Thomas R. Teehan
Senior Counsel

June 10, 2011

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4206 - Revenue Decoupling Mechanism Proposal ("RDM")
Responses to Record Requests

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] responses to Record Requests that were issued at the Commission's Evidentiary Hearing on May 17, 2011, concerning the above-captioned proceeding.

In addition, during the hearing, the Company agreed to make certain clarifying revisions to the electric RDM tariff. The Company is providing clean and redlined versions of the tariff reflecting the changes.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4206 Service List
Leo Wold, Esq.
Steve Scialabba, Division

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

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Record Request Wiley-1

Request:

To the extent such information currently exists please provide the 5 year sales forecast for electric Rate A-16 and Rate A-60 assuming the impact of energy efficiency and no impact of energy efficiency and the 5 year forecast from the last GCR filing. (TR, Pages 12-13 and 18)

Response:

The Company's monthly kWh sales forecast for Regular Residential Rate A-16 and Low Income Rate A-60 through 2016 is shown below. The methodology used to produce the kWh forecast is described in the Company's response to Data Request Division 1-19 in this docket. Please note that this kWh forecast was produced in August 2010 and did not incorporate the savings targets established for 2011 in the Company's Energy Efficiency Plan filing submitted November 1, 2010. Nor does the forecast include the kWh savings estimates that may result from the savings goals currently under consideration recently approved in Docket No. 4202. A second forecast has been included which removes the effect of Energy Efficiency kWh savings from historical and forecasted kWh deliveries.

Electric Service Sales Forecast for Rates A-16 and A-60

	Rate A-16			Rate A-60	
Year	With EE	Without EE		With EE	Without EE
	(in GWh)	(in GWh)		(in GWh)	(in GWh)
	(a)	(b)		(a)	(b)
2011	2,802	2,984		258	275
2012	2,795	2,989		259	277
2013	2,839	3,032		267	285
2014	2,875	3,068		275	293
2015	2,906	3,099		283	302

The chart below provides the Company's 5 year gas forecast that was utilized in Company's most recent GCR filing that was approved by the Commission in Docket No. 4199. For forecasting purposes, the low-income residential gas classes are not tracked separately, but rather are included in the non-discounted residential classes. Like the electric forecast noted above, this forecast was also produced in August 2010 and did not incorporate the savings targets established for 2011 in the Company's Energy Efficiency Plan filing submitted November 1, 2010.

Record Request Wiley-1 (continued)

	National Grid RI-Gas		
	Rates 1247 and 1301	Rates 1012 and 1101	
	Residential Heating (Dth)	Residential Non-Heating (Dth)	Residential Total Dth
Year			
2011	16,883,057	697,272	17,580,329
2012	16,848,699	691,847	17,540,546
2013	16,910,136	695,555	17,605,691
2014	16,938,157	700,326	17,641,738
2015	16,939,827	707,487	17,647,314

Prepared by or under the supervision of: Jeanne A. Lloyd and Jennifer B. Feinstein

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Record Request Wiley-2

Request:

Please provide the annual gas use for residential customers and low income residential customers, similar to what is reflected in Narragansett Electric's FERC Form 1, page 304 for calendar year 2010. (TR, page 21, lines 6-21).

Response:

Attachment 1 includes total 2010 kWh deliveries and average number of electric service customers by rate class. Although this information was not requested, the Company notes that the number of customers and kWh deliveries indicated on page 304 of Narragansett Electric Company's FERC FORM 1 includes only information for sales, i.e. Standard Offer Service customers, and excludes customer counts and kWh deliveries attributable to customers receiving service from competitive suppliers.

Attachment 2 includes monthly total gas usage and number of Residential Heating, Residential Heating Low Income, Residential Non-heating and Residential Non-Heating Low-Income customers for calendar year 2010.

