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June 1, 2007

VIA E-FILE AND FIRST CLASS MAIL

Ms. Karen Geraghty
Administrative Director
Maine Public Utilities Commission
242 State Street, 18 State House Station
Augusta, Maine 04333

Ms. Debra Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, New Hampshire 03301

Re: Northern Utilities, Inc., Docket Nos. 2006-390 and DG 06-098

Dear Ms. Geraghty and Ms. Howland:

At the May 10 technical conference held by the parties, Northern Utilities, Inc.'s ("Northern's" or "the Company's") Director of Energy Supply Services, Chico DaFonte, indicated that Northern had experienced significantly more demand on its system during the past winter relative to the actual effective degree days ("EDDs"). At the time, Mr. DaFonte reiterated Northern's preliminary belief that the change resulted from increased use by firm dual-fuel customers, as compared to Northern's expectations. Mr. DaFonte indicated Northern would investigate the matter and report back to the parties. Also, see Northern's response to the New Hampshire Staff's information request Set 3, Number 8.

After investigation, Northern has confirmed its initial belief that the increase in firm load was a result of the added consumption of firm dual-fuel customers that burned natural gas rather than an alternative fuel. Because this activity results in additional firm consumption, Northern will need to increase its estimated design day sendout requirements over the forecast period. However, because the increase is for use by dual fuel customers, Northern's estimate for design day sales load is unaffected.

Since the estimated design-day sendout is now updated from Northern's June 30, 2006 long-range forecast and supply plan ("IRP") filing, the Company should supplement and revise a limited amount of the text, tables and schedules included in the June 2006 IRP filing. In addition, Northern should revise any data responses affected by this new information.

Accordingly, Northern hereby files the following information to be included in Northern's IRP:

- Addendum B, added to describe the new information and updates and should be included as pages 50 – 54 in the IRP
- Schedule III-11 and Schedule III-12
- Page 5 (Revised); Page 34 (Revised); and Page 40 (Revised) at Table IV-1; and
- Schedule III-9 Revised; and Schedule IV-5 2nd Revised

In addition, Northern revised the following information request responses:

Staff 1-19 Revised; Staff 1-27 Revised; Staff 1-45 Revised; Staff 2-8 Revised; ODR-2 Sep 19 Revised (Confidential Attachment); ODR-4 May 10 Revised; ODR-5 May 10 Revised; and ADR 4-13 Revised

If you have any questions or need additional information, please do not hesitate to telephone me at 508.836.7394.

Very truly yours,

Patricia M. French/SBU

Patricia M. French

Enclosures

cc: Carol MacLennan, Esq., Hearing Examiner, MPUC
Edward Damon, Esq., Staff Counsel, NHPUC
Service List

ADDENDUM B

JUNE 2007
REVISION TO THE DESIGN DAY DEMAND FORECAST

Recent experience over the past winter period demonstrates that Northern's design day planning did not properly account for the consumption characteristics of Northern's Maine Division and New Hampshire Division firm dual-fuel customers, which may dramatically increase consumption from one year to the next with changing price signals. Therefore, this addendum to Northern's June 30, 2006 IRP filing appropriately adjusts Northern's design day forecast and reflects an important improvement in its planning process.

As background, firm dual-fuel customers have the ability to burn natural gas or an alternate fuel. On Northern's system, these dual-fuel customers are among the largest firm customers. From April 2005 through March 2006, dual-fuel customers consumed almost 3 Bcf of natural gas from Northern's system. However, from April 2006 through March 2007, dual-fuel customers consumed almost 4 Bcf, or 25 percent more natural gas. New Schedule III-11 includes the monthly volumes used by Northern's 21 largest dual-fuel customers from January 2005 through March 2007. Because Northern's forecast in its IRP was based primarily on consumption data from April 2005 through March 2006, it excluded a significant amount of relevant load data for Northern's system.

Many of Northern's dual-fuel customers have firm service: they seek to call upon their natural gas service at any time during the year, and accordingly, have selected firm service so that they can purchase natural gas service from Northern on a firm, rather than interruptible, basis[1]. In this way, Northern's firm dual-fuel customers preserve the option of using their alternate fuel equipment when it is advantageous for them to do so. While Northern previously forecast firm dual-fuel loads in conjunction with its other firm customers, Northern had not separately attributed a portion of its planning to the special treatment required of a service character that permits the ability to alternate between using and not using natural gas.

The primary alternative fuel that Northern's dual-fuel customers rely upon is oil. Historically, oil and natural gas have tracked closely with one another on a commodity cost basis and because of this, the majority of firm dual-fuel customers continued to burn significant amounts of natural gas. However, during the April 2005 through March 2006 period, many of these firm dual-fuel customers elected to burn significantly lower proportions of natural gas when prices for natural gas rose more rapidly than oil. As a result, firm dual-fuel customers were not utilizing firm natural gas service as compared to times when gas commodity prices were more competitive with oil prices.

During the most recent winter, Northern's actual firm customer consumption on colder days materially exceeded expectations embedded in the forecasts underlying its most recent IRP filing. This occurred on days with EDDs that were well below design levels. Upon further investigation, Northern determined that a contributing factor to the unexpectedly high level of customer use was the fact that many firm dual-fuel customers had switched back to natural gas for the 2006-07 winter period as natural gas commodity prices regained competitiveness with oil. Because Northern relies upon historic consumption characteristics to predict the future, its

[1] Firm dual-fuel customers that desire the reliability of firm natural gas service pay the rates and charges currently effective in Northern's firm gas Rate Schedules.

existing planning process understated and will continue to understate the design requirements of its firm dual-fuel customers following periods when they are utilizing oil on a consistent basis.

Modification to Planning Process

Northern will therefore adjust its planning process by separately projecting the design day requirements of firm dual-fuel customers. Specifically, Northern will calculate the impact of firm dual-fuel customers on the regression analyses utilized to forecast design day loads. These regression analyses are described on pages 23-24 of Northern's June 30, 2006 IRP filing and the results are presented in Schedule III-8 and Schedule III-9. Of the total design day load reported in Schedule III-9, 10,208 Dth is associated with the requirements of firm dual-fuel customers. Northern estimated the proportion of total design day load that equates to firm dual-fuel use by performing a regression of the monthly data for the largest firm dual-fuel customers in each division for the same time period utilized to prepare Schedules III-8 and III-9. These regressions of monthly firm dual-fuel data indicate that the contribution of these customers to the total estimated design day in the original IRP filing was 4,941 Dth in the New Hampshire Division and 5,267 Dth in the Maine Division. Once these values were calculated, Northern subtracted them from the total design day forecast in order to obtain a design day forecast without any firm dual-fuel load. See new Schedule III-12 for these regression results.

Next, Northern prepared a customized estimate of design day consumption for its firm dual fuel customers based on a more recent and historic peak usage of these customers. The peak usage was adjusted for the difference between the actual peak level of degree days and the design level of degree days in each of Northern's Divisions. For purposes of these calculations, the same adjustment was performed for all firm dual-fuel customers in the group using a calculated use per EDD factor based on the most recent data for these customers. The customized estimates of firm dual-fuel design day usage for the 2006-2007 winter period are 9,668 Dth in Northern's New Hampshire Division and 11,845 Dth in the Maine Division and are presented in new Schedule III-12.

This modification is appropriate given the unique consumption characteristics of dual-fuel customers so that, Northern is able to continue to provide reliable service whenever called upon by its firm customers. During any particular winter period, Northern must be prepared to provide service to the peak requirements of its firm dual-fuel customers. These customers may burn natural gas on a design day due to favorable relative natural gas to oil commodity prices in the period leading up to a design day or due to the unavailability of alternate fuel or equipment failure.

Impact of Modification on Northern IRP

The impact of this change to Northern's planning process is important for the time period reported in Northern's IRP. Specifically, the design day forecasts reflected in the initial IRP is understated by approximately 11,300 Dth due to the impact of the low firm dual-fuel consumption during the historic period that was relied upon to project design day consumption. Therefore, Northern submits the following revised schedules to reflect the impact of this update on its forecast:

(1) Schedule III-9 Revised: Design Day Forecast

(2) Schedule IV-5 Revised: Summary of Northern Utilities Demand and Available Resources

In addition to these revised schedules, Northern includes those portions of revised IRP text that are affected by this change: Page 5 (Revised), Page 34 (Revised) and Page 40 (Revised) at Table IV-1.

