Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: **January 15, 2014 .... Agenda Item #3**

Company: Minnesota Energy Resources Corporation (MERC)

Docket Nos. **G-011/M-11-1082**
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-PNG GLGT) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2011.

G-011/M-11-1083
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-PNG Viking) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2011.

G-011/M-11-1084
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-PNG NNG) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2011.

G-007/M-11-1088
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-NMU) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2011.

Issue: Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, effective November 1, 2011?

Staff: Bob Brill 651-201-2242
Bob Harding 651-201-2237

Relevant Documents

G-011/M-11-1082 (MERC-PNG GLGT)
MERC Initial Petition ....November 1, 2011
Department of Commerce (Department) Comments .... January 3, 2012
MERC Reply Comments .... January 12, 2012

G-011/M-11-1083 (MERC-PNG VGT)
MERC Initial Petition ....November 1, 2011
Department of Commerce (Department) Comments .... January 10, 2012
MERC Reply Comments .... January 13, 2012
Department Reply Comments... August 1, 2012
MERC Supplemental Reply Comments .... August 13, 2012

G-011/M-11-1084 (MERC-PNG NNG)
MERC Initial Petition ....November 1, 2011
Department of Commerce (Department) Comments .... March 12, 2012
MERC Reply Comments .... March 22, 2012
Department Reply Comments... August 1, 2012
MERC Supplemental Reply Comments .... August 13, 2012

G-007/M-11-1088 (MERC-NMU)
MERC Initial Petition ....November 1, 2011
Department of Commerce (Department) Comments .... March 12, 2012
MERC Reply Comments .... March 22, 2012
Department Reply Comments... August 1, 2012
MERC Supplemental Reply Comments .... August 13, 2012

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless otherwise noted.

Table of Contents

Statement of the Issue 1
Introduction 1
Minnesota Rules 1
Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, effective November 1, 2011? 2
MERC 2
MERC's Design Day (DD) Requirements 2
MERC's Demand Entitlement Contract Levels 2
MERC's Reserve Margin 3
MERC's Demand Entitlement Contract Costs 3
Other Demand Entitlements Contract Costs 4
Department 5
Design Day and Demand Entitlement Requirements 6
Reserve Margins 6
Balancing Costs (includes SMS, LMS, Union Balancing, and etc.) 6
PUC Staff Comment 7
Additional Bison and NBPL contract costs 7
Cost Recovery of the additional Bison/NBPL contracts 8
Elimination of the LS Power arrangement 9
Balancing costs shift from demand to commodity recovery 10
Should the Commission approve MERC's proposed allocation method for assigning storage demand charges to firm and interruptible customers? 11
PUC Staff Comment 12
Decision Alternatives 13

Statement of the Issue

Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, effective November 1, 2011?

Introduction

MERC has entered into various natural gas supply and interstate pipeline contracts to provide natural gas to its customers. MERC annually reviews and updates these contracts to ensure continued system reliability of natural gas supply deliveries to its customers.

MERC's annual demand entitlement[1] petitions seek Commission approval to recover certain cost and capacity changes in these interstate pipeline transportation entitlements, supplier reservation fees, and other demand-related contract costs and to implement the rate impact of these petitions through its Purchased Gas Adjustment (PGA)[2] charges.

PUC staff reviewed MERC's Demand Entitlement Petitions and the several rounds of *Comments* filed by MERC and the Department. The Department and MERC have worked together and resolved all of issues raised by the Department. PUC staff generally agrees with the Department's January 3, 2012 (in docket #11-1082) and August 1, 2012 (in docket #s 11-1083, 11-1084 and 11-1088) recommendations with minor qualifications.

For its briefing papers, PUC staff is consolidating all of MERC's 4 PGA areas[3] into one discussion, but will discuss issues related to a particular PGA area separately.

Minnesota Rules

Minnesota Rule, part 7825.2910, subpart 2[4] require gas utilities to make a filing whenever there is a change to its demand-related entitlement services provided by a supplier or transporter of natural gas.

---

[1] D*emand entitlements* can be defined as reservation charges paid by the Local Distribution Company (LDC) to an interstate natural gas pipeline to reserve pipeline capacity used to store and transport the natural gas supply for delivery to its system and contract charges associated with the LDC procuring its gas supply; these costs are recovered through the LDC's PGA.

[2] The Purchased Gas Adjustment is a mechanism used by regulated utilities to recover its cost of energy. Minn. Rules 7825.2390 through 7825.2920 enable regulated gas and electric utilities to adjust rates on a monthly basis to reflect changes in its cost of energy delivered to customers based upon costs authorized by the Commission in the utility's most recent general rate case.

[3] MERC has four separate PGA areas, MERC-NMU (11-1088), MERC-PNG Viking (11-1083), MERC-PNG GLGT (11-1082), and MERC-PNG NNG (11-1084).

[4] Filing upon a change in demand, is included in the Automatic Adjustment of Charges rule parts 7825.2390 through 7825.2920 and requires gas utilities to file to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.

Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, effective November 1, 2011?

MERC

MERC's Design Day (DD) Requirements

MERC calculated its 2011-2012 Design Day (DD) requirements at 285,326 Mcf/day.

Table 1 - Design Day (DD) requirements[5] by PGA areas (reflected in Mcf/day):

Total MERC	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
285,326	57,989	6,851	9,304	211,182

Table 2 - DD requirements by interstate pipeline (reflected in Mcf/day):

Pipeline	Total	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
NNG	234,960	23,778			211,182
Viking	17,897	11,046	6,851		
GLGT	24,174	14,870		9,304	
Centra	8,295	8,295			
Total	285,326	57,989	6,851	9,304	211,182

MERC's Demand Entitlement Contract Levels

To transport its DD requirements, MERC used a series of interstate pipeline contracts to meet its annual total system transportation and storage requirements for each PGA area, i.e. demand entitlements. The 2011-2012 transportation demand entitlement contract levels were modified from the previous 2010-2011 levels, which resulted in 300,801 Mcf/day of available interstate pipeline transportation capacity.

Table 3 – Transportation Demand Entitlements[6] by PGA area (reflected in Mcf/day):

Total MERC	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
300,801	62,100	7,116	10,149	221,436

[PUC staff note: The transportation demand entitlements reflected in Table 3 <u>does not</u> include the 50,000 Dth/d Bison and NBPL interstate pipeline contracts.]

---

[5] Includes Transportation only, does not include Storage Entitlements.
[6] Ibid.

MERC's Reserve Margin

The Reserve Margin is the difference between MERC's DD requirements and its transportation demand entitlements. MERC stated that its reserve margin in each PGA area is appropriate given the need to balance the uncertainty of DD conditions, customer demand during these conditions, and the need to protect against the potential firm gas supply loss; maintain system reliability.

Table 4 - Reserve Margins[7] by PGA areas.

	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
Quantities in Mcf[8]	4,111	265	845	10,254
As a Percentage[9]	7.09%	3.87%	9.08%	4.86%

Table 5 - Reserve Margin – MERC total system

All Dockets-Total MERC	Quantities in Mcf
Total MERC Reserve Margin	15,475
Total MERC DD requirements	285,326
Reserve Margin as a percentage	**5.42%**

MERC's Demand Entitlement Contract Costs

In its 2010-2011 demand entitlement petitions, MERC is seeking Commission approval for its Bison/NBPL interstate pipeline contracts. The Commission decision is expected at its January 15, 2015 Agenda meeting.

MERC proposed to recover its 2010-2011 demand entitlement contract costs of $34,069,682 while MERC proposed to recover 2011-2012 demand entitlement costs of $35,692,006, an increase of $1,622,324. The majority of this increase is caused by including an annual level of Bison/NBPL contract expense in MERC's 2011-2012 petitions as opposed to only 9½ months of costs in its 2010-2011 demand entitlement petitions.[10] MERC has allocated the total 50,000 Mcf/day capacity to PNG-NNG at 44,940 Dth/day and to NMU at 5,060 Dth/day.

As previously stated in MERC's 2010-2011 demand entitlement petitions, the Bison/NBPL capacity does not add any incremental capacity to its demand entitlements, but allows MERC to use Rockies supply for PNG-NNG and NMU-NNG customers at NBPL's interconnection with NNG. Tables 6a reflects the Bison/NBPL contract cost as part of MERC's demand entitlement costs, while Table 6b does not reflect the contracts as part of MERC's demand entitlement costs.

[7] See Appendix A for calculation

[8] Calculated by taking the Total Demand Entitlements contracts and subtracting the total DD requirements

[9] Calculated by dividing the difference between the total Demand Entitlements contracts and the total DD requirements by the total DD requirements

[10] The contracts did not start until January 15, 2011, the in-service date of both Bison and the NBPL facilities

Table 6a - Transportation Demand Entitlement Costs, with Bison and NBPL:

PGA area	2010-2011 Demand Cost of Gas	2011-2012 Demand Cost of Gas	Difference
MERC-NMU	$5,145,359	$5,358,794	$213,435
MERC-PNG Viking	$285,943	$256,818	($29,125)
MERC-PNG GLGT	$440,895	$387,264	($53,631)
MERC-PNG NNG	$28,197,485	$29,689,130	$1,491,645
Total	**$34,069,682**	**$35,692,006**	**$1,622,324**

Table 6b - Transportation Demand Entitlement Costs, without Bison and NBPL:

PGA area	2010-2011 Demand Cost of Gas	2011-2012 Demand Cost of Gas	Difference
MERC-NMU	$3,754,970	$3,872,854	$117,884
MERC-PNG Viking	$285,943	$256,818	($29,125)
MERC-PNG GLGT	$440,895	$387,264	($53,631)
MERC-PNG NNG	$16,740,074	$16,491,870	($248,204)
Total	**$21,221,882**	**$21,008,806**	**($213,076)**

Other Demand Entitlements Contract Costs

In its 2011-2012 demand entitlement petitions, MERC terminated the LSP Peaking Service provision with LS Power and replaced the capacity with a physical delivered Gas Daily NNG Zone Delivery call option of 12,500 Mcf/day (11,235 Mcf/day (PNG-NNG) and 1,265 Mcf/day (NMU-NNG). Further, NNG sold its line that served the City of Ortonville to Northwestern Energy in April 2011. Ortonville is a PNG-NNG customer, this capacity (910 Dth) was directly assigned to PNG-NNG.