Prepared by or under the supervision of: Jeanne A. Lloyd and Jennifer B. Feinstein

Rate Class	Average # of Customers	kWh
A-16	385,994	2,859,465,034
A-60	39,679	266,177,509
B-32	5	6,952,309
B-62	2	142,449,857
C-06	47,236	562,654,819
G-02	8,385	1,336,504,933
G-32	1,055	2,072,018,159
G-62	11	420,898,664
M-1	3	2,041,006
S-10	2,742	9,452,156
S-14	387	56,519,090
X-01	1	23,312,116
	485,499	7,758,445,652

Narragansett Gas Company

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total	Average annual usage per customer
Residential Non-Heating (therms)	1,062,102	854,851	750,609	560,747	438,063	347,728	313,372	260,376	281,556	336,391	407,981	634,529	6,248,306	
Residential Non-Heating Low Income (therms)	39,205	39,821	36,960	21,979	14,652	8,657	6,813	5,853	6,554	7,565	13,981	27,769	229,807	
Total Residential Non-Heating (therms)	1,101,307	894,672	787,569	582,725	452,715	356,385	320,185	266,228	288,110	343,956	421,962	662,298	6,478,113	
Residential Non-Heating (customers)	29,021	28,492	28,393	28,097	27,911	27,766	27,489	27,451	27,280	27,304	27,386	27,296	333,886	**19**
Residential Non-Heating Low Income (customers)	412	472	403	421	410	392	376	367	362	356	329	321	4,621	**50**
Total Residential Non-Heating (customers)	29,433	28,964	28,796	28,518	28,321	28,158	27,865	27,818	27,642	27,660	27,715	27,617	338,507	**19**
Residential Heating (therms)	30,638,856	27,974,532	22,475,789	13,085,700	7,668,432	4,577,831	3,666,741	3,211,083	3,380,646	4,258,567	9,203,530	20,130,458	150,272,164	
Residential Heating Low Income (therms)	3,371,795	3,165,503	2,893,124	1,659,071	1,071,445	656,721	479,495	408,819	435,255	514,573	1,047,713	2,054,817	17,758,332	
Total Residential Heating (therms)	34,010,651	31,140,035	25,368,913	14,744,771	8,739,876	5,234,552	4,146,237	3,619,902	3,815,901	4,773,140	10,251,242	22,185,275	168,030,496	
Residential Heating (customers)	177,227	175,647	176,788	174,349	173,688	173,502	173,647	173,579	174,399	175,754	179,758	181,706	2,110,044	**71**
Residential Heating Low Income (customers)	20,240	22,735	21,988	23,793	23,353	22,011	21,304	20,904	20,374	20,273	18,618	18,301	253,894	**70**
Total Residential Heating (customers)	197,467	198,382	198,776	198,142	197,041	195,513	194,951	194,483	194,773	196,027	198,376	200,007	2,363,938	**71**

Record Request Division-1

Request:

Please provide the itemization of IT costs to program the Company's billing system (Advantage and CSS) for the ability to identify out-of-period billing adjustments between distribution charges and all other charges as presented in the Company's supplemental response to Information Request Division 1-9. (TR, Page 51, lines 19-23)

Response:

Initially, it is important to note that the $400K estimate that was provided by IT to program the Company's Advantage gas billing system to identify out-of-period adjustments between distribution charges and other charges represented the Company's best cost estimate at this time based upon an assumption that the Company would continue to utilize the Advantage billing system in the future. However, as noted in the Company's supplemental response to DIV 1-9, the Company is in the process of converting its existing gas Advantage billing system to the CSS billing system beginning November 1, 2011. As part of this conversion, the Company has begun to limit modifications to the Advantage billing system. For example, this limitation is necessary so the Company can begin transferring most recent 12 months worth of data into the CSS system. In addition, it is estimated that it would take approximately 4-6 months from the time an Order is received in this case to complete the Advantage system programming that would be required to track prior period adjustments. As a result, it is not informative to attempt to further itemize the $400K estimate as making any changes in the current Advantage system to track adjustments would not be cost effective or timely and could further delay conversion.

With respect to the CSS billing system, the additional costs to implement changes to remove any previous out-of-period adjustments from the revenue reporting are estimated to be approximately $600K for gas and electric. This includes an estimate for programming of new reports to extract monthly billing data with out-of-period adjustments greater than $1,000, restricting these adjustments to only delivery charges, and for programming to include a new field on any adjustments to identify the period the adjustment relates to. These represent the Company's best estimates at this time and it is important to note that manual intervention will still be required (and associated incremental labor costs will be incurred) for certain types of adjustments in the CSS billing system such as a miscellaneous billing adjustment that covers multiple periods and is credited to the customer in a lump-sum credit. In addition, in converting from Advantage to CSS, tracking any corrected bills for earlier periods will be difficult in that only 12 months of history will be brought into the system. Instead, a miscellaneous adjustment will be placed on the account and there would be no ability, in an automated way, to identify the period in which the adjustment was being made. Finally, it is also estimated to take approximately 4-6 months from the time an Order is received to complete the above referenced programming for the CSS system.

