division of energy resources
Minnesota Department of Commerce

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January 3, 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-11-1082

Dear Dr. Haar:

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

> A request by Minnesota Energy Resources Corporation-PNG (MERC-PNG, MERC, or Company) for approval by the Minnesota Public Utilities Commission (Commission) of a change in demand rates on its Great Lakes Transmission (GLGT or Great Lakes) Purchased Gas Adjustment (PGA) system 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 DOC 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
- require MERC to file its annual demand entitlement filing by August 1 on a going-forward basis.

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

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

Sincerely,

/s/ MARK A. JOHNSON
Financial Analyst

MAJ/jl
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

DOCKET NO. G011/M-11-1082

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 Great Lakes Transmission (GLGT or Great Lakes) Purchased Gas Adjustment (PGA) system. In its *Petition*, MERC requested that the Minnesota Public Utilities Commission (Commission) accept the following changes in the Company's overall level of contracted capacity.

MERC-PNG's Proposed Total Entitlement Changes

Type of Entitlement	Proposed Changes increase (decrease) (Dkt)[1]
FT0016	(206)
FT0075	(1,973)
FT0155(12)	(1,036)
FT0155(5)	(100)
FT8466	(1,500)
FT15782	3,464
Total Entitlement Changes	(1,351)

The Company's proposal would decrease MERC-PNG's proposed total entitlement level (winter capacity) by 1,351 Dekatherms (Dkt). In addition, the Company's proposal would decrease MERC's proposed design-day requirement by 136 Dkt per Day.

[1] Dekatherms (Dkt).

The DOC 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 by $0.1630 per Dkt or approximately $16.30 per year for customers using 100 Mcf. The Company requests that the Commission allow recovery of the associated demand costs in its monthly PGA effective November 1, 2011.

The Company stated that it made the following changes to non-capacity items in the November 2011 PGA compared to the October 2011 PGA:

> As shown in Attachment 6, MERC-PNG-GLGT terminated the Nexen PSO and replaced it with AECO Storage. To deliver the supply from storage to MERC-NMU's markets, MERC entered in an AECO/Emerson swap. MERC sells gas at the storage point (AECO) to a supplier and MERC buys an equivalent volume at Emerson/Spruce, which MERC then transports to its PNG-GLGT, PNG-VGT and NMU (GLGT, VGT and Centra) customers. The swap substituted the need to contract for firm transport on TransCanada Pipeline (TCPL) to transport the gas from AECO to Emerson/Spruce. The cost of TCPL would have been approximately $927,919 compared to the $417,042 to swap the gas.

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

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

- the proposed overall demand entitlement level;
- the changes to non-capacity items;
- the design-day requirement;
- the reserve margin;
- the PGA cost recovery proposal; and
- the DOC's inquiries regarding annual demand entitlement filings.

A. THE COMPANY'S DEMAND ENTITLEMENT LEVEL

1. Proposed Overall Demand Entitlement Level

As shown in DOC Attachment No. 1, the Company proposed to decrease its total entitlement level in Dkt as follows:

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
11,500	10,149	(1,351)	(11.75)

In contrast to the changes shown above, the Company stated on page 13 of its Petition that it was not changing the firm transportation capacity available to MERC-PNG-GLGT customers during winter peak periods. The Department asked MERC (via email) to explain this statement. MERC replied that this statement was incorrect and that it should have read that the Company decreased its firm transportation capacity by 1,351 Dkt.[2]

The Department also asked MERC to explain why it was reducing its total entitlements by 1,351. MERC replied that:

> MERC decreased the level of firm transportation to address a large positive reserve margin that was filed in the previous year's Demand Entitlement filing. MERC's design day for the 2010/11 design day was calculated at 9,440 Dth, which was a decrease of 1,362 Dth year-over-year. Historically, the design day requirements has been in the 9,400 – 9,600 range, as indicated in Schedule 1, page 3 of 3, with the exception of 08/09 and 09/10 years. MERC believes the historically [sic] design day range is the level that is more indicative of MERC's projected firm peak day load. MERC had capacity that was expiring October 31, 2011, which presented the opportunity to reduce the amount of firm capacity for customers served off of GLGT (PNG and NMU).[3]

