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Xcel Energy

414 Nicollet Mall
Minneapolis, Minnesota 55401

November 1, 2007

ELECTRONIC FILING

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

Re: PETITION FOR APPROVAL OF CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-07-_______

Dear Dr. Haar:

Enclosed is the Petition for Approval of Changes in Contract Demand Entitlements of Northern States Power Company ("Xcel Energy or the "Company"), a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc. for approval of a change in Contract Demand Entitlements pursuant to Minn. Rule 7825.2910, Subd. 2. Copies of the non-public version are being provided separately.

Portions of our filing contain trade secret information as defined under Minn. Stat. § 13.37. As such, this data is protected from public disclosure and has been marked accordingly. Xcel Energy makes extensive efforts to maintain the secrecy of this information. This information is not available outside the Company except to other parties involved in contracts and to regulatory agencies under the confidentiality provisions of state or federal law, as evidenced by the non-disclosure provisions in the contracts. Xcel Energy also provides this information to state regulatory agencies in the Annual Automatic Adjustment of Charges Reports and in the monthly purchased gas adjustment ("PGA") filings in the confidential trade secret versions of these reports.

The supply information has economic value to Xcel Energy, its customers, suppliers, and competitors in at least three ways. If suppliers know the terms of Xcel Energy's supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. Suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Competitors of Xcel Energy such as other LDCs also purchase their services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may offer slightly better prices to suppliers, denying Xcel Energy's access to this gas or other services.

Any of these results would hard Xcel Energy and it's natural gas customers. Because Xcel Energy competes for supplies, transportation, storage, and other services in the wholesale market, disclosure would directly harm Xcel Energy by making its delivered supply cost less competitive. To the extent that Xcel Energy supply costs rise, Xcel Energy's regulated sales customers would have to pay higher natural gas rates. This result would not serve the public interest.

Copies of this filing have been served on the Department of Commerce, the Office of the Attorney General – Residential Utilities Division and the attached service list. Please call me at (612) 330-2865 if you have any questions regarding this filing.

Sincerely,

NANCY A. HALEY
REGULATORY CASE SPECIALIST

Enclosures
c: Service List

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN APPROVED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
David C. Boyd	Commissioner
Marshall Johnson	Commissioner
Thomas Pugh	Commissioner
Phyllis Reha	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION AND WHOLLY OWNED SUBSIDIARY OF XCEL ENERGY INC., FOR APPROVAL OF CHANGES IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-07-____

PETITION

INTRODUCTION

Pursuant to Minnesota Statute § 216B.16, subd. 7 and Minnesota Rule 7825.2910, subp. 2, Northern States Power Company ("Xcel Energy" or the "Company"), a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc., submits to the Minnesota Public Utilities Commission ("Commission") this Petition for approval of a Change in Contract Demand Entitlements ("Petition"). Xcel Energy requests approval to implement our 2007-2008 Heating Season Supply Plan effective November 1, 2007, for customers served with natural gas in the State of Minnesota.

I. Summary of Filing

A one-paragraph summary of the filing accompanies this Petition pursuant to Minnesota Rule 7829.1300, subp. 1.

II. Service on Other Parties

Pursuant to Minnesota Rule 7829.1300, subp. 2, Xcel Energy has served a copy of this Petition on the Department of Commerce and the Office of the Attorney General-Residential Utilities Division. Pursuant to Minnesota Rule 7829.2910, subp. 2, Xcel Energy has also served a copy of this Petition on the interveners in the two most recent (2006 and 2004) general rate case filings for the Company's natural gas utility operation. In addition, the summary of filing has been served on all parties on Xcel Energy's miscellaneous gas service list.

III. General Filing Information

Pursuant to Minnesota Rule 7829.1300, subp. 3, Xcel Energy provides the following required information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company
414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall, 5th Floor
Minneapolis, Minnesota 55401
(612) 215-4592

C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy is submitting this filing on November 1, 2007. Xcel Energy requests Commission approval to implement the rate impact of this filing in our purchase gas adjustment ("PGA") effective with the November 2007 cycle 1 billings. Pursuant to Minn. Stat. § 216B.16, subd. 7 and our Purchase Gas Adjustment tariff (Minnesota Gas Rate Book sheet number 5-40, revision 2; sheet number 5-41, revision 3; and sheet number 5-42, revision 2) Xcel Energy has provisionally placed the PGA changes into effect on November 1, 2007, subject to later Commission approval.

D. Statute Controlling Schedule for Processing the Filing

The applicable statute is Minn. Stat. § 216B.16, subd. 7. This statute does not state a specific time frame for Commission action. The applicable rules are Minn. Rules 7825.2910, subp. 2, 7829.1300, 7929.1400 and 7825.2910. Under Minn. Rule 7829.0100, subp. 11, the Commission treats all filings that do not fall into a specific category as a Miscellaneous Tariff Filing. Minn. Rule 7829.1400, Subp. 1, permits comments in response to a miscellaneous filing within 30 days of filing, with reply comments 10 days thereafter.

E. Utility Employee Responsible for Filing

Judy Poferl
Director, Regulatory Administration
Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-2865

IV. Description and Purpose of Filing

This filing seeks Commission approval to allow the Company to implement through the PGA changes in our interstate pipeline transportation, storage entitlements, and other demand-related contracts for the upcoming year. Updating our natural gas transportation, storage entitlements, and supply contracts on an annual basis is important to ensuring the Company has access to sufficient capacity to cover the anticipated peak demand of our natural gas customers. To determine the amount required, we consider our forecast of customer needs under Design Day conditions. By comparing that anticipated need to our current supply arrangements, we can determine what incremental additions are needed to ensure we can meet our growing customer needs under the most extreme conditions at reasonable cost.

Pursuant to Minn. Rule 7825.2910, Subp. 2, and prior Commission practice, we provisionally implemented the PGA rate changes associated with this filing on November 1, 2007, and respectfully request Commission approval of the revised entitlements effective on November 1, 2007. We list the changes reflected in this filing below.

A. Change in Design Day

Our filing reflects a change in our Design Day forecast from the 2006-2007 heating season due to customer growth and due to increased contracted firm billing demand for Small and Large Commercial Demand Billed Customers, as described in **Attachment 1**.

As requested in the Department of Commerce's ("Department") comments filed on August 21, 2007, for the Company's 2006 Contract Demand Entitlement filing, Docket No. G002/M-06-1454, we have provided evidence substantiating our design day methodology. Xcel Energy's design day methodology remains the same from the 2006-2007 heading season, and support of this methodology is described in **Attachment 5.**

B. Change in Resources to meet Design Day

Reflected in this filing are changes in our resources used to meet our Design Day customer requirements, including entitlements on our pipeline and storage supplier systems: Northern Natural Gas Company ("Northern"), Viking Gas Transmission Company ("Viking"), Great Lakes Transmission Company ("Great Lakes"), ANR Pipeline Company ("ANR"), and Williston Basin Interstate Pipeline Company ("WBI"). Depending on the service, these changes take effect at various times during the heating season.

Attachment 1 and **Attachment 2** provide background information regarding each of these proposed changes. Specifically, **Attachment 1** contains certain documentation required by Rule 7825.2910, Subp. 2. The information provided in **Attachment 2** is in response to the October 1, 1993 letter from the Department, and outlines the changes in the Company's Energy Firm Design Day Requirements, daily pipeline entitlement and pipeline billing units from the 2006-2007 entitlement levels pending Commission approval in Docket No. G002/M-06-1454.

C. Change in Jurisdictional Allocations

The changes in the Design Day forecast alter the allocation of entitlements between the Minnesota and North Dakota retail natural gas jurisdictions. This filing reflects this reallocation.

D. Change in Supply Reservation Fees

This filing also reflects updated costs for firm gas supply reservation fees.

E. Heating Season Plan for Use of Financial Instruments

Attachment 3 provides information in response to the reporting requirements established in Docket No. G002/M-03-1627 (Order dated January 23, 2004) regarding our use of financial instruments to limit commodity price volatility. The attachment shows a summary of hedge transactions for the 2007-2008 heating season and how each instrument relates to the $20 million cap on such costs.

F. Classification and Billing of Demand Costs

In the Company's 2006 Contract Demand Entitlement filing, Docket No. G002/M-06-1454, we included a proposal to assign some demand costs to interruptible customers. The Department moved this matter to the 2006 Annual Automatic Adjustment of Charges ("AAA") report filing discussion, Docket No. G002/AA-06-1208. In their comments dated October 19, 2007, the Department recommended that the Commission require each gas utility to:

- Provide its unique set of facts in determining whether it is reasonable to classify Producer Demand and Storage costs as commodity or demand costs;
- Clarify which customer classes are to be assigned related costs;
- Provide a detailed explanation of its rationale for its proposal; and
- Provide a rate impact analysis for all affected customer classes based on the utility's currently approved method of classifying and billing Producer Demand and Storage costs, together with a similar comparison of classifying and billing Producer Demand and Storage costs as commodity costs.

In response to the Department's recommendation, we have included our proposal, rational, and analysis as **Attachment 4**.

Xcel Energy has endeavored to provide all requested information, and has taken steps to ensure the filing's accuracy so that this Petition contains the necessary information for approval of the changes in Contract Demand Entitlements. Xcel Energy respectfully requests Commission approval of the 2007-2008 Heating Season Supply Plan, which enables continued reliable and competitive service for our natural gas customers in Minnesota, effective November 1, 2007, and approval to reflect the costs associated with the revised entitlements in rates through the PGA effective with November cycle billings.

V. Effect of Change upon Xcel Energy Revenue

The effect of the proposed changes in demand cost upon Xcel Energy's annual revenue is a decrease of ***[Trade Secret Begins Trade Secret Ends]*** effective November 1, 2007. The cost change will automatically be reflected in rates through the operation of the Company's PGA clause. The cost change elements are provided in Trade Secret **Attachment 1, Schedule 2, Page 1 of 2**. The demand rate calculation is shown in **Attachment 1, Schedule 2, Page 2 of 2.**

VI. Miscellaneous Information

Pursuant to Minnesota Rule 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall, 5th Floor
Minneapolis, Minnesota 55401

SaGonna Thompson
Records Specialist
Xcel Energy
414 Nicollet Mall
Minneapolis, Minnesota 55401

CONCLUSION

Xcel Energy respectfully requests Commission approval of our 2007-2008 Heating Season Supply Plan effective November 1, 2007, and approval to implement the retail rate impact of this filing in our PGA effective with the November 2007 cycle 1 billings. The Company has provisionally reflected the change in entitlement costs associated with the revised contract demand entitlements in the Company's December PGA, subject to Commission approval.

Dated: November 1, 2007

Northern States Power Company,
A Minnesota corporation and wholly
owned subsidiary of Xcel Energy Inc.

BY: ______________________

JONI H. ZICH
MANAGER, GAS SUPPLY

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
David C. Boyd	Commissioner
Marshall Johnson	Commissioner
Thomas Pugh	Commissioner
Phyllis Reha	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION AND WHOLLY OWNED SUBSIDIARY OF XCEL ENERGY INC. FOR APPROVAL OF CHANGE IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-07-____

SUMMARY

SUMMARY OF FILING

Please take notice that on November 1, 2007, Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc., filed a Request for Change in Contract Demand Entitlements pursuant to Minnesota Rule 7825.2910, Subp. 2. Xcel Energy requests Commission approval to implement its 2007-2008 Heating Season Supply Plan effective November 1, 2007. The costs related to the entitlement changes will be provisionally reflected in retail gas rates through the Purchase Gas Adjustment effective November 1, 2007, subject to later Commission approval.

ATTACHMENT 1

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of
Xcel Energy Inc.

Filing Upon Change in Demand
Filing Requirements Pursuant to Minnesota Rule 7825.2910, subp. 2

**Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of
Xcel Energy Inc.**

**Filing Requirements Pursuant to Minnesota Rule 7825.2910, subp. 2
Filing Upon Change in Demand**

A. A description of the factors contributing to the need for change in demand:

As discussed in our Petition, the factors contributing to the need for a change in demand include:

- Change in Design Day requirements due to customer growth,
- Resources required to meet the Design Day and provide an adequate reserve margin,
- Changes in Jurisdictional Allocations, and
- Changes in Supply Reservation Fees

We discuss each of these factors below.

CHANGE IN DESIGN DAY

1. Increase in Design Day due to Customer Growth (effective November 1, 2007)

Xcel Energy's objective for calculating Design Day customer demand is to forecast anticipated demand at design temperatures accurately so adequate firm supply resources can be planned for and available if Design Day weather does occur. Xcel Energy recognizes that customer response to temperature is dynamic, particularly if we experience severely cold seasonal temperatures. Therefore, Xcel Energy continues to calculate Design Day using both Actual Peak Use Per Customer Design Day ("UPC DD") and Average Monthly Design Day ("Avg. Monthly DD") methods and considers the results when predicting future Design Day needs.

In the Company's 2004-2005 Contract Demand Entitlements filing, Docket No. G002/M-05-1813, the Company filed to add a second methodology for calculating its Design Day. Prior to this docket, the Company utilized a single methodology which utilized a linear regression calculation. In the 2004-2005 Contract Demand

Entitlements filing, the Company filed to include a second methodology, UPC DD, to ensure that the Design Day is adequately and accurately estimated.

We project our firm customer count to increase by 8,409 (476,092 -467,683) between the 2006-2007 heating season and the 2007-2008 heating season. This projection equates to an increase in Design Day requirements of 14,384 Dekatherms ("Dth") (770,067 - 755,683) utilizing the UPC DD method as detailed on **Attachment 1, Schedule 3, Page 1 of 2**. This increase in required firm Dth stems solely from the increased number of customers.

The Avg. Monthly DD was also utilized to develop the allocations by state and by service region as shown on **Attachment 1, Schedule 1, Page 1 of 3**. This year the Company has modified the service regions in which customers are grouped to enable Xcel Energy to ensure that we have adequate levels of firm pipeline deliverability to each pipeline lateral. The Avg. Monthly DD calculation is based on the linear regression, which uses February 2005 – February 2007 data as shown on **Attachment 1, Schedule 1 Pages 2 and 3**. Xcel Energy was only able to use 25 months of data instead of the usual 60 months of data because of the change in customer groups. However, the regressions statistics were very strong with r-squared values in excess of 95%. This method captures the relationship of Design Day between the states and service regions and incorporates non-electronic pipeline measurements that are estimated in the UPC DD.

The actual use per firm customer data contains the daily total usage for all the firm customers that do not have individual actual peak day information. As described in **Attachment 1, Schedule 3, Page 2 of 2,** the peak day actual use per firm customer remains the same at 1.57393 Dth. The 130 customers in the Small and Large Demand Billed classes are not included with the Residential, Small Commercial, and Large Commercial customers to determine the product of the customers multiplied by the peak day actual use per customer to yield the Projected Design Day for these customers of 749,129 Dth. The Small and Large Demand Billed contracted customer Billing Demand is 20,938 Dth and is added to the Design Day estimate for the Residential, Small Commercial, and Large Commercial classes to determine the total Design Day Projection of 770,067 Dth as shown on **Attachment 1, Schedule 3, Pages 1 and 2**.