Prepared by or under the supervision of: Jeanne A. Lloyd and Jennifer B. Feinstein

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Record Request Commission-1

Request:

How does the penalty for the reliability metrics in the Company's Service Quality Plan compare to the value of outages that would be inherently reflected in the RDM reconciliation? (TR, Page 106, lines 16-20)

Response:

Under the Company's existing Service Quality Plan ("Plan") approved in Docket No. 3628, the Company incurs penalties for non-performance if customer service interruptions exceed established thresholds for frequency and duration. An interruption is defined as the loss of electric service to more than one customer for more than one minute. The interruption duration is defined as the period of time, measured in minutes, from the initial notification of the interruption event to the time when service has been restored to the customers. Interruptions are tracked using System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). SAIFI is calculated by dividing the total number of customers interrupted by the total number of customers served. SAIFI measures the number of times per year the average customer experienced an interruption. This measure reflects an average; therefore, specific customers may experience more or fewer interruptions than the average. SAIDI measures the length of interruption time that the average customer experienced for the year. It is calculated by dividing the total customer minutes of interruption by the total number of customers served. Under the provisions of the Plan, the Company could incur a maximum penalty of $916,000 for exceeding a SAIFI threshold of 1.18 frequency of interruptions per customer and a maximum penalty of $916,000 for exceeding a SAIDI threshold of 89.9 duration of minutes of interruptions.

When calculating SAIDI and SAIFI statistics, the Plan allows for the exclusion of Major Event Days. Major Event Days represent those few days during the year on which the delivery system experienced stresses beyond that normally expected, such as severe weather. A day is considered a Major Event Day if the daily SAIDI exceeds a threshold value, calculated using the IEEE 1366 methodology. Attachment 1 lists all of the Major Event Days that have occurred since 2006.

Attachment 2, page 1 calculates the estimated lost distribution revenue associated with exceeding the maximum SAIFI and SAIDI thresholds established under the Plan at $46,360 per year. This value is estimated by multiplying an estimate of revenue per minute ($0.0009 per minute) by the total minutes of service interruption assuming the Company fails to meet the SAIFI and SAIDI goals (51,511,444 minutes). Revenue per customer minute is calculated by dividing the annual distribution revenue requirement approved in Docket No. 4065 by the total

Record Request Commission-1 (continued)

customer minutes in a year. The total customer minutes of interruption per year is calculated by multiplying (1) the maximum SAIFI penalty threshold of 1.18 interruptions per customer, (2) the maximum SAIDI penalty threshold of 89.9 minutes of interruptions, resulting in 106.1 total minutes per customer per year, and (3) the average number of customers of 485,499, resulting in 51,502,705 total customer minutes interrupted for all customers. Under the Plan, if the Company failed to meet the reliability metrics in their entirety, it would incur a penalty of $1,832,000, well in excess of the estimated lost distribution revenue of $46,460.

Attachment 2, page 2 calculates the lost distribution revenue associated with the SAIDI and SAIFI results reported by the Company in its 2010 Service Quality Report. During 2010, the Company reported a SAIFI of 1.07 (above the 1.05 value to avoid a penalty) and a SAIDI of 76.3 (above the 71.9 value to avoid a penalty). Since the reported results exceeded the thresholds to avoid a penalty established for both SAIDI and SAIFI, the Company incurred a penalty of $162,162 for SAIFI and $224,929 for SAIDI, or a total penalty of $386,991. The estimated lost distribution revenue associated with the customer minutes interrupted is $35,655.