Finally, the Department asked MERC why it was re-allocating some of its capacity to FT15782 as shown on Attachment 3 of the *Petition*. MERC replied that:

> MERC decreased the total firm capacity from 27,946 Dth to 26,368 Dth (PNG and NMU). A total reduction of 1,578 Dth. As stated in previous paragraph, MERC had capacity that was expiring on

[2] Per MERC's email response to DOC questions. See DOC Attachment No. 2.
[3] Per MERC's email response to DOC questions. See DOC Attachment No. 2.

> October 31, 2011. MERC consolidated volumes that were previously on contracts FT0017 (4,105 Dth), FT0075 (1,973 Dth) and FT8466 (4,500 Dth) into FT15782 (9,000 Dth).[4]

The Department reviewed MERC's overall entitlement level. Based on its review, the Department concludes that Company's proposed recovery of overall demand costs is reasonable. The DOC analyzes below the Company's proposed design-day requirement and proposed reserve margin.

2. Changes to Non-Capacity Items

In its Petition, MERC discussed a storage contract change and associated swap that have the effect of decreasing non-capacity costs. The Department does not oppose MERC's proposal.

The Commission has not yet determined whether storage costs are more appropriately recovered through the commodity or through the demand portion of MERC's PGA. The DOC notes that it has advocated in several recent demand entitlement filings[5] that demand costs associated with storage costs should be recovered through the commodity portion of the PGA since all customers, not just firm customers, benefit from storage gas. The Department continues to hold this view and recommends that the Commission determine that all customers, not just firm customers, should pay for costs of storage gas.

3. Design-Day Requirement

MERC included as part of it initial filing significant discussion regarding its design-day calculation. The Department notes that the Company's design-day analysis is substantively similar to the process that it has used in prior demand entitlement filings. The Department notes that, in its *Petition*, MERC included additional weather variables in its design-day regression calculations. The Department does not necessarily oppose the inclusion of these additional variables; however, the Department notes that some of this data is taken from a propriety source. When a utility uses proprietary data in its analysis, the Department is unable to verify the calculation of the data and whether it is reasonable. Given this situation, although it appears that MERC's analysis allows for sufficient firm entitlements on a peak day, the Department cannot fully verify that these results are correct.

[4] Per MERC's email response to DOC questions. See DOC Attachment No. 2.
[5] For example, please see the Department's July 2, 2008 comments in G011/M-07-1405.

4. Reserve Margin

As indicated in DOC Attachment 1, the reserve margin is as follows:

Total Entitlement (Dkt)	Design-day Estimate (Dkt)	Difference (Dkt)	Reserve Margin %	% Change From Previous Year[6]
10,149	9,304	845	9.08	(12.74)

MERC-PNG's proposed reserve margin of 9.08 percent for its Great Lakes PGA system represents a significant decrease over last year's reserve margin. Based on this information and the DOC's analysis of the Company's design-day analysis, the DOC concludes that the reserve margin appears to be reasonable at this time.

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 (the Company's Attachment 4, page 1 of 4). The Company's demand entitlement proposal would result in the following annual rate impacts:

- Annual bill decrease of $13.69 related to demand costs, or approximately 19.36 percent, for the average General Service customer consuming 84 Dkt annually;[7] and
- There are no demand charge impacts related to MERC's other rate classes.

Based on its analysis, the DOC recommends that the Commission allow the recovery of associated demand costs effective November 1, 2011.

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.

[6] As shown on DOC Attachment 1, the Company's average reserve margin since the 1999-2000 heating season is 5.07 percent.
[7] 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.

1. Timeline

Based on the discovery responses by each utility, 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. Therefore, the Department recommends that the Commission require MERC-PNG to file its annual demand entitlement filing on August 1 on a going-forward basis.