Exising Dual Fuel Major Accounts In Maine and NI
Monthly gas usage 2005 - 3/2007 and associated peak day usag
Date: 5/11/07

DUAL FUEL CUSTOMER	2007 Monthly Gas Use Jan-07	Feb-07	Mar-07		2006 Monthly Gas Usage Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
1	45,811	49,593	49,965		35,532	34,151	39,689	34,796	35,530	34,721	32,683	42,397	38,588	42,517	41,493	40,240
2	17,867	16,317	17,197		15,930	14,222	15,265	13,849	13,344	13,710	13,346	12,654	12,872	14,001	13,988	16,187
3	59,456	55,770	60,135		65,741	60,432	66,203	58,641	64,298	62,564	52,409	52,907	52,636	53,123	50,721	50,713
4	5,543	5,391	5,141		2,624	1,930	4,729	3,940	3,699	3,277	2,923	3,160	3,325	4,034	4,121	4,752
5	14,932	14,576	14,292		1,016	57	12,798	7,297	5,295	4,699	4,942	5,251	5,298	5,393	10,922	12,829
6	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0
7	55,313	49,862	63,939		0	0	0	3,086	11,228	29,767	28,387	45,329	43,325	15,453	43,934	54,520
8	5,034	5,134	4,771		4,727	4,632	4,577	4,173	3,904	3,411	2,980	3,302	3,429	4,037	4,449	4,775
9	14,669	14,420	12,612		0	28	9,479	7,860	4,123	6	0	0	20	6,913	8,390	11,912
10	6,194	5,959	5,968		86	0	1,701	5,747	4,935	4,212	4,153	4,345	3,586	4,620	4,959	4,489
11	9,470	8,710	7,820		8,730	6,890	6,330	5,570	4,910	5,520	6,020	6,760	6,590	7,170	5,830	8,190
12	6,490	8,580	7,600		6,240	5,740	5,790	3,760	4,260	4,070	3,320	4,630	3,920	5,650	5,680	6,520
13	16,648	16,595	13,864		14	46	12,211	8,199	5,604	4,680	4,478	4,470	4,896	7,100	8,586	12,247
14	7,800	7,909	6,872		4,754	4,085	6,929	4,236	2,950	2,526	2,072	2,558	2,718	3,960	4,508	6,224
15	22,557	16,520	17,196		23,073	21,235	19,633	19,763	20,860	17,308	19,180	18,985	14,137	18,383	15,879	15,238
16	5,099	5,075	3,125		0	22	3,243	1,415	716	0	0	0	33	1,084	1,903	3,796
17	18,844	20,247	13,067		320	175	16,481	12,646	11,302	7,059	8,140	9,056	10,107	11,895	12,467	14,034
18	9,412	7,319	3,004		6,305	7,737	8,748	8,560	7,268	8,366	8,443	8,792	6,882	8,942	8,587	9,086
19	15,059	18,489	12,509		157	458	11,130	6,354	4,417	3,201	2,825	2,994	3,613	6,055	7,952	11,763
20	103,064	85,327	94,309		62,099	56,972	47,512	79,521	46,920	47,334	50,628	49,257	51,632	57,531	83,360	97,451
21	5,900	6,690	5,130		0	30	4,900	3,760	3,230	2,390	1,950	2,200	2,640	3,620	4,040	5,020
TOTAL	446,878	405,583	424,236	0	239,350	218,852	297,353	293,193	256,793	258,819	248,881	279,037	272,453	281,481	341,617	389,986

DUAL FUEL CUSTOMER	2005 Monthly Gas Usage Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
1	35,392	32,624	37,446	36,204	35,696	39,350	35,330	39,085	18,395	40,577	35,366	31,040
2	16,032	13,888	15,710	14,502	14,675	13,196	13,039	11,738	11,989	13,459	13,936	16,537
3	55,821	56,508	63,143	61,913	65,274	59,150	57,936	57,925	60,134	65,030	61,294	60,299
4	6,040	4,907	5,196	4,111	4,322	3,324	3,114	3,146	3,147	3,901	4,556	3,404
5	16,711	13,647	14,382	10,073	5,231	4,930	5,040	5,245	4,965	5,229	8,346	13,352
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	5,789	4,838	5,697	5,081	4,099	3,149	2,971	2,991	3,253	3,802	4,437	5,034
9	518	0	0	0	0	0	0	0	0	0	0	0
10	14,284	11,872	11,096	8,697	8,179	6,755	6,292	5,850	6,020	5,919	5,681	3,850
11	9,060	7,430	8,270	6,790	6,230	6,010	7,210	7,200	7,460	7,800	7,640	8,910
12	6,840	5,730	6,150	4,620	5,260	4,540	3,950	4,350	4,670	5,960	5,180	5,490
13	14,934	13,729	13,911	8,489	7,090	5,189	4,874	4,775	5,024	6,407	0	13
14	8,179	7,093	7,336	4,544	4,008	2,709	2,097	2,595	2,558	4,207	5,033	7,819
15	24,139	21,307	23,508	21,576	22,674	20,470	18,061	20,909	20,135	22,658	15,720	20,594
16	0	0	0	2	2	0	0	0	45	1,169	2,594	4,439
17	155	135	17,112	13,154	13,055	9,555	9,276	9,236	9,447	11,800	12,956	16,415
18	6,670	5,633	6,917	6,373	4,496	52	1,433	5,852	6,917	7,436	7,298	8,205
19	1,091	910	261	110	157	276	3,707	3,594	3,933	7,249	9,176	265
20	46,568	42,937	45,886	40,249	56,511	47,628	47,983	46,175	37,675	55,586	46,707	71,233
21	10	40	5,340	4,030	3,830	2,450	2,120	2,150	2,260	20	0	0
TOTAL	268,233	243,478	287,361	250,718	260,789	228,733	224,533	232,815	206,027	268,209	244,920	275,951

SCHEDULE III-12

Contribution of Dual Fuel Customers to Design Day

	Volume on Design Day 2006 1				Expected Volume 2	Difference
	Base Load	Dth/EDD	EDD	DTH	DTH	DTH
NH	4,093	10.3407	82	4,941	9,668	4,727
ME	3,824	17.3827	83	5,267	11,845	6,578
NU				10,208	21,513	11,306

1 . Based on Monthly Regressions for 12 months ended Mar 2006 and Northern's system maximum observed base load
2 Based on customers' maximum observed base loads (summer 2006) and heating increments (peak day 2007)

in order to satisfy its obligation to ensure that each decision constitutes the best alternative available at the time a decision is made.

Since the planning process and resource decisions are made within a dynamic environment and marketplace and will be based on the best information known at the time, the above assessments and expected final decisions may change. All assessments, however, will be based upon the methodology set forth in the Plan.

A. Background

Northern provides local distribution service to approximately 25,000 customers in its Maine Division and 27,000 customers in its New Hampshire Division. A significant portion of Northern's customer base is comprised of weather-sensitive residential heating customers. The remainder of Northern's customers are traditional commercial and industrial ("C&I") loads as well as some larger industrial customers. The aggregate design day load on Northern's system for the upcoming winter is approximately 138,000 Dth, while the design winter season load is approximately 9 Bcf. Annual normal load is almost 14 Bcf.

Northern's C&I customers in both its Maine Division and its New Hampshire Division have the option of purchasing supply from a competitive supplier and receiving transportation-only service from Northern pursuant to unbundled tariff options. The terms and conditions applicable to transportation service specify Northern's obligation to assign capacity to portions of the transportation customer loads in each Division. In addition, Northern maintains a capacity reserve calculated based on transportation loads to which Northern does not assign capacity. Therefore, Northern's resource planning process reflects its obligation to assign capacity and maintain a reliability reserve in conjunction with its unbundled service offerings, in addition to its sales service obligations.

to capacity-exempt customers, the Company believes that the majority of the existing operational risks is mitigated under the approved capacity reserve.

Northern will reserve a portion of its LNG and propane assets to provide the necessary capacity to fulfill the capacity reserve requirement. These assets serve a dual purpose of providing distribution system pressure support as well as providing a source of supply. They are preferable for this type of reserve because they are under the direct control of Northern, are located on the distribution system, and most importantly, can be dispatched on a no-notice basis to satisfy changing demand requirements attributable to weather and/or upstream supply disruptions.

Northern analyzes its resource needs on the basis of the design weather requirements of its sales and non-capacity-exempt transportation customers. The capacity reserve contributes to a resource need applicable to a limited portion of the requirements of capacity-exempt firm transportation customers in addition to Northern's other total portfolio resource needs. This need is factored into Northern's IRP process increasing the quantity of capacity necessary to maintain reliable service. Based on existing levels of combined Division customer loads, the incremental planning standard would translate into a calculated capacity reserve of 10,247 Dth for the 2006-2007 Winter Period. The total reserve will change over the forecast period to the extent that there is any change in the level of capacity-exempt loads.

C. Description of the Current Resource Portfolio

1. Overview of Supply-Side Resources

Northern's upstream resource portfolio is made up of over 30 long-term supply, transportation, and storage contracts that serve the combined system. These contracts are

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See MPUC Docket No. 2006-114 and NHPUC Docket DG06-033.

and Northeast Pipeline ("M&NE") with gas purchased at a Dracut index price. The M&NE option was available to be selected in both 2008/09 or 2011/12 to replace other resource options in those years. A replacement DOMAC option was made available upon expiration of the existing combined liquid and vapor contract also in 2011/12.

In order to appropriately capture the impact of the contracts expiring in 2011/12 on contract decisions that must be made during the five-year planning horizon of the IRP, Northern performed a 10-year Resource Mix for the period 2006/07 through 2015/16 in order to determine the optimal portfolio of resources. A 10-year analysis is consistent with the type of analysis that Northern performs whenever an incremental capacity option is considered. Table IV-1 below lists the contract quantities included in the Resource Mix as well as the quantities selected in a portfolio of optimal cost.

Table IV-1
SENDOUT Model
Resource Mix Parameters and Results

Resource	Effective Date	Minimum MDQ	Maximum MDQ	Selected Quantity
Tennessee Long-Haul	10/1/08	0	13,155	13,155
Tennessee Short-Haul	10/1/08	0	2,653	2,653
MCN Storage/TCPL	10/1/08	0	33,000	33,000
Maritimes - 2008	10/1/08	0	50,000	0
DOMAC	10/1/11	0	5,000	3,000
Maritimes – 2011	10/1/11	0	50,000	43,972

NOTE: The maximum MDQ and Selected Quantity differ slightly from the amount delivered to Northern due to fuel retention upstream of the city gate.

