division of energy resources
Minnesota Department of Commerce

85 7th Place East, Suite 500, St. Paul, MN 55101-2198
main: 651.296.4026
tty: 651.296.2860
fax: 651.297.7891
www.energy.mn.gov

January 10, 2012

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

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G011/M-11-1083

Dear Dr. Haar:

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

> A request by Minnesota Energy Resources Corporation-PNG (MERC or the Company) for approval by the Minnesota Public Utilities Commission (Commission) of a change in demand entitlement for its Viking Gas Transmission System Purchased Gas Adjustment (PGA) effective November 1, 2011.

The filing was submitted on November 1, 2011. The petitioner is:

> Gregory J. Walters
> Minnesota Energy Resources Corporation
> 3460 Technology Drive NW
> Rochester, MN 55901

Based on its investigation, the Department recommends that the Commission:

- **accept** the peak day analysis;
- **accept** the Company's proposed level of demand entitlement;
- **allow** the proposed recovery of associated demand costs effective November 1, 2011 as allocated in column B of Table 1 in the attached comments; and
- **request that** MERC file its annual demand entitlement filing on, or about, August 1st of each year, on a going-forward basis.

The Department also requests that MERC provide in its reply comments a response to Interstate's proposed procedure for demand entitlement filings.

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

Sincerely,

LERMA LA PLANTE
Financial Analyst

LL/sm
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

DOCKET NO. G011/M-11-1083

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Minnesota Energy Resources Corporation-PNG (MERC-PNG, MERC or Company) filed a change in demand entitlement petition (*Petition)* on November 1, 2011 for its Viking Gas Transmission (VGT or Viking) Purchased Gas Adjustment (PGA) system. In its *Petition*, MERC requests that the Minnesota Public Utilities Commission (Commission) accept the following changes in the Company's overall level of contracted capacity.

The Company's Proposed Total Entitlement Changes	
Type of Entitlement	Proposed Changes: increase (decrease) (Dkt)[1]
FT-A 12 months	(979)
FT-A 3 months	(678)
FT-A 5 months	1,148
Wadena Delivered Option	(1,098)
Sum of Increase	1,148
Sum of Decrease	(2,755)
Total Entitlement Net Change	**(1,607)**

The Company's proposal would decrease the Company's proposed design-day (winter) capacity by 1,607 Dekatherms (Dkt). In addition, the Company's proposal would decrease MERC's proposed design-day requirements by 441 Dkt per day.

The Department discusses the various effects on the Company's rates for different customer classes below, but notes that MERC-PNG's proposal would decrease demand rates for General Service customers (which include residential customers) by $0.0864 Dkt or approximately

[1] Dekatherms (Dkt).

$7.08[2] per year for customers using 82 Mcf. The Company requested that the Commission allow recovery of the associated demand costs in its monthly PGA effective November 1, 2011.

MERC included an attachment showing the rate impacts resulting from moving cost recovery of storage contracts from the demand cost recovery portion of the monthly PGA to the commodity portion.[3] On this attachment, MERC calculated that there would be a larger decrease in demand rates for the General Service Residential customer class when storage contract costs are included in the commodity portion of the PGA. Shifting storage costs to the commodity portion of the PGA would decrease the demand rates per year by $0.4499 per Dkt, or approximately $36.89, for General Service Residential customers using 82 Mcf.

II. THE DEPARTMENT'S ANALYSIS OF THE COMPANY'S PROPOSAL

The Department's analysis of the Company's request includes the following sections:

- the proposed overall demand entitlement level;
- the design-day requirement;
- the reserve margin;
- the PGA cost recovery proposal; and
- the Department's inquiries regarding annual demand entitlement filings.

A. THE COMPANY'S DEMAND ENTITLEMENT LEVEL

1. Proposed Overall Demand Entitlement Level

As indicated in Department's Attachment 1, the Company has proposed to decrease its total entitlement level in Dkt as follows:

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
8,723	7,110	(1,607)	-18.42%

The Department analyzes below the proposed changes, the proposed design day requirement, and proposed reserve margin. The Department concludes that the Company's proposed recovery of overall demand costs is reasonable.

