division of energy resources
Minnesota Department of Commerce

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August 29, 2013 **PUBLIC DOCUMENT**

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-13-663

Dear Dr. Haar:

Attached are the **PUBLIC** *Comments* of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Petition of Northern States Power Company (Xcel or Company) for Approval of Changes in Contract Demand Entitlements.

The petition was filed on August 1, 2013. The petitioner on behalf of Xcel is:

Paul J. Lehman
Manager, Regulatory Compliance and Filings
Xcel Energy
414 Nicollet Mall - 7th Floor
Minneapolis, MN 55401

The Department recommends that the Commission:

- approve Xcel's proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2013 supplemental filing;
- allow Xcel to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2013 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2013; and
- Approve changes in the jurisdictional allocation of demand costs.

The Department recommends that Xcel fully explain, in its *Reply Comments*:

- whether the customer count figure for the 2012-2013 heating season presented in the current filing is correct;
- whether the Company has considered the use of a daily, regression based, design-day analysis and, if so, why it decided to maintain its current method of analysis. If Xcel has not considered the use of a daily analysis, the Company should provide a discussion of whether a daily analysis is feasible, and reasonable, to use for its gas system; and
- whether Xcel believes the current peak-day definition (coldest temperature in the past 20 years) is appropriate or whether maintaining the 1995-1996 heating season event as the planning objective, on a going-forward basis, is more appropriate.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ ADAM J. HEINEN
Rates Analyst
651-539-1825

AJH/jl
Attachment

division of energy resources
Minnesota Department of Commerce

PUBLIC DOCUMENT

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G002/M-13-663

I. SUMMARY OF XCEL'S REQUEST

Northern States Power Company (Xcel or Company) filed a demand-entitlement petition (*Petition*) on August 1, 2013, with the Minnesota Public Utilities Commission (Commission). The Company requested Commission approval to place the Purchased Gas Adjustment (PGA) changes into effect on November 1, 2013. The Company stated that, in the event that the Commission does not act by November 1, 2013, the Company, pursuant to Minnesota Statute § 216B.16, Subd. 7, Minnesota Rule 7825.2920, and Xcel's PGA tariffs, will provisionally place the PGA changes into effect on November 1, 2013, subject to later Commission approval.

In its *Petition*, Xcel requested approval from the Commission to implement its proposed interstate pipeline transportation, storage entitlements, and other demand-related contracts for 2013-2014 effective November 1, 2013. The Company requested that the adjustments be made through the PGA to reflect changes in its firm pipeline demand entitlement levels[1] as follows:

- increase its Minnesota jurisdictional design-day capacity by 4,776 dekatherms per day (Dth/day), about 0.68 percent (4,776 Dth/706,935 Dth);
- change the capacity resources used to meet the design-day requirement and increase the amount of capacity resources (total entitlements) for Minnesota by 4,078 Dth/day or 0.55 percent (4,078 Dth/745,247 Dth);

[1] The entitlement levels discussed in Xcel's filing are for the total Minnesota Company which encompasses the combined entitlements for Xcel's Minnesota and North Dakota jurisdictions. Minnesota's portion of the entitlements is the total combined entitlements times the Minnesota allocation factor discussed below. The Department has included Department Attachment 2, which shows the effect of the demand entitlement changes in the Minnesota jurisdiction.

- with these minor changes in Minnesota's need and resources, the reserve margin decreases slightly from 6.1 percent to 6.0 percent for Minnesota;
- slightly decease the Jurisdictional Allocations to Minnesota (rather than North Dakota) to reflect usage patterns; and
- change its recovery of Supply Reservation fees.

Specifically, Xcel requested the following changes in demand volumes for the total Minnesota Company as shown in Table 1.