Schedule III - 9 REVISED
Design Day Forecast

Jan 2007 NU	Design Day Dth	Sales	CE Trans	NCE Trans	Design Day Dth less CE	DSM	Design less CE less DSM
Maine	65,170	33,118	19,315	12,737	45,855		45,855
New Hampshire	72,854	53,979	14,835	4,040	58,020	(244)	57,776
Total	138,024	87,097	34,150	16,777	103,874	(244)	103,630

Jan 2008 NU	Design Day Dth	Sales	CE Trans	NCE Trans	Design Day Dth less CE	DSM	Design less CE less DSM
Maine	65,259	32,194	19,822	13,243	45,437	(42)	45,396
New Hampshire	74,218	55,342	14,835	4,040	59,383	(487)	58,896
Total	139,476	87,536	34,657	17,284	104,820	(529)	104,291

Jan 2009 NU	Design Day Dth	Sales	CE Trans	NCE Trans	Design Day Dth less CE	DSM	Design less CE less DSM
Maine	65,344	31,249	20,337	13,759	45,007	(88)	44,919
New Hampshire	75,650	56,775	14,835	4,040	60,815	(731)	60,084
Total	140,994	88,023	35,172	17,799	105,822	(819)	105,003

Jan 2010 NU	Design Day Dth	Sales	CE Trans	NCE Trans	Design Day Dth less CE	DSM	Design less CE less DSM
Maine	65,393	30,293	20,839	14,261	44,554	(320)	44,234
New Hampshire	76,874	57,999	14,835	4,040	62,040	(974)	61,066
Total	142,268	88,292	35,674	18,301	106,594	(1,294)	105,300

Jan 2011 NU	Design Day Dth	Sales	CE Trans	NCE Trans	Design Day Dth less CE	DSM	Design less CE less DSM
Maine	65,343	29,306	21,307	14,729	44,035	(566)	43,469
New Hampshire	78,284	59,408	14,835	4,040	63,449	(1,218)	62,231
Total	143,626	88,715	36,142	18,769	107,484	(1,784)	105,700

CE - Capacity Exempt
NCE - Non Capacity Exempt

Summary of Northern Utilities Demand & Available Resources

SCHEDULE IV-5
2nd REVISED

No Contract Renewals During 2006-2011
(MMBtu)
Design Day

	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012*
Pipeline						
Tennessee Longhaul	13,089	13,089	0	0	0	0
Algonquin	1,303	1,303	1,303	1,303	1,303	1,303
Tennessee Boundary	2,323	2,323	2,323	2,323	0	0
Tennessee Husky	945	945	945	945	945	945
Tennessee Iroquois	2,215	2,215	2,215	2,215	2,215	2,215
Algonquin Iroquois	4,190	4,190	4,190	4,190	4,190	4,190
DEM PNGTS	1,095	1,095	1,095	1,095	1,095	1,095
Total Pipeline	25,161	25,161	12,071	12,071	9,748	9,748
Storage						
Texas Eastern	85	85	85	85	85	85
Tennessee	2,640	2,640	0	0	0	0
DTE/ PNGTS**	32,835	32,835	0	0	0	0
Total Storage	35,559	35,559	85	85	85	85
Peaking						
Lewiston LNG	10,000	10,000	10,000	10,000	10,000	10,000
Propane	4,000	4,000	4,000	4,000	4,000	4,000
Duke	35,820	35,820	46,765	52,735	57,113	0
DOMAC 1	4,975	4,975	4,975	4,975	4,975	0
Total Peaking	54,795	54,795	65,740	71,710	76,088	14,000
Total Capacity	115,515	115,515	77,896	83,866	85,921	23,833
Total Demand	137,779	138,947	140,174	140,973	141,842	142,551
Capacity-exempt Requirement	34,150	34,657	35,172	35,674	36,142	36,266
Reserve Capacity***	10,245	10,397	10,552	10,702	10,843	10,880
NET Demand	113,874	114,687	115,554	116,001	116,543	117,165
Surplus/(Deficiency)	1,641	828	(37,658)	(32,135)	(30,622)	(93,332)

*: Reflects contract termination dates that fall just outside of the five year analysis period

**: Although the DTE contracts is set to expire in 2008, the PNGTS contract will not terminate until 2019.

***: Subject to Northern's capacity allocation proposal. Reflects 30% of all non-assigned capacity.

Request: Schedule IV-5 indicates that the Company expects to carry a supply surplus in 2006-2007 and 2007-2008 relative to design day demand under a 1-in-33 probability of occurrence. In addition, the schedule indicates that that surplus will increase substantially if the Company renews or replaces each expiring contract through 2010-2011 at its existing capacity level. Please respond to the following:

(i) Does the Company agree with the above interpretation of Schedule IV-5? If not, explain why not.
(ii) Does the Company currently plan to replace each expiring contract through 2010-2011 at its existing capacity level? If not, specify the renewal or replacement capacity for each.
(iii) Provide Schedule IV-5 under a scenario in which each expiring contract through 2010-2011 is renewed or replaced at the level reflected in Northern's current procurement plan.
(iv) If Northern plans on replacing the Duke contract prior to 2011-2012, please add the replacement capacity to the version of Schedule IV-5 provide in response to (iii) above.
(v) Explain why Northern currently plans to replace the Duke contract prior to its expiration date and provide all associated workpapers.

Response: (i) Schedule IV-5 is intended to show the surplus or deficiency in each year of the forecast period under the assumption that Northern does not renew expiring resources. This schedule shows a small surplus for the first two years of the forecast period and significant shortfalls beginning in the winter of 2008-09.

(ii) Northern's resource action plan is summarized in Section V of the 2006 IRP, pages 42-44. As noted therein, Northern anticipates renewing a number of its existing capacity resources that come up for renewal during the term of the plan. These include the renewal of Tennessee long-haul and short-haul capacity and the renewal or replacement of MCN Storage capacity in 2008 at existing MDQ levels. As indicated by the resource analysis discussed on pages 37-42 of the 2006 IRP, the renewal of these resources represents the most cost-effective course of action to meet the requirements of Northern's customers. Although this would result in a surplus on design day during the three-year period beginning the winter of 2008-09, the potential future costs of replacing the expiring Duke contract in 2011 must be evaluated in conjunction with the decisions that are made in 2008. In general, the embedded costs of depreciated capacity resources such as the Tennessee system are lower than the costs of new pipelines and expansions of existing pipelines. Therefore, the renewal of the Tennessee capacity represents an appropriate strategy to retain competitively-priced service alternatives and important supply diversity benefits. Moreover, the cost of the surplus is relatively low due to the favorable pricing to Northern associated with the Duke contract.

The process of contracting for capacity, by its nature, creates a resource imbalance due to the lumpiness of the capacity decision given that this decision must be made presently to serve a need that materializes over time. Northern will continue to assess the appropriate course of action with respect to each decision to contract or de-contract for capacity that will be made to satisfy its obligation to ensure that each decision constitutes the best alternative available at the time a decision is made.

(iii) Please see Attachment Staff 1-19(i), which provides a schedule similar to Schedule IV-5 reflecting the renewal and replacement of resources consistent with Northern's 2006 IRP.

(iv) Northern does not plan on replacing the Duke contract prior to its expiration.

(v) Northern does not plan on replacing the Duke contract prior to its expiration.

REVISED
Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

(i) The appropriate schedule is Schedule IV-5 REVISED.

(iii) The appropriate attachment is Attachment Staff 1-19 (i) REVISED.

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Summary of Northern Utilities Demand & Available Resources

Attachment Staff 1-19(i) REVISED

Utilization of Current Rollover Rights
(MMBtu)
Design Day

	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012*
Pipeline						
Tennessee Longhaul	13,089	13,089	13,089	13,089	13,089	13,089
Algonquin	1,303	1,303	1,303	1,303	1,303	1,303
Tennessee Boundary	2,323	2,323	2,323	2,323	2,323	2,323
Tennessee Husky	945	945	945	945	945	945
Tennessee Iroquois	2,215	2,215	2,215	2,215	2,215	2,215
Algonquin Iroquois	4,190	4,190	4,190	4,190	4,190	4,190
DEM PNGTS	1,095	1,095	1,095	1,095	1,095	1,095
Maritimes Incremental	0	0	0	0	0	43,972
Total Pipeline	25,161	25,161	25,161	25,161	25,161	69,133
Storage						
Texas Eastern	85	85	85	85	85	85
Tennessee	2,640	2,640	2,640	2,640	2,640	2,640
DTE/ PNGTS**	32,835	32,835	32,835	32,835	32,835	32,835
Total Storage	35,559	35,559	35,559	35,559	35,559	35,559
Peaking						
Lewiston LNG	10,000	10,000	10,000	10,000	10,000	10,000
Propane	4,000	4,000	4,000	4,000	4,000	4,000
Duke	35,820	35,820	46,765	52,735	57,113	0
DOMAC 1	4,975	4,975	4,975	4,975	4,975	2,985
Total Peaking	54,795	54,795	65,740	71,710	76,088	16,985
Total Capacity	115,515	115,515	126,460	132,430	136,808	121,677
Total Demand	137,779	138,947	140,174	140,973	141,842	142,551
Capacity-exempt Requirement	34,150	34,657	35,172	35,674	36,142	36,266
Reserve Capacity***	10,245	10,397	10,552	10,702	10,843	10,880
NET Demand	113,874	114,687	115,554	116,001	116,543	117,165
Surplus/(Deficiency)	1,641	828	10,906	16,429	20,265	4,512

*: Reflects contract termination dates that fall just outside of the five year analysis period

**: Although the DTE contracts is set to expire in 2008, the PNGTS contract will not terminate until 2019.

***: Subject to Northern's capacity allocation proposal. Reflects 30% of all non-assigned capacity.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 1
Response: 27
Responsible: Francisco C. DaFonte,
Director' Energy Supply Services;
Joseph A. Ferro,
Manager, Regulatory Policy

Request: Assuming the Company renews or replaces each expiring contract during the period ending 2011-2012 at the level reflected in its current procurement plan, what is the estimated incremental cost of the resources to support the 30% capacity reserve? Please provide the analysis underlying this cost estimate. Please also explain: (i) how this incremental cost is allocated between, on the one hand, firm sales and capacity assigned transportation customers and, on the other, capacity exempt transportation customers; and (ii) the basis of this allocation.