On the topic of the demand entitlement filing timeline, Interstate's response to the Department's information request (see DOC Attachment No. 3) 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 July 1 or August 1 initial filing 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. The Department requests that MERC-PNG provide a response in their reply comments to Interstate's proposed procedure for demand entitlement filings.

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 a standard 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 DOC'S RECOMMENDATIONS

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

- accept the Company's 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
- require MERC to file its annual demand entitlement filing on August 1, on a going-forward basis.

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

/jl

Minnesota Department of Commerce
Division of Energy Resources
MERC-PNG's Great Lakes Purchased Gas Adjustment Area Demand Entitlement Analysis
Docket No. G011/M-11-1082

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving + Peak Shaving			Reserve Margin
Heating Season *	(1) Number of DD Customers	(2) Change From Previous Year	(3) % Change From Previous Year	(4) Design Day (Mcf)	(5) Change From Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (Mcf)	(8) Change From Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2011-2012	**6,041**	**(12)**	**-0.20%**	**9,304**	**(136)**	**-1.44%**	**10,149**	**-1,351**	**-11.75%**	**9.08%**
2010-2011	6,053	(15)	-0.25%	9,440	(1,362)	-12.61%	11,500	0	0.00%	21.82%
2009-2010	6,068	194	3.30%	10,802	503	4.88%	11,500	1,000	9.52%	6.46%
2008-2009	5,874	58	1.00%	10,299	749	7.84%	10,500	500	5.00%	1.95%
2007-2008#	5,816	69	1.20%	9,550	7	0.07%	10,000	314	3.24%	4.71%
2006-2007	5,747	68	1.20%	9,543	33	0.35%	9,686	0	0.00%	1.50%
2005-2006	5,679	165	2.99%	9,510	61	0.65%	9,686	0	0.00%	1.85%
2004-2005	5,514	103	1.90%	9,449	(198)	-2.05%	9,686	0	0.00%	2.51%
2003-2004	5,411	133	2.52%	9,647	1,659	20.77%	9,686	1,186	13.95%	0.40%
2002-2003	5,278	172	3.37%	7,988	(123)	-1.52%	8,500	0	0.00%	6.41%
2001-2002	5,106	134	2.70%	8,111	(254)	-3.04%	8,500	0	0.00%	4.80%
2000-2001	4,972	175	3.65%	8,365	92	1.11%	8,500	0	0.00%	1.61%
1999-2000**	4,797	341	7.65%	8,273	588	7.65%	8,500	2,422	39.85%	2.74%
1998-1999	4,456	241	5.72%	7,685	416	5.72%	6,078	0	0.00%	-20.91%
1997-1998	4,215	386	10.08%	7,269	665	10.07%	6,078	0	0.00%	-16.38%
1996-1997	3,829	336	9.62%	6,604	579	9.61%	6,078	0	0.00%	-7.96%
1995-1996	3,493			6,025			6,078			
Average Change Since 1999-2000:			2.39%			1.74%			4.60%	5.07%

Per Peoples, the 2001-02 Design Day declined due to a downward trend in consumption and heat factor possibly due to high gas costs in 2000-01 and more energy efficient housing.