Table 1: Proposed Changes in Entitlement for Minnesota Company

Type of Entitlement	Proposed Dth Change	Rate	Months	Proposed Cost Change
NNG TFX (Nov - Mar)	4,839	$15.1530	5	$366,626.84
NNG TFX (Nov - Mar)	(4,603)	$15.1530	5	($348,746.30)
NNG TFX (Apr - Oct)	4,839	$5.6830	7	$192,500.26
NNG TFX (Apr - Oct)	(4,603)	$5.6830	7	($183,111.94)
NNG TFX (Jan – Dec)	2,078	$3.8000	12	$94,756.80
NNG TFX (Nov – Mar)	1,498	$8.6272	5	$64,617.73
NNG TFX (Apr – Oct)	1,498	$4.0000	7	$41,944.00
VGT FTA (Dec - Feb)	14,287	$4.8871	3	$209,465.99
VGT FTA (Dec – Feb)	(14,287)	$4.8871	3	($209,465.99)
VGT FTA (Dec – Feb)	5,713	$3.7671	3	$64,564.33
GLGT FT (Nov - Mar)[2]	6,706	$9.4560	5	$317,059.68
ANR FTS (Jan - Dec)	(4,895)	$4.1700	7	($142,885.05)
ANR FTS (Jan - Dec)	4,855	$4.1600	7	$141,377.60
ANR FSS (Jan - Dec)	17	$2.0400	12	$416.16
ANR FSS (Jan - Dec)	88	$0.4000	12	$421.60
Total for Change in Pipeline Entitlement				$609,541.70

As indicated in the table above, Xcel proposed a number of changes in its demand entitlements that would increase costs from all source systems by approximately $610,000. This amount is for Minnesota and North Dakota customers. As discussed further below, the increases are related to various reliability needs across the Xcel service territory.

The Company proposed to increase its net supply entitlements from Northern Natural Gas (NNG or Northern) and Viking Gas Transmission Company (VGT).[3] The net change is an increase of 5,713 Dth/day for the total Minnesota Company but only 4,078 Dth/day for the Minnesota

[2] The Company stated in its last demand entitlement filing, Docket No. G002/M-12-862, that it intended to procure 15,266 Dth/day of entitlements on Great Lakes Transmission Company (GLGT). This contract was ultimately not executed and substituted with a supplier reservation contract.

[3] There is the addition of a backhaul contract for GLGT, but this is not included in this discussion because the contract does not increase design-day deliverability.

jurisdiction. There is a small decrease in the reserve margin - from 6.1 percent to 6.0 percent – due to an increase in the estimated design-day consumption, and a larger increase in capacity associated with Minnesota than is associated with North Dakota.

Xcel also requested approval to recover certain Producer Demand and Storage costs from both firm and interruptible customers in the Company's monthly PGA, effective with the November 1, 2013 billings. In addition, the Company stated, in its *Petition*, that it supports the Department's recommendation made in Docket No. G999/AA-12-756 that all balancing service costs be recovered in the commodity portion of the PGA. Regarding balancing services, Xcel stated that the effects on interruptible customer of balancing services are analogous to Producer Demand and Storage costs and that the Department's recommended methodology is simpler from an accounting standpoint than the Company's current methodology. The Producer Demand and Storage costs proposal is a carryover of a plan first presented in the Company's 2007-2008 demand-entitlement filing, Docket No. G002/M-07-1395 (2007-2008 Demand Entitlement) and again in Xcel's subsequent demand entitlement filings (Docket Nos. G002/M-08-1315, G002/M-09-1287, and G002/M-10-1163). The Commission has not yet acted on these filings or the balancing service proposal discussed in Docket No. G999/AA-12-756.

Xcel also provided a summary of hedging transactions in place for the 2013-2014 heating season in response to reporting requirements established in the Commission's May 27, 2008 *Order* in Docket No. G002/M-08-46. Xcel has not entered into hedging transactions for the 2013-2014 heating season because the Company's variance to use financial instrument expired on June 30, 2012. Xcel filed a petition to extend this variance on May 25, 2012 and the petition was subsequently approved by the Commission on August 22, 2013. With approval by the Commission happening subsequent to Xcel filing its *Petition*, the Department recommends that the Company provide, in its November 1, 2013 supplemental filing, an update on any hedging transactions that are entered into for the 2013-2014 heating season.

II. DEPARTMENT'S ANALYSIS OF XCEL'S REQUEST

The Department's analysis of the Company's request includes a description and an evaluation of the Company's demand-entitlement petition. The Department discusses each part of the Company's request below.

A. XCEL'S PROPOSED DESIGN-DAY LEVELS

1. Xcel's Customer Base

There were no significant changes (*e.g.,* new communities) to Xcel's service areas between the 2012-2013 heating season and the 2013-2014 heating season. Xcel expects an increase of 2,363 firm customers in the Minnesota jurisdiction between these two periods (from 439,210 to 441,573). The Department notes that the customer count figure from the 2012-2013 heating season is the same as the projected figure referenced in the Company's last demand entitlement filing. This suggests that the Company's customer forecast was perfect in last year's demand entitlement filing. The Department recommends that Xcel fully explain, in its *Reply Comments*, if the customer count figure for the 2012-2013 heating season presented in the current filing is correct.