2. Design-Day Requirement

MERC included, as part of its initial filing, significant discussion regarding its design-day calculation. The Department notes that the Company's design-day analysis is similar to the

[2] MERC Attachment 4, Page 1 of 4.
[3] MERC Attachment 4, Page 3 of 4.

process that it has used in prior demand entitlement filings. MERC explored the use of additional weather variables in its review of other design-day regression models but did not use the variables in the Company's final design-day analysis. The Department does not oppose MERC's evaluation of other weather determinants in its efforts to produce the most robust design-day estimates possible; however, the Department notes that some of these additional data were taken from a proprietary source (DOC Attachment 3). When a utility uses proprietary data in its analysis, the Department cannot fully verify that the results of the analysis are correct.

3. Reserve Margin

As indicated in the Department's Attachment 1, the reserve margin is as follows:

Total Entitlement (Dkt)	**Design-day Estimate (Dkt)**	**Difference (Dkt)**	**Reserve Margin[4] %**	**% Change From Previous Year**
7,116	6,851	265	3.87%	-15.75%

The proposed reserve margin of 3.87 percent is significantly less than the 19.62 percent 2010-2011 reserve margin. However, the Department conducted an historical analysis of actual daily usage, adjusted for firm use and peak-day conditions, and concludes that MERC's current design-day analysis, and accompanying reserve margin, ensure sufficient capacity on an all-time peak day. The Department will continue to discuss the level of MERC's reserve margin with the Company.

B. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amounts listed in DOC Attachment 1 represent the demand entitlements for which the Company's firm customers would pay. In its Petition, the Company compared its October 2011 PGA to its November 2011 PGA as a means of highlighting its changes in demand costs (MERC Attachment 4, Page 1 of 4). The Company's demand entitlement proposal would result in the following annual demand cost impacts:

- Annual bill decrease of $7.08 related to demand costs, or approximately 9.8 percent, for the average General Service customer consuming 82 Dkt annually;[5] and
- There are no demand charge impacts related to MERC's other rate classes.

Table 1 below shows the changes in the average annual total cost of gas in the November PGA compared with the October PGA in two scenarios: Column A - storage costs included in the demand portion of the PGA, and Column B - storage costs included in commodity portion. It has been the Department's position since the Company's 2008-2009 demand entitlement filing (see Docket Numbers G011/M-08-1328 and G011/M-09-1285) that storage costs should be

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[4] As shown on Department Attachment 1, the Company's average reserve margin since 2001-2002 is 5.45%
[5] The bill impacts recommended by the Company do not take into account a shift in storage costs from the demand portion of the monthly PGA to the commodity portion of the monthly PGA.

included in the commodity portion of the PGA rather than the demand portion because all ratepayers benefit from storage gas. The Department continues to recommend that MERC include storage gas contract costs in the commodity portion of the PGA rather than the demand portion. Therefore, the Department recommends that the Commission approve the transactions that cause the increase in rates shown below, and adopt the allocation in column B.

Table 1: Changes in Average Annual Total Cost of Gas[6]– Storage Cost Treatment

Customer Class	(A) Storage Costs Included in Demand Charge[7]	(B) Storage Costs Included in Commodity Charge[8]
General Service Residential 82 Dkt Annual Use	$17.35	$12.40
General Service 3,859 Dkt Annual Use	$1,149.84	$2,319.66
Small Volume Firm/Interruptible 2,860 Dkt Annual Use	$852.18	$1,719.16
Large Volume Interruptible 89,334 Dkt Annual Use	$26,618.34	$53,699.02

C. DEPARTMENT INQUIRIES REGARDING ANNUAL DEMAND ENTITLEMENT FILINGS

The Department issued discovery to each regulated Minnesota gas utility requesting input regarding the annual demand entitlement filing timeline and the reasonableness of acquiring capacity contracts for the upcoming heating season in excess of the amount estimated by the design-day analysis. Utility responses to the Department's inquiry are discussed below.