Xcel Energy continues to maintain and compare both methodologies. The actual peak days experienced by the Company under non-Design Day conditions were compared with both the UPC DD and the Avg. Monthly DD to ensure adequate firm resources are available to meet the varied demand requirements of our customers. If cold temperatures occurred, then the actual use per customer of 1.57393, as shown on **Attachment 1, Schedule 3, Page 2 of 2**, would be adjusted accordingly. Likewise, if cold temperatures were not experienced, the actual use per customer of 1.57393 would be maintained (assuming no operating experience contrary to the conditions observed on January 29, 2004). In that case, the UPC DD would be adjusted for updated Residential, Small Commercial, and Large Commercial customer counts and any changes to the contracted Billing Demand for the Small and Large Demand Billed customers.

CHANGE IN RESOURCES TO MEET DESIGN DAY

Attachment 2, Schedule 1, Page 1 of 2 details the demand entitlement changes to meet Design Day for the Xcel Energy 2007-2008 Heating Season Gas Resource Plan compared to the 2006-07 plan filed in Docket No. G002/M-06-1454. **Attachment 1, Schedule 2, Page 1 of 2** details the demand cost component changes for the 2007-2008 heating season.

1. *Change in Northern Natural Gas Company entitlements (effective November 1, 2007)*

The majority of Xcel Energy's firm pipeline transportation contracts with Northern Natural Gas ("Northern") will expire on November 1, 2007. As a result, in 2003 the Company evaluated several alternates to provide firm gas supplies to the Twin Cities metro area. These options included bypassing Northern and interconnecting with several other interstate pipelines in the Midwest located both north and south of the metro area. The Company also received a competitive bid from Northern to renew the expiring contracts. Xcel Energy selected the lowest cost option and renewed its contracts with Northern. **Attachment 2, Schedule 1** details the modifications to the Northern contracts.

In past demand entitlement filings, the Company has requested an extension to its filing deadline in order to receive the annual redetermination of Xcel Energy's base/variable split. Pursuant to Northern's tariff, an allocation of the TF12 transportation entitlement is made between the TF12 Base (TF12B) and TF12 Variable (TF12V) entitlements annually based on actual throughput from May through September of the current year. This year, Xcel Energy proposes to include the actual revised Base/Variable split effective November 1st in its AAA and PGA True-up filing due September 1, 2008. This is similar to the approach used by other gas utilities in Minnesota. In addition, Xcel Energy will supplement this filing with the actual redetermination of the base variable split once it is received from Northern.

2. *Change in Viking Gas entitlements (effective November 1, 2007)*

Xcel Energy increased firm transportation capacity entitlements on Viking by 9,100 Dth/Day under Rate Schedule FT-A to meet system growth November 1, 2007.

As a result of contract negotiations with Northern, Xcel Energy turned back capacity totaling 28,280 Dth/day on Northern which was delivered to Chisago the interconnect between Northern and Viking. In previous years, the gas that was delivered to Chisago was backhauled on Viking. Since the capacity that was delivered to Chisago was turned back to Northern, Xcel Energy no longer has a use for the backhaul contracts on Viking. Therefore, those backhaul agreements were posted for release on Viking's website. **Attachment 2, Schedule 1, Page 1 of 2** details these capacity releases on Viking.

CHANGE IN JURISDICTIONAL ALLOCATIONS

1. *Decrease in Minnesota Jurisdiction Allocation Factor*

The Design Day allocation factor decreased slightly for the Minnesota jurisdiction from 89.68% to 88.79%. As in previous years, we calculate the allocation factor by dividing the Design Day forecasted demand for the State of Minnesota by the design day demand for the Company. The State of Minnesota, State of North Dakota, and Company total are provided on **Attachment 1, Schedule 1**. The traditional method of Avg. Monthly DD was used to update the allocation factors, since this approach accurately estimates the relationship of Design Day between the states and regional jurisdictions and incorporates accurately the monthly non-electronic pipeline measurements.

2. *Increase in Minnesota Grand Forks Area Jurisdictional Allocation Factor*

The Design Day allocation factor for East Grand Forks, Minnesota increased from 13.58% to 14.80%. This increase is the result of an increase in Design Day demand for East Grand Forks, Minnesota relative to the change in Design Day demand for Grand Forks, North Dakota. The allocation factor is calculated by dividing the Design Day demand for the city of East Grand Forks, Minnesota by the Design Day demand total for the Grand Forks area (Grand Forks and East Grand Forks). This allocation factor is used to allocate the costs of the incremental capacity on Viking related to the Grand Forks area transmissionlooping project. The State of Minnesota, State of North Dakota, and Minnesota Company totals are provided on **Attachment 1, Schedule 1**. The traditional method of Avg. Monthly DD was also used to update the Minnesota Grand Forks Area Jurisdictional Allocation Factor.

3. Decrease Minnesota Fargo Area Jurisdictional Allocation Factor

The Design Day allocation factor decreased for Moorhead, Minnesota from 21.99% to 21.75%. The allocation factor is calculated by dividing the Design Day demand for the Moorhead, Minnesota by the total Design Day demand for Fargo, North Dakota and Moorhead, Minnesota. This allocation factor is used to allocate the costs of the incremental capacity on Viking related to the Fargo/Moorhead area-looping project. The State of Minnesota, State of North Dakota, and Minnesota Company totals are provided on **Attachment 1, Schedule 1**. The traditional method of Avg. Monthly DD was also used to update the Minnesota Moorhead Area Jurisdictional Allocation Factor.

CHANGE IN SUPPLIER RESERVATION FEES

1. Change in Supply Reservation Fees

The total change in existing supplier reservation charges is ******Trade Secret Begins*** ***Trade Secret Ends******. **Attachment 2, Schedule 1, Page 1 of 2** lists the changes in Supply Entitlements. Our producer demand expense is attributable to a Viking citygate peaking contract that was done in lieu of acquiring additional annual or heating season interstate pipeline firm transportation service.

B. The Utility's design day demand by customer class and the change in design day demand, if any, necessitating the demand revision:

See **Attachment 1, Schedule 3**.

Xcel Energy proposes to increase our capacity reserve margin from 2.74% in November 2006 to 5.52% in November 2007, as described in **Attachment 2, Schedule 1, Page 2 of 2**. Xcel Energy believes this reserve margin is appropriate, given the need to balance the uncertainty of (a) the likelihood of experiencing Design Day conditions (the most recent extreme cold period occurred in late January to early February 1996), (b) actual consumer demand during Design Day conditions (given the recent decline in use per customer described in Docket Nos.

G002/GR-04-1511 and G002/GR-06-1429), and (c) the need to protect against the potential loss of a source of firm gas supply.

Xcel Energy adds firm resources to meet projected firm customer demand and plans to maintain a reserve margin as close as practicable to either the capability of the largest pump at Wescott used to vaporize LNG or to the capability of either of the St. Paul metro propane – air peak shaving plants. Capacity decisions are based on projected demand, and the most economic method of adding capacity often involves adding increments that do not precisely match expected changes in demand. The reserve margin ensures reliability for the Company's gas utility firm customers in Minnesota. The proposed Design Day reserve margin for 2007–2008 is 42,531 Dth/day.

C. <u>A summary of the levels of winter versus summer usage for all customer classes:</u>

See **Attachment 1, Schedule 4**.

D. <u>A description of design day gas supply from all sources under the new level allocation, or form of demand:</u>

See **Attachment 1, Schedule 5.**

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
DERIVATION OF MINNESOTA JURISDICTION ALLOCATION FACTOR
2007-2008 Heating Season

Service Region (1)	Projected Jan 2008 Firm Res & Comm'l Customers (2)	Contracted Demand by Small & Large Demand Billed Comm'l Customers (3a)	(3b)	Load Variation (Dth/Degree) (4)	Degree per Design Day (5)	Monthly Base Use (Dth) (6)	Unacc. Factor (7)	Res & Comm'l Design Day (Dth) (8)	Total Design Day (Dth) (9)	Jurisdictional Allocation Factors (10)
METRO EAST	295,307	74	11,748	0.0171207	91	2.1676342	1.009	464,223	475,971	
METRO WEST	2,068	0	0	0.0136965	91	1.6887515	1.009	2,601	2,601	
MAINLINE	17,771	10	1,896	0.0156097	88	2.2954549	1.009	25,985	27,881	
WILLMAR	3,117	0	0	0.0126299	88	1.4406899	1.009	3,645	3,645	
PAYNESVILLE	50,930	23	2,609	0.0151011	94	2.0562320	1.009	76,423	79,032	
CHISAGO	11,602	2	224	0.0161029	91	1.6505872	1.009	17,789	18,013	
WATKINS	14,568	2	90	0.0123766	94	1.8895888	1.009	18,014	18,104	
TOMAH	15,317	12	1,509	0.0161321	88	1.3620796	1.009	22,633	24,142	
RED WING	7,622	5	2,074	0.0155154	88	2.2942485	1.009	11,080	13,154	
GRAND FORKS MN	2,813	1	63	0.0162513	98	1.3647222	1.009	4,647	4,710	14.80%
FARGO MN	10,259	1	725	0.0150047	98	1.5214524	1.009	15,739	16,464	21.75%
MN State	431,373	130	20,938					662,779	683,716	88.79%
GRAND FORKS ND	13,854	0	0	0.0190688	98	2.1775033	1.009	27,125	27,125	85.20%
FARGO ND	30,735	0	0	0.0184572	98	3.0704731	1.009	59,226	59,226	78.25%
ND State	44,589	0	0					86,350	86,350	11.21%
TOTAL	475,962	130	20,938					749,129	770,067	100.00%

(1) Regional areas of the company.
(2) Estimated firm customers.
(3a) Firm Large and Small Commercial Demand Billed customers.
(3b) Firm contracted Design Day entitlement for Large and Small Commercial Demand Billed customers.
(4) Temperature dependent usage as determined by linear regression based on using 25 months Feb. 2005 to Feb 2007
(5) Degree Days for a Design Day in that region.
(6) Monthly base usage determined by linear regression based on using the same 25 months as in (4).
(7) Factor to correct for unaccounted gas usage.
(8) Estimated Design Day Demand for Firm Residential & Commercial Customers.
(9) Estimated Total Design Day for Firm Residential, Commercial, and Demand Billed Customers.
(10) Jurisdictional allocation factors based on percent of Total Company Design Day Demand.

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
MINNESOTA/NORTH DAKOTA BY FIRM RATE CLASS

Division/Region (1)	Projected Firm Jan 2007 Cust (2)	Load Variation (Mcf/Deg) (3) X Variable 1	DD/ Design Day (4)	Monthly Base Use (Mcf) (5) Intercept	R-Sqaure	Lost & Unacc. Factor (6)	Design Day (Mcf) 2008				2007 Design Day	Mcf Difference % Diff.	UPC DD Method	UPC DD Method Totals
							Unacc. Volume	Load Variation	Day Base	Total				
METRO EAST														
Total Residential	275,118	0.01050118	91	1.50364691	0.9849	0.0090	2,489	262,904	13,608	279,001	NA	NA	38,620	317,621
Total Commercial	20,189	0.06541106	91	11.22368502	0.9783	0.0090	1,149	120,175	7,454	128,777	NA	NA	17,826	146,603
Contract Demand	74		–	–		–	–	–	–	11,748	NA	NA	–	11,748
	295,381	0.0142516		2.167634239			3,637	383,079	21,062	419,526	–	-	56,445	475,971
METRO WEST														
Total Residential	1,914	0.00966127	91	1.26247949	0.9623	0.0090	16	1,683	80	1,779	NA	NA	246	2,025
Total Commercial	154	0.03333648	91	6.99863503	0.9028	0.0090	5	466	35	506	NA	NA	70	576
Contract Demand	0		–	–		–	–	–	–	–	NA	NA	–	–
	2,068	0.0114206		1.688751527			20	2,149	115	2,285	–	-	316	2,601
MAINLINE														
Total Residential	16,154	0.009651483	88	1.483754509	0.9663	0.009	131	13,720	788	14,639	NA	NA	2,026	16,666
Total Commercial	1,617	0.05313095	88	10.41987185	0.9409	0.009	73	7,559	554	8,186	NA	NA	1,133	9,319
Contract Demand	10		-	0		0	-	-	-	1,896	NA	NA	-	1,896
	17,781	0.013599573		2.295454926			204	21,279	1,343	24,721	-	-	3,160	27,881
WILLMAR														
Total Residential	2,830	0.008978471	88	0.915115604	0.9707	0.009	21	2,236	85	2,342	NA	NA	324	2,667
Total Commercial	287	0.031274082	88	6.630367697	0.9144	0.009	8	789	63	859	NA	NA	119	978
Contract Demand	0		-	0		0	-	-	-	-	NA	NA	-	-
	3,117	0.011028774		1.440689926			29	3,025	148	3,201	-	-	443	3,645
PAYNESVILLE														
Total Residential	45,731	0.00910723	94	1.189907928	0.9816	0.009	368	39,150	1,790	41,308	NA	NA	5,718	47,026
Total Commercial	5,199	0.04897637	94	9.685649859	0.9806	0.009	230	23,935	1,656	25,822	NA	NA	3,574	29,397
Contract Demand	23		-	0		0	-	-	-	2,609	NA	NA	-	2,609
	50,954	0.013171139		2.056231995			599	63,085	3,446	69,739	-	-	9,292	79,032
CHISAGO														
Total Residential	10,847	0.010501176	91	1.442291294	0.9849	0.009	98	10,365	515	10,978	NA	NA	1,520	12,498
Total Commercial	755	0.065411059	91	4.649553751	0.9783	0.009	41	4,491	115	4,648	NA	NA	643	5,291
Contract Demand	2		-	0		0	-	-	-	224	NA	NA	-	224
	11,604	0.014069818		1.650587246			139	14,857	630	15,850	0	-	2,163	18,013
WATKINS														
Total Residential	13,793	0.008738093	94	1.455051019	0.9849	0.009	108	11,329	660	12,097	NA	NA	1,675	13,772
Total Commercial	775	0.047336498	94	9.629229521	0.9783	0.009	33	3,448	245	3,727	NA	NA	516	4,243
Contract Demand	2		-	0		0	-	-	-	90	NA	NA	-	90
	14,570	0.010789708		1.889588796			141	14,777	906	15,914	0	-	2,190	18,104
TOMAH														
Total Residential	13,724	0.009779335	88	0.772485203	0.9665	0.009	109	11,810	349	12,269	NA	NA	1,698	13,967
Total Commercial	1,593	0.051392068	88	6.450015413	0.9588	0.009	68	7,206	338	7,612	NA	NA	1,054	8,666
Contract Demand	12		-	0		0	-	-	-	1,509	NA	NA	-	1,509
	15,329	0.014097575		1.362079568			177.3324981	19016.79685	686.81404	21389.9434	0	-	2,752	24,142
RED WING														
Total Residential	6,851	0.009229892	88	1.357845326	0.9722	0.009	53	5,565	306	5,923	NA	NA	820	6,743
Total Commercial	771	0.051702086	88	10.63573645	0.9082	0.009	34	3,506	270	3,809	NA	NA	527	4,337
Contract Demand	5		-	0		0	-	-	-	2,074	NA	NA	-	2,074
	7,627	0.0135144		2.294248472			87	9,070	576	11,807	0	-	1,347	13,154
GRAND FORKS MN														
Total Residential	2,517	0.00985025	98	0.700598429	0.9704	0.009	22	2,429	58	2,510	2,295	214	347	2,857
Total Commercial	296	0.051384507	98	7.019062129	0.9704	0.009	14	1,490	68	1,572	1,456	116	218	1,790
Contract Demand	1		-	0		0	-	-	-	63	-	63	-	63
	2,814	0.014213855		1.364722232			36	3,919	126	4,145	3,752	393	565	4,710
FARGO MN														
Total Residential	9,212	0.008994076	98	0.621383574	0.9672	0.009	75	8,119	188	8,382	7,745	638	1,160	9,543
Total Commercial	1,047	0.049387442	98	9.438790234	0.9648	0.009	49	5,069	325	5,443	4,990	453	753	6,197
Contract Demand	1		-	0		0	-	-	-	725	836	(111)	-	725
	10,260	0.013116757		1.521452397			123	13,189	513	14,551	13,571	980	1,914	16,464
MN Company														
Total Residential	398,691									391,229	413,295	-22,066	54,155	445,383
Total Commercial	32,682									190,962	192,752	-1,790	26,433	217,396
Contract Demand	130									20,938	19,787	1,151		20,938
	431,503									603,129	625,834	-22,705	80,588	683,717
GRAND FORKS ND March 2005 to February 2007														
Total Residential	12,071	0.00970485	98	0.774368544	0.9841	0.009	106	11,481	307	11,894	11,755	140	1,646	13,541
Total Commercial	1,783	0.063761837	98	11.67772934	0.9744	0.009	106	11,141	685	11,932	12,125	(193)	1,652	13,584
Contract Demand	0		-	0		0	-	-	-	0	-	0	-	-
	13,854	0.016661351		2.177503319			213	22,622	992	23,826	23,880	(54)	3,298	27,125
FARGO ND														
Total Residential	26,063	0.008779639	98	1.416452985	0.9064	0.009	213	22,424	1,214	23,851	23,036	816	3,302	27,153
Total Commercial	4,672	0.056854417	98	12.29713854	0.9764	0.009	251	26,032	1,890	28,173	24,886	3,287	3,900	32,073
Contract Demand	0		-	0		0	-	-	-	0	-	0	-	-
	30,735	0.016087686		3.07047314			464	48,456	3,104	52,024	47,922	4,102	7,201	59,226
ND Company														
Total Residential	38,134									35,746	34,790	955	4,948	40,694
Total Commercial	6,455									40,105	37,011	3,094	5,551	45,656
Contract Demand	0									0	0	0		0
	44,589									75,851	71,802	4,049	10,499	86,350
											11.17%			
Grand Total														
Total Residential	436,825									426,975	448,085	(21,111)	59,103	486,077
Total Commercial	39,137									231,067	229,763	1,304	31,985	263,052
Contract Demand	130									20,938	19,787	1,151	-	20,938
	476,092									678,980	697,636	(18,656)	91,087	770,067