For PNG-GLGT, PNG-Viking, NMU-GLGT, NMU-Viking, and NMU-NNG, MERC terminated its Nexen PSO and replaced it with AECO Storage (located in Canada). This arrangement allows MERC to sell its gas at its AECO storage point to a natural gas supplier and then re-buy an equivalent volume at Viking's Emerson/Spruce receipt point (gas swap); the gas is then transported to its PNG-GLGT, PNG-VGT, and NMU (GLGT, VGT and Centra) customers. The gas swap substitutes the need for a contract for firm transport on TransCanada Pipeline (TCPL) to transport the gas from AECO to Emerson/Spruce, while providing additional storage capacity to its system. The cost of TCPL transportation is approximately $930,000 compared to the $417,000 for the AECO storage gas swap.

MERC's NMU-Viking and PNG-Viking purchased firm capacity from Viking Gas Transmission (VGT), which replaced the Wadena Call Option from the previous year. Capacity on VGT was allocated between MERC-NMU and MERC-PNG-VGT based on design day numbers.

(PUC staff has summarized MERC's transportation DD requirements and demand entitlements in ***Appendix A***, and its demand entitlement costs in ***Appendix B***.)

Department

The Department reviewed MERC's proposed Design Day (DD) requirements, demand entitlements, resulting reserve margins, and the additional Bison/NBPL contracts for 50,000 Dth/day, and other miscellaneous changes that occurred since MERC's last 2010-2011 demand entitlement petitions.

The Department summarized MERC's proposed DD requirements by PGA area, for a total increase of 16,334 Mcf/day, see Table 7:

Table 7 – MERC's DD requirements

PGA area	2010-2011	2011-2012	Difference	% increase/(decrease)
MERC-NMU	57,662	57,989	327	0.57%
MERC-PNG Viking	7,292	6,851	(441)	(6.05%)
MERC-PNG GLGT	9,440	9,304	(136)	(1.44%)
MERC-PNG NNG	194,598	211,182	16,190	8.32%
Total	268,992	285,326	16,334	6.07%

MERC's proposed changes to it 2011-2012 demand entitlement requirements and Reserve Margin levels in its 4 PGA areas are summarized in Tables 8 and 9.

Table 8 – MERC's Demand Entitlements requirements

PGA area	2010-2011	2011-2012	Difference	% increase/(decrease)
MERC-NMU	71,819	62,100	(9,719)	(13.53%)
MERC-PNG Viking	7,625	7,116	(509)	(6.68%)
MERC-PNG GLGT	11,500	10,149	(1,351)	(11.75%)
MERC-PNG NNG	233,627	221,436	(12,191)	(5.22%)
Total	324,571	300,801	(23,770)	(7.32%)

Table 9 – Reserve Margin Comparison by PGA area

PGA area	2010-2011 Demand Entitlement Filing	2011-2012 Demand Entitlement Filing	Difference	% Difference
MERC-NMU	24.55%	7.09%	(17.46%)	(71.12%)
MERC-PNG Viking	4.57%	3.87%	(0.70%)	(15.32%)
MERC-PNG GLGT	21.82%	9.08%	(12.74%)	(58.39%)
MERC-PNG NNG	20.06%	4.86%	(15.20%)	(75.77%)

The Department has stated in previous dockets that a typical Reserve Margin range is between 5% - 7%.

Design Day and Demand Entitlement Requirements
After various rounds of *Comment* and *Reply Comments*, the Department reviewed MERC's proposed levels of DD requirements and demand entitlements, and determined that the proposed levels were reasonable.

Reserve Margins
The Department reviewed MERC's adjustments to its DD requirements and the demand entitlement contract, including the elimination of the LS Power arrangement. The Department stated that all 4 PGA areas' reserve margins decreased in the 2011-2012 demand entitlement petitions when compared to the 2010-2011 petitions and determined that the proposed reserve margin percentages were reasonable.

Balancing Costs (includes SMS, LMS, Union Balancing, and etc.)
On MERC's system, all firm and non-firm customers are balanced behind MERC's system. Transportation customers are cashed out monthly. MERC stated that it has the responsibility to balance all customers behind its system; and stated that the balancing costs are solely paid for by its firm customers through the PGA demand portion even though all firm and non-firm customers benefit from these balancing services.

As a result of its review, the Department recommended that the Commission require MERC to remove all balancing costs[11] from demand costs and move the costs to commodity portion in its September 1, 2012 monthly PGA filings to coincide with the Annual Automatic Adjustment (AAA) Report and True-up filing due on September 1, 2012 thus ensuring that all customers who benefit from these services pay for the associated costs.