Response: This response requires the Company to run its SENDOUT® model, and the Company representative capable of doing this is out of the country through September 5, 2006. The Company will supplement this response with the requested data as soon as possible.

SUPPLEMENTAL RESPONSE: For the 2006-2011 forecast period, the incremental cost of supporting a capacity reserve equal to 30% of capacity-exempt load will be small since the Company's existing resources throughout this period are adequate to satisfy the reserve. A minor cost impact may occur if the Company's on-system LP and LNG resources are required to back stop marketer under-deliveries as these resources are to be held to meet the 30% reserve and would not be available to meet sales service requirements.

Once the Company's Duke contract expires in 2011, it has the opportunity to reshape its portfolio and isolate the resources required to satisfy the 30% reserve. At this time, Northern is assuming that the incremental capacity required to satisfy the reserve will come Maritimes & Northeast Pipeline ("M&NE"). Attachment Staff 1-27 shows the estimated incremental cost (approximately $1.2 million) associated with meeting this reserve with M&NE service. The table shows the difference in total portfolio costs with and without the reserve requirement. The cost difference includes an estimate of capacity release revenue that would help mitigate some of the pipeline capacity cost impact; however, future capacity release market values could vary significantly

Please note that Northern has not committed to any capacity with Maritimes & Northeast Pipeline at this time. Northern will continue to look for other alternatives that may be more economic to the Company's portfolio at the time such capacity is required.

(i) Currently, all portfolio capacity costs are recovered from firm sales and non-capacity exempt customers through the Cost of Gas mechanism and Capacity Assignment provisions pursuant to the Company's Delivery Service Terms and Conditions. Any incremental cost that would be caused by the additional requirement of a reserve would be part of the overall portfolio costs charged through the Cost of Gas or as capacity costs assigned to transportation customers. Any Capacity Reserve Charge that may be implemented would first establish the allocated level of capacity reserve costs based on the capacity exempt load contribution to design day demand. The allocation or recovery of these costs from customers or customer groups has not yet been decided.

(ii) The basis for the current methodology of recovering the entire portfolio capacity costs is the high- and low-load factor customer classes' contribution to design day demand. The high- and low-load factor C&I customers are assigned capacity and associated costs based on the ratios derived from the Capacity Allocators calculation used to assign percentages of the Company's portfolio costs (by Pipeline, Storage and Peaking). These percentages are derived, and thus, the capacity costs are assigned to classes, on the basis of the classes' contribution to the system's design day load.

REVISED Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

The appropriate attachment is Attachment Staff 1-27 REVISED. The revised estimated incremental cost is approximately $1.8 million.

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Attachment Staff 1-27 REVISED

Northern Utilities Inc.
Cost Estimate for 30% Reserve
Utilizing the SENDOUT Model
2011-2012

Year	Total Portfolio Cost With 30% Reserve	Total Portfolio Cost Without 30 % Reserve	Difference	Estimated Capacity Release Revenue	Estimated Net Cost
2011-2012	$120,193,890	$116,641,770	$3,552,120	-$1,783,723	$1,768,397

Maritimes & Northeast Pipeline

Capacity Release	Total Reserve Capacity	Max Rate	Total cost	Estimated Release Price	Total Release Revenue
November	10,880	$27.98	$304,446	$27.98	$304,446.18
December	10,880	$27.98	$304,446	$0.00	$0.00
January	10,880	$27.98	$304,446	$0.00	$0.00
February	10,880	$27.98	$304,446	$0.00	$0.00
March	10,880	$27.98	$304,446	$27.98	$304,446.18
April	10,880	$27.98	$304,446	$27.98	$304,446.18
May	10,880	$27.98	$304,446	$20.00	$217,596.00
June	10,880	$27.98	$304,446	$10.00	$108,798.00
July	10,880	$27.98	$304,446	$10.00	$108,798.00
August	10,880	$27.98	$304,446	$10.00	$108,798.00
September	10,880	$27.98	$304,446	$10.00	$108,798.00
October	10,880	$27.98	$304,446	$20.00	$217,596.00
Total					$1,783,723

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 1
Response: 45
Responsible: Francisco C. DaFonte, Director, Energy Supply Services

Request: Ref. 2006 IRP, page 44. Northern states that it is faced with the need for significant resources beginning in 2011/2012. What quantity of capacity does the Company currently plan to purchase to address the expiration of the Duke peaking contract? Also, when does the Company plan to purchase this new resource and will the quantity be fixed or change over time to track demand growth?

Response: Based on the current demand forecast, Table IV-1 on page 40, indicates that a best-cost portfolio requires 40,654 Dth of Maritimes capacity beginning 10/1/11 to replace the expiring Duke contract. This assumes the renewal of all other resources in the current portfolio at the same contract levels except the DOMAC contract, which is reduced by 2,000 by the SENDOUT® model.

Northern is currently examining proposed projects to replace the Duke contract and will continue to examine these and other projects as market conditions change. Prior to making any resource decision, Northern will conduct a comprehensive RFP process designed to solicit the "best-cost" resource. As part of the RFP process, Northern will explore opportunities to contract for a "demand shaped" service if it is the best fit for the portfolio. It is not known exactly when the Company will purchase this needed resource but it is anticipated it will do so within the next 3-4 years.

REVISED
Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

The appropriate table is TABLE IV-1 on Page 40 (Revised 6-1-07).

The revised best-cost portfolio requires 43,972 Dth of Maritimes capacity beginning in the Fall of 2011, to replace the expiring Duke contract.

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 2
Response: 8
Responsible: Francisco C. DaFonte
Director, Energy Supply Services

Request: Ref. Response to Staff 45. The Company states that a best-cost portfolio would require 40,654 Dth of Maritimes capacity beginning 10/1/11 to replace the expiring Duke contract, assuming renewal of all other resources in the current portfolio at the same contract levels except the DOMAC contract. Inclusion of 40,451 MMBtu of supply in 2011 in Revised Schedule IV-5 plus renewal of existing contracts at existing levels (DOMAC at 2,985 MMBtu) indicates a surplus of just under 5,000 MMBtu in 2011-12 relative to the design day demand for non-grandfathered customers. Please respond to the following:

(i) Explain why it is optimal to plan for a capacity surplus of approximately 5,000 MMBtu relative to net design day demand.
(ii) If the capacity surplus is designed to cover expected post-2011 growth in design day demand, provide the forecast design day demand for each year during the period 2011-2016.
(iii) What are the likelihood of procuring additional incremental capacity after 2011 or entering into a contract prior to 2011 that has the MDQ increasing in line with expected load growth?
(iv) Identify the proposed projects that Northern is currently examining as replacements for the Duke contract.
(v) Specify the calendar years associated with the phrase "within the next 3-4 years."

Response: (i) The approximate 4,500 MMBTU imbalance is due to the SENDOUT® model sizing the Maritimes & Northeast Pipeline (""Maritimes" or "M&NE") contract through 2016. From 2012 through 2016, additional quantities of M&NE are needed to meet growing design day needs. By 2016, the resource imbalance would be virtually eliminated given the anticipated design day demand.

(ii) Please see Attachment Staff 2-8(ii).

(iii) Without conducting an RFP process it is not possible to determine whether there is market receptivity for a contract that has escalating MDQ's in line with Northern's expected growth. With regard to procuring incremental contracts on a year-to-year basis after 2011, the tight capacity market in New England and the historical contracting patterns on the New England pipelines make this improbable. Northern also believes this is an unwise method of system planning, if the goal is to ensure system reliability using a best cost portfolio.

(iv) Northern is currently examining several LNG projects that would deliver gas to Eastern Canada and transport it through M&NE. This includes the Canaport ™ project as well as other proposed LNG projects that would deliver gas into Maritimes. At the current time, the Canaport ™ project is the furthest along and is projected to have a Winter 2008 in-service date. In addition, Northern does and will continue to explore other pipeline alternatives that may develop.

Also, please see Company responses to Staff 1-34 and 1-36.

(v) The referenced years are 2007, 2008, 2009 & 2010.

REVISED
Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

(ii) The appropriate attachment is Attachment Staff 2-8 (ii) Revised.