2. Xcel's Forecast

Consistent with its approach since its 2004-2005 demand-entitlement filing, the Company used two forecast methodologies in its estimate of its design-day requirement forecast for the 2013-2014 heating season: the Actual Peak Use per Customer Design Day (UPC DD) and the Average Monthly Design Day (Avg. Monthly DD). The Department assesses the foundations of the methodologies below.

a. Actual Peak Use per Customer Design Day (UPC DD)

The UPC DD method employs a use-per-customer number of 1.57393 Dth/day to estimate the design-day demand forecast, based on the actual use per customer on Thursday, January 29, 2004, the coldest day in recent years. Xcel multiplied the 1.57393/Dth/day value by estimates of total firm customers in all of Xcel's service areas and added the contracted billing demand for Small and Large Demand Billed customers to arrive at the total expected design-day demand for the Xcel system. Thus, the way customers are distributed among service areas does not affect the aggregate forecasts produced by the UPC DD method because the total number of customers and the resulting total volume is unchanged no matter where the customers are assigned.

If either cold temperatures or differences with the Avg. Monthly DD method indicate that the 1.57393 Dth/day peak-day use-per-customer volume is out of date, the Company stated that it will adjust the volume accordingly.

b. Average Monthly Design Day

The Avg. Monthly DD method is a statistical method that uses slope analysis to estimate design-day demand. Xcel performs a separate slope analysis on each demand area for both residential and commercial customers.[4] These separate demand areas have their own specific usage characteristics based on the input data; as such, the coefficients used to estimate use per customer vary from service area to service area. Consequently, the shifting of customers among demand areas can affect the aggregate forecasts produced by the Avg. Monthly DD method. The Company's service areas were unchanged from the 2012-2013 heating season to the 2013-2014 heating season; therefore, any changes in the aggregate forecast numbers using the Avg. Monthly

[4] Xcel has 15 separate demand areas. The demand areas that the Company conducts separate analyses on are as follows: Metro, Brainerd, Mainline, Mainline—Welcome, Willmar, Paynesville, VGT-Chisago, Watkins, Tomah, Red Wing, Grand Forks MN, Fargo MN, Grand Forks ND, Fargo ND, and WBI ND.

DD method are related to typical growth dynamics and data turnover (Xcel uses the 60 most recent months of data in its analysis), and not the make-up of customers in a given demand area.

c. Average Monthly Design-Day Reliability

Xcel Energy used 60 months of data, or the five years covering January 2008-December 2012, as inputs for the Avg. Monthly DD method. The 2011-2012 analysis was the first since the Company made the structural changes where the Company had 60 data points available in five calendar years. In last year's demand entitlement filing, Xcel stated that it had investigated using 72 months of data, January 2006 to December 2011, but the regression statistics (*e.g.,* R-squared values) associated with these analyses were not as robust as the 60-month analysis. It does not appear that the Company investigated a 72-month analysis in this proceeding. However, the Department notes that, in recent years, the general long-term trend in natural-gas usage per customer has been downward. All else being equal, the preference in regression analysis is to have more data points than fewer because using more data points diminishes the impacts of outlier data points and cyclical weather changes on the results. However, when a probable downward trend in consumption exists, adding 12 data points that are six years old carries the risk of including data that is out of date. Whatever gain in statistical accuracy associated with adding these older data points for the outlier and weather reasons is likely more than offset by the loss caused by using data from a year when per-customer usage is not likely representative of current usage characteristics. Moreover, 60 data points is a large enough sample to address the problems that outliers and weather cause. Therefore, the Department concludes that Xcel's decision to use 60 data points in this analysis is reasonable.

The Company summarizes its output statistics for each of its demand areas in Attachment 1, Schedule 1, of its *Petition*. The R-squared values for its various statistical models are generally greater than 0.90, which suggests that a high level of the predictive quality of the model is included in the input data for the specified variables. There are four models that have R-squared values less than 0.90. These lower predictive models are generally associated with models that have a smaller number of customers. This result is not surprising, or necessarily a concern, because a smaller number of customers will inherently increase data variability because changes in consumption by a single customer, or group of customers, will have a much greater impact on total consumption than an estimation group that has a large number of customers.