Regarding Major Event Days, Attachment 1 also identifies the total minutes of interruption, number of customers affected, and the estimated lost distribution revenue associated with each event. As indicated, the storm that occurred on March 30-31, 2010 was the most significant event that has occurred in the past five years in terms of the duration of the outage. However, the estimated lost distribution revenue associated with this two-day event was only approximately $25,000. If the Company were to change its business operations in way that results in an increase in the restoration time after a major outage, the incremental costs that would likely be incurred due to a protracted restoration time would likely far exceed the estimated lost revenue associated with the outage. Although Major Event Days are excluded from the reliability metrics of the Plan, any storm related expenses that may be associated with Major Event Days are not necessarily reimbursed to the Company from the Storm Contingency Fund ("Storm Fund"). For those events that do not qualify for reimbursement from the Storm Fund, the Company must fund these costs from its distribution rates then-in-effect. Therefore, the Company has the incentive to restore service during these events as quickly as possible. For those storm events that do qualify for incremental cost reimbursement above the deductible, the Company must file with the Commission a final accounting of all storm restoration costs incurred that would be subject to recovery from the Storm Fund, at which time the Commission may review to determine the appropriateness of recovering the incremental cost from the Storm Fund.

Prepared by or under the supervision of: Jeanne A. Lloyd

Date of Major Event (a)	Total Customer Minutes of Interruption (b)	Number of Customers Affected (c)	Total Estimated Lost Revenue per Event (d)
Aug 2-3, 2006	10,115,316	77,307	$9,104
Jul 18-19, 2006	17,615,151	87,381	$15,854
Apr 16, 2007	12,378,193	61,580	$11,140
Sep 6-7, 2008	2,846,136	28,696	$2,562
July 23, 2008	4,832,089	30,388	$4,349
July 14, 2008	2,694,666	77,307	$2,425
March 31, 2010	4,779,507	376	$4,302
March 30, 2010	22,724,417	27,089	$20,452
March 14, 2010	4,033,502	21,045	$3,630

(a)-(c) per 2006, 2007, 2008, 2009 and 2010 Srvice Qualtiy Reports filed May 1 of each year
(d) column (b) x Attachment 2, page 1, line 5

CALCULATION OF LOST DISTRIBUTION REVENUE ASSOCIATED WITH MAXIMUM PENALTY INCURRED UNDER SERVICE QUALITY PLAN PROVISIONS

1.	Number of Minutes per Year	525,600
2.	Average Number of Customers	485,499
3.	Total Customer Minutes per Year	255,178,274,400
4.	Annual Target Revenue	$230,771,000
5.	Revenue per Customer Minute	$0.00090
6.	Maximum Frequency (SAIFI) Threshold	1.18
7.	Maximum Duration (SAIDI) Threshold	89.9
8.	Average Minutes Interrupted per Customer	106.1
9.	Average Number of Customers	485,499
10.	Total Customer Minutes Interruped	51,511,444
11.	Total Lost Distribution Revenue due to Outage	$46,360

1. 365 days x 24 hours x 60 minutes
2. Average number of customers during 2010
3. Line 1 x Line 2
4. Schedule NG-HSG-4(C) wnd Amended, page 1, line 36 (Docket No. 4065)
5. Line 4 ÷ Line 3
6. Maximum Service Quality Plan threshold, Section 2, page 1, column (d)
7. Maximum Service Quality Plan threshold, Section 2, page 1, column (d)
8. Line 6 x Line 7
9. Line 2
10. Line 8 x Line 9
11. Line 5 x Line 10

CALCULATION OF LOST DISTRIBUTION REVENUE ASSOCIATED WITH ACTUAL PENALTY INCURRED DURING 2010 UNDER SERVICE QUALITY PLAN PROVISIONS

1.	Number of Minutes per Year	525,600
2.	Average Number of Customers	485,499
3.	Total Customer Minutes per Year	255,178,274,400
4.	Annual Target Revenue	$230,771,000
5.	Revenue per Customer Minute	$0.00090
6.	2010 Frequency (SAIFI) Threshold	1.07
7.	2010 Duration (SAIDI) Threshold	76.3
8.	Average Minutes Interrupted per Customer	81.6
9.	Average Number of Customers	485,499
10.	Total Customer Minutes Interruped	39,616,718
11.	Total Lost Distribution Revenue due to Outage	$35,655

1. 365 days x 24 hours x 60 minutes
2. Average number of customers during 2010
3. Line 1 x Line 2
4. Schedule NG-HSG-4(C) wnd Amended, page 1, line 36 (Docket No. 4065)
5. Line 4 ÷ Line 3
6. 2010 Service Quality Plan results, Section 2, page 1, column (c)
7. 2010 Service Quality Plan results, Section 2, page 1, column (c)
8. Line 6 x Line 7
9. Line 2
10. Line 8 x Line 9
11. Line 5 x Line 10

RDM Tariff Sheets

Clean and Redlined Versions

NARRAGANSETT ELECTRIC COMPANY
REVENUE DECOUPLING MECHANISM PROVISION

In accordance with *An Act Relating to Public Utilities and Carriers – Revenue Decoupling*, the prices for distribution service contained in all of the Company's tariffs are subject to adjustment to reflect the operation of its Revenue Decoupling Mechanism ("RDM") Provision.