1. Timeline

Based on the discovery responses, there is universal agreement that the demand entitlement filings could be filed in the summer rather than in the fall. In particular, the utilities stated that they could make their filings either on July 1st or August 1st of each year. The Department prefers the utilities' suggested earlier timeline because it would enable any reliability issues to be identified and possibly resolved prior to the start of the heating season. Minnesota Rule 7825.2910, subpart 2 states the following:

[6] Includes Commodity Cost of Gas (WACOG), Demand Cost and Commodity Margin.
[7] MERC Attachment 7, Page 1 of 2
[8] MERC Attachment 7, Page 2 of 2

Subp. 2. Filing upon change in demand.

Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another. A filing must contain:

A. a description of the factors contributing to the need for changing demand;
B. the utility's design-day demand by customer class and the change in design-day demand, if any, necessitating the demand revision;
C. a summary of the levels of winter versus summer usage for all customer classes; and
D. a description of design-day gas supply from all sources under the new level, allocation, or form of demand.

Although Minnesota Rule 7825.2910, subpart 2 does not specify a timeline for making the demand entitlement filing, the Department recommends that the Commission request MERC to file, on a going-forward basis, its annual demand entitlement filing by August 1.

On the topic of the demand entitlement filing timeline, Interstate's response to the Department's Information Request No. 1 (DOC Attachment 4) also discussed the possibility of making a follow-up demand entitlement filing on November 1st of each year, which would include final cost estimates and a discussion of any changes in entitlements since the summer filing. Interstate also stated that it envisions the focus of this second filing to be relatively narrow. The Department believes that there is merit to Interstate's proposal. A supplemental November 1 filing to a August 1 initial filing not only would allow the Department and the Commission to analyze the Company's proposed design day expeditiously, while ensuring that ratepayers are charged the most up-to-date costs, but also provide the most current levels of winter versus summer usage for all customer classes as required by Minnesota Rule 7825.2910, subpart 2.

2. Excess Capacity

The Department also requested that each utility provide a discussion regarding the level of capacity procurement as it relates to the demand entitlement filing. In particular, the Department requested that the utilities comment on the practice of acquiring capacity contracts in excess of the amount estimated by the design-day analysis for the upcoming heating season. The utilities generally stated that the nature of the interstate pipeline business requires these pipelines to sell capacity in larger blocks so that they are able to fully recover capital costs. The Department acknowledges this fact, but is concerned that local distribution companies do not, in general, provide design-day analyses for future heating seasons when requesting cost recovery of additional entitlements above the amount estimated for the upcoming heating season. The Department suggests that, if utilities want to include additional capacity above an adequate reserve margin calculated for the upcoming heating season, the utilities should provide information substantiating that these additional volumes will be necessary in future heating seasons and provide justification for recovering the corresponding costs from ratepayers in the current heating season, prior to the time when such capacity is needed.

III. THE DEPARTMENT'S RECOMMENDATIONS

Based on its investigation, the Department recommends that the Commission:

- accept the peak-day analysis;
- accept the Company's proposed level of demand entitlement;
- allow the proposed recovery of associated demand costs effective November 1, 2011 and as allocated in column B of Table 1 above; and
- request that MERC file, on a going-forward basis, its annual demand entitlement filing on, or about, August 1st of each year.

The Department also requests that MERC provide in its reply comments a response to Interstate's proposed procedure for demand entitlement filings.

/sm

Department Attachment 1
Docket No. G011/M-11-1083
Demand Entitlement Analysis--Minnesota Jurisdiction