The statistics presented by the Company in its *Petition* suggests that the Avg. Monthly DD method produces acceptable forecasts. However, after reviewing the Company's analytical approach, the Department is unsure if the method employed by Xcel represents the best option available. The method used by Xcel estimates peak-day consumption by calculating the slope on monthly average usage per degree day over the 60 month period from January 2008 to December 2012. The potential issue with this approach is twofold. First, the method assumes that natural gas consumption is constant at all temperatures; in other words, the Company's approach assumes that a change in temperature from 1 HDD to 2 HDD (*i.e.,* 59°F to 58°F) is the same as when it is 79 HDD to 80 HDD (*i.e.,* -14°F to -15°F). When looking at this assumption at face value, it does not appear likely that natural gas consumption characteristics are similar at different temperature levels.

Second, as noted by the Company, the method Xcel used is an average monthly design day, which means that, based on a given temperature, the average demand area consumption would be a certain amount during a given month. Under many instances, this method is not unreasonable; however, the goal of a design-day analysis is to determine consumption on a peak day. On a peak day, the individual consumption characteristics for each ratepayer is likely to be above average, so the average monthly calculation may not be appropriate. This conclusion is supported by the fact that the results of Xcel's UPC DD method, which is based on an actual high consumption event, generally resulted in higher forecasted requirements for design days than the Avg. Monthly DD method.

There are various different ways to estimate usage on a peak day. The Department notes that most Minnesota gas utilities determine peak-day consumption using regression models based on daily consumption data. The use of daily data increases the amount of data available, and the granularity of the analysis, but it also requires estimation of daily interruptible load because interstate pipelines do not meter consumption data at the class level. In terms of Xcel's analysis, the use of an average monthly method reduces the level of specificity in the data on a day-to-day basis, but it does remove the issue of having to estimate interruptible usage because monthly interruptible consumption is readily available at the local distribution company (LDC) level.

Given the fact that Xcel uses a dual method approach, the Department does not believe that Xcel's Avg. Monthly DD method is unreasonable, and the Department agrees with Xcel that the Company should continue to use the two methods to develop its design-day estimate, updating the UPC DD method when appropriate. The Department does, however, recommend that Xcel provide a discussion in *Reply Comments* stating whether the Company has considered the use of a daily, regression based, design-day analysis and, if so, why it decided to maintain its current analysis. If Xcel has not considered the use of a daily analysis, the Company should provide a discussion of whether a daily analysis is feasible, and reasonable, to use for its gas system.

The Department further notes that a Commission-prescribed peak day has generally been interpreted as the coldest 24-hour average temperature in the past 20 years. Generally speaking, these events occurred during the 1995-1996 heating season; as such, the 20-year anniversary of the coldest day for most Minnesota natural gas utilities is approaching. In the time since the 1995-1996 heating season, there has not been a cold weather event that has equaled what occurred during that heating season. Therefore, based on the Commission peak-day definition, the design-day planning target for the natural gas utilities will change, and become less stringent, in the near future. Minnesota ratepayers will benefit from a less stringent planning objective through lower demand costs; however, if a cold weather event similar to the 1995-1996 heating season were to occur in the future, under different planning requirements, reliability could be at risk. The Department recommends that Xcel provide a detailed discussion, in its *Reply Comments*, explaining whether it believes the current peak-day definition (coldest temperature in the past 20 years) is appropriate or whether maintaining the 1995-1996 heating season event as the planning objective, on a going-forward basis, is more appropriate.

3. Xcel's Forecasts

Xcel projected that its system (Minnesota and North Dakota) design-day requirement will increase by 6,474 Dth/day to 794,772 Dth/day in the 2013-2014 heating season, or a 0.8 percent increase. The Company's forecast of its Minnesota design-day requirement is 706,935 Dth/day, an increase of 4,776 Dth/day, or an increase of 0.7 percent. In addition, the forecasted North Dakota usage for 2013-2014 is 87,837 Dth/day, up 1,698 Dth/day, or 2.0 percent from 2012-2013.

Xcel's customer forecast shows the number of Minnesota customers increasing by 2,359 from 439,087 in the 2012-2013 forecast to 441,446 in the 2013-2014 forecast, an increase of approximately 0.5 percent. The North Dakota customer count is forecasted to increase by 2.6 percent to 50,006 in 2013-2014, up from 48,750 in 2012-2013.

The Department notes that the smaller rate of increase in forecasted Minnesota gas consumption indicates that the proportion of design-day responsibility on the Xcel system continues to shift from Minnesota to North Dakota. According to the *Petition*, the consumption allocator for Minnesota for the 2013-2014 heating season is 88.95 percent, down from 89.07 percent during the 2012-2013 heating season. The higher overall economic growth rates in North Dakota, relative to Minnesota, has been on-going and has led to incremental decreases in the allocator factor over the past few years; as such, these small changes in apportionment year-to-year are not significant.