The Department justified its recommendation by stating that the Commission has approved similar proposals of other regulated gas utilities, including Great Plains Natural Gas Company, to allocate its storage and balancing costs to all sales customers effective November 1, 2010.[12] The Department concluded that all sales customers benefit from storage and balancing services and thus all storage and balancing costs should be allocated to all sales customers.

As a result of its analysis, the Department recommended that the Commission:

- approve MERC's demand entitlement level for all PGA areas;

- approve the PGA recovery of costs associated with MERC's proposed demand entitlement level effective November 1, 2011 for MERC PNG-GLGT and PNG-Viking;

[11] Includes SMS, LMS, Union Balancing, and etc.
[12] See the Commission's *September 30, 2010 Order Accepting Demand Entitlement Filings, Requiring Consultation, and Requiring Other Action*.

- approve the PGA recovery of costs associated with MERC-NMU's proposed demand entitlement levels effective November 1, 2011 with the modification that MERC recover costs associated with Storage and the Bison contract through the commodity portion of the monthly PGA;

- approve the PGA recovery of costs associated with MERC-PNG's Northern PGA system proposed demand entitlement levels effective November 1, 2011 with the modification that MERC recover costs associated with Storage and the Bison contract through the commodity portion of the monthly PGA; and

- Order MERC to remove all balancing costs such as (SMS, LMS, Union Balancing, etc.) from demand costs and move them to commodity costs in its September 1, 2012 monthly PGA filings to coincide with the *Annual Automatic Adjustment (AAA) Report and True-up filing* due on September 1, 2012 costs thus ensuring that all sales customers who benefit from these services pay for the associated costs.

PUC Staff Comment

PUC staff reviewed the 2011-2012 demand entitlement petitions for all of MERC's PGA areas and appreciates all the party comments. Staff believes that for the time period at issue in these dockets, all issues have been resolved by the parties in the various rounds of *Comments* and *Reply Comments.* PUC staff believes that the Department's analysis covers most of the relevant factors and will not repeat those comments.

PUC staff generally agrees with the Department's January 3, 2012 (in docket #11-1082) and August 1, 2012 (in docket #s 11-1083, 11-1084 and 11-1088) recommendations. PUC staff continues to be concerned over MERC's economic value of its Bison and NBPL contracts and its cost recovery, and the elimination of the LS Power arrangement.

Additional Bison and NBPL contract costs

In the 2010-2011 demand entitlement dockets, the Department analyzed MERC's proposed Bison/NBPL contracts and determined it to be reasonable based on the facts known to MERC in its 2008 petition. The Department has continued that recommendation for the 2011-2012 petitions.

PUC staff[13] has previously discussed the Bison/NBPL contracts in its briefing papers for the 2010-2011 demand entitlements petitions. [14]

[13] See 2010-2011 demand entitlement petitions, PUC staff briefing papers, pp. 8-10

[14] In Docket 08-698, MERC submitted its petition to the Commission requesting preapproval for its bid (i.e. its offer and precedent agreement) for capacity of 50,000 Dth/day on the proposed Bison Pipeline Project for a ten (10) year term at a negotiated rate of $0.55 per Dth. Further, MERC submitted a proposal for Northern Border capacity of 49,690 Dth/day[14] for a ten (10) year term at a negotiated rate of $.23 per Dth. At its August 21, 2008 meeting, the Commission voted to take no action in this docket.

In the 2011-2012 demand entitlement petitions,[15] MERC has requested Bison/NBPL contract cost recovery of approximately $14.7 million. To offset this additional contract costs, MERC continues to state that it will achieve projected cost savings based on it being able to exploit the difference in purchased gas cost at Ventura, Iowa pipeline interconnection point, and the cost of gas purchased in the Rocky Mountains.

PUC staff continues to believe that MERC utilized the best information known at the time when the contracts were signed, in 2008. As discussed in the 2010-2011 demand entitlement petitions, PUC staff continues to be of the opinion that the Bison/NBPL contract option may not currently be the least cost gas option to supply its customers. While PUC staff firmly believes that a LDC should have a diversified gas supply, the cost of the diversification should not over-burden MERC's rate payers.

PUC staff is not recommending any changes to the Department's recommendation regarding these contracts, but it is of the opinion that the Commission may wish to require MERC to address the Bison/NBPL contracts in MERC's 2015-2016 demand entitlement petitions, by requiring MERC to evaluate available gas supply alternatives to its Bison/NBPL contracts and provide the parties with its analysis in its 2015-2016 demand entitlement petitions. (MERC's 2014-2015 demand entitlement petitions are pending in Docket Nos. G-011/M-14-660 and 661.)