C-PNG's Viking Area Demand Entitlement Analysis

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
eating ason*	(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 (7) - (4)	(11) % of Reserve [(7)-(4)]/(4)
2011-2012	4,672	(3)	-0.06%	6,851	(441)	-6.05%	7,116	(1,607)	-18.42%	265	3.87%
2010-2011	4,675	267	6.06%	7,292	401	5.82%	8,723	1,098	14.40%	1,431	19.62%
2009-2010	4,408	(227)	-4.90%	6,891	(529)	-7.13%	7,625	0	0.00%	734	10.65%
2008-2009	4,635	49	1.07%	7,420	(715)	-8.79%	7,625	(915)	-10.71%	205	2.76%
2007-2008	4,586	63	1.39%	8,135	23	0.28%	8,540	(324)	-3.66%	405	4.98%
2006-2007	4,523	62	1.39%	8,112	198	2.50%	8,864	778	9.62%	752	9.27%
2005-2006	4,461	(63)	-1.39%	7,914	316	4.16%	8,086	268	3.43%	172	2.17%
2004-2005	4,524	211	4.89%	7,598	175	2.36%	7,818	300	3.99%	220	2.90%
2003-2004	4,313	89	2.11%	7,423	340	4.80%	7,518	293	4.06%	95	1.28%
2002-2003	4,224	9	0.21%	7,083	286	4.21%	7,225	400	5.86%	142	2.00%
2001-2002	4,215	23	0.55%	6,797	93	1.39%	6,825	0	0.00%	28	0.41%
2000-2001	4,192			6,704			6,825				
Average:			1.03%			0.32%			0.78%		5.45%

	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)
2011-2012	unknown			0.0567	1.4664	1.5231	unknown
2010-2011	5,287	583	12.39%	0.3061	1.5598	1.8659	1.1309
2009-2010	4,704	(985)	-17.31%	0.1665	1.5633	1.7298	1.0672
2008-2009	5,689	(1,369)	-19.40%	0.0442	1.6009	1.6451	1.2274
2007-2008	7,058	143	2.07%	0.0883	1.7739	1.8622	1.5390
2006-2007	6,915	(849)	-10.94%	0.1663	1.7935	1.9598	1.5289
2005-2006	7,764	2,191	39.31%	0.0386	1.7740	1.8126	1.7404
2004-2005	5,573	(428)	-7.13%	0.0486	1.6795	1.7281	1.2319
2003-2004	6,001	85	1.44%	0.0220	1.7211	1.7431	1.3914
2002-2003	5,916	1,816	44.29%	0.0336	1.6768	1.7105	1.4006
2001-2002	4,100	(439)	-9.67%	0.0066	1.6126	1.6192	0.9727
2000-2001	4,539						
Average			3.51%	0.0971	1.6565	1.7454	1.3230

Prepared by theMinnesota Department of Commerce

Department Attachment 2
Docket No. G011/M-11-1083
Details of MERC -PNG's Demand Entitlements Historical and Current Proposal

2008-2009 Heating Season	Quantity (Mcf)	2009-2010 Heating Season	Quantity (Mcf)	2010-2011 Heating Season	Quantity (Mcf)	2009-2010 Heating Season	Quantity (Mcf)	Change in Quantity
FT-A 12 months	6,527	FT-A 12 months	6,527	FT-A 12 months	6,527	FT-A 12 months	5,548	(979)
FT-A 3 months	1,098	FT-A 3 months	1,098	FT-A 3 months	1,098	FT-A 3 months	420	(678)
FT-A (5 month backhaul)	0	FT-A (5 month backhaul)	0	FT-A 5 months	0	FT-A 5 months	1,148	1,148
NNG TF 12 mos (backhaul)	1,098	NNG TF 12 mos (backhaul)	1,098	FT-A (5 month backhaul)	0	FT-A (5 month backhaul)	0	0
TF12 (NNG)	172	TF12 (NNG)	432	NNG TF 12 mos (backhaul)	1,098	NNG TF 12 mos (backhaul)	0	(1,098)
TF5 (NNG)	389	TF5 (NNG)	105	TF12 (NNG)	0	TF12 (NNG)	0	0
TFX12 (NNG)	432	TFX12 (NNG)	389	TF5 (NNG)	0	TF5 (NNG)	0	0
TFX5 (NNG)	105	TFX5 (NNG)	172	TFX12 (NNG)	0	TFX12 (NNG)	0	0
FT-D 12 months	0	FT-D 12 months	0	TFX5 (NNG)	0	TFX5 (NNG)	0	0
				FT-D 12 months	0	FT-D 12 months	0	0
				Wadena Delivered Option	1,098	Wadena Delivered Option	0	(1,098)
Total Design Day Capacity	7,625	Total Design Day Capacity	7,625	Total Design Day Capacity	8,723	Total Design Day Capacity	7,116	(1,607)
Total Viking Transportation	7,625	Total Viking Transportation	7,625	Total Viking Transportation	8,723	Total Viking Transportation	7,116	(1,607)
Total Annual Transportation	7,131	Total Annual Transportation	7,348	Total Annual Transportation	7,625	Total Annual Transportation	5,548	(2,077)
Total Seasonal Transport	1,592	Total Seasonal Transport	1,375	Total Seasonal Transport	2,196	Total Seasonal Transport	1,568	(628)
Percent Seasonal on Viking	20.9%	Percent Seasonal on Viking	18.0%	Percent Seasonal on Viking	25.2%	Percent Seasonal on Viking	22.0%	-3.14%