The Department concludes from the Company's descriptions of its forecasting techniques that Xcel's forecasting of design-day levels are performed appropriately.

B. PROPOSED CHANGES IN XCEL ENERGY'S DESIGN-DAY RESOURCES

Xcel's filing proposed changes in the resources used to meet its design-day customer requirements. Overall, the Company's system firm supply entitlements, which include entitlements for Minnesota and North Dakota, rose slightly, from 836,698 Dth/day to 842,411 Dth/day, or 0.7 percent.

The majority of Xcel's firm pipeline transportation contracts are with Northern. Most of these contracts were put in place in 2007 and run through October 2017. The Company makes three changes to its Northern entitlements for its 2013-2014 heating season that serve peak demand. The first change relates to an increase in capacity of 236 Dth/day for delivery to the Brainerd Town-Border Station (TBS) in response to incremental growth to meet firm demand and to maintain a 5 percent reserve margin. The second change relates to an increase in capacity of 2,078 Dth/day for delivery in the Hugo, MN area. While reviewing historical peak throughput in the Hugo area, the Company stated that it observed that peak use at the Forest Lake #1A TBS and Stacy #1 TBS would have been short compared to the historical peak day on January 15, 2009. The third change relates to an increase in capacity of 1,498 Dth/day for delivery into the Saint Cloud area. Xcel stated that an analysis in March 2012 suggested that this area would be short by 881 Dth/day if peak-day conditions occur and entitlements levels from the 2012-2013 heating season are maintained.

The Company also proposed two adjustments to demand entitlements to serve peak demand on its VGT pipeline. The first relates to the addition of 5,713 Dth/day in forward capacity to serve the Fargo, ND area. This contract is needed to serve firm need on a peak day in that demand area. Xcel also proposed to decrease its contract for delivery at Chisago, MN by 3,812 Dth/day. The Company did not provide an explanation for why they made this adjustment.

When these entitlement changes are added together, they result in an increase in peak-day entitlements of 5,713 Dth/day, which corresponds to the entitlement figures presented in Xcel's *Petition*. The Department has analyzed the above changes in design-day entitlement resources and each change appears reasonable to serve firm customers on a peak day. The Department, therefore, concludes that the changes for 2013-2014 demand entitlements are reasonable.

C. CHANGE IN XCEL'S RESERVE MARGIN

Xcel's proposed design-day reserve margin in Minnesota is 6.0 percent for 2013-2014, which is slightly less than the 6.1 percent figure in 2012-2013 (DOC Attachment 1). Xcel stated that it bases its reserve margin on the firm resources necessary to meet projected firm customer demand plus the capability of either the largest pump at its Wescott facility used to vaporize liquefied natural gas (LNG) or either of its St. Paul metro propane-air peak-shaving plants. The capacity decision reflects Xcel's assessment of the most economical method of adding capacity to meet demand beyond the forecasted design-day demand. The reserve margin balances protecting against the loss of a firm gas-supply source and actual consumer demand under design-day conditions, with the likelihood of experiencing design-day conditions. Xcel stated that its proposed reserve margin in Minnesota of 47,639 Dth/day is appropriate to meet its design-day needs. The Company further stated that the most economical method of adding capacity often involves adding increments that do not precisely match expected changes in demand. Xcel's proposed reserve margin is within the 5-7 percent range that serves as a rule of thumb in deciding whether a given margin is reasonable. The Department, therefore, concludes that the 2013-2014 reserve margin is reasonable.

D. CHANGES IN XCEL'S SUPPLIER RESERVATION FEES

Xcel stated that its Supplier Reservation fees have changed. The proposed decrease is **[TRADE SECRET DATA HAS BEEN EXCISED].** The new total expense level reflects these changes. Therefore, the Department concludes that Xcel's proposal is reasonable.

E. XCEL'S PGA COST RECOVERY PROPOSAL

Xcel proposed to reflect the costs associated with the demand entitlements in the *Petition* in the PGA effective November 1, 2013. The demand entitlements in Xcel **Trade Secret** Attachment 2, Schedule 1, Page 1 of 2, represent the demand entitlements for which the Company's firm customers will pay. Department Attachment 2 compares the July 2013 PGA costs to the anticipated November 2013 PGA costs for the several customer classes. The resulting per Dth cost changes related strictly to changes in demand costs have the following annual rate effects:[5]

- Annual demand cost decrease of $0.0003/Dth, or approximately $0.03 annually per year, for the average Residential customer consuming 87 Dth annually;
- Annual demand cost decrease of $0.0003/Dth, or approximately $0.09 annually , for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand cost decrease of $0.0004/Dth, or approximately $0.59 annually, for the average Large Commercial customer consuming 1,463 Dth annually; and
- No change in annual demand costs for the average Small Interruptible, Medium Interruptible, and Large Interruptible customers. These customer classes are not allocated demand costs under the current cost allocation plan.