Cost Recovery of the additional Bison/NBPL contracts

As reflected in MERC's 2011-2012 demand entitlement petitions, MERC continues to seek cost recovery of the Bison/NBPL contracts through the demand portion of its PGA. In its August 1, 2012 comments for these petitions, the Department continued to recommend that MERC recover its Bison and NBPL contract costs proposal to NMU (docket 11-1088) and PNG-NNG (docket 11-1084) PGA areas through the PGA commodity portion, as follows:

- <u>approve the PGA recovery of costs associated with MERC-NMU's proposed demand entitlement levels effective November 1, 2011 with the modification that MERC recover costs associated with</u> Storage and <u>the Bison contract through the commodity portion of the monthly PGA (only the underlined portion applies to the Bison/NBPL recommendation);</u>

- <u>approve the PGA recovery of costs associated with MERC-PNG's Northern PGA system proposed demand entitlement levels effective November 1, 2011 with the modification that MERC recover costs associated with</u> Storage and <u>the Bison contract through the commodity portion of the monthly PGA (only the underlined portion applies to the Bison/NBPL recommendation)</u>; and

The Department's justification was that it believes all of MERC's sales customers benefit from these contracts (including firm, joint and interruptible sales customers), not just the firm sales customers.

[15] Reflects an annual cost for the current period, where the 2010-2011 petitions only included 9 1/2 months of costs; the contract has an effective date of January 15, 2011.

PUC staff continues to believe it would be impractical for the Commission to accept the Department's original recommendation because MERC's annual true-up petitions and Automatic Annual Adjustment (AAA) reports for 2010, 2011, 2012, and 2013 have been ruled on by the Commission. Thus, without reopening those dockets, no mechanism appears readily available to the Commission that would allow the Commission to require MERC to adjust its monthly customer billings back to November 2010 to reflect the cost recovery change from demand to commodity. [16]

In the 2010-2011 MERC demand entitlement dockets, PUC staff suggested to the Commission that this demand to commodity cost recovery shift be made effective as of November 1, 2014.[17] PUC staff continues to recommend to the Commission that it modify the Department's recommendation to clarify the effective date of the cost recovery shift from demand to commodity in its PGA. If the Commission issues informal letter orders adopting the Department's recommendations in these dockets, it may want to make clear in its order that it is not adopting that part of the Department's recommendation.

Elimination of the LS Power arrangement

In its 2011-2012 demand entitlement petitions, MERC eliminated the 29,100 Mcf/day LS Power arrangement[18] and replaced it with a physical delivered 12,500 Mcf/day NNG Zone GDD Call Option contract.

MERC stated that this gas daily call option delivered to MERC's EF Zone was a short term contract for a period starting December 1, 2011, through February 29, 2012. The purpose of the contract was to: (1) replace the LS Power contract, (2) meet the theoretical peak day and (3) address the positive reserve margins that have occurred in the previous demand entitlement filings.

The main benefit of this change is that MERC was able to reduce its Reserve Margin from its 2010-2011 petition level of 20.06% to the 2011-2012 petition level of 4.86%, which is more in line with the Department's reserve margin range of 5% to 7%. This change reduced MERC's cost by approximately $345,000 during the two time periods.

As a result of the information provided by MERC in its Reply Comments, the Department concluded that MERC's proposal is reasonable.

PUC staff agrees.

[16] From the 2010-2011 petitions to the current 2014-2015 demand entitlement petitions, MERC has continued to include the Bison and NBPL contract costs in its demand PGA factors. Because it has taken time to bring MERC's 2011-2012 demand entitlement petitions to the Commission for a decision; PUC staff believes that any change in cost recovery should be made on a prospective basis.

[17] Since November 1, 2014 has already passed and MERC has billed its customers for this time period using demand cost recovery in its calculation, the period of time from November 1, 2014 until the effective date of the Commission Order should be trued-up in MERC's 2014-2015 annual true-up filing and AAA report, which will be filed on September 1, 2015.

[18] Provided MERC with 20 days of capacity during the months of December through February

Balancing costs shift from demand to commodity recovery
As result of its review, the Department suggested to the Commission that it require MERC to change its recovery of balancing costs from the demand portion of the PGA to the commodity portion. The Department's reasoning was that MERC made statements in these dockets that all customers benefit from balancing services since MERC balances all customers behind its system on a daily basis; therefore, balancing services benefit all sales (firm, joint, and interruptible) as well as transportation customers.[19] The Department recommended to the Commission the following:

- Order MERC to remove all balancing costs such as (SMS, LMS, Union Balancing, etc.) from demand costs and move them to commodity costs in its September 1, 2012 monthly PGA filings to coincide with the Annual Automatic Adjustment (AAA) Report and True-up filing due on September 1, 2012 costs thus ensuring that all sales customers who benefit from these services pay for the associated costs. [Emphasis Added]

PUC staff believes it would be impractical for the Commission to accept the Department's recommendation with a September 1, 2012 effective date because MERC's annual true-up petitions and Automatic Annual Adjustment (AAA) reports for 2011, 2012, and 2013 have been ruled on by the Commission. Thus, without reopening those dockets, no mechanism appears readily available that would allow the Commission to require MERC to adjust its monthly customer billings back to September 2012 to reflect the cost recovery change from demand to commodity.

