LORI SWANSON
ATTORNEY GENERAL

STATE OF MINNESOTA

OFFICE OF THE ATTORNEY GENERAL

SUITE 1400
445 MINNESOTA STREET
ST. PAUL, MN 55101-2131
TELEPHONE: (651) 296-7575

August 25, 2016

The Honorable Jeanne M. Cochran
Administrative Law Judge
Office of Administrative Hearings
600 North Robert Street
P.O. Box 64620
St. Paul, MN 55164-0620

Re: *In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.*
MPUC Docket No. G-011/GP-15-895
OAH Docket No.68-2500-33191

Dear Judge Cochran:

Enclosed and e-filed in the above-referenced matter please find the PUBLIC Surrebuttal Testimony with Schedules of the Office of the Attorney General – Residential Utilities and Antitrust Division's witness Julie Urban.

The Highly-Sensitive Trade Secret version of this testimony is filed in Docket 16-315.

By copy of this letter all parties have been served. An Affidavit of Service is also enclosed.

Sincerely,

s/ Joseph A. Dammel

JOSEPH A. DAMMEL
Assistant Attorney General

(651) 757-1061 (Voice)
(651) 296-9663 (Fax)

Enclosure

AFFIDAVIT OF SERVICE

Re: ***In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.***
MPUC Docket No. G-011/GP-15-895
OAH Docket No.68-2500-33191

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I hereby state that on August 25, 2016, I filed with eDockets the PUBLIC and HSTS ***Surrebuttal Testimony with Schedules of the Office of the Attorney General – Residential Utilities and Antitrust Division's witness Julie Urban*** and served the same upon all parties listed on the attached service list by email, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ Judy Sigal
Judy Sigal

Subscribed and sworn to before me
this 25th day of August, 2016.

s/ Patricia Jotblad
Notary Public

My Commission expires: January 31, 2020.

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mitchell	Abeln	mitchellabeln@dmceda.org	Destination Medical Center - Economic Development Agency	195 W Broadway Rochester, MN 55902	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Terry L.	Adkins	tadkins@rochestermn.gov	City Of Rochester	Room 247 201 4th Street SE Rochester, MN 55904	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Sundra	Bender	sundra.bender@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 Saint Paul, MN 55101-2147	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Elizabeth	Brama	ebrama@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Ardell	Brede	abrede@rochestermn.gov	Rochester City Hall	201 Fourth St SE Room 281 Rochester, MN 55904	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Bob	Brill	bob.brill@state.mn.us	Public Utilities Commission	121 E. 7th Place, Suite 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Joseph	Dammel	joseph.dammel@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Laura	Demman	laura.demman@nngco.com	Northern Natural Gas Company	1111 S. 103rd Street Omaha, NE 68125	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Brett	Gorden	gorden.brett@mayo.edu	Mayo Clinic	200 First St SW Rochester, MN 55905	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Mark	Kotschevar	mkotschevar@rpu.org	Rochester Public Utilities	4000 East River Road NE Rochester, MN 55906	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
David G.	Kult	dgkult@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St. NW Rosemount, MN 55068	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Steven	Kvenvold	skvenvold@rochestermn.gov	City of Rochester - Administrator	201 4th Street SE Rochester, MN 55904	Electronic Service	No	OFF_SL_15-895_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St W Rosemount, MN 55068	Electronic Service	No	OFF_SL_15-895_Official CC Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Catherine	Phillips	catherine.phillips@we-energies.com	We Energies	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Walter	Schlink	wschlink@rpu.org	Rochester Public Utilities	4000 East River Road NE Rochester, MN 559062813	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Kristin	Stastny	kstastny@briggs.com	Briggs and Morgan, P.A.	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List

OAG No. 116

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Reproduce MERC's growth estimates for the Rochester area without the DMC program. Include the source material used for the growth estimates, the methodology used to generate the growth estimates, and the specific changes to the methodology and source material used to generate the growth with the DMC program.

RESPONSE:

The Rochester area sales forecasting provided in Appendix C of our Petition did not incorporate growth assumptions specific to the Destination Medical Center ("DMC") program. The forecasts were developed using Ordinary Least Squares statistical methodology, and based on monthly historical billed and customer count data for the Rochester area, and economic and demographic variables from Moody's Analytics ("MA"). The MA variables were specific to the Rochester Metropolitan Statistical Area ("MSA"), and included gross metro product, total employment, unemployment rate, personal income growth, median, household income, population growth, net migration, housing construction permits, and real estate prices. While the variables presumably reflect some assumption about the impact of the DMC plan, MERC cannot determine the degree of that impact for any particular variable.

Response by: Harry W. John
Title: Senior Load Forecaster
Department: Budgets & Forecasts
Telephone: 920 433 1553

OAG No. 206

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	August 4, 2016
Telephone:	(651) 757-1473	**Due Date:**	August 16, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Clabots Direct, Heinen Direct, Urban Direct.

Reproduce the Company's forecast with the following changes, holding all else constant:

1. Use of Rochester specific weather data as discussed in Mr. Clabots' Direct, at 7:21–23;

2. Use of Mr. Heinen's customer count growth model, as discussed in Mr. Heinen's Direct, at 26–27; and

3. Incorporate the time trend variable in the use per customer model as discussed in the response to OAG IR 155.7 and Dr. Urban's Direct, at 28–29.

4. Apply these models to estimate future sales.

5. Then provide the new forecast estimate for design day. Explain how the design day forecast is related to the sales forecast. Provide evidence supporting the reasonableness of the design-day growth figure.

Response by David Clabots and Russell Laursen
Title Senior Projects Specialist/Manager of Gas Supply
Department Finance/Gas Supply
Telephone 920-433-1355/920-433-1740

OAG No. 206
Page 2

After reproducing the forecast as discussed above, provide the following information:

1. Produce a table comparing estimated peak demand from the "reproduced forecast" to the forecast discussed in Mr. Clabots direct testimony;

2. Produce a table demonstrating reserve margins for the Rochester area using the estimated peak demand from the "reproduced forecast" and available capacity assuming MERC's preferred plan for the Rochester Project.

    a. In providing this answer, produce multiple tables using different assumptions regarding the capacity deliverability to other TBSs, as discussed by Mr. Clabots Direct, at 38:1–8. Produce three reserve margin tables, assuming 1) that no capacity is delivered to other TBSs; 2) that 10% of capacity is delivered to other TBSs; and 3) that 20% of capacity is delivered to other TBSs.

Provide your answers in Excel format with all links and formulas intact.

MERC Response:

MERC objects to this Information Request as being beyond the proper scope of discovery and calling upon MERC to create a hypothetical forecast. This Information Request is further objected to as overly-broad and unduly burdensome, and seeks irrelevant information. MERC provides the following response to this Information Request but does so subject to and in light of these objections.

While MERC does not agree that it is appropriate to add a trend variable in isolation without reviewing the entire model construct for appropriateness, MERC prepared the forecast as requested by the OAG. While MERC disagrees with the OAG's instructions in the Information Request, we have complied and provided the data as requested.

A trend variable was added to the Residential Use-Per-Customer ("UPC") model and the customer count forecasts developed by the Department were used. The forecasts were based on using Rochester weather. All else was held constant. For LC&I MERC prepares a total sales forecast. The customer count forecast is independent and does not impact the sales forecast. For purposes of this Information Request and the produced hypothetical forecast, MERC had to back into a LC&I UPC forecast by dividing its total sales forecast by the number of customers on a monthly basis. MERC then multiplied the calculated UPC times the Department's LC&I customer count forecast to create a hypothetical forecast to meet the OAG's request.

The result of this was a 10 year average Total Retail Sales growth of -0.1%. MERC does not believe this growth rate for the Rochester area over the next 10 years is even remotely reasonable with or without the Mayo Clinic / DMC expansion. MERC continues to support the forecast it prepared in this case and believes that it is a statistically valid forecast that supports a more realistic approach than the Department's status quo forecast.

Response by **David Clabots and Russell Laursen**
Title **Senior Projects Specialist/Manager of Gas Supply**
Department **Finance/Gas Supply**
Telephone **920-433-1355/920-433-1740**

Further, forecasting is a complex process with many inputs and variables and based on the information available at a point in time. MERC has concerns with just adding a trend variable in isolation of other adjustments or variables. Changing variables in isolation risks inconsistent and potentially skewed results.

Mr. Heinen has stated in his testimony that he views his customer forecast as a status quo forecast or lower bound and that he views MERC's forecast as a more optimistic forecast. MERC believes our forecast is appropriate and statistically valid. MERC expects growth in the Rochester area that will far outstrip the results of the calculation using the OAG's assumptions as set forth in this Information Request. Significant money has already been invested by Mayo Clinic and other businesses in the Rochester area and recent reports indicate that the goal to reach the $200 million will be reached relatively soon thus releasing the $585 million of government funds.