Based on its review, the Department concludes that the Company's proposal appears to be reasonable. The Department is aware that minor changes in cost and entitlement levels may occur between the filing of these *Comments* and November 1, 2013. As such, the Department recommends that the Company provide a supplemental filing on November 1, 2013 detailing final demand entitlement levels and costs.

III. CONCLUSIONS AND RECOMMENDATIONS

The Department recommends that the Commission:

- approve Xcel's proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2013 supplemental filing; and
- allow Xcel to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2013 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2013; and
- Approve changes in the jurisdictional allocation for demand costs.

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[5] These demand cost changes do not include the proposed shift in costs to the interruptible classes as originally proposed in Docket No. G002/M-07-1395.

The Department also recommends that Xcel fully explain, in its *Reply Comments*:

- whether the customer count figure for the 2012-2013 heating season presented in the current filing is correct;
- whether the Company has considered the use of a daily, regression based, design-day analysis and, if so, why it decided to maintain its current analysis. If Xcel has not considered the use of a daily analysis, the Company should provide a discussion of whether a daily analysis is feasible, and reasonable, to use for its gas system; and
- whether Xcel believes the current peak-day definition (coldest temperature in the past 20 years) is appropriate or whether maintaining the 1995-1996 heating season event as the planning objective, on a going-forward basis, is more appropriate.

The Department also recommends that the Company provide, in its November 1, 2013 supplemental filing, an update on any hedging transactions that are entered into for the 2013-2014 heating season.

/jl

Northern States Power Company d/b/a Xcel Energy

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
Heating Season	(1) Number of Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Dth)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Design-Day Capacity (Dth)	(8) Change from Previous Year	(9) % Change From Previous Year	(10) Reserve Margin	(11) % of Reserve [(7)-(4)]/(4)
2013-2014**	441,573	2,363	0.54%	706,935	4,776	0.68%	749,325	4,078	0.55%	42,390	6.00%
2012-2013**	439,210	155	0.04%	702,159	(135)	-0.02%	745,247	153	0.02%	43,088	6.14%
2011-2012**	439,055	2,461	0.56%	702,294	2,683	0.38%	745,094	1,313	0.18%	42,800	6.09%
2010-2011**	436,594	2,896	0.67%	699,611	5,124	0.74%	743,781	(4,486)	-0.60%	44,170	6.31%
2009-2010**	433,698	4,846	1.13%	694,487	9,482	1.38%	748,267	15,976	2.18%	53,780	7.74%
2008-2009**	428,852	(2,651)	-0.61%	685,005	1,288	0.19%	732,291	10,785	1.49%	47,286	6.90%
2007-2008**	431,503	7,088	1.67%	683,717	5,984	0.88%	721,506	25,249	3.63%	37,789	5.53%
2006-2007	424,415	2,845	0.67%	677,733	6,887	1.03%	696,257	4,568	0.66%	18,524	2.73%
2005-2006	421,570	10,584	2.58%	670,846	21,191	3.26%	691,689	16,569	2.45%	20,843	3.11%
2004-2005	410,986	9,353	2.33%	649,655	46,187	7.65%	675,120	31,805	4.94%	25,465	3.92%
2003-2004	401,633	5,826	1.47%	603,468	(4,388)	-0.72%	643,315	1,040	0.16%	39,847	6.60%
2002-2003	395,807			607,856			642,275			34,419	5.66%
Average:			1.00%			1.41%			1.42%		5.56%