From these 2011-2012 dockets to the current 2014-2015 demand entitlement dockets, MERC has continued to include all balancing costs such as (SMS, LMS, Union Balancing, etc.) in its demand PGA factors. Because it has taken time to bring MERC's 2011-2012 demand entitlement petitions to the Commission for a decision; PUC staff believes that any change in cost recovery should be made on a prospective basis.

PUC staff suggests to the Commission that this demand to commodity cost recovery shift for all balancing costs such as (SMS, LMS, Union Balancing, etc.) be made effective as of November 1, 2014. Since November 1, 2014 has already passed and MERC has billed its customers for this time period using demand cost recovery in its calculation, the time period from November 1, 2014 until the effective date of the Commission Order should be trued-up in MERC's 2014-2015 annual true-up filing and AAA report, which will be filed on September 1, 2015. PUC staff is recommending to the Commission that it modify the Department's recommendation to clarify the effective date of the cost recovery shift from demand to commodity in its PGA.

[19] Transportation customers are cashed out at the end of each month

Should the Commission approve MERC's proposed allocation method for assigning storage demand charges to firm and interruptible customers?

In Docket No. 06-1208, the Commission requested MERC to submit its proposal on storage classification and allocation. On March 7, 2008, MERC submitted its proposal to allocate all storage demand charges to both firm and interruptible sales customers through its commodity charges. In the 2011-2012 demand entitlement petitions, MERC and the Department continued their discussion of assigning storage demand costs to MERC's commodity costs. MERC's initial petitions do not reflect the assignment of demand storage costs to the commodity factors, with the exception of Attachment 11, page 2[20] provided by MERC that shows the effect of re-classifying storage cost recovery in its commodity factors. The Department continued to endorse its original recommendation to the Commission that MERC be required to reflect the storage demand costs in its commodity factors.[21]

In its January 10, 2012 comments for the 2011-2012 demand entitlement petitions, the Department continues to recommend that MERC apply its storage proposal as follows:

- For PNG-Viking (docket 11-1083), allow the proposed recovery of associated demand costs effective November 1, 2011 and as allocated in column B of Table 1 above, through the commodity portion of the PGA. [Staff note: only the underlined portion applies.]

In its August 1, 2012 comments for the 2011-2012 demand entitlement petitions, the Department continues to recommend that MERC apply its storage proposal as follows:

- approve the PGA recovery of costs associated with MERC-NMU's (docket 11-1088) proposed demand entitlement levels effective November 1, 2011 with the modification that MERC recover costs associated with Storage and the Bison contract through the commodity portion of the monthly PGA (only the underlined portion applies to the Storage recommendation);

- approve the PGA recovery of costs associated with MERC-PNG's (docket 11-1084) Northern PGA system proposed demand entitlement levels effective November 1, 2011 with the modification that MERC recover costs associated with Storage and the Bison contract through the commodity portion of the monthly PGA (only the underlined portion applies to the Storage recommendation); and

In its August 6, 2014 Order on MERC's 2007-2008 demand entitlements, the Commission approved MERC's storage classification and allocation proposal,[22] effective November 1, 2014.

---

[20] For further details, see Petition, Attachment 4, pp. 4 -6, and Attachment 11, p. 2
[21] See the Department comments in MERC's 2008-2009, 2009-2010, and 2010-2011 demand entitlement petitions
[22] For further detail, see the July 15, 2014 PUC staff briefing papers for Docket Nos. 07-1402, 07-1403, 07-1404, and 07-1405

PUC Staff Comment

PUC staff agrees the Department's recommendation that the Commission approve the PGA cost recovery associated with MERC's PNG-NNG and NMU PGA systems, but it considers the FDD storage costs allocation issue to be resolved on a going forward basis for all outstanding MERC demand entitlement petitions, thus, will not revisit it in the 2011-2012 demand entitlement petitions briefing papers. The Commission approved MERC's March 7, 2008 storage classification and allocation proposal,[23] effective November 1, 2014, in its August 6, 2014 Order in MERC's 2007-2008 demand entitlement petitions.

PUC staff believes the Commission does not need to address the Department's recommendation in this docket because the Commission has made its decision on storage cost recovery.
Staff did not include this issue in the decision alternatives at the end of these briefing papers because it believes this issue has been addressed and resolved. If the Commission issues informal letter orders adopting the Department's recommendations in these dockets, it may want to make clear in its order that it is not adopting that part of the Department's recommendation.

(Staff is working on bringing the filings from 2012-2014 to the Commission now that this issue is resolved.)

[23] Ibid.

Decision Alternatives

The following Decision Alternatives apply to all of the MERC dockets addressed in these briefing papers. Those dockets were:

Docket Nos. G-011/M-11-1082 (MERC-PNG GLGT)
Docket Nos. G-011/M-11-1083 (MERC-PNG Viking)
Docket Nos. G-011/M-11-1084 (MERC-PNG NNG)
Docket Nos. G-007/M-11-1088 (MERC NMU)

1. MERC Change in Demand Entitlements for 2011-2012

MERC is seeking Commission Approval for Demand Entitlement petitions effective November 1, 2011 for its 4 PGA areas; MERC-NMU, MERC-PNG Viking, MERC-PNG GLGT, and MERC-PNG NNG.