Finally, because of our concerns of the sales forecast using the OAG's assumptions, MERC took an extra step. Keeping the models and forecast results the same, we added 2015 weather normalized sales to the tables attached. In the normal course of business, if another full year of actuals were available it would be appropriate to update the forecast tables with a full year of available weather normalized data. This changed the 10 year average Total Retail Sales growth from -0.1% to 1.1%.

I note that MERC has some concerns with this number as well and cautions care in using it. 2015 had an El Nino event, which greatly reduced sales. The weather normalization model added sales back to get to "normal," but under extreme weather situations, use of the model may not result in fully reliable numbers.

Attachments:
For the new monthly forecast by class based on the OAG's modeling requirements in 1, 2, & 3 of Part 1 above please see Excel file: OAG-206.xlsx.

Please see Excel file OAG-206 Rochester Gas pipeline Certification Revised with Rochester Weather not WN.xlsx for the sales forecast by class that determined the growth rate of -0.1% to develop the peak day forecast.

Please see Excel file OAG-206 Rochester Gas pipeline Certification Revised with Rochester Weather WN.xlsx for the sales forecast by class that determined the growth rate of 1.1% to develop the peak day forecast.

For the new peak day forecast based on a -0.1% please see Excel file OAG-206 Rochester Design Peak Day Analysis Revised with Rochester Weather not WN.xlsx.

For the new peak day forecast based on a 1.1% please see Excel file OAG-206 Rochester Design Peak Day Analysis Revised with Rochester Weather WN.xlsx.

Response by David Clabots and Russell Laursen
Title Senior Projects Specialist/Manager of Gas Supply
Department Finance/Gas Supply
Telephone 920-433-1355/920-433-1740

Please see Excel file OAG-206 Peak Day Comparison Table.xlsx to see a comparison between MERC's peak day forecast based on using Rochester weather to the OAG-206 peak day forecast based on their requested model parameters and the two above scenarios.

Explain how the design day forecast is related to the sales forecast.
The design day forecast is related to the sales forecast in the same manner as was prepared and presented in the petition. The average growth rate from the 10 year forecast was applied to the design peak day forecast for the term of the forecast.

Provide evidence supporting the reasonableness of the design-day growth figure.
MERC cannot support the growth rate arising out of using the assumptions contained in this Information Request since the parameters of the models in this request were dictated by the OAG and MERC does not agree with the parameters. Again, MERC has concerns with just adding a trend variable without reevaluating the entire model to see if other adjustments or variables should be added or dropped due to the addition of the this variable. MERC also considers the Department's customer count forecast as a low bound scenario as acknowledged by Mr. Heinen.

MERC believes its Residential UPC model is statistically valid. As MERC stated in Docket No. 15-895_MERC Supplemental Response to OAG-155-7 "MERC further believes, in those circumstances where a time-trend variable may be useful, the use of Real Personal Income as a forward looking economic trend variable would be appropriate to address reasonably anticipated future trends in Residential use per customer. As described in MERC's response to OAG IR-155 (question 8), in this circumstance, MERC concluded that not using a time-trend variable was reasonable and that without the use of such variable, the model proved to be statistically valid in order to estimate usage."

2. **Produce a table demonstrating reserve margins for the Rochester area using the estimated peak demand from the "reproduced forecast" and available capacity assuming MERC's preferred plan for the Rochester Project**.

   Please see OAG 206 part 2.xlsx.

Response by David Clabots and Russell Laursen
Title Senior Projects Specialist/Manager of Gas Supply
Department Finance/Gas Supply
Telephone 920-433-1355/920-433-1740

		Res UPC		Res Customers		Res Total Sales						SC&I UPC	SC&I Customers		SC&I Total Sales		
Year	Month	As Filed[1]	w/ Trend	As Filed	DOC Fcst	MERC	Per OAG	%Chg	%Chg	Year	Month	As Filed[1]	As Filed	DOC Fcst	MERC	Per OAG	%Chg
2007						33,961,670	33,961,670								849,212	849,212	
2008						34,260,026	34,260,026	0.88%							878,272	878,272	3.42%
2009						35,015,321	35,015,321	2.20%							1,001,809	1,001,809	14.07%
2010						33,978,659	33,978,659	-2.96%							988,495	988,495	-1.33%
2011						34,870,219	34,870,219	2.62%							1,207,431	1,207,431	22.15%
2012						34,540,486	34,540,486	-0.95%							1,037,764	1,037,764	-14.05%
2013						35,537,412	35,537,412	2.89%							1,358,933	1,358,933	30.95%
2014						38,303,726	38,303,726	7.78%							1,700,834	1,700,834	25.16%
2015				41,010	40,919	37,139,767	35,968,086	-6.10%					1,414	1,417	1,803,052	1,799,371	5.79%
2016				41,554	41,171	37,296,946	35,738,000	-0.64%					1,437	1,424	1,812,270	1,797,514	-0.10%
2017				42,191	41,451	37,859,048	35,796,859	0.16%					1,462	1,437	1,836,608	1,806,701	0.51%
2018				42,912	41,738	38,499,171	35,858,596	0.17%					1,493	1,452	1,867,813	1,819,333	0.70%
2019				43,710	42,033	39,210,092	35,925,250	0.19%					1,526	1,467	1,902,471	1,832,409	0.72%
2020				44,579	42,335	39,986,081	35,995,392	0.20%					1,562	1,483	1,939,185	1,844,156	0.64%
2021				45,515	42,639	40,822,383	36,064,420	0.19%					1,598	1,497	1,977,343	1,855,244	0.60%
2022				46,513	42,944	41,714,846	36,131,905	0.19%					1,635	1,510	2,016,646	1,865,051	0.53%
2023				47,569	43,251	42,659,741	36,198,380	0.18%					1,674	1,522	2,056,915	1,873,547	0.46%
2024				48,679	43,560	43,653,647	36,263,559	0.18%					1,714	1,534	2,098,032	1,880,692	0.38%
2025				49,840	43,870	44,693,392	36,327,341	0.18%					1,755	1,544	2,139,893	1,886,940	0.33%

		LC&I UPC	LC&I Customers		LC&I Total Sales		
Year	Month	As Filed	As Filed	DOC Fcst	MERC	Per OAG	%Chg
					15,064,531	15,064,531	
					15,024,138	15,024,138	-0.27%
					14,936,265	14,936,265	-0.58%
					14,324,214	14,324,214	-4.10%
					15,574,247	15,574,247	8.73%
					16,115,770	16,115,770	3.48%
					16,553,501	16,553,501	2.72%
					17,903,468	17,903,468	8.16%
			1,594	1,593	18,719,353	18,679,900	4.34%
			1,623	1,608	18,753,404	18,597,646	-0.44%
			1,657	1,628	18,902,860	18,592,157	-0.03%
			1,685	1,639	19,052,317	18,552,694	-0.21%
			1,706	1,641	19,201,774	18,487,979	-0.35%
			1,723	1,636	19,351,232	18,399,857	-0.48%
			1,741	1,631	19,500,688	18,292,367	-0.58%
			1,761	1,626	19,650,145	18,166,427	-0.69%
			1,780	1,619	19,799,602	18,027,172	-0.77%
			1,800	1,611	19,949,059	17,877,135	-0.83%
			1,821	1,603	20,098,515	17,714,981	-0.91%