	Firm Peak-Day Sendout						
Heating Season	(12) Firm Peak-Day Sendout (Dth)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess per Customer [(7) - (4)]/(1)	(16) Design Day per Customer (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18) Peak-Day Send per Customer (12)/(1)
2013-2014**	NA			0.0981	1.6009	1.6969	NA
2012-2013**	661134	1,871	0.28%	0.0981	1.5987	1.6968	1.5015
2011-2012**	659,263	(16,314)	-2.41%	0.0975	1.5996	1.6970	1.5015
2010-2011	675,577	84,646	14.32%	0.1012	1.6024	1.7036	1.5474
2009-2010	590,931	(10,494)	-1.74%	0.1240	1.6013	1.7253	1.3625
2008-2009	601,425	15,551	2.65%	0.1103	1.5973	1.7076	1.4024
2007-2008	585,874	16,911	2.97%	0.0876	1.5845	1.6721	1.3578
2006-2007	568,963	31,303	5.82%	0.0436	1.5969	1.6405	1.3406
2005-2006	537,660	286	0.05%	0.0494	1.5913	1.6407	1.2754
2004-2005	537,374	(23,876)	-4.25%	0.0620	1.5807	1.6427	1.3075
2003-2004	561,250	26,865	5.03%	0.0992	1.5025	1.6017	1.3974
2002-2003	534,385			0.0870	1.5357	1.6227	1.3501
Average			2.27%	0.0882	1.5827	1.6706	1.3949

*-Some numbers may differ from Xcel Attachments due to rounding
**-Reflects the UPC DD method.

Prepared by the Minnesota Department of Commerce, Division of Energy Resources

Docket No. G002/M-13-663
Demand Entitlement--PGA Cost Recovery Analysis
DOC Attachment 2

Residential	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/13)	Nov 2013 PGAs with Proposed Demand Entitlement Changes	Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.5042	$7.0824	$3.8046	$3.8046	$3.8046	-30.88%	-46.28%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.9008	$1.0716	$0.9350	$0.9347	$0.9218	3.76%	-12.78%	-0.03%	($0.0003)
Distribution Margin	$1.8591	$1.6263	$1.8591	$1.8591	$1.8591	0.00%	14.32%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$9.7803	$6.5987	$6.5984	$6.5855	-20.16%	-32.53%	0.00%	($0.0003)
Average Annual Usage (Dk)	87	87	87	87	87				
Average Annual Total Cost	$718.60	$850.43	$573.78	$573.76	$572.64	-20.16%	-32.53%	0.00%	($0.03)
Average Annual Total Demand Cost of Gas	$78.33	$93.18	$81.30	$81.28	$80.15			**Current Allocation**	**($0.03)**
								Demand Costs to Non-Firm	**($1.15)**

Small Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/13)	Nov 2013 PGAs with Proposed Demand Entitlement Changes	Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$3.8046	$3.8046	$3.8046	-30.66%	-46.28%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8984	$1.0873	$0.9326	$0.9323	$0.9193	3.77%	-14.26%	-0.03%	($0.0003)
Distribution Margin	$1.2331	$1.1366	$1.2331	$1.2331	$1.2331	0.00%	8.49%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$9.3063	$5.9703	$5.9700	$5.9570	-21.64%	-35.85%	-0.01%	($0.0003)
Average Annual Usage (Dk)	284	284	284	284	284				
Average Annual Total Cost	$2,163.87	$2,643.22	$1,695.72	$1,695.63	$1,691.94	-21.64%	-35.85%	-0.01%	($0.09)
Average Annual Total Demand Cost of Gas	$255.17	$308.82	$264.88	$264.80	$261.10			**Current Allocation**	**($0.09)**
								Demand Costs to Non-Firm	**($3.78)**

Large Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/13)	Nov 2013 PGAs with Proposed Demand Entitlement Changes	Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$3.8046	$3.8046	$3.8046	-30.66%	-46.28%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8917	$1.0569	$0.9259	$0.9255	$0.9128	3.79%	-12.43%	-0.04%	($0.0004)
Distribution Margin	$1.2315	$1.1324	$1.2315	$1.2315	$1.2315	0.00%	8.75%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$9.2717	$5.9620	$5.9616	$5.9489	-21.66%	-35.70%	-0.01%	($0.0004)
Average Annual Usage (Dk)	1,463	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$13,561.15	$8,720.27	$8,719.69	$8,701.11	-21.66%	-35.70%	-0.01%	($0.59)
Average Annual Total Demand Cost of Gas	$1,304.24	$1,545.86	$1,354.26	$1,353.67	$1,335.10			**Current Allocation**	**($0.59)**
								Demand Costs to Non-Firm	**($19.16)**