MERC and the Department do not have any issues remaining on the following resolved issues:

- Design Day Requirements Estimates
- Demand Entitlement Estimates <u>without endorsing its design-day study analysis</u>
- Bison and NBPL pipeline contract costs
- Reserve Margin Calculation
- Peak day send-out use per customer
- Storage Contract changes and cost recovery
- PGA Cost Recovery

A. Approve MERC's request for interstate pipeline and other capacity changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, <u>and</u>

B. Approve MERC's request to recover the associated cost changes in its pipeline demand entitlement contracts and supplier reservation fees as requested by MERC, <u>and</u>

C. Require MERC to remove all balancing costs such as SMS, LMS, Union Balancing, etc. from demand costs and move them to commodity costs effective November 1, 2014. Require MERC in its September 1, 2015 *Annual Automatic Adjustment (AAA) Report and True-up filing*, to adjust its PGA demand revenue collected for the time period from November 1, 2014 until the date of the Commission Order to reflect all balancing costs being collected through MERC's commodity PGA factors,[24] <u>and</u>

[24] The prospective change in how balancing costs are recovered through the PGA should be implemented to be effective on customer bills February 1, 2015. The November 1, 2014 through January 31, 2015 portion would need to be made effective through an adjustment to MERC's true-up factors in MERC's September 1, 2015 annual true-up filing.

D. Require MERC to address the Bison/NBPL contracts in it 2015-2016 demand entitlement petitions, by requiring MERC to evaluate available gas supply alternatives to its Bison/NBPL contracts and provide parties with its analysis in its petitions in the 2015-2016 dockets.

2. Should the Commission approve the Department's recommendation to allocate the Bison/NBPL contract costs to all of MERC's customers, i.e. firm, interruptible, joint sales customers, as modified?

A. Approve the PGA recovery of costs associated with MERC-NMU's proposed demand entitlement level effective November 1, 2011 with the modification that MERC recover costs associated with the Bison Contract through the commodity portion of the monthly PGA and not the demand portion on a going-forward (prospective) basis. (The Commission may want to clarify the effective date of the cost recovery treatment from demand to commodity in MERC's PGA, for example, November 1, 2014.)[25] and

B. Approve the PGA recovery of costs associated with MERC-PNG's Northern PGA system proposed demand entitlement level effective November 1, 2011 with the modification that MERC recover costs associated with the Bison Contract through the commodity portion of the monthly PGA and not the demand portion on a going forward (prospective) basis. (The Commission may also want to clarify the effective date of the cost recovery treatment from demand to commodity in MERC's PGA, for example, November 1, 2014.)[26]

OR

C. Require MERC to continue treating the Bison/NBPL contract costs as demand costs in the demand portion of MERC's PGA chargeable to firm sales customers only.

[25] The change in PGA demand and commodity rate factors should be implemented to be effective on customer bills February 1, 2015. The November 1, 2014 through January 31, 2015 portion would need to be made effective through an adjustment to MERC's true-up factors in MERC's September 1, 2015 annual true-up filing.
[26] Ibid.

Transportation Demand Entitlements Changes

MERC-NMU	06-1535	07-1402	08-1329	09-1282	10-1166	11-1088	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
							(6) - (5)
NNG TF 12 B&V	13,270	12,756	9,296	12,756	8,151	7,622	(529)
NNG TF 5	2,102	1,991	5,451	1,991	3,493	3,267	(226)
NNG TFX 12	0	0	0	0	3,495	3,268	(227)
NNG TFX 5	5,514	6,139	6,139	6,139	9,759	9,126	(633)
LS Power	0	2,777	2,777	2,725	3,149	0	(3,149)
Bison	0	0	0	0	5,411	5,060	(351)
NBPL	0	0	0	0	5,411	5,060	(351)
NNG Zone GDD Call Option	0	0	0	0	0	1,265	1,265
GLGT FT	10,130	10,130	10,130	10,130	10,130	6,231	(3,899)
GLGT FT (12)	1,178	1,178	1,178	1,178	1,178	2,214	1,036
GLGT FT (5)	2,138	2,138	2,138	2,138	2,138	2,238	100
GLGT FT	0	4,500	4,000	3,000	3,000	0	(3,000)
GLGT FT15782	0	0	0	0	0	5,536	5,536
VGT FT-A AF0012	7,966	7,966	7,966	7,966	7,966	7,711	(255)
VGT FT-A AF0014	0	0	0	0	0	678	678
VGT FT-A AF0102	0	0	0	0	0	1,234	1,234
VGT FT-A AF0183	0	0	0	0	0	1,852	1,852
VGT FT-A (4)	0	0	5,902	5,902	0	0	0
NNG-TF 12 Chisago Base	2,546	782	926	1,368	0	0	0
NNG-TF 12 Chisago Var.	0	0	0	955	0	0	0
NNG-TF 5 Chisago	2,079	1,765	2,089	563	0	0	0
NNG-TFX12 Chisago	0	1,963	2,324	2,089	0	0	0
NNG-TFX 5 Chisago	0	476	563	926	0	0	0
Wadena Delivered Option	0	0	0	0	5,902	0	(5,902)
Centra FT-1	9,858	9,858	9,858	9,858	9,858	9,858	0
NEXEN/VGT CR	6,000	0	0	0	0	0	0
Total Demand Entitlements	62,781	64,419	64,835	63,782	68,219	62,100	(6,119)
Total DD Requirements	61,060	61,008	63,726	60,918	57,662	57,989	327
Surplus/Deficient	1,721	3,411	1,109	2,864	10,557	4,111	(6,446)
Reserve Margin	**2.82%**	**5.59%**	**1.74%**	**4.70%**	**18.31%**	**7.09%**	