Table 1: Rochester Area NNG Reserve Margin as Filed

			No Capacity to other TBS				10% Capacity to other TBS				20% Capacity to other TBS			
Winter Period	NNG Current Capacity	NNG Design Day	Additional Capacity	Total NNG Capacity	Capacity Long/(Short)	Reserve Margin	Additional Capacity	Total NNG Capacity	Capacity Long/(Short)	Reserve Margin	Additional Capacity	Total NNG Capacity	Capacity Long/(Short)	Reserve Margin
2015/2016	74,129	85,001		74,129	(10,872)	-12.79%		74,129	(10,872)	-12.79%		74,129	(10,872)	-12.79%
2016/2017	74,129	86,276		74,129	(12,147)	-14.08%		74,129	(12,147)	-14.08%		74,129	(12,147)	-14.08%
2017/2018	74,129	87,570		74,129	(13,441)	-15.35%		74,129	(13,441)	-15.35%		74,129	(13,441)	-15.35%
2018/2019	74,129	88,884	15,939	90,068	1,184	1.33%	14,345	88,474	(410)	-0.46%	12,751	86,880	(2,004)	-2.25%
2019/2020	74,129	90,217	53,032	127,161	36,944	40.95%	47,729	121,858	31,641	35.07%	42,426	116,555	26,338	29.19%
2020/2021	74,129	91,570	53,032	127,161	35,591	38.87%	47,729	121,858	30,288	33.08%	42,426	116,555	24,984	27.28%
2021/2022	74,129	92,944	53,032	127,161	34,217	36.81%	47,729	121,858	28,914	31.11%	42,426	116,555	23,611	25.40%
2022/2023	74,129	94,338	53,032	127,161	32,823	34.79%	47,729	121,858	27,520	29.17%	42,426	116,555	22,217	23.55%
2023/2024	74,129	95,753	53,032	127,161	31,408	32.80%	47,729	121,858	26,105	27.26%	42,426	116,555	20,802	21.72%
2024/2025	74,129	97,189	53,032	127,161	29,972	30.84%	47,729	121,858	24,668	25.38%	42,426	116,555	19,365	19.93%
2025/2026	74,129	98,647	53,032	127,161	28,514	28.90%	47,729	121,858	23,211	23.53%	42,426	116,555	17,907	18.15%
2026/2027	74,129	100,127	53,032	127,161	27,034	27.00%	47,729	121,858	21,731	21.70%	42,426	116,555	16,428	16.41%
2027/2028	74,129	101,629	53,032	127,161	25,532	25.12%	47,729	121,858	20,229	19.90%	42,426	116,555	14,926	14.69%
2028/2029	74,129	103,153	53,032	127,161	24,008	23.27%	47,729	121,858	18,705	18.13%	42,426	116,555	13,401	12.99%
2029/2030	74,129	104,701	53,032	127,161	22,460	21.45%	47,729	121,858	17,157	16.39%	42,426	116,555	11,854	11.32%
2030/2031	74,129	106,271	53,032	127,161	20,890	19.66%	47,729	121,858	15,587	14.67%	42,426	116,555	10,284	9.68%
2031/2032	74,129	107,865	53,032	127,161	19,296	17.89%	47,729	121,858	13,993	12.97%	42,426	116,555	8,690	8.06%
2032/2033	74,129	109,483	53,032	127,161	17,678	16.15%	47,729	121,858	12,375	11.30%	42,426	116,555	7,072	6.46%
2033/2034	74,129	111,125	53,032	127,161	16,036	14.43%	47,729	121,858	10,732	9.66%	42,426	116,555	5,429	4.89%
2034/2035	74,129	112,792	53,032	127,161	14,369	12.74%	47,729	121,858	9,066	8.04%	42,426	116,555	3,762	3.34%
2035/2036	74,129	114,484	53,032	127,161	12,677	11.07%	47,729	121,858	7,374	6.44%	42,426	116,555	2,071	1.81%
2036/2037	74,129	116,201	53,032	127,161	10,960	9.43%	47,729	121,858	5,656	4.87%	42,426	116,555	353	0.30%
2037/2038	74,129	117,944	53,032	127,161	9,217	7.81%	47,729	121,858	3,913	3.32%	42,426	116,555	(1,390)	-1.18%
2038/2039	74,129	119,714	53,032	127,161	7,447	6.22%	47,729	121,858	2,144	1.79%	42,426	116,555	(3,159)	-2.64%
2039/2040	74,129	121,509	53,032	127,161	5,652	4.65%	47,729	121,858	349	0.29%	42,426	116,555	(4,955)	-4.08%
2040/2041	74,129	123,332	53,032	127,161	3,829	3.10%	47,729	121,858	(1,474)	-1.20%	42,426	116,555	(6,777)	-5.50%
2041/2042	74,129	125,182	53,032	127,161	1,979	1.58%	47,729	121,858	(3,324)	-2.66%	42,426	116,555	(8,627)	-6.89%
2042/2043	74,129	127,060	53,032	127,161	101	0.08%	47,729	121,858	(5,202)	-4.09%	42,426	116,555	(10,505)	-8.27%
2043/2044	74,129	128,965	53,032	127,161	(1,804)	-1.40%	47,729	121,858	(7,108)	-5.51%	42,426	116,555	(12,411)	-9.62%

Table 2: Rochester Area NNG Reserve Margin with OAG "reproduced forecast"

			No Capacity to other TBS				10% Capacity to other TBS				20% Capacity to other TBS			
Winter Period	NNG rrent Capac	NNG Design Day	Additional Capacity	Total NNG Capacity	Capacity ong/(Short	Reserve Margin	Additional Capacity	Total NNG Capacity	Capacity ong/(Short	Reserve Margin	Additional Capacity	Total NNG Capacity	Capacity ong/(Short	Reserve Margin
2015/2016	74,129	85,001		74,129	(10,872)	-12.79%		74,129	(10,872)	-12.79%		74,129	(10,872)	-12.79%
2016/2017	74,129	84,916		74,129	(10,787)	-12.70%		74,129	(10,787)	-12.70%		74,129	(10,787)	-12.70%
2017/2018	74,129	84,831		74,129	(10,702)	-12.62%		74,129	(10,702)	-12.62%		74,129	(10,702)	-12.62%
2018/2019	74,129	84,746	15,939	90,068	5,322	6.28%	14,345	88,474	3,728	4.40%	12,751	86,880	2,134	2.52%
2019/2020	74,129	84,662	53,032	127,161	42,499	50.20%	47,729	121,858	37,196	43.94%	42,426	116,555	31,893	37.67%
2020/2021	74,129	84,577	53,032	127,161	42,584	50.35%	47,729	121,858	37,281	44.08%	42,426	116,555	31,978	37.81%
2021/2022	74,129	84,492	53,032	127,161	42,669	50.50%	47,729	121,858	37,366	44.22%	42,426	116,555	32,062	37.95%
2022/2023	74,129	84,408	53,032	127,161	42,753	50.65%	47,729	121,858	37,450	44.37%	42,426	116,555	32,147	38.09%
2023/2024	74,129	84,323	53,032	127,161	42,838	50.80%	47,729	121,858	37,534	44.51%	42,426	116,555	32,231	38.22%
2024/2025	74,129	84,239	53,032	127,161	42,922	50.95%	47,729	121,858	37,619	44.66%	42,426	116,555	32,316	38.36%
2025/2026	74,129	84,155	53,032	127,161	43,006	51.10%	47,729	121,858	37,703	44.80%	42,426	116,555	32,400	38.50%
2026/2027	74,129	84,071	53,032	127,161	43,090	51.25%	47,729	121,858	37,787	44.95%	42,426	116,555	32,484	38.64%
2027/2028	74,129	83,987	53,032	127,161	43,174	51.41%	47,729	121,858	37,871	45.09%	42,426	116,555	32,568	38.78%
2028/2029	74,129	83,903	53,032	127,161	43,258	51.56%	47,729	121,858	37,955	45.24%	42,426	116,555	32,652	38.92%
2029/2030	74,129	83,819	53,032	127,161	43,342	51.71%	47,729	121,858	38,039	45.38%	42,426	116,555	32,736	39.06%
2030/2031	74,129	83,735	53,032	127,161	43,426	51.86%	47,729	121,858	38,123	45.53%	42,426	116,555	32,820	39.19%
2031/2032	74,129	83,651	53,032	127,161	43,510	52.01%	47,729	121,858	38,207	45.67%	42,426	116,555	32,903	39.33%
2032/2033	74,129	83,568	53,032	127,161	43,593	52.17%	47,729	121,858	38,290	45.82%	42,426	116,555	32,987	39.47%
2033/2034	74,129	83,484	53,032	127,161	43,677	52.32%	47,729	121,858	38,374	45.97%	42,426	116,555	33,071	39.61%
2034/2035	74,129	83,400	53,032	127,161	43,761	52.47%	47,729	121,858	38,457	46.11%	42,426	116,555	33,154	39.75%
2035/2036	74,129	83,317	53,032	127,161	43,844	52.62%	47,729	121,858	38,541	46.26%	42,426	116,555	33,238	39.89%
2036/2037	74,129	83,234	53,032	127,161	43,927	52.78%	47,729	121,858	38,624	46.40%	42,426	116,555	33,321	40.03%
2037/2038	74,129	83,151	53,032	127,161	44,010	52.93%	47,729	121,858	38,707	46.55%	42,426	116,555	33,404	40.17%
2038/2039	74,129	83,067	53,032	127,161	44,094	53.08%	47,729	121,858	38,790	46.70%	42,426	116,555	33,487	40.31%
2039/2040	74,129	82,984	53,032	127,161	44,177	53.24%	47,729	121,858	38,874	46.84%	42,426	116,555	33,570	40.45%
2040/2041	74,129	82,901	53,032	127,161	44,260	53.39%	47,729	121,858	38,956	46.99%	42,426	116,555	33,653	40.59%
2041/2042	74,129	82,818	53,032	127,161	44,343	53.54%	47,729	121,858	39,039	47.14%	42,426	116,555	33,736	40.74%
2042/2043	74,129	82,736	53,032	127,161	44,425	53.70%	47,729	121,858	39,122	47.29%	42,426	116,555	33,819	40.88%
2043/2044	74,129	82,653	53,032	127,161	44,508	53.85%	47,729	121,858	39,205	47.43%	42,426	116,555	33,902	41.02%

OAG No. 108

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Does MERC have any agreements to increase natural gas usage by Rochester Public Utilities after the Rochester Project? Has MERC had any discussions with Rochester Public Utilities about increasing natural gas usage? Produce all relevant documents.