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
MINNESOTA/NORTH DAKOTA BY FIRM RATE CLASS

Customers by Area

Area	2008 DD	2007 DD	Difference	%Diff
METRO EAST	295,381	0	295,381	#DIV/0!
METRO WEST	2,068	0	2,068	#DIV/0!
MAINLINE	17,781	0	17,781	#DIV/0!
WILLMAR	3,117	0	3,117	#DIV/0!
PAYNESVILLE	50,954	0	50,954	#DIV/0!
CHISAGO	11,604	0	11,604	#DIV/0!
WATKINS	14,570	0	14,570	#DIV/0!
TOMAH	15,329	0	15,329	#DIV/0!
RED WING	7,627	0	7,627	#DIV/0!
GRAND FORKS MN	2,814	2,703	111	4.1%
FARGO MN	10,260	9,596	664	6.9%
MN State	431,503	424,415	419,204	98.8%
GRAND FORKS ND	13,854	13,642	212	1.6%
FARGO ND	30,735	29,626	1,109	3.7%
ND State	44,589	43,268	1,321	3.1%
TOTAL NSP(Mn)	476,092	467,683	8,409	1.798%

Customer #s

	MN	ND	
Res	398,691	38,134	436,825
Com	32,682	6,455	39,137
Ind	130	0	130
	431,503	44,589	476,092

Design Day Use By Customer Class

	MN	ND	
Res	391,229	35,746	426,975
Com	190,962	40,105	231,067
Ind		0	
	582,191	75,851	658,042

Design Day MMBtu Demand by Area

Area	2008 DD	2007 DD	Difference	%Diff
METRO EAST	475,971	0	475,971	#DIV/0!
METRO WEST	2,601	0	2,601	#DIV/0!
MAINLINE	27,881	0	27,881	#DIV/0!
WILLMAR	3,645	0	3,645	#DIV/0!
PAYNESVILLE	79,032	0	79,032	#DIV/0!
CHISAGO	18,013	0	18,013	#DIV/0!
WATKINS	18,104	0	18,104	#DIV/0!
TOMAH	24,142	0	24,142	#DIV/0!
RED WING	13,154	0	13,154	#DIV/0!
GRAND FORKS MN	4,710	4,073	637	15.6%
FARGO MN	16,464	14,662	1,802	12.3%
MN State	683,717	677,733	664,982	98.1%
GRAND FORKS ND	27,125	25,925	1,200	4.6%
FARGO ND	59,226	52,025	7,201	13.8%
ND State	86,350	77,950	8,400	10.8%
TOTAL NSP(Mn)	770,067	755,683	14,384	1.903%

MN / ND Allocation Factors

2007 DD	2008 DD	
0.8968	0.8879	**MN State Allocation**
0.1032	0.1121	**ND State Allocation**
1.0000	1.0000	

NNG System	2008 DD	2007 DD
METRO EAST	475971	
METRO WEST	2601	
MAINLINE	27881	0
WILLMAR	3645	0
PAYNESVILLE	79032	0
CHISAGO	18013	0
WATKINS	18104	0
TOMAH	24142	
RED WING	13154	0
Total	662,543	658,998

Fargo / Grand Forks Allocation Factors

2007 DD	2008 DD	
		Fargo Demand Allocator
0.7801	0.7825	ND Fargo Demand Allocator
0.2199	0.2175	MN Fargo Demand Allocator
1.0000	1.0000	
		Grand Forks Demand Allocation
0.8642	0.8520	ND Grand Forks Demand Allocator
0.1358	0.1480	MN Grand Forks Demand Allocator
1.0000	1.0000	

VGT System	2008 DD	2007 DD
GRAND FORKS ND	27,125	25,925
GRAND FORKS MN	4,710	4,073
FARGO MN	16,464	14,662
FARGO ND	59,226	52,025
Total	107,524	96,685
VGT & NNG Total	770,067	755,683

DEMAND COST OF GAS IMPACT - NOVEMBER 2007

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day		Current Monthly Demand Rates	No. of Months		Total Annual Cost
NNG TFF	(162,714)	$	9.8530	5	$	(8,016,105.21)
NNG TFF	(162,714)	$	5.4730	7	$	(6,233,736.05)
NNG TF12 Base (Nov-Mar)[1]	(157,130)	$	10.2300	5	$	(8,037,199.50)
NNG TF12 Base (Apr-Oct)[1]	(157,130)	$	5.6830	7	$	(6,250,788.53)
NNG TF12 Variable (Nov-Mar)[1]	(60,785)	$	13.8660	5	$	(4,214,224.05)
NNG TF12 Variable (Apr-Oct)[1]	(60,785)	$	5.6830	7	$	(2,418,088.09)
NNG TF12 Base (Nov-Mar)[1]	134,235	$	10.2300	5	$	6,866,120.25
NNG TF12 Base (Apr-Oct)[1]	134,235	$	5.6830	7	$	5,340,002.54
NNG TF12 Variable (Nov-Mar)[1]	0	$	13.8660	5	$	-
NNG TF12 Variable (Apr-Oct)[1]	0	$	5.6830	7	$	-
NNG TF12 Base (Nov-Mar)[4]	3,624	$	4.2000	5	$	76,104.00
NNG TF12 Base (Apr-Oct)[4]	3,624	$	4.2000	7	$	106,545.60
NNG TF12 Variable (Nov-Mar)[4]	28,984	$	4.2000	5	$	608,664.00
NNG TF12 Variable (Apr-Oct)[4]	28,984	$	4.2000	7	$	852,129.60
NNG TF12 Variable (Nov-Mar)[5]	31,801	$	3.6000	5	$	572,418.00
NNG TF12 Variable (Apr-Oct)[5]	31,801	$	3.6000	7	$	801,385.20
NNG TF5 (Nov-Mar)[1]	(101,023)	$	15.1530	5	$	(7,654,007.60)
NNG TF5 (Nov-Mar)[1]	63,443	$	15.1530	5	$	4,806,758.90
NNG TF5 (Nov-Mar)4	15,338	$	4.2000	5	$	322,098.00
NNG TF5 (Nov-Mar)5	13,233	$	3.6000	5	$	238,194.00
NNG TFX (Nov-Mar)	(55,000)	$	4.9765	5	$	(1,368,537.50)
NNG TFX (Nov-Mar)	25,000	$	12.5000	5	$	1,562,500.00
NNG TFX (Nov-Mar)	(6,545)	$	11.3420	5	$	(371,166.95)
NNG TFX (Nov-Mar)	(24,628)	$	15.1530	5	$	(1,865,940.42)
NNG TFX (May-Sept)	(24,628)	$	5.6830	5	$	(699,804.62)
NNG TFX (Apr & Oct)	(1,000)	$	5.6830	2	$	(11,366.00)
NNG TFX (Nov-Mar)	(8,998)	$	15.1530	5	$	(681,733.47)
NNG TFX (Nov-Mar)	(2,475)	$	14.0000	5	$	(173,250.00)
NNG TFX (Nov-Mar)	(20,000)	$	9.0000	5	$	(900,000.00)
NNG TFX	1,680	$	3.9000	12	$	78,624.00
NNG TFX (Nov-Mar)	48,576	$	3.6000	5	$	874,368.00
NNG TFX (Nov-Mar)	2,270	$	4.2000	5	$	47,670.00
NNG TFX (Nov-Mar)	52,025	$	15.1530	5	$	3,941,674.13
NNG TFX	29,428	$	5.6830	5	$	836,196.62
NNG TFX	5,800	$	5.6830	2	$	65,922.80
NNG TFX (Nov-Mar)	(10,084)	$	15.1530	5	$	(764,014.26)
NNG TFX (Nov-Mar)	38,584	$	15.1530	5	$	2,923,316.76
VGT FT-A (Nov-Mar)[2]	(2,500)	$	3.7671	5	$	(47,088.75)
VGT FT-A (Nov-Mar)2	(4,000)	$	3.7671	3	$	(45,205.20)
VGT FT-A (Nov-Mar)[2]	15,600	$	4.5871	12	$	858,705.12
Great Lakes Gas Trans FT Forwardhaul[3]	(960)	$	10.2780	7	$	(69,068.16)
Great Lakes Gas Trans FT Forwardhaul[3]	960	$	10.2780	7	$	69,068.16
Total for Change in Pipeline Entitlement					*$*	*(17,972,858.69)*

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

[1]NNG Fifth Revised Volume No. 1, 74 Revised Sheet No. 50, Effective November 1, 2006

[2]VGT First Revised Volume No. 1, Twelfth Revised Sheet No. 5, Effective January 1, 2006

[3]GLT Second Revised Volume No. 1, Eighth Revised Sheet No. 4, August 1, 2004

[4] NNG Discount - Lake Elmo

5 NNG Discount - Cedar/Rosemont

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.

DERIVATION OF CURRENT PGA COSTS

November 2007 - Projected Costs (Actual prices will be determined Nov.1, 2007)*

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$22,306,100	$27,458,220	
2.	x Minnesota Design Day Ratio (2007 Demand Entitlement Filing)	88.79%	88.79%	
3.	Annual System Demand Allocation to MN	$19,805,586	$24,380,154	
4.	Grand Forks Total Demand	$275,226	$369,376	
5.	x Minnesota Allocator (2007 Demand Entitlement Filing)	14.80%	14.80%	
6.	Annual Grand Forks Demand Allocation to MN	$40,733	$54,668	
7.	Fargo Base Total Demand	$226,748	$107,735	
8.	x Minnesota Allocator (2007 Demand Entitlement Filing)	21.75%	21.75%	
9.	Annual Fargo Demand Allocation to MN	$49,318	$23,432	
10.	Minnesota Total Demand (3 + 6 + 9)	$19,895,637	$24,458,254	
11.	MN State Design Day (2007 Demand Entitlement Filing)	683,716	683,716	
12.	- Small & Large Demand Billed Dkt (2007 Demand Entitlement Filing)	20,938	20,938	
13.	Non-Demand Billed Design Day Dkt (11-12)	662,778	662,778	
14.	Non-Demand Billed Allocation (10 x 13 / 11)	$19,286,356	$23,709,249	
15.	Demand Billed Cost Allocation (10-14)	$609,281	$749,005	
16.	MN Annual / Seasonal Firm Therm Sales (2004 Rate Case)	551,314,240	406,801,350	
17.	Demand Unit Cost $/Therm (14 / 16)	$0.03498	$0.05828	$0.09326
18.	Demand Cost True-up - Residential (Page 4) Oct-May			$0.00000
19.	Demand Cost True-up - Commercial (Page 4) Oct-May			$0.00000
20.	Total Demnd Rate - Residential (17 +18)			$0.09326
21.	Total Demnd Rate -Commercial (17 + 19)			$0.09326
	Demand Cost (Demand Billed)			
22.	Cost Allocated to Demand Billed (15)	$609,281	$749,005	$1,358,286
23.	/ Annual Contract Billing Demand (2007 Demand Entitlement Filing)			2,512,560
24.	Monthly Commercial Demand Billed Demand Rate			$0.54060
	Commodity Costs			Monthly Cost
25.	NNG Annual/Best Effort/Viking/WBI/Xcel Pk Shv			$56,362,929
26.	Storage Commodity per docket G-002/M-05-865			$267,516
27.	Total Monthly Commodity Costs			$56,630,445
28.	x MN Portion of Monthly Retail Sales			88.06%
29.	MN Portion of Monthly Commodity Costs			$49,868,770
30.	MN Budgeted Calendar Month Retail Therm Sales			75,866,935
31.	Commodity Unit Cost $/Therm (29 / 30)			$0.65732
	Total Gas Cost per Therm			
32.	Residential (20 + 31)			**$0.75058**
33.	Small & Large Commercial (21 + 31)			**$0.75058**
34.	Small & Large Demand Billed - Demand (24)			**$0.54060**
35.	Small & Large Demand Billed - Commodity; All Interruptible (31)			**$0.65732**

*Commodity costs are projected and for illustrative purposed only.