Small Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/13)	Nov 2013 PGAs with Proposed Demand Entitlement Changes	Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4926	$7.0824	$3.8046	$3.8046	$3.8046	-30.73%	-46.28%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0707	NA	NA	NA	$0.0000
Distribution Margin	$0.9635	$0.8675	$0.9635	$0.9635	$0.9635	0.00%	11.07%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$7.9499	$4.7681	$4.7681	$4.7681	-26.15%	-40.02%	0.00%	$0.0000
Average Annual Usage (Dk)	8,114	8,114	8,114	8,114	8,114				
Average Annual Total Cost	$52,384.66	$64,504.92	$38,688.35	$38,688.35	$38,688.35	-26.15%	-40.02%	0.00%	$0.00
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$573.65			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$573.65**

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Medium Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/13)	Nov 2013 PGAs with Proposed Demand Entitlement Changes	Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.4696	$7.0824	$3.8046	$3.8046	$3.8046	-30.44%	-46.28%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0547	NA	NA	NA	$0.0000
Distribution Margin	$0.4751	$0.3900	$0.4751	$0.4751	$0.4751	0.00%	21.83%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$7.4724	$4.2797	$4.2797	$4.3344	-28.01%	-42.73%	0.00%	$0.0000
Average Annual Usage (Dk)	60,791	60,791	60,791	60,791	60,791				
Average Annual Total Cost	$361,383.73	$454,252.47	$260,167.20	$260,167.20	$263,492.45	-28.01%	-42.73%	0.00%	$0.00
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$3,325.25			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$3,325.25**

Large Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	July PGA (7/1/13)	Nov 2013 PGAs with Proposed Demand Entitlement Changes	Nov 2013 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From July PGA	Change ($) From July PGA
Commodity Cost of Gas (WACOG)	$5.5501	$7.0824	$3.8046	$3.8046	$3.8046	-31.45%	-46.28%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0575	NA	NA	NA	$0.0000
Distribution Margin	$0.4346	$0.3565	$0.4346	$0.4346	$0.4346	0.00%	21.91%	0.00%	$0.0000
Total per Dth Cost	$5.9847	$7.4389	$4.2392	$4.2392	$4.2967	-29.17%	-43.01%	0.00%	$0.0000
Average Annual Usage (Dk)	839,818	839,818	839,818	839,818	839,818				
Average Annual Total Cost	$5,026,031.87	$6,247,319.98	$3,560,163.64	$3,560,163.64	$3,608,453.16	-29.17%	-43.01%	0.00%	$0.00
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$48,289.52			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$48,289.52**

(1) Does not include demand smoothing
(2) WACOG held constant to isolate price changes related solely to demand changes.

Current Allocation Summary Change from most recent PGA Customer Class	Commodity Change (\$/Dk)	Commodity Change (Percent)	Demand Change (\$/Dk)	Demand Change (Percent)	Demand Annual Change (\$/Dk)	Total Annual Change (\$/Dk)	Total Annual Change (Percent)
Residential	$0.0000	0.00%	-$0.0003	-0.03%	($0.03)	($0.03)	0.00%
Small Commercial	$0.0000	0.00%	-$0.0003	-0.03%	($0.09)	($0.09)	-0.01%
Large Commercial	$0.0000	0.00%	-$0.0004	-0.04%	($0.59)	($0.59)	-0.01%
Small Interruptible	$0.0000	0.00%	$0.0000	NA	$0.00	$0.00	0.00%
Medium Interruptible	$0.0000	0.00%	$0.0000	NA	$0.00	$0.00	0.00%
Large Interruptible	$0.0000	0.00%	$0.0000	NA	$0.00	$0.00	0.00%

Demand Costs to Non-Firm Summary Change from most recent PGA Customer Class	Commodity Change (\$/Dk)	Commodity Change (Percent)	Demand Change (\$/Dk)	Demand Change (Percent)	Demand Annual Change (\$/Dk)	Total Annual Change (\$/Dk)	Total Annual Change (Percent)
Residential	$0.0000	0.00%	-$0.0132	-1.41%	($1.15)	($1.15)	-0.20%
Small Commercial	$0.0000	0.00%	-$0.0133	-1.43%	($3.78)	($3.78)	-0.22%
Large Commercial	$0.0000	0.00%	-$0.0131	-1.43%	($19.16)	($19.16)	-0.22%
Small Interruptible	$0.0000	0.00%	$0.0707	NA	$573.65	$573.65	0.00%
Medium Interruptible	$0.0000	0.00%	$0.0547	NA	$3,325.25	$3,325.25	1.28%
Large Interruptible	$0.0000	0.00%	$0.0575	NA	$48,289.52	$48,289.52	1.36%

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. G002/M-13-663

Dated this **30th** day of **August, 2013**

/s/Sharon Ferguson

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