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Attachment Staff 2-8(ii) REVISED

Summary of Northern Utilities Demand & Available Resources
Utilization of Current Rollover Rights
(MMBtu)
Design Day

	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012*	2012-2013*	2013-2014*	2014-2015*	2015-2016*
Pipeline										
Tennessee Longhaul	13,089	13,089	13,089	13,089	13,089	13,089	13,089	13,089	13,089	13,089
Algonquin	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303	1,303
Tennessee Boundary	2,323	2,323	2,323	2,323	2,323	2,323	2,323	2,323	2,323	2,323
Tennessee Niagara	945	945	945	945	945	945	945	945	945	945
Tennessee Iroquois	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215
Algonquin Iroquois	4,190	4,190	4,190	4,190	4,190	4,190	4,190	4,190	4,190	4,190
DEM PNGTS	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095
Maritimes Incremental	0	0	0	0	0	43,752	43,752	43,752	43,752	43,752
Total Pipeline	25,161	25,161	25,161	25,161	25,161	68,913	68,913	68,913	68,913	68,913
Storage										
Texas Eastern	85	85	85	85	85	85	85	85	85	85
Tennessee	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640
MCN/ PNGTS**	32,835	32,835	32,835	32,835	32,835	32,835	32,835	32,835	32,835	32,835
Total Storage	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,559
Peaking										
Lewiston LNG	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Propane	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Duke	35,820	35,820	46,765	52,735	57,113	0	0	0	0	0
DOMAC	4,975	4,975	4,975	4,975	4,975	2,985	2,985	2,985	2,985	2,985
Total Peaking	54,795	54,795	65,740	71,710	76,088	16,985	16,985	16,985	16,985	16,985
Total Capacity	115,515	115,515	126,460	132,430	136,808	121,457	121,457	121,457	121,457	121,457
Total Demand	**137,779**	**138,947**	**140,174**	**140,973**	**141,842**	**142,551**	143,977	145,416	146,871	148,339
Grandfathered Requirements	34,150	34,657	35,172	35,674	36,142	**36,323**	36,868	37,421	37,982	38,552
Reserve Capacity***	10,245	10,397	10,552	10,702	10,843	**10,897**	11,060	11,226	11,395	11,565
NET Demand	113,874	114,687	115,554	116,001	116,543	**117,125**	118,169	119,222	120,283	121,353
Surplus/Deficiency	1,641	828	10,906	16,429	20,265	**4,332**	3,288	2,235	1,174	104

*: Reflects contract termination dates that fall just outside of the five year analysis period
**: Although the MCN and TransCanada contracts are set to expire in 2008, the PNGTS contract will not terminate until 2019.
***: Subject to Northern's capacity allocation proposal. Reflects 30% of all non-assigned capacity

Northern Utilities, Inc.
Maine Division
Docket No. 2006-390
Advisor's Oral Data Request
From 9-19-06 Technical Conference
Responsible: Francisco C. DaFonte
Director, Energy Supply Services

ODR-2: Please re-run the SENDOUT® resource mix with lower Maritimes and Northeast rates.

Response: Please see CONFIDENTIAL Attachment ODR-2. It includes a summary schedule with the Optimal selected resource quantities and the CONFIDENTIAL SENDOUT® Model run.

REVISED
Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

The appropriate attachment is CONFIDENTIAL Attachment ODR-2 REVISED.

Northern requests that the Motion for Protective Order provided for the CONFIDENTIAL Attachment ODR-2 originally filed on November 27, 2006, be amended to included protection for Revised Attachment ODR-2.

Northern Utilities, Inc.
New Hampshire Division
Docket No. DG 06-098
Maine Division
Docket No. 2006-390
Oral Data Request from
5-10-07 Joint Technical Conference
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

ODR-4: Please list the design-day MDQs of Northern's daily-metered and non-daily metered capacity-exempt and non-capacity-exempt customers.

Response: Attachment ODR-4 presents the current design day load (or MDQ) of Northern's firm transportation customers, for the Maine and New Hampshire divisions, by Capacity and Non-capacity Exempt, and by Daily Metered and Non-daily Metered services.

Please note that Northern's aggregate level of Capacity and Non-capacity Exempt load has increased (by over 5,000 Dth/day) from that listed in the Company's IRP at Schedule III-9. This is due mostly to the addition of 209 Non-daily Metered customers since September 2006, of which 72 are located in the New Hampshire Division, and are Non-capacity Exempt, and 137 are located in the Maine Division.

Also note that, 97% of the NH Division Capacity Exempt design day load is the load of customers in Daily Metered pools. The observed imbalances of these Daily Metered pools formed the basis for Northern's proposed capacity reserve level of 30% of Capacity Exempt design day load.

REVISED
Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

Attachment ODR-4 REVISED presents the requested design day firm transportation loads for each division. It reflects an additional 11,305 Dth of firm dual-fuel design-day load. Also, this attachment should be compared to Schedule III-9 Revised as described above.

Attachment ODR-4
REVISED

Northern Utilities
Design Day Load
As of May 15, 2007 Data and
Dual Fuel Design Day Load Adjustment on June 1, 2007

		Capacity Exempt MDQ (Dth)		Non-Cap. Exempt MDQ (Dth)		Total MDQ (Dth)
New Hampshire:	Daily Metered	14,504.9	1/	2,964.2	2/	17,469.1
	Non-daily Metered	289.0		4,133.5		4,422.4
Total NH Div.		14,793.9		7,097.6		21,891.5
Maine:	Daily Metered	17,475.4	3/	9,890.8		27,366.2
	Non-daily Metered	3,480.6		3,480.6		6,961.3
Total Maine Div.		20,956.1		13,371.4		34,327.5
Total Northern	Daily Metered	31,980.3		12,854.9		44,835.3
	Non-daily Metered	3,769.6		7,614.1		11,383.7

1/ Reflects Total NH Dual Fuel adj of 4,727 Dth less 122 for the only Non-Cap. Exempt customer.
2/ Reflects the addition of 122 Dth (1,672 vs. 1,550) of the only Non-Cap. Exempt DF customer.
3/ Includes the total ME Dual Fuel adj of 6,578 Dth, since Cap. Assigned volumes (TCQ) do not change.

Northern Utilities, Inc.
New Hampshire Division
Docket No. DG 06-098
Maine Division
Docket No. 2006-390
Oral Data Request from
5-10-07 Joint Technical Conference
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

ODR-5: At Northern's current Capacity Reserve proposal of 30% of capacity-exempt peak day load, please provide for the Maine Division (a) Northern's proposed associated cost of the reserve; (b) the Capacity Reserve Charge ("CRC") calculation; and (c) the associated typical bill impacts.

Response: Attachment ODR-5-(a) presents the calculation of Northern's proposed capacity reserve costs using the capacity-exempt peak day load estimated for January 2007 of 12,737 Dth shown on Schedule III-9 of Northern's June 29, 2006 filing. These costs are based on the capacity costs of Northern's on-system resources, as those resources would be set aside to be used in the event of the need to draw from a reserve.

Attachment ODR-5-(a) also presents the calculation of the Capacity Reserve Charge (CRC) using the estimated costs in part (a) and the forecast annual sales and transportation volumes of 6,892,000 Mcf for 2007 shown on Schedule III-6 of Northern's June 29, 2006 filing.

Attachment ODR-5-(b) presents the typical bill calculations for all rate classes isolating the impact of applying the CRC. Note that because the recovery of the capacity reserve costs will be credited back to firm sales customers, the CRC charged to sales customers will be offset by the credit of these revenues. The credit reflected in the calculation of the residential typical bill analysis is derived by the capacity reserve costs (or recoveries) divided by annual firm sales as follows:

($186,756 / 31,540,000 ccf => $0.0059 per ccf).

This credit is more than twice the CRC and thus, implementation of a CRC today will result in a slight reduction in a sales customer's bill, as is shown in the analysis for the residential heating rate class. The analysis for the commercial & industrial rate classes is based on a transportation customer, and thus does not reflect the unit credit inherent in crediting the capacity reserve revenues back through the Cost of Gas Factor.

REVISED
Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

Attachment ODR-5-(a) REVISED presents the calculation of Northern's proposed capacity reserve costs, as explained above, using the capacity-exempt peak day load estimated for January 2007 of 12,737 Dth, plus the increased design-day load associated with the updated estimate of Northern's firm dual fuel customers (6,578 Dth). These loads have been filed and shown on Schedule III-9 REVISED.

Attachment ODR-5-(a) REVISED also presents the calculation of the CRC as described above.

Attachment ODR-5-(b) REVISED presents the typical bill calculations for all rate classes isolating the impact of applying the CRC as described above. Note that the credit has changed slightly from that determined above.

($295,941 / 31,540,000 ccf => $0.0094 per ccf).

NORTHERN UTILITIES - MAINE DIVISION

CAPACITY RESERVE CHARGE CALCULATION

Using January 2007 Estimated Design Day and 2007 Vols and Costs

Row	Calculation				Incl. 6-1-07 *Adjustment*
(1)		Unassigned Capacity - Dth (50% of Design Day FT Load)		**19,315**	*6,578*
(2)		Annual Unit Cap. Cost	$	**69.301**	
(3)	(1) x (2)	30% of Unit Cap. Cost	$	**20.790**	
(4)	(1) x (3)	Capacity Reserve Costs	$	**401,563**	
		Less: Capacity Release Revs:			
(5)		Maine Cap Rel Revs	$	**1 197,334**	(May 06 - Apr 07 actual)
(6)		On-System % of System Avg.		**31.4%**	
(7)		Cap. Rel. @ On-System Value	$	**375,457**	
(8)		Unassigned Capacity - Dth		**19,315**	*6,578*
(9)		Total Maine Design Day - Dth		**65,170**	*6,578* (Sales and FT)
(10)	(7) x (8)/(9)	Revs allocated to Cap. Reserve	$	**111,278**	
(11)		Plus: Prior Period Under/Over	$	**-**	
(12)	See Att. A-2	Plus: Forecast Interest	$	**5,656**	
(13)	(4)-(10)+(11)+(12)	Costs to be Recovered	$	**295,941**	
		Firm Forecast Demand - ccf:			
(14)		Sales		**31,540,000**	
(15)		Transportation		**37,380,000**	
(16)	(14) + (15)	TOTAL		**68,920,000**	
(17)	(13) / (16)	CRC Rate per ccf	**$**	**0.0043**	

Calculation of On-System Unit Cap. Cost and % of Avg.