SUMMARY OF DESIGN DAY DEMAND BY CUSTOMER CLASS
Design Day: Heating Season 2007 - 2008

DESIGN DAY CALCULATION

State of Minnesota	Jan-2008 Budget Customer	2008 MMBtu Design Day[1]	2007 MMBtu Design Day[1]	MMBtu Change
Residential	398,691	445,383	448,687	(3,304)
Commercial	32,682	217,396	209,259	8,137
Demand Billed	130	20,938	19,787	1,151
State of Minnesota Total	431,503	683,717	677,733	5,984
State of North Dakota Total	44,589	86,350	77,950	8,400
Total Xcel Energy - Gas Operations	476,092	770,067	755,683	14,384

[1] 91 Heating Degree Days for Design Day

DESIGN DAY ESTIMATE FROM ACTUAL USE PER CUSTOMER

Minnesota Company	Jan-2008 Budget	Jan-2007 Budget	Change
Residential Customers	436,825	429,081	7,744
Commercial Customers	39,137	38,473	664
TOTAL CUSTOMERS	475,962	467,554	8,408
Peak Day Use/Cust[2]	1.57393	1.57393	
Peak Day Res. & Comm. MMBtus	749,129	735,896	
Demand Billed Customers	130	129	
Contracted Billing Demand of Demand Billed Customers	20,938	19,787	
Projected Design Day (Dth)	770,067	755,683	14,384

[2] Determined from Peak Day usage at an average temperature of -15 degrees Fahrenheit on Thursday, Jan. 29, 2004

ENTITLEMENT ESTIMATE PER CUSTOMER

	Jan-2008 Budget	Jan-2007 Budget
Reserve Margin	42,531	20,696
Total Available Capacity	812,598	776,379
Entitlement per Customer	1.7068	1.6601

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
DERIVATION OF ACTUAL PEAK DAY USE PER CUSTOMER
Design Day: Heating Season 2007-2008

	Description	Values	Units	Equation
(1)	Date of Peak Day	January 29, 2004		
(2)	Day of the Week	Thursday		
(3)	Total Throughput including Peakshaving	648,400	Dth	
(4)	Actual Large and Small Comm'l Demand Billed Usage	(13,863)	Dth	
(5)	Total Throughput including Peakshaving less Demand Billed	634,537	Dth	(5) = (3) - (4)
(6)	Interruptible Customers Status	All Curtailed		
(7)	Average Actual Gas Day Temperature	-15	Deg F	
(8)	Heating Degree Days (HDD) 65 degree base	80	HDDs	(8) = 65 - (7)
		[TRADE SECRET BEGINS		
(9)	Limited Firm/Standby Dth Demand on system			
(10)	Total Firm Throughput less Ltd F/Stdby & Demand Billed Customers			
(11)	2004 Non-HDD Sensitive Base Dth[1]			
(12)	Total HDD sensitive Firm throughput			
(13)	Actual Peak Day Dth/HDD			
		TRADE SECRET ENDS]		
(14)	Base + (Actual Dth/HDD * 91 HDDs)	695,134	Dth	(14) = -(11) + [(13) x 91 HDDs]
(15)	Base + (Actual Dth/HDD * 91 HDDs) + Actual Demand Billed Usage	708,997		(15) = (14) + -(4)
(16)	Average Monthly Projected 2004 Design Day[1]	677,930	Dth	
(17)	Actual Peak Day UPC vs. Avg Monthly Design Day	(31,067)	Dth	(17) = (16) - (15)
(18)	Average Monthly 2004 Design Day Reserve Margin[1]	44,733	Dth	
(19)	Actual 2004 Reserve Margin based on Peak Actuals	13,666	Dth	(19) = (18) + (17)
(20)	January 2004 Projected Firm Residential & Comm'l Customers[1]	441,656	Customers	
(21)	Peak Day Actual Use Per Residential & Comm'l Firm Customer	1.57393	Dth/customer	(21) = (14) / (20)

[1]As described in Company's 2003 - 2004 Contract Demand Filing

Northern States Power Company,
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HISTORICAL SALES (July 2006 - June 2007)
(dkt)

Customer Class	Jul-2006	Aug-2006	Sep-2006	Oct-2006	Nov-2006	Dec-2006	Jan-2007	Feb-2007	Mar-2007	Apr-2007	May-2007	Jun-2007	Total	Winter	Summer
Residential	694,886	678,345	735,000	1,512,227	2,904,855	4,167,718	5,536,605	6,517,610	5,276,599	3,099,178	1,527,071	865,223	33,515,317	24,403,387	9,111,930
Residential - FMPP (actual usage less cancellations)	16,477	9,713	12,315	31,662	63,596	162,056	231,811	234,173	206,678	104,128	58,010	28,022	1,158,640	898,314	260,326
Total Residential	711,363	688,058	747,315	1,543,889	2,968,451	4,329,774	5,768,416	6,751,783	5,483,277	3,203,306	1,585,081	893,245	34,673,957	25,301,702	9,372,256
Interdepartmental	31	223	72	4,413	781	480	1,997	1,566	1,505	1,118	7,846	467	20,499	6,329	14,170
Small Commercial Firm	148,101	137,318	161,641	290,477	595,095	874,207	1,309,879	1,493,190	1,329,949	703,469	387,521	202,445	7,633,292	5,602,319	2,030,973
Small Comm. Firm - FMPP (actual usage less cancellations)	537	(173)	394	310	1,835	6,450	11,747	11,427	10,146	5,135	2,160	1,577	51,545	41,605	9,940
Large Commercial Firm	230,079	216,703	243,885	435,941	797,388	1,124,974	1,626,682	1,669,139	1,575,642	964,349	573,723	295,367	9,753,873	6,793,826	2,960,047
Commercial Firm	378,748	354,071	405,993	731,141	1,395,099	2,006,111	2,950,305	3,175,322	2,917,242	1,674,071	971,250	499,856	17,459,209	12,444,079	5,015,130
Small Commercial Demand Billed	5,074	8,753	7,178	8,378	12,561	14,194	15,657	17,050	16,033	15,344	11,346	10,531			
Large Commercial Demand Billed	119,011	131,514	143,874	147,453	208,321	231,462	257,788	301,490	286,387	215,180	178,601	140,101	2,361,181	1,285,449	1,075,733
Large Demand Billed - Generation	5,217	3,543	2,455	8,731	3,696	6,734	5,596	3,240	5,409	5,277	11,451	6,342	67,692	24,675	43,017
Commercial Demand Billed	129,302	143,810	153,507	164,562	224,578	252,389	279,041	321,780	307,829	235,800	201,398	156,974	2,570,971	1,385,617	1,185,354
Total Commercial Firm	508,050	497,881	559,500	895,703	1,619,677	2,258,501	3,229,346	3,497,102	3,225,070	1,909,871	1,172,649	656,830	20,030,180	13,829,696	6,200,483
Total Firm	1,219,413	1,185,939	1,306,815	2,439,592	4,588,129	6,588,275	8,997,762	10,248,885	8,708,348	5,113,177	2,757,730	1,550,074	54,704,137	39,131,398	15,572,739
Small Interruptible	80,685	87,587	116,365	146,254	275,746	375,162	539,438	473,318	503,495	360,399	223,768	109,170	3,291,387	2,167,159	1,124,228
Medium Interruptible	499,875	476,263	476,263	450,027	751,771	704,560	676,711	828,127	732,331	643,839	682,940	411,790	7,334,497	3,693,500	3,640,997
Large Interruptible	166,773	126,786	196,570	148,681	190,159	212,037	231,288	332,382	253,330	234,003	156,734	111,700	2,360,442	1,219,196	1,141,247
Med. & Lg. Interruptible - Generation	606,922	122,293	4,369	181,531	105,082	100,797	56,201	197,439	230,739	280,283	169,163	215,141	2,269,961	690,259	1,579,702
Total Interruptible	1,354,255	812,929	793,567	926,493	1,322,757	1,392,556	1,503,638	1,831,266	1,719,895	1,518,524	1,232,605	847,801	15,256,287	7,770,113	7,486,174
Total Firm and Interruptible	2,573,668	1,998,868	2,100,381	3,366,085	5,910,886	7,980,831	10,501,401	12,080,151	10,428,243	6,631,701	3,990,335	2,397,875	69,960,425	46,901,511	23,058,913
Firm Transportation	21,461	16,523	23,153	24,258	28,097	22,334	28,276	22,975	28,282	20,187	24,588	21,836	281,970	129,964	152,006
Interruptible Transportation	26,473	41,439	21,894	30,013	41,993	39,929	46,816	46,373	35,574	32,239	30,096	26,658	419,497	210,685	208,812
Negotiated Transporation	157,760	264,671	316,308	996,070	493,438	624,364	577,309	529,921	559,783	381,349	481,386	338,185	5,720,544	2,784,815	2,935,729
Interdepartmental Transport - Generation	625,035	258,955	9,833	112,529	57,770	286,621	16,963	8,306	12,290	89,134	32,086	258,214	1,767,734	381,950	1,385,784
Total Transportation	830,729	581,588	371,188	1,162,870	621,298	973,248	669,364	607,576	635,929	522,909	568,156	644,893	8,189,745	3,507,414	4,682,331
Total Customer Sales	3,404,397	2,580,456	2,471,569	4,528,955	6,532,184	8,954,079	11,170,764	12,687,727	11,064,171	7,154,609	4,558,491	3,042,768	78,150,170	50,408,925	27,741,245
Monthly Heating Degree Days	0	0	204	597	848	1,109	1,391	1,443	828	545	110	8	7,085	5,619	1,465

Attachment 1
Schedule 4

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
FIRM SUPPLY ENTITLEMENTS

Attachment 1
Schedule 5

Firm Supplies (1)	Current Quantity Effective 11/1/2006 Dth/Day	Proposed Quantity Effective 11/1/2007 Dth/Day	Proposed Quantity Change 11/1/2007 Dth/Day
A. Upstream Supply			
ANR Firm 3rd Party (2)	4,829	4,829	0
ANRP Storage (2)	15,171	15,171	0
ANR Storage Company (3)	15,297	15,297	0
GLGT Firm 3rd Party (3)	3,799	3,799	-
B. Delivered Supply			
WBI Firm 3rd Party	8,461	8,461	-
VGT Firm 3rd Party	79,230	75,044	(4,186)
NNG Firm 3rd Party	205,574	245,979	40,405
NNG FDD Storage	193,718	193,718	-
LP Peak Shaving	94,300	94,300	-
LNG Peak Shaving	156,000	156,000	-
TOTAL	776,379	812,598	36,219

(1) The Company's contracts are available for inspection during normal business hours at 825 Rice Street, St. Paul, Minnesota.
(2) ANR feeds VGT.
(3) GLGT feeds NNG

ATTACHMENT 2

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of
Xcel Energy Inc.

Proposal for Entitlement Changes

Information provided in response to the Minnesota Department of Commerce letter dated October 1, 1993.

PROPOSAL FOR ENTITLEMENT CHANGE
Department Information Format dated October 1, 1993

1 Provide a peak-day/design-day study by class for the twelve months ending one year from the proposed implementation date of the change(s):

See Attachment 1, Schedule 3.

2 Provide Heating Degree Day ("HDD") data for the most recent twelve month period ending March 31 or September 30. This should include HDD, use per firm customer, and the peak season and off-peak HDD used for calculating the Company's design days:

See Attachment 1, Schedule 1, and Attachment 1, Schedule 4.

3 Historical and Projected Design-Day and Peak Demand Requirements:

Minnesota Only

Heating Season1 1)	Number of Firm Customers2 2)	Design Day Requirement (Dth) 3)	Total Entitlement plus Storage plus Peak Shaving3 (Dth) 4)	Peak Day Sendout (Dth) 5)	Heating Degree Days 6)	Actual Peak Day
Proposed: 2007/2008	431,373	683,716	721,506	Unknown	Unknown	Unknown
2006/2007	424,286	677,733	696,257	568,963	67	2/2/2007
2005/2006	421,570	670,846	691,689	537,660	63	12/5/2005
2004/2005	410,986	649,655	675,120	537,374	60	1/5/2005
2003/2004	401,633	603,468	643,315	561,250	80	1/29/2004
2002/2003	395,807	607,856	642,275	534,385	64.8	1/20/2003

1 Per Annual Financial Reports.

2 Provide data and calculations for projected number of firm customers by class and in total corresponding to the design day requirement.

3 Total entitlement for Minnesota is calculated from the Proposed January 1 Entitlement.

See Attachment 1, Schedule 3.

4 Demand Profile:

See Attachment 2, Schedule 1.

5 Rate Impact:

See Attachment 2, Schedule 2.

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
DEMAND PROFILE
2007-2008 Heating Season

Contract No.	Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu	Contract Length and Expiration Date	Change Description	% of Peak Day Entitlement	
	Capacity Entitlements							
26268	NNG TF12 Base	157,130	(157,130)	0	15 yrs - 10/31/07	Contract Expire	0.00%	
26268	NNG TF12 Variable	60,785	(60,785)	0	15 yrs - 10/31/07	Contract Expire	0.00%	
112183	NNG TF12 BASE (Max)	0	134,235	134,235	10 yrs - 10/31/17	Contract Renewal	16.52%	
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/17	Contract Renewal	0.00%	
112182	NNG TF12 BASE (Disc.)	0	3,624	3,624	10 yrs - 10/31/17	Contract Renewal	0.45%	
112182	NNG TF12 VARIABLE (Disc.)	0	60,785	60,785	10 yrs - 10/31/17	Contract Renewal	7.48%	
26268	NNG TF5	101,023	(101,023)	0	15 yrs - 10/31/07	Contract Expire	0.00%	
112183	NNG TF5 (Max)	0	63,443	63,443	10 yrs - 10/31/17	Contract Renewal	7.81%	
112182	NNG TF5 (Disc.)	0	28,571	28,571	10 yrs - 10/31/17	Contract Renewal	3.52%	
23333	NNG TFX (Nov-Mar)	55,000	(55,000)	0	15 yrs - 10/31/07	Contract Expire	0.00%	
103532	NNG TFX (Nov-Mar)	6,545	(6,545)	0	15 yrs - 10/31/12	Terminated (1)	0.00%	
103008	NNG Peak Day 2000	24,628	(24,628)	0	15 yrs - 10/31/12	Terminated (1)	0.00%	
109134 .	NNG Pk Day Max (Nov-Mar)	8,998	(8,998)	0	3 yrs - 3/31/07	Contract Expire	0.00%	
105463	NNG TFX (Nov-Mar)	2,475	(2,475)	0	12 yrs - 10/31/13	Terminated (1)	0.00%	
100896	NNG TFX (Nov-Mar)	20,000	(20,000)	0	1 year - 10/31/07	Contract Expire	0.00%	
111739	NNG TFX (Nov-Mar)	10,084	28,500	38,584	2 yrs - 10/31/09	Contract Renegotiation	4.75%	
112185	TFX (Disc.)	0	52,526	52,526	10 yrs - 10/31/17	Contract Renewal	6.46%	
112186	TFX (Max)	0	52,025	52,025	10 yrs - 10/31/17	Contract Renewal	6.40%	
112186	TFX 2 (Max)	0	5,800	5,800	10 yrs - 10/31/17	Contract Renewal	Summer Only	
112186	TFX 5 (Max)	0	29,428	29,428	10 yrs - 10/31/17	Contract Renewal	Summer Only	
112184	TFX (Disc.)	0	25,000	25,000	10 yrs - 10/31/17	Contract Renewal	3.08%	
								[TRADE SECRET BEGINS TRADE SECRET ENDS]
AF0044/54	VGT FT-A 12 Mos.	34,915	0	34,915	15 yrs - 10/31/08		4.30%	
AF0044/54	VGT FT-A (Nov-Mar)	20,485	0	20,485	15 yrs - 10/31/08		2.52%	
AF0054	Capacity Release (Nov-Mar)	0	(22,159)	(22,159)			-2.73%	
AF0055	VGT FT-A 12 Mos.	300	0	300	4 yrs - 10/31/08		0.04%	
AF0055	VGT FT-A (Nov-Mar)	300	0	300	4 yrs - 10/31/08		0.04%	
AF0054	Capacity Release (Nov-Mar)	0	(600)	(600)			-0.07%	
AF0036	VGT FT-A 12 Mos.	5,000	0	5,000	15 yrs - 10/31/11		0.62%	
AF0036	VGT FT-A (Nov-Mar)	16,105	0	16,105	15 yrs - 10/31/11		1.98%	
AF0036	Capacity Release (Nov-Mar)	0	(1,105)	(1,105)			-0.14%	
AF0103	VGT FT-D (Apr-Oct)	5,000	0	5,000	15 yrs - 10/31/14		Summer Only	
AF0103	VGT FT-D 12 Mos.	10,000	0	10,000	15 yrs - 10/31/14		1.23%	
AF0035	VGT FT-A 12 Mos.	5,450	0	5,450	10 yrs - 10/31/10		0.67%	
AF0035	VGT FT-A (Nov-Mar)	6,550	0	6,550	10 yrs - 10/31/10		0.81%	
AF0035	Capacity Release (Nov-Mar)	0	(12,000)	(12,000)			-1.48%	
	VGT FT-A 5 Mos.	2,500	(2,500)	0	2 yrs - 3/31/07	expired	0.00%	
	VGT FT-A 5 Mos.	4,000	(4,000)	0	1 yr - 2/28/07	expired	0.00%	
AF0037	VGT FT-A 12 Mos.	0	15,600	15,600	4/30/2014	new contract	1.92%	
RF0169	VGT FT-A 12 Mos.	300	0	300	2 yrs - 5/31/08		0.04%	
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 4/30/11		0.23%	
								[TRADE SECRET BEGINS TRADE SECRET ENDS]
	WBI X-13	8,000	0	8,000	20 yrs - 10/31/12		0.98%	
	WBI FT-1	461	0	461	20 yrs - 07/01/13		0.06%	
	City Gate Deliveries	1,422	22,578	24,000	10 yrs - 10/31/17	Included in Supply Entitlement bel<	2.95%	
	LP Peak Shaving	94,300	0	94,300			11.60%	
	LNG Peak Shaving	156,000	0	156,000			19.20%	
	Total Design Day Capacity	776,379		812,598			100.00%	
	Heating Season Total	776,379		812,598				
	Non-Heating Season Total	311,669		320,801				
	Miscellaneous Entitlements with Reservation Fees							
	Additional Pipeline Entitlements							
	ANR FT-106209 12 Mos. (1)	4,829		4,829	16 yrs - 03/31/08			
	ANR FT-106211 (Summer) (1)	4,761	160	4,921	16 yrs - 03/31/08	error		
	ANR FT-106211 (Winter) (1)	15,171		15,171	16 yrs - 03/31/08			
	GLT FT-043 (2)	3,799		3,799	16 yrs - 03/31/10			
	GLT FT-142 (Nov-Apr) (2)	15,195		15,195	17 yr - 04/30/11			
	GLT FT-6187 (2)	960		960	7 month 10/31/07	expired		
	NNG TFF (3)	162,714	(162,714)	0	15 yrs - 10/31/07	expired		
	NNG SMS (3)	30,500		30,500	15 yrs - 10/31/17			
	VGT OBA (3)	7,400		7,400	13 yrs - 03/31/08			
	Supply Entitlements (4)							
							[TRADE SECRET BEGINS	
							TRADE SECRET ENDS]	
	Storage Entitlements							
	ANR Pipeline Storage (.953 Bcf)	15,386		15,386	16 yrs - 3/31/08			
	ANR Storage (.994 Bcf)	15,297		15,297	7 yrs - 3/31/14			
	FDD Service (8.085Bcf)	140,230		140,230	4 yrs - 5/31/07 (1.4 Bcf expires 5/31/08)			
	FDD Service (1.875Bcf)	32,518		32,518	12 yrs - 5/31/17			
	FDD Service (4.5Bcf)	78,050		78,050	15 yrs - 5/31/27			