RESPONSE:

No, MERC has not entered into any agreements with Rochester Public Utilities ("RPU") to increase natural gas usage as a result of the Rochester Project.

Prior to submitting our Petition in this proceeding, MERC asked RPU whether it anticipated increased future natural gas needs. RPU did not respond to our inquiry, and as a result MERC did not include any projection of increased RPU usage in its analysis of the need for the Rochester Project.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 205

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	August 4, 2016
Telephone:	(651) 757-1473	**Due Date:**	August 16, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide the following:

1. The annual firm load factor for the Rochester area (in percent) for the most recent five years;

   a. In addition, provide firm load factors for the time periods March-October and November-February for the Rochester area; and

   b. Provide firm load factors by month for the Rochester area.

2. The maximum daily quantity of firm peak-day demand deliverability for the Rochester area (MCF), i.e. the maximum amount of gas that can be delivered to firm customers in one day.

MERC Response:

1. a/b. Please see the following tables. Please note that robust data was not available for this entire period, so estimates of non-firm load were required.

Response by Russell Laursen
Title Manager Gas Supply
Department Gas Supply
Telephone 920-433-1740

OAG No. 206
pg. 2

Roachester Area Annual Load Factor				
Year Beginning	Annual Flow (Dth)	Max Load (Dth)	Number of Days	Annual Load Factor
7/1/2011	8,381,709	67,481	366	0.34
7/1/2012	9,884,208	74,857	365	0.36
7/1/2013	11,401,206	77,660	365	0.40
7/1/2014	10,652,665	80,071	365	0.36
7/1/2015	9,537,820	79,389	366	0.33

Rochester Area Seasonal Load Factor				
Season Beginning	Seasonal Flow (Dth)	Max Load (Dth)	Number of Days	Seasonal Load Factor
11/1/2011	4,455,693	67,481	121	0.55
3/1/2012	4,150,151	31,958	245	0.53
11/1/2012	4,947,476	74,857	120	0.55
3/1/2013	4,862,760	40,438	245	0.49
11/1/2013	6,418,802	77,660	120	0.69
3/1/2014	5,094,494	42,352	245	0.49
11/1/2014	6,021,566	80,071	120	0.63
3/1/2015	4,456,912	35,229	245	0.52
11/1/2015	5,103,629	79,389	121	0.53

Rochester Area Five Year Monthly Load Factor				
Month	Five Year Monthly Flow (Dth)	Max Load (Dth)	Number of Days	Monthly Load Factor
1	8,049,994	80,071	155.0	0.65
2	7,130,654	76,531	142.0	0.66
3	5,285,284	73,168	155.0	0.47
4	3,643,638	43,562	150.0	0.56
5	2,289,602	34,424	155.0	0.43
6	1,970,066	24,772	150.0	0.53
7	2,185,660	31,958	155.0	0.44
8	2,120,609	19,528	155.0	0.70
9	2,111,883	20,189	150.0	0.70
10	3,303,699	42,024	155.0	0.51
11	5,034,314	61,502	150.0	0.55
12	6,732,203	73,749	155.0	0.59

Response by Russell Laursen
Title Manager Gas Supply
Department Gas Supply
Telephone 920-433-1740

2. MERC currently holds 74,129 dth of firm winter capacity in the Rochester area, where the "Rochester area" is defined as all of Olmstead County and the communities of Kasson and Blooming Prairie located in Dodge County.

Response by Russell Laursen
Title Manager Gas Supply
Department Gas Supply
Telephone 920-433-1740

OAG No. 121

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

MERC indicates that it utilized "nearly 100% of its peak-day capacity" on January 6, 2014. Identify the ten highest utilization days in the last five years, and indicate the capacity utilization and the number and percentage of non-firm customers who were curtailed.

RESPONSE:

As explained in MERC's response to OAG IR No. 133, on January 6, 2014, MERC utilized all of the capacity available at Rochester TBS 1B and 1D to serve its firm system sales customers. . See MERC response to OAG IR No. 117 for a list of curtailments in the Rochester area over the past five years. See MERC response to OAG IR No. 134 for the list of Large Volume Interruptible customers who engaged in unauthorized use during the January 6, 2014, curtailment. In the table below, MERC provides the ten highest utilization days in order of highest utilization since December 2012. Prior to December 2012, MERC did not have telemetry data for its interruptible customers. Because interruptible demand does not factor into the peak day requirements, the capacity utilization of the interruptible customers is not included in the utilization data below.

Response by: Sarah R. Mead
Title: Manager – Gas Supply
Department: Gas Supply
Telephone: 920-433-7647

Date	Dth/d
1/6/2014	55,678
1/5/2014	53,049
1/27/2014	51,373
1/7/2015	48,343
1/21/2013	48,112
1/22/2014	47,861
1/23/2014	47,597
2/18/2015	47,410
2/5/2014	47,370
1/28/2014	47,338

Response by: Sarah R. Mead
Title: Manager – Gas Supply
Department: Gas Supply
Telephone: 920-433-7647

OAG No. 118

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Has MERC turned away any potential new customers that would be served by the Rochester Project because MERC did not have sufficient capacity to serve them? Describe each instance with specificity.

How many new customers has MERC added that would be served by the Rochester Project in the last five years? For each year, identify the number of new customers for each class, and the marginal increase in natural gas consumption for the new customers.

RESPONSE:

Over the past five years, MERC has not turned away any potential new customers that would be served by the Rochester Project because of insufficient capacity. In some instances, however, customers declined to proceed with becoming a customer because the cost of the Contribution in Aid of Construction ("CIAC") was too high. This is especially true in situations that required additional transmission capacity on the NNG pipeline.

With respect to the requested information, MERC does not track a new customer's usage versus the usage of existing class customers. Instead we track each customer class's total customer usage and customer count for the year. As a result, MERC cannot say how much of an upward or downward variance in a class's usage and customer count from one year to the next is

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

attributable to current customers versus new customers versus customers who have left our system. We provide in the tables below the incremental increases/decreases in energy usage and customer counts for each customer class for each of the last five years.

Table 1: Change in Customer Usage (Total Sales in Therms by Customer Class) 2010-2014

	2010	2011	2012	2013	2014
Residential Change in Usage	-2,683,977	+1,780,772	-6,625,411	+9,051,845	+4,404,613
Residential % Change	-7.5%	+5.4%	-19.0%	+32.0%	+11.8%
Small C/I Change in Usage	-62,841	+252,394	-410,124	+622,461	+430,060
Small C/I % Change	-6.1%	+26.0%	-33.5%	+76.5%	+30.0%
Large C/I Change in Usage	-1,194,448	+1,397,778	-2,219,111	+3,802,801	+2,355,785
Large C/I % Change	-7.7%	+9.8%	-14.2%	+28.3%	+13.7%
Interruptible Change in Usage	-156,540	-416,081	-961,512	+537,230	123,966
Interruptible % Change	-4.7%	-13.1%	-34.9%	+30.0%	5.3%
Transport Change in Usage	-104,890	-303,361	+2,723,499	-3,141,785	4,725,978
Transport % Change	-0.3%	-0.8%	+7.0%	-7.6%	+12.3%

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

Table 2: Change in Customer Count 2010-2014

	2010	2011	2012	2013	2014
Residential Change in Customer Count	+310	+132	+261	+405	+363
Residential % Change	+0.8%	+0.3%	+0.7%	+1.0%	+0.9%
Small C/I Change in Customer Count	+114	+29	+116	+57	+11
Small C/I % Change	+10.8%	+2.5%	+9.7%	+4.3%	+0.8%
Large C/I Change in Customer Count	-116	+2	-95	-42	+12
Large C/I % Change	-6.4%	+0.1%	-5.6%	-2.7%	+0.8%
Interruptible Change in Customer Count	0	-12	-16	0	-3
Interruptible % Change	0.0%	-21.1%	-35.6%	-0.0%	-10.4%
Transport Change in Customer Count	0	1	0	-1	1
Transport % Change	0.0%	5.5%	0.0%	-1.0%	5.9%

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 201

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from: **MPUC Docket No.** G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Ryan Barlow
Telephone: (651) 757-1473

Date of Request: July 6, 2016
Due Date: July 18, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide the following information:

1. Assuming that the Phase I and Phase II costs are recovered from all of MERC's customers, and the capacity costs recovered through the PGA from all NNG-PGA customers including interruptible and transport customers, produce a table demonstrating the all-in monthly and annual cost for an average customer in each customer class from 2016 to the end of the useful life of the assets in question. Ensure that the final all-in cost includes *all* costs, including the costs for both MERC and NNG, and costs recovered both through riders and base rates.