MERC Winter 2011-2012 List of Potential Peak Day Explanatory Variables

Explanatory December through February Variables

"Day of" and "Prior Day" Weather Variables

AHDD55	Adjusted HDD with pivot point 55 formula:	=(MAX(0,HDD55))*((100+Windmph)/100)
AHDD60	Adjusted HDD with pivot point 60 formula:	=(MAX(0,HDD60))*((100+Windmph)/100)
AHDD65	Adjusted HDD with pivot point 65 formula:	=(MAX(0,HDD65))*((100+Windmph)/100)
HDD55	Traditional Heating Degree Day Pivot Point 55 formula:	=MAX(0,55-AvgTemp)
HDD60	Traditional Heating Degree Day Pivot Point 60 formula:	=MAX(0,60-AvgTemp)
HDD65	Traditional Heating Degree Day Pivot Point 65 formula:	=MAX(0,65-AvgTemp)
HDDW55	GasDay Wind Adjusted HDD pivot point 55 formula:	CONFIDENTIAL - Developed and marketed by Marquette University GasDay Lab.
HDDW60	GasDay Wind Adjusted HDD pivot point 60 formula:	CONFIDENTIAL - Developed and marketed by Marquette University GasDay Lab.
HDDW65	GasDay Wind Adjusted HDD pivot point 65 formula:	CONFIDENTIAL - Developed and marketed by Marquette University GasDay Lab.
MGUAdj55	HDD adjusted for effects of cloud cover and wind 55 formula	=MAX(0,(HDD55-(1-(Cloud/100))*10/3+(HDD55*Wind*0.01)))
MGUAdj60	HDD adjusted for effects of cloud cover and wind 60 formula	=MAX(0,(HDD60-(1-(Cloud/100))*10/3+(HDD60*Wind*0.01)))
MGUAdj65	HDD adjusted for effects of cloud cover and wind 65 formula	=MAX(0,(HDD65-(1-(Cloud/100))*10/3+(HDD65*Wind*0.01)))
WCHDD55	HDD based on Windchill at pivot point 55 formula:	=MAX(0,55-Windchill)
WCHDD60	HDD based on Windchill at pivot point 60 formula:	=MAX(0,60-Windchill)
WCHDD65	HDD based on Windchill at pivot point 65 formula:	=MAX(0,65-Windchill)

"Day of" Weather Variables: Based on 24 hour "Gas Day" average

Wind	Wind speed in miles per hour
Cloud Pct.	Percentage of cloud cover

Binary Indicator Variables

Daytype	Used to isolate the effects of weekends on customer demand. Causal basis is that industrials and some commercials run fewer hours or partial shifts Friday, Saturday, or Sunday.
Month	Adjust for the commercial and industrial practice of tending to be open more (or less) hours per day on average in December, January, or February.