I. Definitions

"Actual Billed Distribution Revenue" shall mean the amounts the Company has billed during the applicable RDM Year for customer charges, distribution demand charges, distribution energy charges, Second Feeder Service charges, and any other charges or discounts that the Company records as distribution revenue. Actual Billed Distribution Revenue shall not include charges billed pursuant to the provisions of the Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044, as may be amended from time to time. Actual Billed Distribution Revenue shall exclude the RDM Adjustment Factor, as it is subject to its own reconciliation.

"Annual Target Revenue" or "ATR" shall mean the revenue requirement as approved by the Commission less any adjustments to that revenue requirement as approved by the Commission.

"RDM Year" shall mean the twelve-month period beginning April 1.

"Forecasted kWh" shall mean the forecasted amount of electricity, as measured in kWh, to be distributed to the Company's distribution customers for the twelve month period during which the proposed RDM Adjustment Factor will be in effect.

"RDM Adjustment Factor" shall mean a per-kWh factor equal to the RDM Reconciliation Amount divided by the Forecasted kWh for all rate classes.

"RDM Reconciliation Amount" shall mean the difference (either positive or negative) between the Actual Billed Distribution Revenue and the ATR for the RDM Year

II. RDM Revenue Reconciliation and Adjustment Factor

The Company's RDM shall include an annual RDM Revenue Reconciliation which will reconcile ATR and Actual Billed Distribution Revenue for the same RDM Year. The RDM Revenue Reconciliation amount (either positive or negative) shall determine the RDM Adjustment Factor. The Company shall submit a filing no later than June 1, in which the Company shall propose adjustments to distribution rates to reflect the RDM Adjustment Factor. These adjustments to distribution rates will be effective for the twelve months beginning with the first of the month following 30 days after the filing of the RDM Adjustment Factor, or July 1.

The RDM Adjustment Factor will be based on the RDM Revenue Reconciliation Amount for the prior RDM Year as determined above. The amount of over- or under-recovery resulting from the RDM Revenue Reconciliation, including interest at the rate paid on customer deposits,

NARRAGANSETT ELECTRIC COMPANY
REVENUE DECOUPLING MECHANISM PROVISION

shall be used to determine a uniform per-kWh RDM Adjustment Factor based on the Forecasted kWh. The RDM Adjustment Factor shall be applicable to all retail delivery service customers. The amount approved by the Commission to be recovered or refunded through the RDM Adjustment Factor shall be subject to reconciliation.

III. Adjustments to Annual Target Revenue

The ATR shall be based on the revenue requirement approved by the Commission in the Company's most recent general rate case. The ATR may be adjusted should the Commission approve recovery mechanisms for costs included in the revenue requirement such that those costs would be recovered from customers through two mechanisms or not recovered at all. Should the Company's ATR change during a RDM Year as a result of a new revenue requirement arising from a general rate case that may be approved by the Commission, the Company shall allocate the prior ATR and new ATR to each month within the RDM Year based on the rate year kWh deliveries reflected in the general rate case from which the revenue requirement was based.

IV. Interim RDM Adjustments

If at any time during the year, the total of cumulative Actual Billed Distribution Revenue excess/shortfall for the Company in total is estimated to be 10% above or below the Company's ATR for the current RDM Year, the Company will petition the Commission for an interim adjustment prior to its next scheduled RDM Filing.

V. Adjustments to Rates

Adjustments to rates pursuant to the RDM Provision are subject to review and approval by the Commission. Modifications to the factors contained in this RDM Provision shall be in accordance with a notice filed with the Commission 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.

Effective: April 1, 2011

NARRAGANSETT ELECTRIC COMPANY
REVENUE DECOUPLING MECHANISM PROVISION

In accordance with *An Act Relating to Public Utilities and Carriers – Revenue Decoupling*, the prices for distribution service contained in all of the Company's tariffs are subject to adjustment to reflect the operation of its Revenue Decoupling Mechanism ("RDM") Provision.