2. What is the average price of excess natural gas capacity on the capacity market for the last five years?

MERC Response:

1. See Attachment_OAG_201_Part 1.

2. The average price over the past five years for capacity release across all pipelines has been $0.13356 per dekatherm. Note that that the length of each contract for capacity release varies, although most are one-month capacity release contracts.

Response by Sarah Mead and Amber Lee
Title Manager of Gas Supply/Regulatory and Leg. Affairs Manager
Department Gas Supply/Regulatory
Telephone 920-433-7647/651-322-8956

PUBLIC VERSION
HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED

BEFORE THE MINNESOTA OFFICE OF THE ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East
Suite 350
St. Paul, Minnesota 55101-2147

MPUC Docket No. G011/GP-15-895
OAH Docket No. 68-2500-33191

In the Matter of the Petition of Minnesota Energy Resources Corporation
for Evaluation and Approval of Rider Recovery for its
Rochester Natural Gas Extension Project

SURREBUTTAL TESTIMONY AND EXHIBITS OF MINNESOTA OFFICE OF THE ATTORNEY GENERAL – RESIDENTIAL UTILITIES AND ANTITRUST DIVISION WITNESS

JULIE A. URBAN

August 25, 2016

TABLE OF CONTENTS

I. BACKGROUND AND QUALIFICATIONS

Q. Please state your name.

A. My name is Dr. Julie A. Urban. I am a Utilities Economist with the Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG"). My business address is Suite 1400, 445 Minnesota Street St. Paul, Minnesota.

Q. Have you previous filed testimony in this matter?

A. Yes, I have. I filed Direct Testimony on July 1, 2016, and Rebuttal Testimony on July 28, 2016.

Q. What issues will you be addressing in this Surrebuttal Testimony?

A. In my Surrebuttal Testimony, I will respond to the Rebuttal Testimony of the Company witnesses Mr. Clabots, Ms. Mead, Ms. Lee and Mr. Sexton.

II. FORECAST METHODOLOGY

A. USE OF "PRIORI" INFORMATION IN THE SALES FORECAST

Q. Discuss the use of *a priori* information in the sales forecast.

A. I have raised concerns in prior testimony[1] that the growth models relied upon by MERC are based on *a priori* information that incorporate expectations of future growth beyond historical growth projections. This results in a sales forecast that relies upon speculative future growth and is too high. In her Rebuttal Testimony, Ms. Lee states that the Company's "forecasts were based on historical growth projections" and did not

[1] Urban Direct, at 30–31; Urban Rebuttal, at 2–3.

incorporate "an additional growth factor specific to the DMC initiative."[2] In its Petition, however, the Company stated: "The assumptions made on Rochester Residential and SC&I are primarily based on the Mayo Clinic expansion, and the economic growth in the Rochester area. These assumptions *do* have significant impact on the forecasts."[3] MERC has also stated that it used the *a priori* information concerning the DMC initiative "to gauge the "reasonableness" of the forecasting model output."[4] Furthermore, the Company's sales forecaster stated that the forecast relied on economic and demographic variables produced by Moody's Analytics. In response to OAG information requests, MERC stated that the Moody's forecasts "presumably reflect some assumption about the impact of the DMC plan" but the Company "cannot determine the degree of that impact for any particular variable."[5] In conclusion, although the Company did not include an additional growth factor based on the DMC initiative, the DMC initiative did play a role in the Company's forecast. As pointed out in Mr. Clabot's testimony, "it is still early in the DMC process," which is why I favor a phased in approach to capacity expansion in the Rochester area. Subjecting ratepayers to excess capacity costs for many years into the future based on speculative growth is not prudent.

[2] Lee Rebuttal, at 31.
[3] Petition, at 78 (emphasis added).
[4] MERC's Response to OAG 154, Schedule JAU-R-1.
[5] MERC's Response to OAG 116, attached as Schedule JAU-SR-1.

B. REVISED SALES FORECAST

Q. Did you ask the Company to revise its sales forecast?

A. Yes. I requested that that the Company rerun its sales forecast using the trend variable in the use per customer (UPC) model as suggested in my Direct Testimony[6] and the customer model described in Mr. Heinen's Direct Testimony.[7]

Q. What are the results of the revised forecast?

A. The sales forecast growth rate was substantially reduced. Table 1 below presents a comparison between the Company's forecast and the revised forecast in the average annual sales growth rate by customer class. This results in an average annual sales growth rate of *negative* 0.092 percent as compared to the Company's growth rate of 1.5 percent.[8]

Table 1

Average Annual Sales Growth Rate (2015-2025)

	Residential	SC&I	LC&I	Total
OAG Revised Forecast	0.10%	0.48%	-0.53%	-0.092%
MERC Forecast	1.87%	1.73%	0.71%	1.500%

Q. What is the impact of the revised sales forecast on the reserve margin?

A. The Company applied the forecasted annual growth rate in sales to increase the design day on an annual basis. The Company provided reserve margins for its forecast and the OAG revised forecast under a number of capacity deliverability assumptions in Table 2 (see Table 2 below). Table 2 highlights the differences in reserve margins when using MERC's initial forecast, and the modified forecast using suggestions made by the OAG

[6] Urban Direct, at 28–29.
[7] Heinen Direct, at 26–27.
[8] MERC's response to OAG IR 206, attachment OAG-206.xlsx, attached as Schedule JAU-SR-2

and the Department. Using the Company's forecast and assuming no capacity deliverability to other TBSs, the reserve margin will remain above five percent out to the year 2038/2039. When assuming that the Company has a need and the ability to deliver 20 percent capacity to other TBSs on peak day, the reserve margin remains above five

Table 2

Rochester Area NNG Reserve Margin

	No Capacity to other TBSs		20% Capacity to other TBSs	
Winter Period	Company Forecast Reserve Margin	OAG Forecast Reserve Margin	Company Forecast Reserve Margin	OAG Forecast Reserve Margin
2015/2016	-12.79%	-12.79%	-12.79%	-12.79%
2016/2017	-14.08%	-12.71%	-14.08%	-12.71%
2017/2018	-15.35%	-12.63%	-15.35%	-12.63%
2018/2019	1.33%	6.25%	-2.25%	2.49%
2019/2020	40.95%	50.15%	29.19%	37.63%
2020/2021	38.87%	50.29%	27.28%	37.75%
2021/2022	36.81%	50.43%	25.40%	37.88%
2022/2023	34.79%	50.57%	23.55%	38.01%
2023/2024	32.80%	50.70%	21.72%	38.13%
2024/2025	30.84%	50.84%	19.93%	38.26%
2025/2026	28.90%	50.98%	18.15%	38.39%
2026/2027	27.00%	51.12%	16.41%	38.52%
2027/2028	25.12%	51.26%	14.69%	38.64%
2028/2029	23.27%	51.40%	12.99%	38.77%
2029/2030	21.45%	51.54%	11.32%	38.90%
2030/2031	19.66%	51.68%	9.68%	39.03%
2031/2032	17.89%	51.82%	8.06%	39.16%
2032/2033	16.15%	51.96%	6.46%	39.28%
2033/2034	14.43%	52.10%	4.89%	39.41%
2034/2035	12.74%	52.24%	3.34%	39.54%
2035/2036	11.07%	52.38%	1.81%	39.67%
2036/2037	9.43%	52.52%	0.30%	39.80%
2037/2038	7.81%	52.66%	-1.18%	39.93%
2038/2039	6.22%	52.80%	-2.64%	40.06%
2039/2040	4.65%	52.94%	-4.08%	40.18%
2040/2041	3.10%	53.08%	-5.50%	40.31%
2041/2042	1.58%	53.22%	-6.89%	40.44%
2042/2043	0.08%	53.36%	-8.27%	40.57%
2043/2044	-1.40%	53.50%	-9.62%	40.70%

percent out to the year 2032/2033. The reserve margin based on the revised OAG forecast, assuming no capacity deliverability to other TBSs, will remain above fifty-three percent beyond the year 2043/2044. Under the assumption of 20 percent capacity deliverability to other TBSs, the reserve margin based on the OAG revised forecast, remains above forty percent beyond the year 2043/2044.[9]

In summary, the Rochester Project meets MERC's forecasted demand out to the year 2036 when using MERC's forecast. When using a forecast modified as I suggest, along with suggestions made by Mr. Heinen, the Rochester Project would be providing between forty and fifty-three percent (depending on deliverability assumptions) more gas than is necessary to satisfy *peak demand in 2044*.

Q. What do you conclude concerning this substantial decrease in capacity needs due to the revised OAG forecast?

A. The adjusted customer count estimation recommended by Mr. Heinen and the adjusted use per customer estimation recommended by myself have significant impact on forecasted sales. Energy use per customer has been trending downward for years due to a number of factors including increased efficiency in heating, cooling, and lighting technology and insulation improvements in residential, commercial, and industrial construction. As noted in my Direct Testimony, this trend should not be ignored in the modeling of forecasted sales.[10]

[9] MERC's response to OAG IR 206, attachment OAG-206.part 2.xlsx, attached as Schedule JAU-SR-2. The Company rounded the revised OAG forecast from -0.092 to -0.1 percent. A second Table 2 has been attached to reflect the actual forecast of -0.092 percent.
[10] Urban Direct, at 29–30.

