,212

Note:. Ngrid EE Screenting Tool values for Transmission and Distribution for 2019 reflect a 2% inflation rate applied to the ori

Energy Peak								
	($/MWh)	**Ngrid BCA**						
		Division	Daymark Email Rec'd 3/16/18					
		Ngrid EE Screening Tool						
		NG Settlement	AESC 2018	$147	$158	$169	$181	

GHG MWh				2044	2045	2046	2047	2048
	($/MWh)	**Ngrid BCA**		$70	$71	$73	$74	
		Division		$70	$71	$73	$74	
		Ngrid EE Screening Tool						
		NG Settlement		$70	$71	$73	$74	$0

GHG tons				2044	2045	2046	2047	
	$/metric tonne	**Ngrid BCA**		$124	$126	$128	$131	
		Division		$124	$126	$128	$131	
		Ngrid EE Screening Tool						
		NG Settlement		$124	$126	$128	$131	

Basis Points	Bps	**Ngrid**

Compliance Attachment 29

Compliance Attachment 29

Consumer and Light Duty Fleet EV Forecasts and Target Calculations

CO2: Consumer Electric Vehicles Target Calculation

Registered EVs in Company's RI Territory -- Summary of Polk Data

Row Labels	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
BEV(PEV)				32	41	117	193	366				
HEV(PHEV)				178	182	413	538	831				
Cumulative EV Registrations with Projections Based on AEO 2018 EV Sales Growth for New England									*Forecast*			
BEV				32	41	117	193	366	631	1,035	1,654	2,600
PHEV				178	182	413	538	831	1,195	1,647	2,209	2,907
Total Ev				210	223	530	731	1197	1,826	2,682	3,863	5,507
Annual New BEV Registrations					9	76	76	173				
Annual New PHEV Registrations					4	231	125	293				
Annual New EV Registrations Total					13	307	201	466	*629*	*857*	*1,180*	*1,644*

Annual New Registrations

	Actual			Forecast			
BEVs - Incremental	2015	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Actuals and Forecast	76	76	173	265	405	619	946

	Actual			Forecast			
PHEVs - Incremental	2015	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Actuals and Forecast	231	125	293	364	452	562	698

	2019	**2020**	**2021**
Forecast	857	1,180	1,644

2018-2021 Growth Rates based on AEO 2018

BEV	0.53
PHEV	0.24
Total	0.44

Fleet & Transit Target Calculations

	2018							
Estimate of Fleet-registered Vehicles in Operation								
Light Duty Cars and Trucks	68							
Medium and Heavy Duty Trucks and Buses	Not Available							
Source: IHS/Polk data, Jan 2018								
Estimate of Annual Fleet Vehicle Registrations								
Estimate for 2017 based on Model Year Data (below)	20	Annualized						
Model Year of Plug-in Fleet Vehicles (Light Duty ONLY) in RI								
2003	1							
2005	1							
2012	2							
2013	8							
2014	6							
2015	19							
2016	14							
2017	16							
2018	1							
Based on data through Q3 2017								
CAGR 2014-2016	53%							
Forecast of Annual Light Duty Fleet Registrations			**2017**	**2018**	**2019**	**2020**	**2021**	
Annual Incremental				31	47	71	109	Assuming growth at CAGR observed from 2014-2016
Cumulative				99	141	205	307	Assumes retirement of vehicles more than 7 years old

THE NARRAGANSETT ELECTRIC COMPANY
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Light-Duty Vehicle Sales (Case Reference case Region New England)
Source: U.S. Energy Information Administration, AEO 2018