Not Used in Regressions (but used in variable calculation)

Windchill	=IF(AveTemp<50,IF(Wind>3,(35.74+(0.6215*AveTemp)-(35.75*Wind^0.16)+(0.4275*AveTemp*Wind^0.16)),AveTemp),AveTemp)

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Response of
Interstate Power and Light Company
to
Minnesota Department of Commerce
Office of Energy Security
Information Request No. 1

Docket No.:	G001/M-11-1066
Date of Request:	November 22, 2011
Response Due:	December 2, 2011
Information Requested By:	Adam J. Heine, Michelle St. Pierre, Hwikwon Ham, Sachin Shah
Date Responded:	December 2, 2011
Author:	Jeff Hicken
Author's Title:	Mgr. Gas Trading and Dispatch
Author's Telephone No.:	(608) 458-3173
Subject:	Annual Demand Entitlement Filing
Reference:	DOC November 15, 2011 *Response Comments* in Docket Nos. G007/M-10-1166, G011/M-10-1167, and G011/M-10-1168, Pages 9 through 11

Information Request No. 1

In the above reference, the Department included a discussion related to the nature of the annual demand entitlement filings. As part of this discussion, the Department made several suggestions that it believes could improve the overall process regarding these filings. Based on this reference, please provide the following:

- a full response to the Department's proposal that the demand entitlement filing date be changed and a detailed explanation of when, on average, during the year the utility conducts its design-day analysis and subsequently procures demand entitlements for the upcoming heating season;
- a detailed discussion of how the utility determines whether additional capacity, beyond the amount calculated in the design-day analysis, is reasonable and should be recovered from firm customers during the current heating season; and
- a detailed discussion of whether the utility believes there is an effective mechanism to alleviate the issue of excess capacity during a given heating season, and the recovery of costs associated with these volumes, and whether the utility has discussed with the various interstate pipeline methods through which procured volumes can be phased in when they are needed rather than in advance of when the volumes are needed.

Response:

Demand Entitlement Filing

IPL agrees with the Department that it would be appropriate to change the timing of the demand entitlement filing. Moving the filing forward would provide more timely information since typically forecasts are completed in the early summer and capacity is settled with the pipeline well before November 1. IPL proposes that the demand entitlement filing be moved up to July 1 each year with a follow-up final filing due on November 1.

July 1 Filing

IPL typically collects actual daily winter demand information in late April after the March measurement data is available. This data is used by IPL's forecasting department to estimate a design day throughput which is usually completed in June, due to Iowa electric regulatory requirements in May. Gas supply then analyzes pipeline needs and sets a plan for adjustments. While IPL's contractual arrangements may not be fully completed by July 1, by that date it can typically file its expected plan. The July 1 filing will typically include the following information.

- Peak day firm forecast;
- Planned pipeline capacity levels costs;
- Expected reserve margin information; and
- Planned peaking supply volumes and expected costs.

November 1 Filing

On November 1, IPL can file its final plan. The November 1 filing would include the following information.

- Final pipeline capacity and cost information (for example, Northern Natural Gas Company (Northern) does not calculate the base/variable split on IPL's contract until late October so exact costs cannot be known in the November 1 filing);
- Actual peaking supply volumes and costs (IPL typically purchases peaking supply in August so the July 1 filing will only include an estimated cost); and
- Any other updated cost, reserve margin or capacity information.

IPL expects that the July 1 and November 1 filings will typically be very similar and will mainly focus on small changes in costs from the estimates made in the July 1 filing to the actual costs in the November 1 filing.

Additional/Reserve Capacity

IPL believes that it is important to hold approximately 5 percent reserve margin to ensure reliability for customers. While IPL does its best to forecast peak day needs, this is a difficult task for several reasons, so a reserve margin above the forecast is important.

Limited Data

IPL has only limited observations near design day conditions with which to validate the design day forecast. IPL's forecast is based on worst case weather conditions of 88 HDD's, but it is fairly rare to have data with weather colder than 75 HDD's. The winter of 2010-2011 provided for some data where the weather was moderately cold, but still no days colder than 75 HDD's and only 10 days which were colder than 65 HDD's. In addition, many of these days were on weekends when demand is typically lower.