(1) On-System Cap. Costs	(2) On-System Capacity (Dth)	(3) Maine PR %	(4) Unit Cap Cost
(in CGFC)			(1) / [(2) x (3)]
$ 480,642	14,000	49.54%	$ 69.3007
Annual System Average Capacity Cost			$ 221.00
On-System % of System Average			31.4%

NORTHERN UTILITIES - MAINE DIVISION
CAPACITY RESERVE CHARGE CALCULATION

Using January 2007 Estimated Design Day and 2007 Vols and Costs

	Beginng Month Balance	CRC Recovery @ $ 0.0043	End of Month Balance	Average Balance	Annual Interest Rate	Monthly Interest Amount	Principal & Interest Balance	Forecast Sales and FT (ccf)
Nov 2007	$ 290,285	$ 28,687	$ 261,598	$ 275,942	4.74%	$ 1,090	$ 262,688	6,680,719
Dec	$ 262,688	$ 37,942	$ 224,747	$ 243,718	4.74%	$ 963	$ 225,710	8,835,990
Jan 2008	$ 225,710	$ 40,989	$ 184,721	$ 205,215	4.74%	$ 811	$ 185,531	9,545,661
Feb	$ 185,531	$ 35,969	$ 149,562	$ 167,547	4.74%	$ 662	$ 150,224	8,376,676
March	$ 150,224	$ 31,927	$ 118,297	$ 134,260	4.74%	$ 530	$ 118,827	7,435,238
April	$ 118,827	$ 23,326	$ 95,501	$ 107,164	4.74%	$ 423	$ 95,925	5,432,248
May	$ 95,925	$ 18,597	$ 77,328	$ 86,626	4.74%	$ 342	$ 77,670	4,330,922
June	$ 77,670	$ 13,879	$ 63,791	$ 70,730	4.74%	$ 279	$ 64,070	3,232,251
July	$ 64,070	$ 14,264	$ 49,806	$ 56,938	4.74%	$ 225	$ 50,031	3,321,917
Aug	$ 50,031	$ 13,245	$ 36,785	$ 43,408	4.74%	$ 171	$ 36,957	3,084,587
Sept	$ 36,957	$ 14,920	$ 22,037	$ 29,497	4.74%	$ 117	$ 22,153	3,474,665
Oct	$ 22,153	$ 22,196	$ (43)	$ 11,055	4.74%	$ 44	$ 1	5,169,128
Total		$ 295,941				$ 5,657		68,920,000

Res_Heat_Annual

NORTHERN UTILITIES, INC. - MAINE DIVISION
Typical Residential Heating Bill - 1,238 ccfs/year
Comparison With and Without CRC

			Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov - Apr	May	June	July	August	September	October	Summer May - Oct	Total Nov - Oct
	Typical Usage: ccf's		107.9	148.5	185.1	186.1	164.4	130.7	922.7	89.1	54.5	29.7	29.7	41.6	70.3	314.9	1,237.60
Residential Heating																	
Winter 2006-07																	
Customer Charge	units @	$4.96	$4.96	$4.96	$4.96	$4.96	$4.96	$4.96	$29.76								
First	40 units @	$0.4026	$16.10	$16.10	$16.10	$16.10	$16.10	$16.10	$96.62								
Over	40 units @	$0.2278	$15.47	$24.72	$33.05	$33.28	$28.34	$20.66	$155.52								
	CGA 1	$1.3435	$144.96	$199.51	$248.68	$250.03	$220.87	$175.60	$1,239.65								
	CGA 2																
	EERA	$0.0084				$1.56	$1.38	$1.10	$4.04								
	ERC	$ 0.0202	$2.18	$3.00	$3.74	$3.76	$3.32	$2.64	$18.64								
Summer 2007																	
Customer Charge	units @	$4.96								$4.96	$4.96	$4.96	$4.96	$4.96	$4.96	$4.96	
First	40 units @	$0.4026								$16.10	$16.10	$11.96	$11.96	$16.10	$16.10	$16.10	
Over	40 units @	$0.2278								$11.18	$3.30	$0.00	$0.00	$0.36	$6.90	$62.62	
	CGA 1	$1.1412								$101.68	$62.20	$33.89	$33.89	$47.47	$80.23	$359.36	
	CGA 2																
	EERA	$0.0084								$0.75	$0.46	$0.25	$0.25	$0.35	$0.59	$2.65	
	ERC	$ 0.0202								$1.80	$1.10	$0.60	$0.60	$0.84	$1.42	$6.36	
Total Bill Amount			$183.67	$248.29	$306.54	$309.69	$274.98	$221.06	$1,544.23	$136.48	$88.12	$51.66	$51.66	$70.09	$110.20	$452.06	$1,996.29
With Capacity Reserve Charge of:		**$ 0.0043**	**$0.46**	**$0.64**	**$0.80**	**$0.80**	**$0.71**	**$0.56**	**$3.97**	**$0.38**	**$0.23**	**$0.13**	**$0.13**	**$0.18**	**$0.30**	**$1.35**	**$5.32**
And With Cap Res Rev. Credit of:		**$ (0.0094)**	-$1.01	-$1.40	-$1.74	-$1.75	-$1.55	-$1.23	-$8.67	-$0.84	-$0.51	-$0.28	-$0.28	-$0.39	-$0.66	-$2.96	-$11.63
Total Bill with CRC Amount			$183.12	$247.53	$305.59	$308.74	$274.14	$220.39	$1,539.53	$136.02	$87.84	$51.51	$51.51	$69.88	$109.84	$450.45	$1,989.98
Percentage Change			-0.30%	-0.31%	-0.31%	-0.31%	-0.30%	-0.30%	-0.30%	-0.33%	-0.32%	-0.29%	-0.29%	-0.30%	-0.33%	-0.36%	-0.32%

NORTHERN UTILITIES, INC. - MAINE DIVISION
Typical G-50 Bill - 1,055.4 ccfs/year
Comparison With and Without CRC

			Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov - Apr	May	June	July	August	September	October	Summer May - Oct	Total Nov - Oct
Typical Usage: ccf's			98.1	117.7	128.7	117	109.1	91.1	661.7	71.4	61.3	56.6	59.1	64.4	80.9	393.7	1,055.40
G-50																	
Winter 2006-07																	
Customer Charge	units @	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$62.82								
First	70 units @	$0.3385	$23.70	$23.70	$23.70	$23.70	$23.70	$23.70	$142.17								
Over	70 units @	$0.2255	$6.34	$10.76	$13.24	$10.60	$8.82	$4.76	$54.50								
	CGA 1	$1.3410	$131.55	$157.84	$172.59	$156.90	$146.30	$122.17	$887.34								
	CGA 2																
	EERA	$0.0084				$0.98	$0.92	$0.77	$2.66								
	ERC	$ 0.0202	$1.98	$2.38	$2.60	$2.36	$2.20	$1.84	$13.37								
Summer 2007																	
Customer Charge	units @	$10.47								$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$62.82	
First	70 units @	$0.3385								$23.70	$20.75	$19.16	$20.01	$21.80	$23.70	$129.10	
Over	70 units @	$0.2255								$0.32	$0.00	$0.00	$0.00	$0.00	$2.46	$2.77	
	CGA 1	$1.0891								$77.76	$66.76	$61.64	$64.37	$70.14	$88.11	$428.78	
	CGA 2																
	EERA	$0.0084								$0.60	$0.51	$0.48	$0.50	$0.54	$0.68	$3.31	
	ERC	$ 0.0202								$1.44	$1.24	$1.14	$1.19	$1.30	$1.63	$7.95	
Total Bill Amount			$174.04	$205.13	$222.59	$205.01	$192.41	$163.69	$1,162.86	$114.28	$99.74	$92.89	$96.53	$104.25	$127.04	$634.74	$1,797.60
With Capacity Reserve Charge of: $ 0.0043			**$0.42**	**$0.51**	**$0.55**	**$0.50**	**$0.47**	**$0.39**	**$2.85**	**$0.31**	**$0.26**	**$0.24**	**$0.25**	**$0.28**	**$0.35**	**$1.69**	**$4.54**
Total Bill with CRC Amount			$174.46	$205.64	$223.14	$205.51	$192.87	$164.09	$1,165.71	$114.59	$100.00	$93.13	$96.79	$104.53	$127.39	$636.43	$1,802.14
Percentage Change			**0.24%**	**0.25%**	**0.25%**	**0.25%**	**0.24%**	**0.24%**	**0.24%**	**0.27%**	**0.26%**	**0.26%**	**0.26%**	**0.27%**	**0.27%**	**0.27%**	**0.25%**

NORTHERN UTILITIES, INC. - MAINE DIVISION
Typical G-40 Bill - 2,018.8 ccfs/year
Comparison of With and Without CRC

			Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov - Apr	May	June	July	August	September	October	Summer May - Oct	Total Nov - Oct
	Typical Usage: ccf's		214.1	309.2	364.6	305.6	259	158	1610.5	83.1	35.6	22.9	25.5	47.4	114.8	329.3	1,939.80
G-40																	
Winter 2006-07																	
Customer Charge	units @	$ 10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$62.82								
First	70 units @	$ 0.3385	$23.70	$23.70	$23.70	$23.70	$23.70	$23.70	$142.17								
Over	70 units @	$ 0.2255	$32.49	$53.94	$66.43	$53.13	$42.62	$19.84	$268.46								
	CGA 1	$1.3605	$291.28	$420.67	$496.04	$415.77	$352.37	$214.96	$2,191.09								
	CGA 2																
	EERA	$0.0084				$2.57	$2.18	$1.33	$6.07								
	ERC	$ 0.0202	$4.32	$6.25	$7.36	$6.17	$5.23	$3.19	$32.53								
Summer 2007																	
Customer Charge	units @	$ 10.47								$10.47	$10.47	$10.47	$10.47	$10.47	$10.47	$62.82	
First	70 units @	$0.3385								$23.70	$12.05	$7.75	$8.63	$16.04	$23.70	$91.87	
Over	70 units @	$0.2255								$2.95	$0.00	$0.00	$0.00	$0.00	$10.10	$13.06	
	CGA 1	$1.1696								$97.19	$41.64	$26.78	$29.82	$55.44	$134.27	$385.15	
	CGA 2																
	EERA	$0.0084								$0.70	$0.30	$0.19	$0.21	$0.40	$0.96	$2.77	
	ERC	$ 0.0202								$1.68	$0.72	$0.46	$0.52	$0.96	$2.32	$6.65	
Total Bill Amount			$362.27	$515.02	$604.00	$511.80	$436.56	$273.49	$2,703.13	$136.69	$65.18	$45.66	$49.66	$83.31	$181.82	$562.31	$3,265.45
With Capacity Reserve Charge of:		**$ 0.0043**	**$0.92**	**$1.33**	**$1.57**	**$1.31**	**$1.11**	**$0.68**	**$6.93**	**$0.36**	**$0.15**	**$0.10**	**$0.11**	**$0.20**	**$0.49**	**$1.42**	**$8.34**
Total Bill with CRC Amount			$363.19	$516.35	$605.57	$513.12	$437.68	$274.17	$2,710.06	$137.05	$65.33	$45.76	$49.77	$83.51	$182.31	$563.73	$3,273.79
Percentage Change			**0.25%**	**0.26%**	**0.26%**	**0.26%**	**0.26%**	**0.25%**	**0.26%**	**0.26%**	**0.23%**	**0.22%**	**0.22%**	**0.24%**	**0.27%**	**0.25%**	**0.26%**

NORTHERN UTILITIES, INC. - MAINE DIVISION
Typical G-51 Bill - 13,413.2 ccfs/year
Comparison of With and Without CRC

			Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov - Apr	May	June	July	August	September	October	Summer May - Oct	Total Nov - Oct
	Typical Usage: ccf's		1147.6	1297.8	1362.8	1283	1211.5	1115.3	7418	915.6	809.2	765.7	1002.3	837.7	1033.2	5363.7	12,781.70
G-51																	
Winter 2006-07																	
Customer Charge	units @	$ 34.22	$34.22	$34.22	$34.22	$34.22	$34.22	$34.22	$205.32								
First	1780 units @	$ 0.2054	$235.72	$266.57	$279.92	$263.53	$248.84	$229.08	$1,523.66								
Over	1780 units @	$ 0.1799	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
	CGA 1	$1.3410	$1,538.93	$1,740.35	$1,827.51	$1,720.50	$1,624.62	$1,495.62	$9,947.54								
	CGA 2																
	EERA	$0.0084				$10.78	$10.18	$9.37	$30.32								
	ERC	$ 0.0202	$23.18	$26.22	$27.53	$25.92	$24.47	$22.53	$149.84								
Summer 2007																	
Customer Charge	units @	$ 34.22								$34.22	$34.22	$34.22	$34.22	$34.22	$34.22	$205.32	
First	1000 units @	$0.2051								$187.79	$165.97	$157.05	$205.10	$171.81	$205.10	$1,092.81	
Over	1000 units @	$0.1701								$0.00	$0.00	$0.00	$0.39	$0.00	$5.65	$6.04	
	CGA 1	$1.0891								$997.18	$881.30	$833.92	$1,091.60	$912.34	$1,125.26	$5,841.61	
	CGA 2																
	EERA	$0.0084								$7.69	$6.80	$6.43	$8.42	$7.04	$8.68	$45.06	
	ERC	$ 0.0196								$17.95	$15.86	$15.01	$19.65	$16.42	$20.25	$105.13	
Total Bill Amount			$1,832.05	$2,067.35	$2,169.18	$2,054.95	$1,942.33	$1,790.82	$11,856.68	$1,244.83	$1,104.14	$1,046.63	$1,359.38	$1,141.83	$1,399.16	$7,295.96	$19,152.64
With Capacity Reserve Charge of:		**$ 0.0043**	**$4.93**	**$5.58**	**$5.86**	**$5.52**	**$5.21**	**$4.80**	**$31.90**	**$3.94**	**$3.48**	**$3.29**	**$4.31**	**$3.60**	**$4.44**	**$23.06**	**$54.96**
Total Bill with CRC Amount			$1,836.98	$2,072.93	$2,175.04	$2,060.46	$1,947.54	$1,795.61	$11,888.58	$1,248.76	$1,107.62	$1,049.92	$1,363.69	$1,145.43	$1,403.60	$7,319.03	$19,207.60
Percentage Change			**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.32%**	**0.32%**	**0.31%**	**0.32%**	**0.32%**	**0.32%**	**0.32%**	**0.29%**

NORTHERN UTILITIES, INC. - MAINE DIVISION
Typical G-41 Bill - 19,157.3 ccfs/year
Comparison of With and Without CRC

									Winter							**Summer**	**Total**
			Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Nov - Apr**	**May**	**June**	**July**	**August**	**September**	**October**	**May - Oct**	**Nov - Oct**
	Typical Usage: ccf's		1985.1	2876.6	3307.5	2945.8	2531.5	1666.2	15312.7	89	430.6	325.3	354.3	619.1	1386.8	3205.1	18,517.80
G-41																	
Winter 2006-07																	
Customer Charge	units @	$ 34.22	$34.22	$34.22	$34.22	$34.22	$34.22	$34.22	$205.32								
First	1780 units @	$ 0.2054	$365.61	$365.61	$365.61	$365.61	$365.61	$342.24	$2,170.30								
Over	1780 units @	$ 0.1799	$36.90	$197.28	$274.80	$209.73	$135.19	$0.00	$853.90								
	CGA 1	$1.3605	$2,700.73	$3,913.61	$4,499.85	$4,007.76	$3,444.11	$2,266.87	$20,832.93								
	CGA 2																
	EERA	$0.0084				$24.74	$21.26	$14.00	$60.01								
	ERC	$ 0.0132	$26.20	$37.97	$43.66	$38.88	$33.42	$21.99	$202.13								
Summer 2007																	
Customer Charge	units @	$ 34.22								$34.22	$34.22	$34.22	$34.22	$34.22	$34.22	$205.32	
First	1000 units @	$0.2051								$18.25	$88.32	$66.72	$72.67	$126.98	$205.10	$578.03	
Over	1000 units @	$0.1701								$0.00	$0.00	$0.00	$0.00	$0.00	$65.79	$65.79	
	CGA 1	$1.1696								$104.09	$503.63	$380.47	$414.39	$724.10	$1,622.00	$3,748.68	
	CGA 2																
	EERA	$0.0084								$0.75	$3.62	$2.73	$2.98	$5.20	$11.65	$26.92	
	ERC	$ 0.0196								$1.74	$8.44	$6.38	$6.94	$12.13	$27.18	$62.82	
Total Bill Amount			$3,163.66	$4,548.70	$5,218.14	$4,680.95	$4,033.81	$2,679.31	$24,324.57	$159.06	$638.22	$490.52	$531.20	$902.63	$1,965.95	$4,687.58	$29,012.15
With Capacity Reserve Charge of:		**$ 0.0043**	**$8.54**	**$12.37**	**$14.22**	**$12.67**	**$10.89**	**$7.16**	**$65.84**	**$0.38**	**$1.85**	**$1.40**	**$1.52**	**$2.66**	**$5.96**	**$13.78**	**$79.63**
Total Bill with CRC Amount			$3,172.20	$4,561.07	$5,232.36	$4,693.62	$4,044.70	$2,686.48	$24,390.42	$159.44	$640.07	$491.92	$532.72	$905.29	$1,971.91	$4,701.36	$29,091.78
Percentage Change			**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.24%**	**0.29%**	**0.29%**	**0.29%**	**0.29%**	**0.30%**	**0.29%**	**0.27%**

NORTHERN UTILITIES, INC. - MAINE DIVISION
Typical G-52 Bill - 88,574.5 ccfs/year
Comparison of With and Without CRC

			Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov - Apr	May	June	July	August	September	October	Summer May - Oct	Total Nov - Oct
	Typical Usage: ccf's		7717.8	8479	9301	9412.2	8655.6	7950	51515.6	6908.5	6123.8	4860	4690.9	4628.2	4651.5	31862.9	83,378.50
G-52																	
Winter 2006-07																	
Customer Charge	units @	$ 230.81	$230.81	$230.81	$230.81	$230.81	$230.81	$230.81	$1,384.86								
First	25000 units @	$ 0.1663	$1,283.47	$1,410.06	$1,546.76	$1,565.25	$1,439.43	$1,322.09	$8,567.04								
Over	25000 units @	$ 0.1194	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
	CGA 1	$1.3410	$10,349.57	$11,370.34	$12,472.64	$12,621.76	$11,607.16	$10,660.95	$69,082.42								
	CGA 2																
	EERA	$0.0084				$79.06	$72.71	$66.78	$218.55								
	ERC	$ 0.0202	$155.90	$171.28	$187.88	$190.13	$174.84	$160.59	$1,040.62								
Summer 2007																	
Customer Charge	units @	$ 230.81								$230.81	$230.81	$230.81	$230.81	$230.81	$230.81	$1,384.86	
First	23000 units @	$0.1073								$741.28	$657.08	$521.48	$503.33	$496.61	$499.11	$3,418.89	
Over	23000 units @	$0.0629								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
	CGA 1	$1.0891								$7,524.05	$6,669.43	$5,293.03	$5,108.86	$5,040.57	$5,065.95	$34,701.88	
	CGA 2																
	EERA	$0.0084								$58.03	$51.44	$40.82	$39.40	$38.88	$39.07	$267.65	
	ERC	$ 0.0202								$139.55	$123.70	$98.17	$94.76	$93.49	$93.96	$643.63	
Total Bill Amount			$12,019.75	$13,182.48	$14,438.09	$14,687.01	$13,524.95	$12,441.22	$80,293.49	$8,693.72	$7,732.47	$6,184.31	$5,977.16	$5,900.36	$5,928.90	$40,416.91	$120,710.40
With Capacity Reserve Charge of:		**$ 0.0043**	**$33.19**	**$36.46**	**$39.99**	**$40.47**	**$37.22**	**$34.19**	**$221.52**	**$29.71**	**$26.33**	**$20.90**	**$20.17**	**$19.90**	**$20.00**	**$137.01**	**$358.53**
Total Bill with CRC Amount			$12,052.94	$13,218.94	$14,478.08	$14,727.48	$13,562.17	$12,475.40	$80,515.01	$8,723.43	$7,758.80	$6,205.21	$5,997.33	$5,920.26	$5,948.90	$40,553.92	$121,068.93
Percentage Change			**0.28%**	**0.28%**	**0.28%**	**0.28%**	**0.28%**	**0.27%**	**0.28%**	**0.34%**	**0.34%**	**0.34%**	**0.34%**	**0.34%**	**0.34%**	**0.34%**	**0.30%**