(1) Contract terminated as part of overall contract negotiation with NNG
(2) Not included in total peak deliverability -- feeds NNG (capacity not additive).
(3) Not included in total peak deliverability -- entitlement delivered by or associated with TF or FT-A service.
(4) Supply contracts containing reservation fees.

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2007
(Total System and MN State)

	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
Total Available Capacity:			
Heating Season	776,379	36,219	812,598
Non-Heating Season	311,669	9,132	320,801
Heating Season Forecasted Design Day	755,683	14,384	770,067
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	20,696	21,835	42,531
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	2.74%	2.78%	5.52%
State of MN Allocation Factor	89.68%	-0.89%	88.79%
State of MN Heating Season Capacity	696,257	25,249	721,506
State of MN Design Day Demand	677,733	5,983	683,716
State of MN Heating Season Capacity Reserve/(Shortage)	18,524	19,266	37,790
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	2.73%	2.79%	5.53%

(1) Entitlement changes for November are included in Available Capacity.
Please reference Attachment 1 Schedule 5 for the detail on supply entitlement changes.

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
RATE IMPACT

Attachment 2
Schedule 2

Please use the following table to illustrate the financial effects of the poposed change, based on the most recent Purchased Gas Adjustment (PGA), the first PGA which implemented the most recently approved demand change and the last rate case for residential customers and all firm customers. If interruptible customers are affected, please identify the rate impact in the same format as specified bleow.

Date to implement proposed change: November 1, 2007
Docket No. of most recently approve demand change: G002/M-05-1813
Date of last rate case: September 17, 2004, 2004 Test Year
Docket No. of last rate case: G002/GR-04-1511

RESIDENTIAL FIRM

All Cost $/Dth	2004 Rate Case (7)	Last Approved Demand Adjustment Dec 2005	Last Month PGA: October 2007 (8)	Current PGA without Adjustment November 2007 (8)	Current PGA with Adjustment November 2007 (8)	Change From Last Rate Case Base Cost	Change From Last Approved Demand Adjustment	Change From Last Month PGA	Change From Current PGA
Commodity Cost of Gas (WACOG) (1)	$5.4731	$9.8611	$5.7339	$6.5732	$6.5732	20.1%	-33.3%	14.6%	0.0%
Demand Cost of Gas -Summer (4)	$0.7359	$0.6349	$0.6225	$0.3538	$0.3498	-52.5%	-44.9%	-43.8%	-1.1%
Demand Cost of Gas - Winter (4, 5)	$1.2527	$1.1263	$1.1783	$0.9432	$0.9326	-25.6%	-17.2%	-20.9%	-1.1%
Total Cost of Gas - Summer (2)	$6.2090	$10.4960	$6.3564	$6.9270	$6.9230	11.5%	-34.0%	8.9%	-0.1%
Total Cost of Gas - Winter (2)	$6.7258	$10.9874	$6.9122	$7.5164	$7.5058	11.6%	-31.7%	8.6%	-0.1%
Average Annual Total Usage (6)	37,125,483	37,125,483	37,125,483	37,125,483	37,125,483	0.0%	0.0%	0.0%	0.0%
Average Annual Total Cost of Gas (2)	244,691,479	403,150,111	251,233,812	273,339,490	273,009,905	11.6%	-32.3%	8.7%	-0.1%

ALL FIRM CUSTOMERS (3)

All Cost $/Dth	2004 Rate Case (7)	Last Approved Demand Adjustment Dec 2005	Last Month PGA: October 2007 (8)	Current PGA without Adjustment November 2007 (8)	Current PGA with Adjustment November 2007 (8)	Change From Last Rate Case Base Cost	Change From Last Approved Demand Adjustment	Change From Last Month PGA	Change From Current PGA
Commodity Cost of Gas (WACOG) (1)	$5.4645	$9.8611	$5.7339	$6.5732	$6.5732	20.3%	-33.3%	14.6%	0.0%
Demand Cost of Gas -Summer (4)	$0.7359	$0.6349	$0.6225	$0.3538	$0.3498	-52.5%	-44.9%	-43.8%	-1.1%
Demand Cost of Gas - Winter (4, 5)	$1.2527	$1.1263	$1.1783	$0.9432	$0.9326	-25.6%	-17.2%	-20.9%	-1.1%
Total Cost of Gas - Summer (2)	$6.2004	$10.4960	$6.3564	$6.9270	$6.9230	11.7%	-34.0%	8.9%	-0.1%
Total Cost of Gas - Winter (2)	$6.7172	$10.9874	$6.9122	$7.5164	$7.5058	11.7%	-31.7%	8.6%	-0.1%
Average Annual Total Usage	55,131,424	55,131,424	55,131,424	55,131,424	55,131,424	0.0%	0.0%	0.0%	0.0%
Average Annual Total Cost of Gas (2)	362,860,375	598,647,539	373,047,403	405,872,246	405,383,231	11.7%	-32.3%	8.7%	-0.1%

(1) Commodity costs include Peakshaving.
(2) Total cost of gas excludes distribution margin
(3) Excludes Demand Billed Customers firm sales.
(4) Rate for Rate Case is a weighted average firm rate since each class has a unique cost of gas.
(5) Not applicable during the summer months
(6) Residential Total Usage for October and November colums were imputed by taking the Residental % of usage in the 2004 Rate Case usage multiplied by the annual usage filed in the PGA for specific months.
(7) As in the compliance filing
(8) Does not include the monthly demand true-up surcharge(credit)

Attachment 2
Schedule 2

ATTACHMENT 3

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of
Xcel Energy Inc.

Information provided in response to reporting requirements in Docket No. G002/M-03-1627 (order dated January 23, 2004) Regarding use of financial instruments to limit price volatility.

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN REMOVED

Northern States Power Company,
A Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
SUMMARY OF HEDGE TRANSACTIONS
2007-2008 Heating Season

							Monthly Volumes						
Transaction Date	**Hedge Instrument**	**Counterparty**	**Premium**	**Call Strike Price**	**Floor Strike Price**	**Basis Point**	**November**	**December**	**January**	**February**	**March**	**Total Volume**	**Total Dollars**

[TRADE SECRET DATA BEGINS

Actual Hedge Activity

TRADE SECRET DATA ENDS]

Attachment 3
Schedule 1
Page 1 of 1

ATTACHMENT 4

Northern States Power Company, a Minnesota Corporation and wholly owned subsidiary of Xcel Energy Inc.
Gas Operations

Information provided in response to Department Recommendation in Docket No. E,G999/AA-06-1208 to discuss alternative methods for the classification and billing of demand costs.

**Northern States Power Company, a Minnesota Corporation and wholly owned subsidiary of Xcel Energy Inc.
Gas Operations**

Information provided in response to Department Recommendation in Docket No. E,G999/AA-06-1208 to discuss alternative methods for the classification and billing of demand costs.

In the Department comments dated October 19, 2007 regarding Xcel Energy's AAA filing, Docket No. G002/AA-06-1208, the Department recommended that the Commission require each gas utility in their 2007-2008 Demand Entitlement filing to:

- Provide its unique set of facts in determining whether it is reasonable to classify Producer Demand and Storage costs as commodity or demand costs;
- Clarify which customer classes are to be assigned related costs;
- Provide a detailed explanation of its rationale for its proposal; and
- Provide a rate impact analysis for all affected customer classes based on the utility's currently approved method of classifying and billing Producer Demand and Storage costs, together with a similar comparison of classifying and billing Producer Demand and Storage costs as commodity costs.

<u>Summary</u>

The Company believes that interruptible sales customers receive some benefit from certain expenses that have historically been allocated on demand, including a portion of storage costs as well as balancing expense. However, the Company does not believe interruptible sales customers receive any benefit from the producer demand expense in our portfolio. Our producer demand expense is attributable to a Viking citygate peaking contract that was done in lieu of acquiring additional annual or heating season interstate pipeline firm transportation service.

Interruptible sales customers provide system value by agreeing to curtail their gas usage when requested by the Company, usually during very cold weather or peak day conditions when gas supplies may be limited. Therefore, the Company does not believe any pipeline transportation demand costs or producer demand costs (a.k.a. supplier reservation costs) should be assigned to the interruptible sales customers. However, the interruptible sales customers are receiving the benefits of both storage and pipeline balancing services on non-design days; therefore the Company believes a portion of these costs could be recovered from interruptible sales customers. Therefore, Xcel Energy proposes on a prospective basis, to assign an annual volumetric charge of $0.0129/dth and a winter volumetric charge of $0.1060/dth to all interruptible gas sales customers on Xcel Energy's system. Based on the Company's 2007-2008 sales forecast, approximately $837,000 in demand costs will be paid for by the interruptible sales customers. The costs allocated to interruptible sales customers will result in lower rates for firm gas customers. Xcel Energy's proposal to assign a portion of demand costs to interruptible sales customers is further detailed below.

Specifics of Xcel Energy Proposal

Xcel Energy's proposal utilizes actual demand costs filed in the November 2007 PGA filing. The first category of demand charges that Xcel Energy proposes to assign to interruptible sales customers is underground storage costs. Storage costs are classified into two categories: deliverability demand charges which determine the amount of peak day deliverability that can be withdrawn in the winter; and capacity demand charges which are placed on the entire cycle quantity of gas that can be stored. Since interruptible sales customers would not receive any gas out of storage on a design day, as their service would be curtailed, Xcel Energy does not believe that interruptible sales customers should be allocated any storage deliverability demand charges. Interruptible sales customers do receive the benefit of gas in storage as reflected in their monthly weighted average cost of gas (WACOG); therefore, Xcel Energy believes a portion of capacity demand charges should be allocated to interruptible sales customers.

In Attachment 4, Schedule 1, Xcel Energy proposes to take the annual cost of storage capacity demand charges for all storage facilities including Northern's Firm Deferred Delivery ("FDD"), ANR Storage Company, and ANR Pipeline Company storage, divided by budgeted heating season sales to determine a per Dth cost to be paid for on all gas commodity sales (firm and interruptible) during the five winter months of November through March. Of the total $5.2 million in storage capacity demand charges, approximately $687,000 or 13 percent will be charged to the interruptible sales customers under our proposal.

The second category of demand charges that Xcel Energy proposes to assign to interruptible sales customers is pipeline balancing costs. Since Xcel Energy balances both firm and interruptible sales customer requirements on a daily basis on both Northern and Viking, Xcel Energy believes that a portion of the interstate pipeline balancing service demand charges should be allocated to interruptible sales customers. In **Attachment 4, Schedule 1**, Xcel Energy proposes to take the annual demand costs of pipeline balancing services divided by the budgeted annual sales to determine a per Dth costs to be paid for on all gas commodity sales on an annual basis. Of the total $891,000 in pipeline balancing demand charges, approximately $150,000 or 17% will be allocated to the interruptible sales customers under our proposal.

An example of how this allocation would appear in the Company's monthly PGA filing is included on line 27 of **Attachment 4, Schedule 2**. The impact of this proposal on both firm and interruptible sales customer bills is shown on **Attachment 4, Schedule 3.**

In addition, based on the Department's recommendation, the Company has also provided the rate impact analysis for all affected customer classes if all Producer Demand and Storage costs were allocated as commodity costs, shown on **Attachment 4, Schedule 4**. The Company does not believe there is appropriate rationale to allocate all Producer Demand and Storage costs on our system as commodity costs, and recommends the specific proposal discussed above.

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.