III. ROLE OF ROCHESTER PUBLIC UTILITY (RPU) IN CAPACITY EXPANSION NEEDS

Q. Who provided Rebuttal Testimony on this subject?

A. Mr. Clabots, Ms. Lee, and Ms. Mead.

Q. What were their comments concerning RPU and the need to expand capacity?

A. All three Company witnesses agree that the future needs of Rochester Public Utility are an important factor to consider in this filing. I also agree. However, as discussed in my Rebuttal Testimony, RPU has stated that the Westside Energy Station that is currently under construction will be a peaking plant and will therefore have interruptible, not firm service.[11] RPU is also considering plans to build a combined heat and power facility and a combined cycle facility. The need for the combined heat and power facility is expected in 2026 and the need for the combined cycle facility is expected in 2031.[12] There is no need for firm service by RPU at this time and RPU is predicting that future firm needs will not occur until 2026.

Q. Do you have any additional concerns about the discussion regarding RPU?

A. Yes, I do. First, it would be problematic to base the Rochester Project as proposed on RPU's needs, because MERC has stated that it did not account for any of RPU's needs in its forecasting process. As the Company explained in OAG IR 108, "Prior to submitting our Petition in this proceeding, MERC asked RPU whether it anticipated increased future natural gas needs. RPU did not respond to our inquiry, and as a result MERC did not include any projection of increased RPU usage in its analysis of the need for the

[11] Urban Rebuttal, at 9.
[12] Correspondence from Mark Kotschevar, General Manager of Rochester Public Utilities, June 3, 2016, Attachment AG 2016 MERC.

Rochester Project."[13] It is unreasonable for MERC to be arguing that the Rochester Project is necessary to serve RPU, when the Company had no idea whether RPU would need additional gas at the time the Project was planned or the Petition was filed.[14]

On top of that, obtaining large amounts of capacity for a single customer or single delivery points, such as RPU, would significantly change the economics of how the costs should be borne. If MERC needs to obtain new capacity to provide gas to new plants constructed by RPU, it may be significantly less reasonable to require all customers to pay for that. If significant investment is necessary just to serve RPU, then it may be more appropriate for those costs to be paid for by RPU similar to line extensions or when new customers are added in normal circumstances. MERC first argued that the Rochester Project was necessary without any regard for RPU, and by now shifting its argument to suggest that capacity upgrades are required for large expansions by RPU, MERC may be shielding one of its large customers from customer specific costs at the expense of general ratepayers.

Q. Are there other issues concerning RPU's impact on this proceeding?

A. Yes. Both Ms. Mead and Ms. Lee observe that the proximity of the new RPU facility to the NNG pipeline make bypass a viable possibility.[15] RPU is primarily a transport customer so is not contributing to the cost of expanding capacity on the NNG pipeline. Should RPU decide to build a bypass, it would no longer be a MERC customer and would no longer contribute to the cost of the upgrades to the MERC distribution system as well.

[13] MERC's Response to OAG IR No. 108, attached as Schedule JAU-SR-3.
[14] MERC responded to OAG IR 108 in November, 2015.
[15] Lee Rebuttal, at 43 and Mead Rebuttal, at 5.

Ms. Lee recognizes that high reserve margins are an incentive for customers to "free ride" and opt for interruptible service thereby avoiding the NNG capacity expansion costs.[16] The Company's recommendation on cost allocation does not assign any of the costs associated with the capacity expansion on the NNG pipeline to interruptible or transport customers. Ms. Lee suggests that "Tariff amendments could be considered to restrict a customer's ability to select interruptible service in an environment where reserve margins are high."[17] However, Ms. Lee recommends postponement of these issues until the next rate case.[18] Persistent high reserve margins, even under the Company's optimistic growth assumptions, will encourage transport and interruptible customers to "free ride" off the firm customers and defies the economic principle of assigning costs commensurate with benefits. In addition to excess capacity costs and imposing excess construction costs on firm customers, the "free rider" incentive of such high reserve margins is yet another reason against such a large increase in capacity at this point in time.

IV. SIZE OF THE PROPOSED CAPACITY EXPANSION

Q. Is the size of the proposed capacity expansion appropriate and prudent?

A. No. There is a problem in the timing and the size of the capacity expansion. Under the current proposal, capacity will be expanded by 10,500 Dth/day in 2018 followed by additional capacity of 34,500 Dth/day in 2019. As stated in my direct and rebuttal testimony, Rochester is currently in need of additional capacity to meet peak demand.

[16] Lee Rebuttal, at 44.
[17] Lee Rebuttal, at 44.
[18] *Id.*

But MERC's proposal will obtain significantly more capacity than is reasonably necessary to meet peak demand. For example, a capacity increase of [**HIGHLY SENSITIVE TRADE SECRET BEGINS]** **[HIGHLY SENSITIVE TRADE SECRET ENDS]** If the growth predicted by the Company materializes, further expansion could be considered at a later date rather than increasing capacity to 45,000 by 2019.

Q. Is such an approach prudent considering the economies of scale associated with capacity expansion on the distribution system and the interstate pipeline?

A. Yes. [**HIGHLY SENSITIVE TRADE SECRET BEGINS]** **[HIGHLY SENSITIVE TRADE SECRET ENDS]**

The primary advantage of these phased proposals is not, as MERC suggests, merely that they came in stages. The value is that the later stages would not be undertaken *unless and until they were necessary*. In other words, a phased proposal could have immediately increased capacity and also provided MERC with the option to increase capacity further in the future. And, in the event that the future capacity increase was not necessary, MERC would have no obligation to pursue it. This approach protects ratepayers from the possibility of unnecessary construction that is based on long-term forecasting which, regardless of the quality of the forecast, is not certain. The reliance on long-term forecasts is even more problematic because Minnesota's gas utilities generally do not submit medium- to long-term forecasts for Commission review like electric utilities do in integrated resource planning dockets.[22] In addition to being "unusual,"[23] a requirement to submit long-term gas resource plans has been considered and declined by the Commission given the review mechanisms already in place via the demand entitlement dockets, true-up dockets, and the review of AAA reports.[24] That is not to say that gas utilities do not run medium- and long-term forecasts for internal use, I expect that they do but the Commission has not subjected this type of forecast to the type of scrutiny afforded to resource decisions made by electric utilities.

Instead of the approach that would deal with existing problems and allow for future upgrades when they are necessary, MERC has essentially decided that its long-term year forecast is 100% correct and that it must immediately procure the amount of capacity it believes it may need more than 20 years from now. That approach is

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[22] *See* Heinen Direct, at 7 (noting that "Minnesota regulated natural gas utilities are not subject to Commission review of their long-range expansion plans, procurement plans, or expected growth" and that MERC's present petition "marks the first time that a gas utility has filed a long-range sales forecast" in Mr. Heinen's time at the Department).

[23] *Id.*

[24] Staff Briefing Papers, *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval to Contract for Capacity on the Bison Pipeline Project*, Docket No. G-007,011/M-08-698, at 4 (Aug. 14, 2008).

unreasonable when MERC had the option of proposals that would permit further expansion if it became necessary, and insulate ratepayers from excessive costs if it was not necessary.

Q. Is there a cost differential between a smaller versus a larger capacity expansion?

A. As discussed in my Rebuttal Testimony[25] the Company estimated that limiting capacity expansion to [**HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]

Q. Does this increase in project cost warrant support for the larger project size as proposed by the Company?

A. No. As pointed out my Rebuttal Testimony the cost each year of excess capacity (as estimated by Mr. Heinen of the Department) is $3 million. Thus, the entire additional cost of the smaller project will be less than the excess capacity cost *for one year*, if the larger capacity project proposed by the company is approved.[27]

V. PEAKING PLANT ALTERNATIVE

Q. Did you offer any other alternative to the Company's capacity expansion proposal?

A. Yes. In addition to a smaller capacity expansion, I addressed the possibility of a peak-shaving facility.

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[25] Urban Rebuttal, at 10.

[27] Heinen Direct, at 35.