NORTHERN UTILITIES, INC. - MAINE DIVISION
Typical G-42 Bill - 176,722.4 ccfs/year
Comparison of With and Without CRC

				Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov - Apr	May	June	July	August	September	October	Summer May - Oct	Total Nov - Oct
		Typical Usage: ccf's		25402.5	28042	26818.3	23333.3	20475	13613.3	137684.4	9643.3	6990	5863.3	10500	11705	17767.5	62469.1	200.153.50
G-42																		
Winter 2006-07																		
Customer Charge		units @	$ 230.81	$230.81	$230.81	$230.81	$230.81	$230.81	$230.81	$1,384.86								
First	18000	units @	$ 0.1764	$3,175.20	$3,175.20	$3,175.20	$3,175.20	$3,175.20	$2,401.39	$18,277.39								
Over	18000	units @	$ 0.1432	$1,060.04	$1,060.04	$1,438.01	$1,262.78	$763.73	$354.42	$5,939.02								
		CGA 1	$1.3605	$34,560.10	$38,151.14	$36,486.30	$31,744.95	$27,856.24	$18,520.89	$187,319.63								
		CGA 2																
		EERA	$0.0084				$196.00	$171.99	$114.35	$482.34								
		ERC	$ 0.0202	$513.13	$566.45	$541.73	$471.33	$413.60	$274.99	$2,781.22								
Summer 2007																		
Customer Charge		units @	$ 230.81								$230.81	$230.81	$230.81	$230.81	$230.81	$230.81	$1,384.86	
First	6000	units @	$0.1396								$837.60	$837.60	$818.52	$837.60	$837.60	$837.60	$5,006.52	
Over	6000	units @	$0.0968								$352.67	$95.83	$0.00	$435.60	$552.24	$1,139.09	$2,575.44	
		CGA 1	$1.1696								$11,278.80	$8,175.50	$6,857.72	$12,280.80	$13,690.17	$20,780.87	$73,063.86	
		CGA 2																
		EERA	$0.0084								$81.00	$58.72	$49.25	$88.20	$98.32	$149.25	$524.74	
		ERC	$ 0.0202								$194.79	$141.20	$118.44	$212.10	$236.44	$358.90	$1,261.88	
Total Bill Amount				$39,539.28	$43,183.64	$41,872.05	$37,081.08	$32,611.56	$21,896.85	$216,184.46	$12,975.68	$9,539.66	$8,074.73	$14,085.11	$15,645.59	$23,496.52	$83,817.29	$300,001.75
With Capacity Reserve Charge of:			**$ 0.0043**	**$109.23**	**$120.58**	**$115.32**	**$100.33**	**$88.04**	**$58.54**	**$592.04**	**$41.47**	**$30.06**	**$25.21**	**$45.15**	**$50.33**	**$76.40**	**$268.62**	**$860.66**
Total Bill with CRC Amount				$39,648.51	$43,304.22	$41,987.37	$37,181.41	$32,699.60	$21,955.39	$216,776.50	$13,017.15	$9,569.72	$8,099.94	$14,130.26	$15,695.92	$23,572.92	$84,085.91	$300,862.41
Percentage Change				**0.28%**	**0.28%**	**0.28%**	**0.27%**	**0.27%**	**0.27%**	**0.27%**	**0.32%**	**0.32%**	**0.31%**	**0.32%**	**0.32%**	**0.33%**	**0.32%**	**0.29%**

Northern Utilities, Inc.
Maine Division
Docket No. 2006-390
Advisor's Data Request Set No. 4
Response: 13
Responsible: Francisco C. DaFonte
Director, Energy Supply Services

Request: For each year in which one or more of the Wells replacement contracts was or will be in force, please list:

1) The actual or forecast peak for the Maine division, assuming design day weather. Please list the peaks for sales and transport customers separately.
2) The total amount of capacity resources available to serve the Maine division customers.
3) Any surplus or shortage of capacity.

In addition, please provide documentation sufficient to replicate the results to this response.

Response: Northern constructs its resource portfolio based on an integration of its two Divisions, New Hampshire and Maine. Thus, Northern's resources serve both Divisions customers and are not planned or assigned to serve one specific division.

However, in an attempt to answer the question Attachment ADR 4-13 provides Northern's Total Capacity resources, by type, and an allocation of these Capacity Resources to the Maine Division. Also, the attachment compares allocated capacity resources to the Maine Division's estimated design-day forecast requirements, broken down by sales and firm transportation load. Any difference is either a derived surplus or a derived deficiency within the Maine Division.

For the periods 2001-2002 through 2006-2007, the corresponding winter CGA forecasts were utilized to determine design-day requirements. All design-day forecasts beginning in 2007-2008 were calculated using Northern's current IRP forecast. Capacity allocations for 2001-2002 through 2004-2005 to the Maine Division were done utilizing the design-day forecasts for each Division less any capacity-exempt transportation load. Beginning in 2005-2006, the modified PR allocator methodology was utilized to allocate capacity to the Maine Division and was assumed to stay constant beginning in 2007-2008.

The analysis presented in Attachment ADR 4-13 assumes Northern will roll over its current Tennessee long-haul firm transportation and storage contracts as well as its current DTE storage service. As indicated in Northern's Schedule IV-5 REVISED, on an integrated basis, Northern will have a significant capacity resource deficiency beginning in 2008-2009 without such a rollover.

REVISED
Response: Due to the recent increased usage of Northern's firm dual-fuel customers and its impact on the design day, this response requires a revision.

The appropriate attachment is Attachment ADR 4-13 REVISED. The appropriate schedule is Schedule IV-5 2nd REVISED.

Attachment ADR 4-13 REVISED

Northern and Maine Division Demand & Allocated Capacity Resources
(MMBtu)
Design Day

	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011
Total Northern Pipeline	25,161	25,161	25,161	25,161	25,161	25,161	25,161	25,161	25,161	25,161
Total Northern Storage	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,559	35,559
Peaking										
Lewiston LNG	13,000	13,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Propane	7,000	7,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Duke	7,960	13,234	18,308	23,880	29,850	35,820	35,820	46,765	52,735	57,113
DOMAC 1	4,975	4,975	4,975	4,975	4,975	4,975	4,975	4,975	4,975	4,975
DOMAC 2	9,950	9,950	9,950	9,950	9,950	0	0	0	0	0
Bay State Sales	18,281	0	0	0	0	0	0	0	0	0
Total Northern Peaking	61,166	48,159	47,233	52,805	58,775	54,795	54,795	65,740	71,710	76,088
Total Northern Capacity	121,886	108,879	107,953	113,525	119,495	115,515	115,515	126,460	132,430	136,808
Maine Capacity Allocation	65,302	60,138	59,115	62,052	62,389	57,226	57,226	62,648	65,606	67,775
Design Day Forecast*	61,176	63,388	63,690	64,327	60,934	65,170	65,217	65,256	65,073	64,777
Transportation Load	15,250	15,250	17,665	17,488	22,924	32,052	33,065	34,136	35,100	36,036
Sales Load	45,926	48,138	46,025	46,839	38,010	33,118	32,152	31,120	29,973	28,741
Surplus/Deficiency	4,126	(3,250)	(4,575)	(2,275)	1,455	(7,944)	(7,991)	(2,608)	533	2,998

*: Forecasts for 2002 through 2006 are based on corresponding Winter CGA forecasts.
All other years are based on current IRP forecast.

Allocation**										
Total ME Load	61,176	63,388	63,690	64,327	60,934	65,170	65,217	65,256	65,073	64,777
Total NH Load	62,319	60,685	61,927	62,670	65,372	72,610	73,731	74,919	75,900	77,066
NH Assigned Load	9,310	9,310	9,310	9,310	9,310	14,835	14,835	14,835	14,835	14,835
Net NH Load	53,009	51,375	52,617	53,360	56,062	57,775	58,896	60,084	61,065	62,231
ME Capacity Allocation	53.58%	55.23%	54.76%	54.66%	52.21%	49.54%	49.54%	49.54%	49.54%	49.54%

**: 2002-2005 based on peak day allocation
2006-2007 based on actual PR allocator
2008-2011 based on 2006-2007 PR allocator