DEMAND CHARGE ALLOCATION TO INTERRUPTIBLE CUSTOMER CLASS

Company Recommendation

1. Allocation of Storage Capacity Demand Charges

	Annual Cost	Total Winter Sales	Cost per Dth	Total Interruptible Winter Sales	Total Winter Cost to Interruptible Customers	12-Month Cost	Winter-Month Cost
NNG:FDD	$4,489,060.58	48,637,199	$0.0923	6,476,350	$597,746.79		$597,746.79
ANR	$376,055.38	48,637,199	$0.0077	6,476,350	$50,074.15		$50,074.15
ANRS	$292,206.35	48,637,199	$0.0060	6,476,350	$38,909.12		$38,909.12
	$5,157,322.31		**$0.1060**		**$686,730.06**		**$686,730.06**
					13%		

2. Allocation of Pipeline Balancing Charges

	Annual Cost	Total Annual Sales	Cost per Dth	Total Interruptible Annual Sales	Total Annual Cost to Interruptible Customers	12-Month Cost	Winter-Month Cost
NNG:SMS	$801,804.00	69,049,569	$0.0116	11,628,525	$135,030.50	$135,030.50	
VGT:OBA	$88,800.00	69,049,569	$0.0013	11,628,525	$14,954.66	$14,954.66	
	$890,604.00		**$0.0129**		**$149,985.16**	**$149,985.16**	
					17%		

Total **$836,715.23**

Attachment 4
Schedule 1

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.

Attachement 4
Schedule 2

DERIVATION OF CURRENT PGA COSTS - WITH SOME DEMAND COSTS MOVED TO COMMODITY

November 2007 - Projected Costs (Actual prices will be determined Nov.1, 2007)*

PROPOSED

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$22,306,100	$27,458,220	
2.	Less Demand Charge Allocation to Commodity	$149,985	$686,730	
3.	MN & ND Total Demand Adjusted	$22,156,115	$26,771,490	
4.	x Minnesota Design Day Ratio (2007 Demand Entitlement Filing)	88.79%	88.79%	
5.	Annual System Demand Allocation to MN	$19,672,414	$23,770,406	
6.	Grand Forks Total Demand	$275,226	$369,376	
7.	x Minnesota Allocator (2007 Demand Entitlement Filing)	14.80%	14.80%	
8.	Annual Grand Forks Demand Allocation to MN	$40,733	$54,668	
9.	Fargo Base Total Demand	$226,748	$107,735	
10.	x Minnesota Allocator (2007 Demand Entitlement Filing)	21.75%	21.75%	
11.	Annual Fargo Demand Allocation to MN	$49,318	$23,432	
12.	Minnesota Total Demand (5 + 8 + 11)	$19,762,465	$23,848,506	
13.	MN State Design Day (2007 Demand Entitlement Filing)	683,716	683,716	
14.	- Small & Large Demand Billed Dkt (2007 Demand Entitlement Filing)	20,938	20,938	
15.	Non-Demand Billed Design Day Dkt (13-14)	662,778	662,778	
16.	Non-Demand Billed Allocation (12 x 15 / 13)	$19,157,263	$23,118,173	
17.	Demand Billed Cost Allocation (12-16)	$605,202	$730,333	
18.	MN Annual / Seasonal Firm Therm Sales (2004 Rate Case)	551,314,240	406,801,350	
19.	Demand Unit Cost $/Therm (16 / 18)	$0.03475	$0.05683	$0.09158
20.	Demand Cost True-up - Residential (Page 4) Oct-May			$0.00000
21.	Demand Cost True-up - Commercial (Page 4) Oct-May			$0.00000
22.	Total Demnd Rate - Residential (19 +20)			$0.09158
23.	Total Demnd Rate -Commercial (19 + 21)			$0.09158
	Demand Cost (Demand Billed)			
24.	Cost Allocated to Demand Billed (17)	$605,202	$730,333	$1,335,535
25.	/ Annual Contract Billing Demand (2007 Demand Entitlement Filing)			2,512,560
26.	Monthly Commercial Demand Billed Demand Rate			$0.53154
	Commodity Costs			Monthly Cost
27.	NNG Annual/Best Effort/Viking/WBI/Xcel Pk Shv			$56,362,929
28.	Storage Commodity per docket G-002/M-05-865			$267,516
29.	Demand Charge Allocation to Commodity - Annual (Line 2-Annual / 12-months)			$12,499
30.	Demand Charge Allocation to Commodity - Winter (Line 2-Winter / 5-months)			$137,346
31.	Total Monthly Commodity Costs			$56,780,290
32.	x MN Portion of Monthly Retail Sales			88.06%
33.	MN Portion of Monthly Commodity Costs			$50,000,723
34.	MN Budgeted Calendar Month Retail Therm Sales			75,866,935
35.	Commodity Unit Cost $/Therm (33 / 34)			$0.65906
	Total Gas Cost per Therm			
36.	Residential (22 + 35)			**$0.75064**
37.	Small & Large Commercial (23 + 35)			**$0.75064**
38.	Small & Large Demand Billed - Demand (26)			**$0.53154**
39.	Small & Large Demand Billed - Commodity; All Interruptible (35)			**$0.65906**

*Commodity costs are projected and for illustrative purposed only.

Northern States Power Company, a Minnesota corporation
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Attachement 4
Schedule 3

COMPARISON OF ALLOCATION METHODOLOGY FOR CERTAIN DEMAND COSTS

Company Recommendation

Class	Typical Annual Usage (dkt)	Typical Annual Bill With Current Demand/Commodity Allocation	Typical Annual Bill With Modified Demand/Commodity Allocation	Difference	Percent of Current
Residential	91	$923.85	$923.87	$0.02	0.003%
Small Commercial Firm	309	$2,900.19	$2,900.26	$0.07	0.003%
Large Commercial Firm	1,684	$14,899.44	$14,899.80	$0.35	0.002%
Small Commercial Demand Billed		$67,356.61	$67,369.85	$13.25	0.02%
Demand Usage	59				
Commodity Usage	8,045				
Large Commercial Demand Billed		$191,034.72	$191,067.91	$33.19	0.02%
Demand Usage	177				
Commodity Usage	22,886				
Small Interruptible	8,036	$62,085.05	$62,184.25	$99.21	0.16%
Medium Interruptible	50,152	$357,446.06	$357,913.90	$467.84	0.13%
Large Interruptible	720,870	$5,068,291.24	$5,075,529.95	$7,238.71	0.14%

Northern States Power Company, a Minnesota corporation
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DEMAND CHARGE ALLOCATION TO INTERRUPTIBLE CUSTOMER CLASS

100% Storage and Producer Demand as Commodity Method

1. Allocation of Storage Capacity and Deliverability Demand Charges

	Annual Cost	Total Winter Sales	Cost per Dth	Total Interruptible Winter Sales	Total Winter Cost to Interruptible Customers	12-Month Cost	Winter-Month Cost
FDD Capacity	$8,978,643.62	48,637,199	$0.1846	6,476,350	$1,195,563.15		$1,195,563.15
ANR	$746,988.35	48,637,199	$0.0154	6,476,350	$99,466.22		$99,466.22
ANRS	$732,754.44	48,637,199	$0.0151	6,476,350	$97,570.88		$97,570.88
	$10,458,386.41		**$0.2150**		**$1,392,600.25**		**$1,392,600.25**
					13%		

2. Allocation of Producer Demand Charges

	Annual Cost	Total Annual Sales	Cost per Dth	Total Interruptible Annual Sales	Total Annual Cost to Interruptible Customers	12-Month Cost	Winter-Month Cost
VGT	$1,357,800.00	69,049,569	$0.0197	11,628,525	$228,664.88		$228,664.88
NNG	$40,950.00	69,049,569	$0.0006	11,628,525	$6,896.32		$6,896.32
	$1,398,750.00		**$0.0203**		**$235,561.20**		**$235,561.20**
					17%		

Total **$1,628,161.45**

COMPARISON OF ALLOCATION METHODOLOGY FOR CERTAIN DEMAND COSTS
100% Storage and Producer Demand as Commodity Method

Class	Typical Annual Usage (dkt)	Typical Annual Bill With Current Demand/Commodity Allocation	Typical Annual Bill With Modified Demand/Commodity Allocation	Difference	Percent of Current
Residential	91	$923.85	$924.08	$0.23	0.03%
Small Commercial Firm	309	$2,900.19	$2,900.97	$0.78	0.03%
Large Commercial Firm	1,684	$14,899.44	$14,903.57	$4.13	0.03%
Small Commercial Demand Billed		$67,356.61	$67,387.34	$30.74	0.05%
Demand Usage	59				
Commodity Usage	8,045				
Large Commercial Demand Billed		$191,034.72	$191,115.37	$80.65	0.04%
Demand Usage	177				
Commodity Usage	22,886				
Small Interruptible	8,036	$62,085.05	$62,292.24	$207.19	0.33%
Medium Interruptible	50,152	$357,446.06	$358,379.44	$933.38	0.26%
Large Interruptible	720,870	$5,068,291.24	$5,082,929.60	$14,638.36	0.29%

ATTACHMENT 5

Northern States Power Company, a Minnesota Corporation and wholly owned subsidiary of Xcel Energy Inc.

Information provided in response to the Department's recommendation in Docket No. G002/M-06-1454, evidence substantiating Design Day study methodology.

ATTACHMENT 5

Northern States Power Company, a Minnesota Corporation and wholly owned subsidiary of Xcel Energy Inc.

Information provided in response to the Department's recommendation in Docket No. G002/M-06-1454, evidence substantiating Design Day study methodology.

In the Department's comments dated August 21, 2007, regarding Xcel Energy's 2006 heating season Contract Demand Entitlement filing, Docket No. G002/M-06-1454, the Department recommended that Xcel Energy include evidence substantiating its Design Day methodology. Xcel Energy believes its method of calculating its Design Day is accurate and provides the following support, which substantiates its methodology.

<u>Inclusion of Summer Usage</u>

The use of summer data increases the model's accuracy in estimating Design Day usage. Xcel Energy used several regressions to analyze the effect of summer gas usage on Design Day estimations for both residential and commercial customer classes for the entire Company system (Minnesota and North Dakota). The models used average customer use as a function of heating degree days ("HDD"). Regressions used 144 months of data for the period 1995-2006. Regressions for only summer (84 observations) and winter months (60 observations) were also used. Results for these regressions are below.

R-Squares for Each Regression			
	All Months	Winter Months	Summer Months
Residential	98.0%	93.2%	92.6%
Commercial	97.1%	89.1%	88.6%

Linear regression separates throughput into base and weather related usage. The summer months include mostly base usage since there is little weather effect, while winter months include mostly weather effects on usage.

Combining the two seasons into the regressions makes the curve fit better as all usage, base and weather related, is represented.

Since the inclusion of summer months results in the highest r-square of any model for each customer class, Xcel Energy maintains including summer data as higher r-squares increase a model's accuracy for predicting dependent variables.

Use of Linear Regression
Xcel Energy does not use linear regression for estimating Design Day usage. Instead, regression results are used to develop allocations by state and regional service area to enable Xcel Energy to ensure that adequate levels of firm pipeline transportation are available in each area.

In the Company's 2004-2005 Contract Demand Entitlements filing, Docket No. G002/M-05-1813, the Company filed to add a second methodology for calculating its Design Day. Prior to this docket, the Company utilized a single methodology which utilized a linear regression calculation. In the 2004-2005 Contract Demand Entitlements filing, the Company filed to include a second methodology, UPC DD, to ensure that the Design Day is adequately and accurately estimated.

Use of 60 months of Data
Xcel Energy contends that using 60 months of data in the Design Day regressions is appropriate because more recent data takes into account the appliance mix currently in the marketplace. Data older than 60 months is based on older, less energy efficient appliances that could skew average use per customer upward.

Xcel Energy tested the regressions used in the first part of this study with similar regressions based on only 60 months of data from 2002-2006. Regressions for only summer (35 observations) and winter months (25 observations) were also used. Results are presented in the table below.

R-Squares for 1995-2006 Regressions			
	All Months	Winter Months	Summer Months
Residential	98.0%	93.2%	92.6%
Commercial	97.1%	89.1%	88.6%

R-Squares for 2002-2006 Regressions			
	All Months	Winter Months	Summer Months
Residential	97.9%	93.1%	91.6%
Commercial	97.8%	92.5%	88.1%

In each scenario, the r-squares are nearly equal, signifying that regressions using only 60 months of data are as reliable as those that use more than double the amount of data. Using these results, the 60-month regression models Xcel Energy has used do capture the extent of weather on average customer use and will accurately predict Design Day usage.

<u>Declining use per customer</u>

While the Company was unable to locate any national studies on the decline in use per customer on a peak day, it is reasonable that some of the same factors contributing to the decline in annual throughput also contribute to a decline in peak day use. The decline in use per customer has been driven by efficiency gains in residential appliance and housing characteristics (e.g., insulation and efficient windows) and because multi-family dwellings have been steadily increasing as a percent of new construction, partly as a result of the aging baby boomer population choosing to live in smaller, maintenance-free living environments. In addition, as a result of the Minnesota 2000 Energy Code, fewer natural gas water heaters are being installed in new home construction. A higher percentage of better insulated homes, a lower percentage saturation for natural gas water heaters, and higher percentage of multi-family dwellings would also result in a decline in average customer use on a peak day. These trends in residential natural gas consumption were detailed in an American Gas Association (AGA) study provided in the Company's 2004 general rate case (G-002/GR-04-1511) in response to DOC information request 503, included in this filing as **Attachment 5, Schedule 1.** In addition, the testimony of Jannell Marks and Mary Jo Woolf in that docket also provides more details on these trends.

The Company believes that its forecast of customer requirements under Design Day conditions is appropriate. This methodology combined with the Company's reserve margin, provides reliable service for our firm natural gas customers.

Attachment 5
Schedule 1

American Gas Association

Energy Analysis

POLICY ANALYSIS GROUP
400 N. Capitol St., NW
Washington, DC 20001
www.aga.org

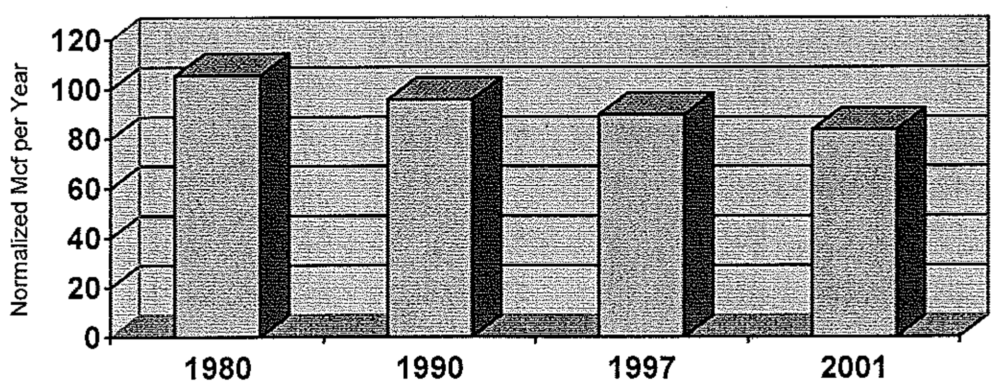
EA 2003-01 June 16, 2003

PATTERNS IN RESIDENTIAL NATURAL GAS CONSUMPTION, 1997-2001

I. Introduction

This analysis concludes that natural gas use per residential customer dropped by 6.4 percent from 1997 through 2001. This reduction per customer is in addition to a 16 percent reduction observed from 1980 through 1997. Nationally, natural gas use per residential customer was 106 thousand cubic feet (Mcf) per year in 1980, 89 Mcf per year in 1997, and 83 Mcf per year in 2001 (Chart 1). A previous AGA analysis[1] quantified the primary factors contributing to this decline on both a national and a regional basis and those same factors are again analyzed herein for the more recent period. It should be noted that all data in these analyses have been adjusted to reflect normal weather.