I. Definitions

"Actual Billed Distribution Revenue" shall mean the amounts the Company has billed during the applicable RDM~~calendar~~ Y~~y~~ear for customer charges, distribution demand charges, distribution energy charges, Second Feeder Service charges, and any other charges or discounts that the Company records as distribution revenue. Actual Billed Distribution Revenue shall not include charges billed pursuant to the provisions of the Infrastructure, Safety and Reliability Provision, R.I.P.U.C. No. 2044, as may be amended from time to time. Actual Billed Distribution Revenue shall exclude the RDM Adjustment Factor, as it is subject to its own reconciliation.

"Annual Target Revenue" or "ATR" shall mean the revenue requirement as approved by the Commission less any adjustments to that revenue requirement as approved by the Commission.

"RDM Year" shall mean the twelve-month period beginning April 1.

"Forecasted kWh" shall mean the forecasted amount of electricity, as measured in kWh, to be distributed to the Company's distribution customers for the twelve month period during which the proposed RDM Adjustment Factor will be in effect.

"RDM Adjustment Factor" shall mean a per-kWh factor equal to the RDM Reconciliation Amount divided by the Forecasted kWh for all rate classes.

"RDM Reconciliation Amount" shall mean the difference (either positive or negative) between the Actual Billed Distribution Revenue and the ATR for the RDM Year

II. RDM Revenue Reconciliation and Adjustment Factor

The Company's RDM shall include an annual RDM Revenue Reconciliation which will reconcile ATR and Actual Billed Distribution Revenue for the same RDM Year. The RDM Revenue Reconciliation amount (either positive or negative) shall determine the RDM Adjustment Factor. The Company shall submit a filing no later than June 1, in which the Company shall propose adjustments to distribution rates to reflect the RDM Adjustment Factor. These adjustments to distribution rates will be effective for the twelve months beginning with the first of the month following 30 days after the filing of the RDM Adjustment Factor, or July 1.

The RDM Adjustment Factor will be based on the RDM Revenue Reconciliation A~~a~~mount for the prior RDM Year as determined above. The amount of over- or under-recovery resulting from the RDM Revenue Reconciliation, including interest at the rate paid on customer

NARRAGANSETT ELECTRIC COMPANY
REVENUE DECOUPLING MECHANISM PROVISION

deposits, shall be used to determine a uniform per-kWh RDM Adjustment Factor based on the Forecasted kWh. The RDM Adjustment Factor shall be applicable to all retail delivery service customers. The amount approved by the Commission to be recovered or refunded through the RDM Adjustment Factor shall be subject to reconciliation.

III. Adjustments to Annual Target Revenue

The ATR shall be based on the revenue requirement approved by the Commission in the Company's most recent general rate case. The ATR may be adjusted should the Commission approve recovery mechanisms for costs included in the revenue requirement such that those costs would be recovered from customers through two mechanisms or not recovered at all. Should the Company's ATR change during a RDM Year as a result of a new revenue requirement arising from a general rate case that may be approved by the Commission, the Company shall allocate the prior ATR and new ATR to each month within the RDM Year based on the rate year kWh deliveries reflected in the general rate case from which the revenue requirement was based.

IV. Interim RDM Adjustments

If at any time during the year, the total of cumulative Actual Billed Distribution Revenue~~distribution revenue~~ excess/shortfall for the Company in total is estimated to be 10% above or below the Company's ATR for the current RDM Year, the Company will petition the Commission for an interim adjustment prior to its next scheduled RDM Filing.

V. Adjustments to Rates

Adjustments to rates pursuant to the RDM Provision are subject to review and approval by the Commission. Modifications to the factors contained in this RDM Provision shall be in accordance with a notice filed with the Commission 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.

Effective: April 1, 2011

Certificate of Service

I hereby certify that a copy of the cover letter and / or any materials accompanying this certificate has been electronically transmitted, sent via U.S. mail or hand-delivered to the individuals listed below.

______________________________ June 10, 2011

Joanne M. Scanlon Date

Docket No. 4206 - National Grid (NGrid) – Revenue Decoupling Mechanism Filing
Service List as of 12/7/10

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