Q. Was there rebuttal testimony provided on this alternative?

A. Yes. Ms. Lyle provided testimony on a peak-shaving proposal. Ms. Lyle argues that a peak-shaving facility does not address projected growth in base demand. Ms. Lyle states that peak shaving "simply does not solve the capacity constraints MERC is experiencing in the Rochester area, and as a result, would not be a viable alternative."[28] The witness goes on to state that the "incremental cost per unit is expensive" and that a "thorough evaluation" of peak-shaving was not undertaken because such a facility or facilities "would not effectively serve the deficit" in the Rochester area.[29] "MERC's demonstrated need in the Rochester area is not only to meet peak demand but to also meet projected growth in base demand."[30]

Q. Do you agree with the statement that a peak-shaving facility would not address growth in base demand?

A. Yes. There is no controversy in the statement that peak-shaving facilities are not built to address growth in base demand because, by their very definition, they are built to address peak demand. However, the Company's projected growth in capacity need is based on growth in peak day demand, not base load firm demand.[31] MERC's current capacity need is not base load demand but peak demand. I believe that MERC is attempting to conflate the two types of demand.

[28] Lyle Rebuttal, at 8.
[29] *Id*.
[30] *Id*. at 7–9.
[31] Urban Direct, at p. 34.

Q. What do you mean when you say that MERC is attempting to conflate peak demand with base demand?

A. Natural gas utilities and regulators logically focus on firm peak demand when considering what firm interstate natural gas capacity or distribution capacity is appropriate to serve an LDC's firm customers. A utility's base firm demand is not typically a focal point for capacity-related discussions because it is usually much lower than firm peak demand. MERC's Rochester project is intended to ensure that firm peak demand is met now and into the future; there is no evidence in the record that MERC's base load demand in the Rochester area is nearing capacity at any time in the foreseeable future. As a rough proxy for firm base demand, the annual firm load factor for MERC-NNG, calculated by the Department after a particularly cold winter season, indicates that the firm load factor was 27.44 percent.[32] This indicates that, on average, MERC utilized less than 30 percent of its actual peak-day firm demand across its NNG PGA. This suggests that, on a PGA-wide basis, its base firm demand was approximately 27 percent of its peak firm demand. I do not dispute that the Rochester area's peak demand may be reaching its peak capacity; in fact, that is why I inquired as to whether MERC seriously considered a peak-shaving facility. But MERC's contention that a peak-shaving facility cannot meet firm base demand is neither on-point nor supported by the record.

Q. What is the evidence that MERC's current capacity need is peak demand?

A. The Annual Firm Load Factor for the 2013–14 season for MERC-NNG was 27.44 percent. This means that the average daily throughput was 27.44 percent of actual firm

[32] Department's Review of 2013-2014 Annual Automatic Adjustment Reports, Docket No. G999/AA-14-580, at 53–54 (May 5, 2015). The load factor equals the daily average firm throughput (annual firm throughput [from Table G9] divided by 365) divided by actual firm peak-day demand.

peak-day demand. This was the lowest load factor of the gas utilities in Minnesota.[33] MERC stated that its average firm load factor for the Rochester area over the past five years was between a low of 0.33 in 2015 and a high of 0.40 in 2013.[34] The OAG requested a list of the ten highest utilization days in the last five years.[35] These data are presented in Table 3 below.

Table 3

Ten Highest Utilization Days in Last Five Years

Date	Dth/day
1/16/2014	55,678
1/5/2014	53,049
1/27/2014	51,373
1/7/2015	48,343
1/21/2013	48,112
1/22/2014	47,861
1/23/2014	47,597
2/18/2015	47,410
2/5/2014	47,370
1/28/2014	47,338

Current firm capacity for Rochester is 55,169 Dth/day.[36] Firm capacity was exceeded once over the past five years on January 16, 2014. In response to another OAG Information Request, MERC stated that it "has not turned away any potential customers that would be served by the Rochester Project because of insufficient capacity."[37] These

[33] *See* Review of the 2013-2014 Annual Automatic Adjustment Reports, Minnesota Department of Commerce, Docket No. G999/AA-14-580, 53 (May 5, 2015).
[34] MERC's response to OAG IR 205, attached as Schedule JAU-SR-4. These load factors are estimated based on years beginning 7/1/2011 to 7/1/2015.
[35] MERC's response to OAG IR 121, attached as Schedule JAU-SR-5.
[36] MERC's response to DOC IR 15, attachment Rochester Design Peak Day Analysis Revised with Rochester Weather.xlsx, Schedule JAU-3.
[37] MERC's response to OAG IR 118, attached as Schedule JAU-SR-6.

responses indicate that the current capacity need for the Company is to meet peak demand not base load demand.

Q. Does Ms. Lyle provide any other argument against the possibility of using a peak-shaving facility?

A. Yes. Ms. Lyle states that "Given the design of the distribution system in and around Rochester, peak-shaving facilities simply could not address MERC's distribution system constraints."[38] I pointed out in my Direct Testimony that installing shaving facilities allow utilities to avoid installation of additional distribution piping. A staff report on the Baltimore Gas and Electric Company's (BGE) peak-shaving facilities states the following "To serve customers exclusively with interstate pipeline gas under design day-like conditions, BGE would have to reinforce its distribution piping in order to maintain the pressures needed to provide customers with reliable gas service."[39] This indicates that utilities can avoid costly upgrades to their distribution system by utilizing peak-shaving facilities. Other Minnesota natural gas utilities (CenterPoint Energy and Xcel Energy) utilize peak-shaving facilities to meet design day, or peak firm demand. Across the state, over 20 percent of utilities' demand day requirements are met by peak-shaving facilities.[40] A peak-shaving facility and the distribution upgrades of Phase I, which are already completed, may be sufficient to address current and more near-term capacity needs. The Company states that such an option would be cost-prohibitive[41] and, in the

[38] Lyle Rebuttal, at 9.
[39] Staff Report on the Baltimore Gas and Electric Company's LNG and Propane Facilities, *In the Matter of the Application of the Baltimore Gas and Electric Company for Revision in its Gas Rates*, Case No. 8829, at 4 (Oct. 2, 2000), attached as exhibit JAU-26.
[40] Review of the 2013-2014 Annual Automatic Adjustment Reports, Minnesota Department of Commerce, Docket No. G999/AA-14-580 71, Table G16 (May 5, 2015).
[41] "The cost of installing these facilities is such that the incremental cost per unit is expensive." Lyle Rebuttal, at 7.

alternative, the "design of the distribution system in and around Rochester" makes a peak-shaving facility infeasible.[42] Both of these explanations may be valid, but there is no cost or engineering study in the record to confirm this assertion by the company. In fact, Ms. Lyle states that a serious evaluation of a peak-shaving alternative was not undertaken.[43] It is thus unclear how the Company could conclude that peak-shaving fails both economic and engineering tests when the Company also admits that it performed no serious study of either or any kind.

Q. Do you recommend a peak-shaving alternative?

A. As stated in my Direct Testimony, I do not have the information or expertise to allow for the analysis that would lead to such a recommendation. In addition, the burden to produce these analyses does not fall on governmental parties. An engineering and/or a cost analysis could have been performed by the Company, but it chose instead to summarily dismiss the alternative. MERC has not shown that its decision not to study a peak-shaving alternative was reasonable. Such a study or studies are necessary to properly determine the prudency of this alternative to meet the capacity needs of Rochester.

VI. REQUEST FOR PROPOSAL (RFP) ANALYSIS

Q. Discuss the RFP analysis provided by the Company.

A. I do not believe that the analysis was sufficient. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

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[42] Lyle Rebuttal, at 9.
[43] *Id.* at 8 (noting that a "thorough evaluation of peak-shaving alternatives was not undertaken).

[HIGHLY SENSITIVE TRADE SECRET ENDS] In fact, MERC failed to provide any substantive discussion of the alternative proposals nor did the Company provide the RFP or the responses to the RFP until prompted through discovery. The detail provided in Mr. Sexton's Rebuttal Testimony should have been provided in his Direct Testimony. Information on the RFP responses and the analysis of those responses was incomplete and non-transparent in both the Company's Petition and its Direct Testimony. The fact that Mr. Sexton conducted additional analysis that was introduced in Rebuttal testimony, more than six months after the Petition was filed and an even greater time after MERC chose a project, only serves to highlight that the Company's initial analysis was incomplete and insufficient.

VII. CAPACITY RELEASE TO MITIGATE EXCESS CAPACITY COSTS

Q. What is a capacity release and how is it pertinent to this docket?

A. A capacity release is a sale of excess capacity on the open market, usually on a short-term basis. A capacity release sale would allow a company to mitigate excess capacity. Mr. Heinen discusses this option in his Direct Testimony[45] and Ms. Mead addresses his

[45] Heinen Direct, at 47–48.

discussion in her Rebuttal Testimony.[46] As Mr. Heinen points out, the revenue from these sales is "typically small compared to the original purchase price of the capacity."[47]

Q. Is it possible to estimate a comparison?

A. Not directly. Both Mr. Heinen and Ms. Mead discuss the possibility of longer-term release agreements due to the size and longevity of excess capacity. Longer-term release agreements will generate more revenue than short-term agreements. The average price for capacity release across all pipelines over the past five years is $0.013356 per therm.[48]

Table 4 provides the comparison between this average market price of a capacity release and the cost of new capacity being added. One can see that the average price of capacity release is but a fraction of the cost of new capacity. It is uncertain whether there will be demand for this capacity. In addition, capacity release prices could fall even lower due to the amount of excess capacity that will be made available via this expansion proposal.