Chart 1
Use Per Residential Customer



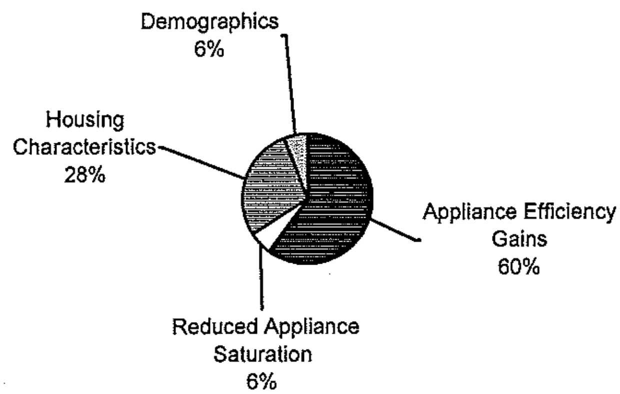
[1] *Patterns in Residential Natural Gas Consumption Since 1980*, American Gas Association, February 2000

II. Executive Summary

Similar to the findings of the previous analysis, the primary cause of the declining use trend was increasing efficiency of gas appliances, predominately space heaters. Other factors include a reduction in the number of gas appliances in homes served with gas and tighter, more energy efficient homes. Chart 2 shows the estimated proportional impact of the various factors contributing to this decline on a national basis.

Chart 2

Factors Contributing to Declining U.S. Natural Gas Use per Residential Customer 1997-2001



- **Regional variation was observed.** There was a decline in the use per customer in all regions of the country: The Northeast lost 1.74 Mcf/year comparing 1997 to 2001, the South and the West lost 2.17 Mcf/year, and the Midwest 4.31 Mcf/year (Table 1). Graphical representation of some of the factors contributing to these trends can be seen in Chart 3.

- **Space heating efficiency gains** contributed almost half of the residential load loss. In 1997, the average furnace efficiency was estimated to be around 74 percent AFUE, since some furnaces sold before federal regulations set the minimum gas space heating efficiency at 78 percent were still operating. During the study period, some of these less efficient furnaces have been replaced, and by 2001 the current weighted average gas space heating appliance efficiency for all units in place is estimated at roughly 77 percent.

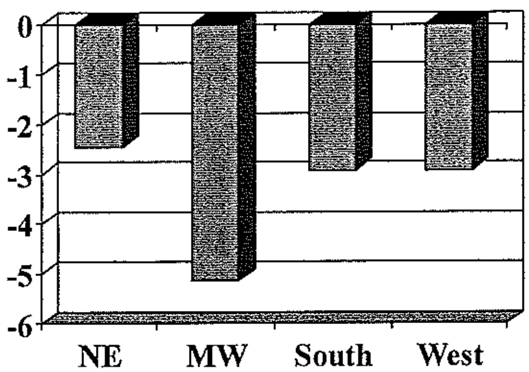
- **Water heating efficiency gains** contributed about 13 percent of the average residential load loss. Federal water heater standards took effect in 1990, setting the minimum gas water heater energy factor (EF) at 0.54, compared to the then-typical 0.5 EF. In addition, consumers are purchasing units with EF ratings higher than 0.54. The 1997 weighted average gas water heating EF is estimated to be slightly less than 0.53, compared to 0.55 in 2001.

Chart 3

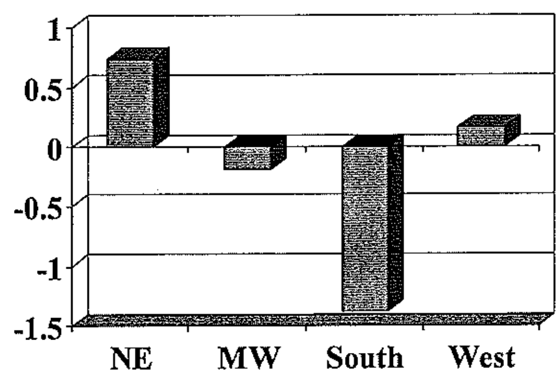
Regional Impact of Major Factors

(Change in Mcf/year per residential customer, 1997 - 2001)

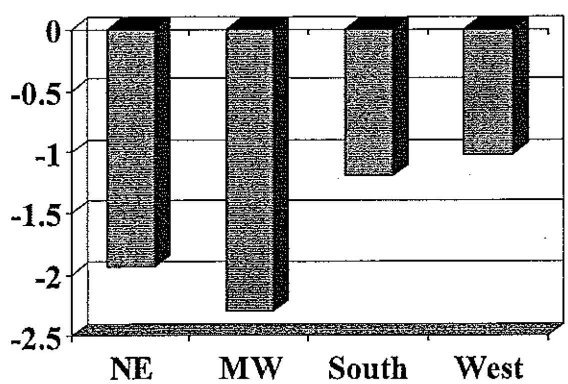
Appliance Efficiency



Appliance Saturation



Housing Characteristics



Note: Contributing factors are calculated independently and may not total to actual change

- **Space heating market share loss** accounted for about two percent of the overall decrease in gas use per residential customer. The proportion of homes with gas service increased since 1997, but the percentage of those gas homes with gas space heat declined slightly. Thus the relative heating base of gas utilities declined.

    - The market share loss in the Midwest and South was two to nine times as great as the national average. In the Northeast and West, however, there was an increase in space heating gas market share (see Chart 2).

- **Baseload appliance market share loss** accounted for about four percent of the residential load loss experienced from 1997-2001. Overall, the number of gas appliances per customer has declined. The market share loss for water heaters, cooking appliances, clothes dryers was relatively small, while gas light market share losses were somewhat higher.

- **Improved home energy efficiency** was responsible for about 29 percent of the decline. Newer homes with improved thermal envelope characteristics, as well as older homes adding insulation and storm windows/doors, reduced the typical amount of gas needed for space heating.

- **Demographic changes** contributed about six percent of the decline in typical residential gas use. Population shifts of gas customers to warmer climates since 1997 accounted for this decline when viewed from a national perspective. Previously quantified factors such as average number of people per residence and number of households setting back their thermostats at night did not change over the study period.

III. Purpose and Data Limitations

This report attempts to provide a broad-based identification and quantification of factors that impacted the average annual natural gas use per residential customer from 1997 to 2001. Most natural gas distribution utilities experienced a slower growth rate in residential demand compared to the growth rate in the number of residential customers during that time period. This trend makes it more difficult for gas companies to achieve expected revenues and to connect new customers economically. This analysis is intended to help companies understand the driving forces behind the declining use trend by updating the previous study.

The results herein estimate the overall impacts of several contributing factors based on national and regional data. Analysis of utility-specific factors could result in conclusions different from those in this report. Individual companies should use this report as a guide in calculating their specific impacts, and they should include factors and influences pertinent to their systems that may not be considered and/or quantified here.

These contributing factors were examined separately. Some of them may have synergistic properties that compound or offset impacts when considered together. The quantification of these factors is not an attempt to determine absolute values for each influence, but rather to indicate the proportional impact that they have on residential use per customer.

Much of the data used in this analysis come from government and AGA surveys. While this information is the best available for national and regional analysis, survey sampling, structure, and/or extrapolation techniques can be flawed, particularly when ascribing results to smaller populations such as states and jurisdictions.

IV. Overview

A previous AGA analysis calculated that normalized use per residential customer declined 16 percent from 1980 to 1997. Since that time, several gas distribution companies have noted a continuation of this trend, with a number of utilities experiencing higher than expected levels of conservation. This analysis updates the previous report, examining the 1997-2001 time frame.

This analysis shows that residential customers are continuing their efforts to reduce natural gas consumption. On a national average basis, natural gas use per residential customer dropped 6.4 percent from 1997 to 2001, from 89.2 Mcf/year to 83.5 Mcf/year. On a regional basis, these impacts varied. For the Northeast, the average gas use per customer decreased about three percent. Residential gas use per customer dropped eight percent for the Midwest, six percent for the South, and four percent for the West.

Table 1
Trends in Residential Natural Gas Use
(Weather Normalized Mcf/Customer/Year)

	1997	2001	Change, 1997-2001
United States	89.2	83.5	-6.4
Northeast	97.1	94.3	-2.9
Midwest	116.4	107.0	-8.1
South	70.2	66.8	-6.2
West	68.3	65.0	-4.2

Residential gas use can be classified as space heating and non-heating. On average, space heating demand accounts for three-quarters of typical gas consumption by residential customers. This demand is very weather sensitive, with use per customer higher in the colder climates than in the warmer regions.

Residential non-heating use of gas is also known as baseload use. This use is typically not very weather sensitive. The primary residential baseload use is for water heating, which accounts for about 86 percent of non-heating demand, based on national averages. The other two primary residential gas appliances are cooking equipment and clothes dryers. Natural gas logs/fireplaces are increasing their market share, and can be used for heating or decorative purposes. Appliances that could also be considered baseload, but have a much lower market penetration, are gas lights, pool heaters, and grills.

V. Contributing Factors

Appliance Efficiency

In response to the energy disruptions of the 1970s, Congress passed the Energy Policy and Conservation Act (EPCA) of 1975. EPCA established an energy conservation program for major household appliances including furnaces, water heaters, refrigerators and freezers, central air conditioners and central air conditioning heat pumps, room air conditioners, dishwashers, clothes washers, clothes dryers, direct heating equipment, pool heaters, kitchen ranges and ovens, fluorescent lamp ballasts, and television sets. The Energy Policy and Conservation Act (EPACT) of 1978 expanded the coverage of EPCA to include commercial building heating and air conditioning equipment, water heaters, certain incandescent and fluorescent lamps, distribution transformers, and electric motors. In 1987, the National Appliance Energy Conservation Act (NAECA), which also incorporates EPCA and EPACT, authorizes the U. S. Department of Energy (DOE) to set energy efficiency standards for major home appliances according to a statutory time schedule stretching into the next century.

DOE's Office of Codes and Standards sets the minimum efficiency ratings of many residential appliances. DOE has set standards for such natural gas appliances as space heaters, water heaters, ovens, and ranges.

Furnaces

During the 1970's natural gas furnaces averaged about 65 percent annual fuel utilization efficiency (AFUE). As interest in more energy efficient appliances increased, the average AFUE for new furnaces increased. DOE, through authority granted by NAECA, set 78 percent AFUE as a minimum for gas furnaces manufactured after January 1, 1992. Furnaces with AFUE ratings up to the mid-90's are available to consumers, and the average AFUE of new residential furnace shipments is currently in the mid-eighties. As the higher efficiency furnaces have worked their way into the residential market in new homes and replacement units, the average AFUE for all residential natural gas furnaces has increased from 65 percent in 1980 to 74 percent in 1997, and to 77 percent by 2001.

Table 2
Residential Natural Gas Furnace Average AFUE
(Percent)

	1980	1997	2001
New Furnace Shipments	66%	85%	86%
All Furnaces In Place	65%	74%	77%

Source for shipment information: Gas Appliance Manufacturers Association

Improvement in overall furnace efficiency caused gas space heating use per customer to fall four percent. However, the impact in terms of sales volume varied by region due to the weather differences. Overall, use per residential customer dropped about 2.7 thousand cubic feet (Mcf) per year from 1997 to 2001, with regional impacts ranging from 1.7 Mcf in the Northeast to 4.3 Mcf in the Midwest, due to the improved furnace efficiency.

Table 3
Impact of Gas Space Heating Efficiency Gains on Use per Customer
(Weather-normalized Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer
	1997	**2001**
United States	61.2	2.7
Northeast	69.8	1.7
Midwest	87.2	4.3
South	44.5	2.2
West	39.1	2.2

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance
Note: Assumes national average furnace efficiency for all regions.

Water Heaters

DOE set the minimum efficiency of natural gas water heater at 0.54 energy factor (EF) for units manufactured after 1989. Starting in 2004, the minimum efficiency will rise to 0.59 EF. Previously, water heaters averaged about 0.5 EF. Industry analysts estimated that the availability of even higher efficiency units raised the average EF of new units sold to 0.57 by the 2001. Based on shipment data and typical retirement rates, the average EF of water heaters went from 0.53 in 1997 to 0.55 in 2001.

Table 4
Residential Natural Gas Water Heater Average EF
(Percent)

	1980	**1997**	**2001**
New Water Heater Shipments	50%	53%	57%
All Water Heaters In Place	50%	53%	55%

Since the average water heater EF improved slightly less than four percent from 1997, the typical consumption by residential customers that have water heaters declined in the same proportion. The average decline was 0.8 Mcf per customer, with regions not varying much from that average.

Table 5
Impact of Gas Water Heating Efficiency Gains on Use per Customer
(Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer
	1997	**2001**
United States	23.9	0.8
Northeast	22.3	0.7
Midwest	25.6	0.8
South	23.5	0.8
West	23.3	0.8

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Appliance Saturation

The most common natural gas appliances found in homes are space heaters, water heaters, cooking equipment, clothes dryers, and, to a lesser extent, outdoor lights. All of these applications face competition from other energy forms, particularly electricity. Since 1997 the average number of gas appliances found in homes has dropped. This trend, discussed below, contributes to the decline in gas use per residential customer.

Space Heaters

The percentage of gas customers that use natural gas as their main space heating fuel declined by 0.2 percentage points over the four year period. Regionally, the Northeast and West regions saw an increase in this market penetration among its customers. The Midwest loss mirrored the national average. The South region exhibited significant declines in the proportion of their customers that use gas for their main space heating fuel. A primary contributing factor to this decline is the increasing popularity of the heat pump during this time. Not only did heat pumps make significant inroads into new construction (particularly in multi-family housing), electric utilities encouraged existing gas customers to add on heat pumps and use their gas furnaces as back-up systems.

Table 6
Natural Gas Space Heating Appliance Market Penetration
(Percent of all gas customers)

	1997	**2001**
United States	84.4%	84.2%
Northeast	71.7%	72.8%
Midwest	93.8%	93.5%
South	83.9%	81.5%
West	84.1%	85.0%

Source: American Housing Survey, Bureau of the Census, various years

Since the overall change for gas space heating market penetration was not substantial, it caused a decrease in heating use of less than one percent for the average U.S. gas customer. This was also true for the typical Midwest gas customer. The Northeast gas utilities experienced a gain of more than 1.1 percent in heating use per customer due to increased market penetration for space heating. The West region experienced increasing space heating demand per customer of one percent due to the increase in market penetration. The South region's use per customer decreased 2.5 percent due to reduced space heating penetration.

Table 7
Impact of Gas Space Heating Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Space Heating Use per Customer	Change in Weighted Average Space Heating Use per Customer
	1997	**2001**
United States	61.2	-0.1
Northeast	69.8	+0.8
Midwest	87.2	-0.2
South	44.5	-1.1
West	39.1	+0.4

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Water Heaters

Water heaters contribute significantly to a utility's load profile. Demand by these appliances is relatively non-weather sensitive, allowing for optimal utilization of utility investment. Also, these appliances can use as much gas as a furnace in some regions. Therefore, any loss in market penetration or improvements in efficiency will impact noticeably on average use per customer.

In most areas, market penetration of gas water heaters changed marginally between 1997 and 2001. Overall, penetration declined slightly. Regionally, the Northeast's, South's and West's market penetration decreased, with the Midwest increasing somewhat.