Year	Conventional Cars: Gasoline thousands	Alternative-Fuel Cars: Ethanol-Flex Fuel ICE thousands	Alternative-Fuel Cars: 100 Mile Electric Vehicle thousands	Alternative-Fuel Cars: 200 Mile Electric Vehicle thousands	Alternative-Fuel Cars: 300 Mile Electric Vehicle thousands	Alternative-Fuel Cars: Plug-in 10 Gasoline Hybrid thousands	Alternative-Fuel Cars: Plug-in 40 Gasoline Hybrid thousands	Alternative-Fuel Cars: Electric-Diesel Hybrid thousands	Alternative-Fuel Cars: Electric-Gasoline Hybrid thousands	Alternative-Fuel Cars: Natural Gas ICE thousands	Alternative-Fuel Cars: Natural Gas Bi-fuel thousands	Alternative-Fuel Cars: Propane thousands	Alternative-Fuel Cars: Fuel Cell Methanol thousands	Alternative-Fuel cars: Fuel Cell Hydrogen thousands	Alternative-Fuel Cars: Total thousands	Total BEV	Total PHEV	Total (BEV+PHEV)
2050	355.345398	20.214737	5.602141	38.633205	36.172871	4.398753	5.196405	2.3959	35.953003	0.510001	0.872672	0.149481	0	1.619605	151.820114	80.40822	9.595158	90.00338
2049	353.642273	20.14179	5.491755	37.543312	35.23542	4.348643	5.133052	2.300105	35.863472	0.507992	0.868197	0.148707	0	1.592154	149.27504	78.27049	9.481695	87.75218
2048	351.753662	20.053083	5.403951	36.554832	34.329487	4.306846	5.08089	2.192646	35.751457	0.505412	0.862891	0.147837	0	1.568198	146.857056	76.28827	9.387736	85.67601
2047	353.321625	20.654562	5.309847	35.558769	33.491611	4.279058	5.024273	2.125003	35.940578	0.507565	0.865571	0.148306	0	1.550405	145.55513	74.36023	9.303331	83.66356
2046	352.144745	20.824108	5.188287	34.392513	32.513676	4.236733	4.939371	2.057598	35.889168	0.505952	0.86164	0.147632	0	1.52972	143.185287	72.09448	9.176104	81.27058
2045	350.304901	20.758434	5.102717	33.397022	31.570978	4.208997	4.87436	1.988463	35.84206	0.503642	0.856632	0.146813	0	1.514753	140.862839	70.07072	9.083357	79.15407
2044	347.485352	20.579248	4.994624	32.259674	30.547705	4.167288	4.789601	1.905477	35.635536	0.499565	0.84861	0.145489	0	1.495994	137.965607	67.802	8.956889	76.75889
2043	343.846741	20.844721	4.905899	31.27088	29.646082	4.130421	4.722566	1.815935	35.368679	0.495101	0.839968	0.144031	0	1.479477	135.759201	65.82286	8.852987	74.67585
2042	340.831299	20.972698	4.839626	30.3423	28.809624	4.113112	4.666744	1.733382	35.14933	0.491304	0.832508	0.142805	0	1.471085	133.658798	63.99155	8.779856	72.77141
2041	338.803894	21.15185	4.787501	29.535984	28.15877	4.094975	4.621519	1.653306	34.997391	0.48887	0.827369	0.141945	0	1.462314	132.015152	62.48226	8.716494	71.19875
2040	336.055084	21.26626	4.747665	28.519258	27.513409	4.078499	4.562747	1.5773	34.641888	0.484997	0.819879	0.14071	0	1.455493	129.900314	60.78033	8.641246	69.42158
2039	334.660522	21.416235	4.691761	26.856398	27.008698	4.07231	4.4656	1.503382	34.381016	0.484053	0.817369	0.140302	0	1.456311	127.384979	58.55686	8.53791	67.09477
2038	332.245483	21.442406	4.662393	25.281816	26.348032	4.086331	4.380548	1.436091	34.060417	0.481681	0.8126	0.139518	0	1.466491	124.689011	56.29224	8.466879	64.75912
2037	330.455383	21.396805	4.650105	23.785894	25.510975	4.102295	4.299524	1.366113	33.775967	0.479568	0.808386	0.138922	0	1.476855	121.881378	53.94697	8.401819	62.34879
2036	330.079895	21.351496	4.597928	22.267881	24.562798	4.09251	4.190804	1.308329	33.540657	0.478907	0.806347	0.138557	0	1.478011	118.903664	51.42861	8.283314	59.71192