[46] Mead Rebuttal, at 9–11.
[47] Heinen Direct, at 47.
[48] Note that the length of each contract for capacity release varies, although most are one-month capacity release contracts. MERC's response to OAG IR 201, attached as Schedule JAU-SR-7.

Table 4

Release Capacity Price vs. Market Price

Total Distribution and NNG Cost per therm[1]	Average Price for Capacity Release[2]	Loss per therm	Market Price as percent of New Capacity Cost
$0.00010	-	-	
$0.00027	-	-	
$0.00498	-	-	
$0.02543	$0.013356	$0.01208	52.52%
$0.04089	$0.013356	$0.02753	32.66%
$0.04146	$0.013356	$0.02811	32.21%
$0.04174	$0.013356	$0.02839	32.00%
$0.04153	$0.013356	$0.02818	32.16%
$0.04022	$0.013356	$0.02686	33.21%
$0.03922	$0.013356	$0.02586	34.06%
[1]Lee Direct Testimony, Exhibit (ASL-1), at 1 and 3			
[2]MERC Response to OAG IR 201			

VIII. REPONSE TO COMPANY WITNESS MR. DAVID CLABOTS

Q. What do you want to address in Mr. Clabots' Rebuttal Testimony?

A. Mr. Clabots suggests that my comparison of the growth rate using the model with Rochester weather and the time trend variable to the growth rate filed in the petition "is a bit misleading."[49]

[49] Clabots Rebuttal, at 14.

Q. Do you agree with Mr. Clabot's characterization of your analysis?

A. No. I was simply comparing the growth rate filed in the petition to the growth rate based on what I thought to be the most appropriate model to be used in forecasting residential use. The inclusion of a time trend variable into the Company's forecasting model based on NNG_PGA weather data, changes the growth rate from 2.00 percent to 1.12 percent. The inclusion of a time trend variable into the Company model based on Rochester weather data changes the growth rate from 1.87 percent to 1.34 percent.[50]

Q. Do you have anything else that you want to address in Mr. Clabots' Rebuttal Testimony?

A. Yes, I have two more comments regarding Mr. Clabots' testimony. First, at page 13 of his Rebuttal Testimony, Mr. Clabots' seems to be indicating that I assumed that weather normalized data was used to estimate sales.[51] I used normalized weather data in Table 2 of my Direct Testimony[52] to help determine whether there was any discernable growth trend in firm sales.

Second, at page 17, Mr. Clabots "notes" that I did not prepare a forecast of my own, despite seeking information on MERC's sales forecast methodology through information requests. The ultimate question in front of the Commission is not which sales forecast is most reasonable, it is whether MERC's first-of-its-kind petition for pre-approval of an infrastructure project should be approved or rejected. My analysis of MERC's sales forecast has uncovered flaws in assumptions and methodology that are well-documented in my testimony and that support my ultimate recommendation to reject

[50] Urban Direct, Schedule JAU-15 (MERC's Response to OAG IR 155.7, Attachment OAG-155-7 Residential UPC Supplemental Response.xlsx).
[51] Clabots Rebuttal, at 13.
[52] Urban Direct, at 28.

the petition. Given the unique nature of this proceeding, which is focused on whether a specific infrastructure project is reasonable to meet future growth, an independent sales forecast with a lower growth rate would lead me to the same conclusion: to reject MERC's petition. Despite this, I have requested that the Company rerun their sales forecast using the trend variable in the use per customer model as suggested in my Direct Testimony[53] and the customer model described in Mr. Heinen's Direct Testimony.[54] The results of this revised forecast were discussed earlier in this testimony and the results show a marked reduction in the expected sales growth in the Rochester Area. This leads me to the same conclusion I arrived at in prior testimony: MERC's sales forecast is unreasonable. Therefore, MERC's proposal to immediately secure the full amount of capacity estimated by its forecast in the 2040s is not a reasonable plan to satisfy the natural gas demand in the Rochester area.

IX. RESPONSE TO COMPANY WITNESS MS. AMBER LEE

Q. What would you like to address in Ms. Lee's Rebuttal Testimony?

A. Ms. Lee's discussion of my alternate recommendation—which I recommend *if and only if* the Commission the Commission approves MERC's petition—that the Commission make a finding that only part of the Rochester Project is used and useful, in order to protect current ratepayers from paying for future infrastructure that may not be needed.[55]

[53] Urban Direct, at 28–29.
[54] Heinen Direct, at 26–27.
[55] Urban Direct, at 56–57.

Q. Could you provide additional details about your alternate recommendation?

A. I conclude that there is an immediate need of additional capacity for the Rochester area based on the Company's current design day. However, the size of the proposed capacity expansion is too large. Even assuming the Company's 1.5 percent annual growth rate in the design day requirement for Rochester, the reserve margin for Rochester under the current proposal will be nearly 17 percent until the year 2040 and 24% for the NNG-PGA until at least 2040.[56] The size of the capacity expansion will require significant capital investment which will impose a significant financial burden on ratepayers. The risk of stranded assets is too high. Caution is justified given the level of projected growth in the area. Exposing current ratepayers to this level of risk is unreasonable; my alternative recommendation ensures that even if the Company's petition is granted, ratepayers will not have to bear the entirety of that risk.

Q. What are Ms. Lee's conclusions concerning your alternate recommendation?

A. Ms. Lee concludes that my alternate recommendation "implies the ability to precisely predict the future and obtain the exact amount of capacity needed."[57]

Q. Is this what you are implying?

A. No, quite the opposite. I am saying that there is a lot of uncertainty surrounding any forecast decades into the future, and the same holds true for the growth in the Rochester area in the coming decades. Instead of exposing ratepayers to the stranded cost of an overbuilt system, a more incremental approach such as the alternate recommendation I make here, may be more prudent.

[56] Urban Direct, at 37–39.
[57] Lee Rebuttal, at 36.

Q. What other conclusions does Ms. Lee draw concerning your alternate recommendation?

She concludes that my recommendation is "not realistic" and that "[h]olding a portion of the Project hostage is inconsistent with the need to provide the Rochester area with sufficient capacity to meet current and future needs."[58] However, as pointed out earlier in my testimony, a smaller capacity expansion of 17,500 Dth/day would provide a reserve margin above 4 percent to the year 2026.[59] Given the level of uncertainty over growth beyond the year 2026, a more modest expansion is a more prudent and realistic approach that would expose ratepayers to far less risk as compared to the Company's current proposal.

In addition Ms. Lee states that if Commission approval of the current proposal is denied that it "would likely be difficult to renegotiate under future conditions."[60] This is pure speculation. NNG proposed several phase in options to avoid the risks of overbuilding, which has been discussed in previous testimony. Moreover, it would be unreasonable for the Commission to approve the Project—not to mention, to ask ratepayers to pay for such a project—simply because the alternative may be difficult for the Company to renegotiate. If the Commission determines that MERC has not selected a reasonable project, then the Company cannot force its ratepayers to pay for the Company's imprudence.

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[58] Lee Rebuttal, at 38–39.
[59] NNG's February 18, 2025 Supplemental Proposals, at 3, attached as Schedule JAU-5.
[60] Lee Rebuttal, at 39.

Ms. Lee also states that if the project as currently proposed is denied that MERC "would notify the City of Rochester about limitations on natural gas service . . . ."[61] As already noted in this testimony, MERC "has not turned away any potential customers that would be served by the Rochester Project because of insufficient capacity."[62] With the Phase I distribution upgrades completed, an immediate capacity expansion, closer to the amounts proposed in my previous testimony, may be possible within the timeline for the current proposed expansion of 2019. I am troubled by the fact that MERC characterizes my alternate recommendation as, in effect, holding the project hostage, while shortly thereafter stating that MERC would discontinue its obligation to serve its captive, firm customers if the Commission rejects its petition.

X. CONCLUSION

Q. What is your recommendation regarding the reasonableness and prudence of MERC's proposal?

A. I conclude that MERC's proposal is not reasonable or prudent and recommend that the Commission make such a finding. The forecast of 1.5 percent growth in peak demand is too high and not substantiated by historic demand. The RFP analysis was flawed and incomplete, resulting in the recommendation of a much larger expansion in capacity than is necessary. To the extent that MERC needs to address current and near-term demand for firm natural gas in the Rochester area, the Company should take a more phased in expansion path that allows for additional expansion should non-historic growth

[61] Lee Rebuttal, at 38.
[62] MERC's response to OAG IR 118, Schedule JAU-SR-6.

materialize, but does not expose rate payers to the risk of excess capacity for many years into the future. In the alternative, if and only if the Commission finds that the project is reasonable, I recommend a portion of the project not be recoverable until it is actually needed by MERC customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.