Normal Variation

Customer use is not the same from day to day even with exactly the same weather. This means that some reserve is necessary to allow for this natural variation in demand. Attachment A is a scatter plot of actual total system load (firm plus interruptible without transportation demand) versus weather from November 1, 2010 to March 31, 2011. A linear regression line of the data is also shown on the plot which shows the expected demand at given weather conditions. The plot demonstrates how much daily variation there is both above and below the expected demand. A reserve margin helps ensure that this variation is covered. The plot also helps show how limited the data is near peak conditions as described above.

Interruptible Demand

Another firm peak day forecasting challenge is the lack of daily demand information for IPL's interruptible customers. IPL starts with total daily demand information from the pipelines (firm plus interruptible) and then must attempt to remove daily interruptible demand from the pipeline measurement information. However, IPL can only estimate daily interruptible demand based on monthly measurement data. As noted in IPL's November 1, 2011 demand entitlement filing, IPL believes it has improved its estimation method by incorporating weather impacts, but it is still only an estimate, so reserve margin is necessary to help allow for forecasting tolerance.

Please see IPL's November 1, 2011 demand entitlement filing for more information on IPL's current reserve margin and the actions IPL is currently taking due to a change in forecast methodology that is also described in that filing.

Growth and Pipeline Capacity Issues

Another important issue to consider for utilities is how to handle potential new customer needs. IPL views the 5 percent reserve margin as necessary mostly as a tolerance for forecasting accuracy and customer demand variation with little, if any, available for growth. In IPL's case, the typical 5 percent reserve is only about 650 decatherms and just one new customer could easily absorb any reserve that might be available for growth. Because of this, it can be reasonable to hold more than the typical 5 percent reserve.

Another important factor is the nature of the pipeline which serves a utility. IPL is served exclusively from Northern. Northern is constructed differently from most U.S. interstate pipelines. Northern, in some ways, resembles a distribution system with many small diameter branch pipeline segments. Because of this configuration, new capacity can be very expensive to construct to reach relatively small loads. Utilities need to be very careful about turning back capacity to Northern when contracts expire. Reacquiring the capacity later might be very expensive if the turn-back capacity has since been sold to other shippers. For this reason it can also be prudent to hold more than 5 percent reserve at times.

Overall IPL does think that a typical reserve of 5 percent is reasonable to balance the concerns of reliability, cost and growth, but there can easily be circumstances when temporary reserves beyond 5 percent are reasonable.

Phased in Capacity/Excess Capacity Costs

IPL's primary tool to alleviate the issue of excess capacity in a given heating season is to make temporary non-recallable capacity releases. Non-recallable releases have a higher value in the marketplace than non-recallable releases so they maximize savings to customers. Even non-recallable releases may not have enough value to recover all costs, but they are an effective mechanism to keep costs as low as possible. As described in IPL's November 1, 2011 demand entitlement filing, IPL is currently making some non-recallable releases.

To handle potential growth, IPL currently has an agreement in place with Northern that allows IPL to add up to 2,000 decatherms of capacity, at IPL option, every five years at tariff rates or rates capped in the agreement (whichever is lower). This agreement was reached in 2007 as part of a 15 year extension of much of IPL's Minnesota capacity. This agreement also set limits on future rate increases and fuel costs. From 2005 to 2007 IPL worked with the cities of Owatonna and Austin, Minnesota on a potential bypass of Northern using Northern Border pipeline. This agreement was the result of that work and it gives IPL a good method of phasing in new capacity if needed.

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
Comments

Docket No. G011/M-11-1083

Dated this **10th o**f **January, 2012**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_11-1083_11-1083
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_11-1083_11-1083
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_11-1083_11-1083
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_11-1083_11-1083
Daryll	Fuentes	N/A	USG	550 W. Adams Street Chicago, IL 60661	Paper Service	No	OFF_SL_11-1083_11-1083
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_11-1083_11-1083
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Paper Service	No	OFF_SL_11-1083_11-1083
Jack	Kegel		MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Paper Service	No	OFF_SL_11-1083_11-1083
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	OFF_SL_11-1083_11-1083
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_11-1083_11-1083

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_11-1083_11-1083
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_11-1083_11-1083
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_11-1083_11-1083
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Paper Service	No	OFF_SL_11-1083_11-1083