Firm Peak Day Sendout

Heating Season *	(11) Number of Peak Day Customers	(12) Firm Peak Day Sendout (Mcf)	(13) Sendout 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 Sendout per PD Customer (12)/(11)	(19) Peak Day Sendout per DD Customer (12)/(1)
2011-2012	**unknown**	**unknown**			**0.1399**	**1.5401**	**1.6800**	**unknown**	**unknown**
2010-2011	unknown	unknown			0.3403	1.5596	1.8999	unknown	unknown
2009-2010	6,071	7,391	(673)	-8.35%	0.1150	1.7802	1.8952	1.2174	1.2180
2008-2009^	6,144	8,064	(63)	-0.78%	0.0342	1.7533	1.7875	1.3125	1.3728
2007-2008	unknown	8,127	1,355	20.01%	0.0774	1.6420	1.7194	unknown	1.3974
2006-2007	unknown	6,772	(959)	-12.40%	0.0249	1.6605	1.6854	unknown	1.1784
2005-2006 ***	unknown	7,731	1,608	26.26%	0.0310	1.6746	1.7056	unknown	1.3613
2004-2005	5,714	6,123	(1,543)	-20.13%	0.0430	1.7136	1.7566	1.0716	1.1104
2003-2004	5,529	7,666	567	7.99%	0.0072	1.7828	1.7901	1.3865	1.4167
2002-2003	5,411	7,099	1,104	18.42%	0.0970	1.5135	1.6105	1.3120	1.3450
2001-2002	5,099	5,995	(567)	-8.64%	0.0762	1.5885	1.6647	1.1757	1.1741
2000-2001	4,970	6,562	(576)	-8.07%	0.0272	1.6824	1.7096	1.3203	1.3198
1999-2000	4,627	7,138	(368)	-4.90%	0.0473	1.7246	1.7719	1.5427	1.4880
1998-1999	4,627	7,506	1,567	26.38%	-0.3606	1.7246	1.3640	1.6222	1.6845
1997-1998	unknown	5,939	588	10.99%	-0.2826	1.7246	1.4420	unknown	1.4090
1996-1997	unknown	5,351	427	8.67%	-0.1374	1.7247	1.5874	unknown	1.3975
1995-1996	unknown	4,924			0.0152	1.7249	1.7401	unknown	1.4097
Average Change Since 1999-2000:				0.86%	0.0816	1.6628	1.7443	1.2923	1.3075

-- The analysis conducted by the OES does not include the 423 Mcf/day capacity related to MERC's FT0011 agreement.
This decision to omit these volumes is discussed in the body of the Comments in Docket No. G011/M-07-1404.
*Per Peoples, information prior to 1995 is not available.
**Corrected from peak day to design day number of customers.

*** The Company has not provided the number of peak-day customers beginning from the 2005-2006 heating season.
^ The number of peak day customers is calculated using the Residential and Commercial customer count data provided in MERC's Attachment 11.

Prepared by the Minnesota Department of Commerce

Question in PNG-GLGT Demand Entitlement Filing from Mark Johnson

1. On page 13 of the filing, MERC stated that it was not changing the firm transportation capacity actually available to MERC-PNG-GLGT customers during winter peak periods. However, is this statement correct since the Company is reducing its total entitlements by 1,351 as shown on Attachment 3? Also, could you please briefly explain why MERC is reducing its total entitlements by 1,351? In addition, could you please briefly explain why the Company is reallocating some of its capacity to FT15782 as shown on Attachment 3?

Response:

The statement on Page 13 is incorrect. Should have read, MERC decreased firm transportation capacity by 1,351 Dth.

MERC decreased the level of firm transportation to address a large positive reserve margin that was filed in the previous year's Demand Entitlement filing. MERC's design day for the 2010/11 design day was calculated at 9,440 Dth, which was a decrease of 1,362 Dth year-over-year. Historically, the design day requirements has been in the 9,400 – 9,600 range, as indicated in Schedule 1, page 3 of 3, with the exception of 08/09 and 09/10 years. MERC believes the historically design day range is the level that is more indicative of MERC's projected firm peak day load. MERC had capacity that was expiring October 31, 2011, which presented the opportunity to reduce the amount of firm capacity for customers served off of GLGT (PNG and NMU).

MERC decreased the total firm capacity from 27,946 Dth to 26,368 Dth (PNG and NMU). A total reduction of 1,578 Dth As stated in previous paragraph, MERC had capacity that was expiring on October 31, 2010. MERC consolidated volumes that were previously on contracts FT0017 (4,105 Dth), FT0075 (1,973 Dth) and FT8466 (4,500 Dth) into FT15782 (9,000 Dth).

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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-11-1082

Dated this **3rd of January, 2012**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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