Table 8
Natural Gas Water Heater Market Penetration
(Percent of all gas customers)

	1997	**2001**
United States	84.2%	84.0%
Northeast	77.9%	77.8%
Midwest	86.2%	86.6%
South	79.0%	78.3%
West	91.9%	91.2%

Source; American Housing Survey, Bureau of the Census, various years

When the proportion of gas customers with gas water heaters declines, the weighted average gas use per customer declines. For example, the national average penetration of water heaters fell 0.2 percentage points from 1997 to 2001, resulting in a decline in overall gas use per customer of 0.05 Mcf/year. The South and West regions' losses averaged about 0.16 Mcf/year, while the Northeast region loss was minor, 0.02 Mcf/year. Conversely, a slight increase in penetration in the Midwest led to a 0.1 Mcf/year increase.

Table 9
Impact of Gas Water Heater Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Water Heating Use per Customer	Change in Weighted Average Water Heating Use per Customer
	1997	**2001**
United States	22.7	-0.05
Northeast	19.9	-0.02
Midwest	22.2	+0.10
South	20.4	-0.17
West	23.7	-0.16

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Cooking

The percentage of gas customers that cook with gas declined in all regions but the West, due to electric products dominating the new home market, even those homes with gas service, as well as replacing old gas units. Nationally, cooking market penetration for gas customers fell 2.6 percent, with the Northeast falling 1.3 percent, the Midwest 5.0 percent, and the South 4.0 percent. The West increased slightly.

Table 10
Natural Gas Cooking Appliance Market Penetration
(Percent of all gas customers)

	1997	2001
United States	58.6%	57.1%
Northeast	77.2%	76.2%
Midwest	52.4%	49.8%
South	53.0%	50.9%
West	56.6%	56.8%

Source: American Housing Survey, Bureau of the Census, various years

Despite the significance of the decline for gas cooking penetration, the resulting impact is relatively small. This is due to the smaller proportion of gas customers with this appliance combined with the modest annual energy consumption from these units. For all regions, the change amounted to less than 0.11 Mcf annually.

Table 11
Impact of Gas Cooking Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Cooking Use per Customer	Change in Weighted Average Cooking Use per Customer
	1997	**2001**
United States	2.5	-0.06
Northeast	3.2	-0.04
Midwest	2.2	-0.11
South	2.2	-0.09
West	2.4	+0.01

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Clothes Dryers

Penetration of gas dryers increased slightly in all regions but the South (four percent decline) from 1997 to 2001, ranging from one percent in the Northeast to six percent in the West.

Table 12
Natural Gas Clothes Dryer Market Penetration
(Percent of all gas customers)

	1997	**2001**
United States	27.0%	27.5%
Northeast	29.4%	29.7%
Midwest	32.6%	33.4%
South	16.0%	15.4%
West	29.0%	30.7%

Source: American Housing Survey, Bureau of the Census, various years

These changes in penetration for gas clothes dryers resulted in marginal changes in typical use per customer, less than one-tenth Mcf in the regions.

Table 13
Impact of Gas Drying Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Drying Use per Customer	Change in Weighted Average Drying Use per Customer
	1997	**2001**
United States	1.1	+0.02
Northeast	1.3	+0.01
Midwest	1.3	+0.03
South	0.7	-0.03
West	1.3	+0.07

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Outdoor Gas Lights

Natural gas lights were somewhat popular with customers the through mid-1970s. During the turmoil in the energy markets in the late-70s, President Carter encouraged people to turn their gas lights off or convert them to electricity. Since that time, their market share for gas customers fell significantly. The decline continued from 1997 (1.5 percent market penetration among gas customers) through 2001 (0.8 percent). Assuming typical gas light usage of 19 Mcf per year, the decline in market share caused the weighted average gas use per residential customer to decline about one-tenth Mcf per year on a national average. No data were available for regional comparisons.

<u>Housing Characteristics</u>

Thermal Efficiency

Homes across the country have become more energy efficient due, in part, to the improved thermal efficiency of the building envelope. New homes, which must meet local regulations implemented over the last two decades regarding thermal efficiency, account for most of this improvement. In addition, many homeowners have retrofitted older residences in order to cut their energy bills.

According to estimates from the U. S. Department of Energy's Energy Information Administration,[2] the average residential building was three percent more efficient in 2001 compared to the 1997 average. This improvement in thermal efficiency reduced the heating demand from the residential sector. Overall, typical consumption decreased by about 1.6 Mcf nationally. Regionally, the decrease in weighted average gas use per customer ranged from about one Mcf in the West to more than two Mcf in the West.

Table 14
Impact of Improving Home Thermal Efficiency on Gas Demand
(Decrease in Mcf per Residential Customer per Year)

United States	1.63
Northeast	1.94
Midwest	2.30
South	1.20
West	1.02

<u>Other</u>

Geographic Population Shifts

From 1997 to 2001, population growth, and subsequently gas customer growth, was greater in the warmer regions (South and West) than in the colder regions (Northeast and Midwest). About 51 percent of the residential gas customers were in the warmer Southern and Western sections of the country in 1997, compared to 52 percent

[2] <u>Annual Energy Outlook</u>, Energy Information Administration, various years.

in 2001. With more of the households in warmer climates, the average heating demand, on a national basis, declined. This larger percentage of gas customers in warmer climates resulted in overall use per gas customer falling about 0.33 Mcf on a national basis. This factor does not impact typical regional use per gas customer.

Table 15
Regional Natural Gas Customer Population Trends
(Percent of all gas customers)

	1997	2001
United States	100.0%	100.0%
Northeast	19.2%	18.9%
Midwest	29.7%	28.9%
South	26.9%	28.0%
West	24.2%	24.3%

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Other Factors

Several factors did not change substantially between 1997 and 2001, and therefore should not have measurably impacted use per customer. The table below shows national factors for such items as thermostat settings for each of the years.

Table 16
Natural Gas Customer Characteristics

	1997	2001
Age of Home	33.1 years	34.6 years
Age of Furnace	13.8 years	13.6 years
Avg. Winter Day Temp	70.2 degrees	70.2 degrees
Avg. Winter Night Temp	67.8 degrees	68.0 degrees
Setback Temp Day	45% do	49% do
Setback Temp Night	47% do	47% do
Avg. Persons per Home	2.64	2.61

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Other Factors Not Quantified

Other factors could have an impact on residential natural gas use, but were not quantified here, primarily due to lack of data. For the most part, these should have impacts less than most of those factors listed above. Some of these factors include:

Water Conservation – Low flow showerheads and increasingly efficient dishwashers and washing machines have decreased the amount of hot water needed per residence.
Economic Influences – Changes in the price of natural gas and in the general economic condition of the general population influence consumption.
Environmental Regulations – Restrictions on certain combustion practices, such as wood fireplaces, may impact consumer purchases of gas products.

Gas Hearth Products – Gas fireplace/logs have become more popular over the past few years, but it is not clear whether these units actually add to load. Some units could displace gas furnace requirements.
Unoccupied/Seasonal Homes – The rise in second home ownership combined with increasing vacancy rates for rental homes could reduce overall use per customer.

VI. National & Regional Summaries

Table 17 summarizes the factors contributing to the decline in use per residential customer. The sum of the estimated factors closely approximates the observed decline for the United States. Regional comparisons do not provide as close a fit. Keep in mind that this report provides a broad-based assessment to the factors contributing to the decline in order to provide an understanding of the relative impact from each of these factors. This report does not attempt to provide precise measures of these factors due to limitations in the data.

Table 17
Summary of Factor Quantification and Comparison to Actual Decline
(Change in use per residential customer, 1997-2001 Mcf/year)

	U.S	NE	MW	South	West
Space Heating Efficiency	-2.68	-1.74	-4.31	-2.17	-2.17
Baseload Appliance Efficiency	-0.77	-0.71	-0.82	-0.75	-0.75
Space Heating Market Penetration	-0.12	+0.79	-0.22	-1.09	+0.38
Baseload Appliance Market Penetration	-0.22	-0.05	+0.03	-0.29	-0.08
Thermal Efficiency Gains	-1.63	-1.94	-2.30	-1.20	-1.02
Population Trends	-0.33	N/A	N/A	N/A	N/A
Total	-5.75	-3.65	-7.62	-5.50	-3.64
Actual Change	-5.71	-2.83	-9.39	-4.40	-2.86
Difference**	-0.04	-0.82	1.77	-1.10	-0.78

*** Can be due to a variety of factors, including data error, omission of other factors, and imprecise methodology*

VII. Methodology

<u>Normalized Use Per Customer</u>

- Calculate actual use per residential customer from EIA data[3]
- Determine heating portion of use based on AGA survey data[4]
- Determine weather normalization factor by dividing the 30-year (1961-1990) normal heating degree days into the actual degree days, based on NOAA data[5]

[3] <u>Natural Gas Annual</u>, various years, Energy Information Administration, U.S. Department of Energy, Washington, DC.
[4] <u>Residential Natural Gas Market Survey</u>, various years, American Gas Association, Washington, DC.
[5] <u>State, Regional, and National Monthly and Seasonal Heating Degree Days</u>, various years, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, Washington, DC.

- Divide heating portion by weather normalization factor, and add back in non-heating load

Average Space Heating AFUE

- Assume 65% AFUE as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas space heating customers from current year's, based on trend analysis of EIA RECS data[6]
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data[7]
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace AFUE for all existing units based on average AFUE of shipments as provided by GAMA

Space Heating Efficiency Impact

- Calculate average use per customer by multiplying the normalized heating load by the percent of gas customers with gas space heating (based on EIA RECS data)
- Calculate change in average furnace AFUE by dividing 1997 AFUE value into the selected year's AFUE value
- Calculate the efficiency-adjusted demand by dividing the 1997 average use per customer by the change in average furnace AFUE for the selected year
- Subtract the efficiency-adjusted demand from the 1997 average use per customer to determine impact

Average Water Heating EF

- Assume 0.50 EF as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas water heating customers from current year's, based on trend analysis of EIA RECS data
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace EF for all existing units based on average EF of shipments estimated at 0.54 EF to 0.56 EF

Water Heating Efficiency Impact

- Calculate average use per customer by multiplying the water heating load (based on AGA survey data) by the percent of gas customers with gas water heating (based on EIA RECS data)
- Calculate change in average EF by dividing 1997 EF value into the selected year's EF value
- Calculate the efficiency-adjusted demand by dividing the 1997 average use per customer by the change in average water heater EF for the selected year
- Subtract the efficiency-adjusted demand from the 1997 average use per customer to determine impact

[6] RECS: Housing Characteristics, various years, Energy Information Administration, U. S. Department of Energy, Washington, DC.
[7] GAMA News, various years, Gas Appliance Manufacturers Association, Arlington, VA.

Appliance Market Penetration Impact

- Calculate appliance penetration by dividing the number of residences with gas service by the number of customers with that appliance, based on EIA RECS data
- Subtract the impact year penetration from the 1997 penetration to determine the change in market penetration
- Calculate the weighted average gas use per customer for that appliance by multiplying the penetration value times the typical gas use for that appliance
- Multiply the change in market penetration by the 1997 weighted average use of that appliance to determine the reduction in weighted average use per customer for that appliance

Thermal Efficiency Impact

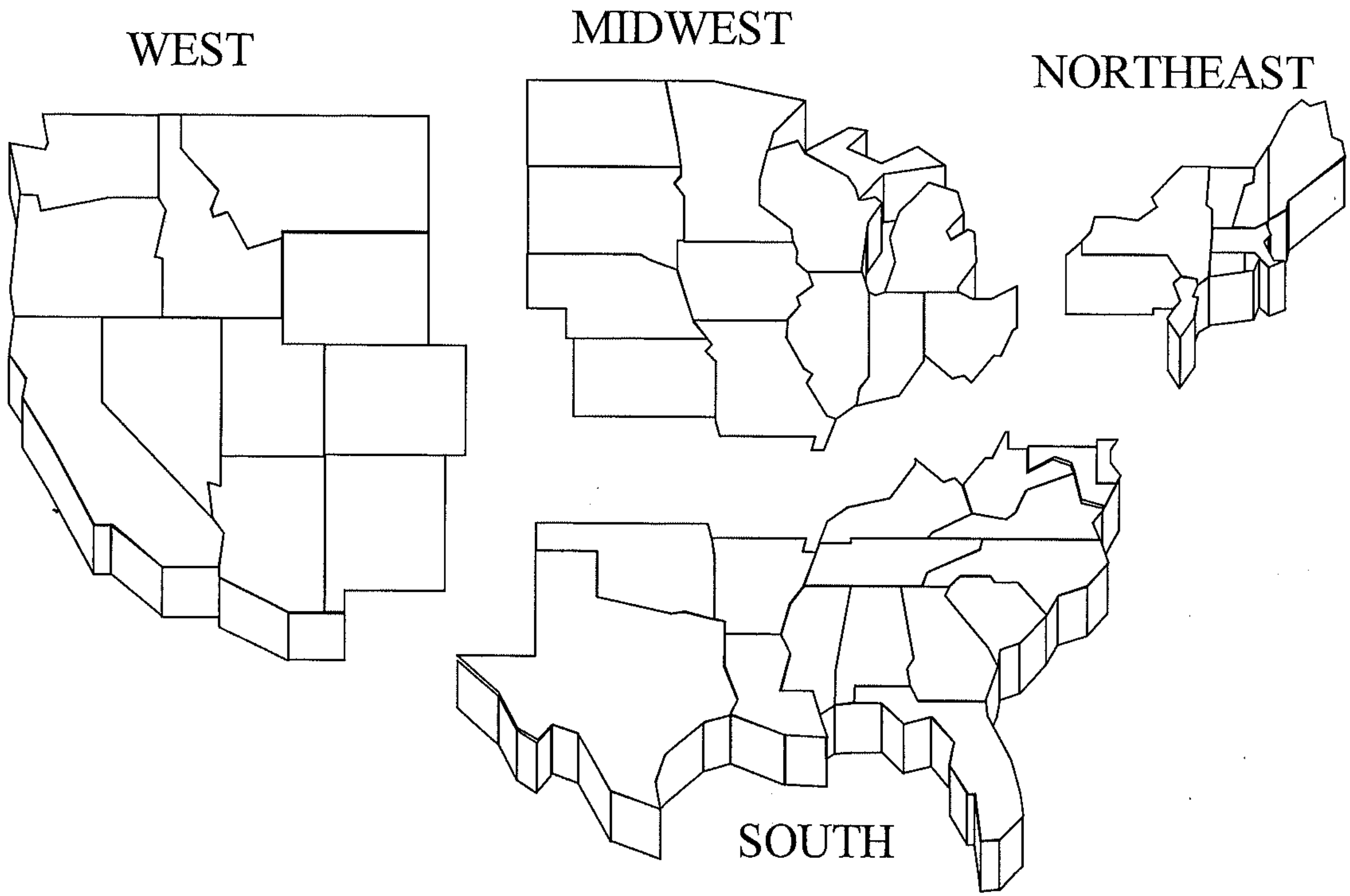
- Obtain an estimate of average percent increase thermal home efficiency enhancements from current and past EIA forecasts[8]
- Multiply the thermal efficiency percent increase by the percent difference in heating load and by the percent of gas homes with gas space heating to determine the thermal efficiency impacts

Population Shift Impact

- Determine the percent of gas customers by region for 1997 and 2001 from EIA RECS data
- Determine the normalized heating demand for those regions in 1997 based on AGA survey data
- Apply those same regional demand figures to the 2001 regional population distribution, calculate the weighted average national numbers for both, and compare the two numbers

[8] *Annual Energy Outlook*, various years, Energy Information Administration, Washington, DC.

Appendix
US Census Regions



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I, Nancy A. Haley, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

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Northern States Power Company d/b/a Xcel Energy

Miscellaneous Gas Service List

3-1-2007

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