2035	330.183441	21.310509	4.568686	21.00374	23.635248	4.079502	4.102505	1.244618	33.413799	0.479047	0.806014	0.138577	0	1.475968	116.347412	49.20767	8.182007	57.38968
2034	330.694122	21.098669	4.54547	19.762232	22.531775	4.069067	4.007761	1.156005	33.295868	0.478168	0.804143	0.138348	0	1.475613	113.451927	46.83948	8.076828	54.91631
2033	331.385162	20.815838	4.487601	18.442158	21.258623	4.033783	3.881815	1.015213	33.12175	0.476647	0.80108	0.137873	0	1.466845	110.027512	44.18838	7.915598	52.10398
2032	333.990295	20.665154	4.46349	17.29084	20.243418	4.014398	3.78396	0.787073	33.165543	0.478508	0.803349	0.138357	0	1.463139	107.385674	41.99775	7.798358	49.79611
2031	336.482849	20.750486	4.410666	15.907731	19.569527	3.981	3.665496	0.436888	33.161896	0.479889	0.804924	0.138733	0	1.455458	104.851173	39.88792	7.646496	47.53442
2030	335.987152	20.94309	4.345813	14.566785	18.552511	3.950255	3.541918	0.094041	32.751087	0.476728	0.799587	0.137859	0	1.45416	101.701637	37.46511	7.492173	44.95728
2029	335.757507	20.794701	4.277223	13.800777	17.286728	3.911695	3.177356	0	32.107693	0.472823	0.793534	0.136865	0	1.449152	98.295448	35.36473	7.089051	42.45378
2028	336.828278	20.516396	4.186686	12.985898	15.936916	3.849896	2.794904	0	31.366304	0.47008	0.788095	0.135997	0	1.436774	94.554176	33.1095	6.6448	39.7543
2027	336.122986	20.213121	4.128845	12.147217	14.525044	3.736123	2.597331	0	30.377541	0.465604	0.777897	0.134285	0	1.440348	90.628372	30.80111	6.333454	37.13456
2026	336.227722	19.364838	4.169695	11.421202	13.25938	3.744987	2.508586	0	29.443655	0.460868	0.769547	0.132898	0	1.484693	86.84436	28.85028	6.253573	35.10385
2025	337.683746	19.554213	4.173252	10.614833	12.019748	3.684446	2.406016	0	28.618664	0.455651	0.76476	0.13219	0	1.493011	84.000153	26.80783	6.090462	32.8983
2024	341.234924	18.970907	3.626055	8.562238	9.985023	3.286909	2.133315	0	28.787758	0.451035	0.759374	0.131395	0	1.282162	78.060097	22.17332	5.420224	27.59354
2023	342.954163	18.72925	3.191939	7.615645	9.43925	2.896113	1.870249	0	27.829237	0.447937	0.748327	0.129625	0	1.072243	74.054657	20.24683	4.766362	25.0132
2022	341.471252	18.314096	2.918794	6.499039	7.795858	2.435257	1.575278	0	26.695114	0.444987	0.733393	0.127222	0	0.941399	68.566467	17.21369	4.010535	21.22423
2021	340.566132	18.404573	2.539417	5.847369	6.638853	2.502763	1.5951	0	25.708946	0.433651	0.72481	0.125845	0	0.781343	65.388618	15.02564	4.097863	19.1235
2020	347.052032	18.824343	2.002526	4.747928	4.791523	2.041853	1.304471	0	24.766338	0.422442	0.730017	0.12672	0	0.544925	60.387497	11.54198	3.346324	14.8883
2019	342.466919	18.540531	1.420105	2.95272	2.451552	1.429988	0.92671	0	23.000076	0.418397	0.71887	0.124295	0	0.291664	52.35611	6.824377	2.356698	9.181075
2018	346.906952	17.696617	1.307958	1.686958	1.206584	1.273967	0.863506	0	22.024769	0.443079	0.709516	0.123161	0	0.157599	47.573231	4.2015	2.137473	6.338973
2017	332.62146	17.204187	1.415067	0.649601	0.507921	1.588685	5.256105	0	23.503204	0.914017	0.701392	0.121784	0	0.088083	52.025845	2.572589	6.84479	9.417379
2016	347.271362	20.222425	1.805895	1.015956	0.088408	3.422762	2.934831	0	20.245571	0.904959	0.744257	0.129047	0	0.088409	51.681202	2.910259	6.357593	9.267852

CAGR BEV (2018-2021)	CAGR PHEV	CAGR Total
0.53	**0.24**	**0.44**

Compliance Attachment 30

Electric Heat Target Calculations

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