[PUC staff note: The VGT FT-A (4)/Bison/NBPL volumes are not included in the Total Demand Entitlement volume, the VGT FT-A (4) was a backhaul arrangement, the Bison and NBPL are used to deliver Rockies supply into NNG - does not add incremental capacity for MERC's design day demand entitlements.]

Transportation Demand Entitlements Changes

MERC-PNG GLGT	06-1535	07-1402	08-1329	09-1282	10-1166	11-1082	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
							(6) - (5)
FT0017	4,105	4,105	4,105	4,105	4,105	3,899	(206)
FT0075	1,973	1,973	1,973	1,973	1,973	0	(1,973)
FT0155 (12)	2,422	2,422	2,422	2,422	2,422	1,386	(1,036)
FT0155 (5)	1,500	1,500	1,500	1,500	1,500	1,400	(100)
FT8466	0	0	500	1,500	1,500	0	(1,500)
FT15782	0	0	0	0	0	3,464	3,464
Total Demand Entitlements	10,000	10,000	10,500	11,500	11,500	10,149	(1,351)
Total DD Requirements	9,543	9,550	10,299	10,802	9,440	9,304	(136)
Surplus/Deficient	457	450	201	698	2,060	845	(1,215)
Reserve Margin	**4.79%**	**4.71%**	**1.95%**	**6.46%**	**21.82%**	**9.08%**	

Transportation Demand Entitlements Changes

MERC-PNG NNG	06-1535	07-1402	08-1329	09-1282	10-1166	11-1084	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
							(6) - (5)
TF-12 Base and Variable	76,240	59,804	62,596	59,804	67,165	67,694	529
TF5	36,772	29,619	26,827	29,619	28,785	29,011	226
TFX-12	9,724	18,409	29,246	31,199	28,802	29,029	227
TFX-5	73,190	90,130	79,293	81,567	80,424	81,057	633
Bison	0	0	0	0	44,589	44,940	351
NBPL	0	0	0	0	44,589	44,940	351
Northwest Gas (Windom)	2,500	2,500	2,500	2,500	2,500	2,500	0
NW Energy (Ortonville)	0	0	0	0	0	910	910
NNG Zone Delivery Call Opt	0	0	0	0	0	11,235	11,235
LSP Peaking Service	29,100	26,323	26,323	26,375	25,951	0	(25,951)
Total Demand Entitlement	227,526	226,785	226,785	231,064	233,627	221,436	(12,191)
Total DD Requirements	200,484	202,263	**225,397**	**206,333**	**194,598**	**211,182**	16,584
Surplus/Deficient	27,042	24,522	1,388	24,731	39,029	10,254	(28,775)
Reserve Margin	**13.49%**	**12.12%**	**0.62%**	**11.99%**	**20.06%**	**4.86%**	

[PUC staff note: The Bison and NBPL are used to deliver Rockies supply into NNG - does not add incremental capacity deliveries for MERC's design day demand entitlements.]

Transportation Demand Entitlements Changes

MERC-PNG Viking	06-1535	07-1402	08-1329	09-1282	10-1166	11-1083	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
							(6) - (5)
AF0012	3,527	3,527	3,527	3,527	3,527	4,782	1,255
AF0014	0	0	0	0	0	420	420
AF0016	1,000	1,000	1,000	1,000	1,000	0	(1,000)
AF0102	2,000	2,000	2,000	2,000	2,000	766	(1,234)
AF0183	0	0	0	0	0	1,148	1,148
Wadena Delivered Option	0	0	0	0	1,098	0	(1,098)
NNG-TF 12 Chisago 112495 B	935	316	172	255	0	0	0
NNG-TF 12 Chisago 112495 V			0	178	0	0	0
NNG-TF 5 Chisago 112495	227	713	389	105	0	0	0
NNG-TFX 12 Chisago 112486	373	793	432	389	0	0	0
NNG-TFX 5 Chisago 112486	841	192	105	172	0	0	0
Total Demand Entitlement	8,903	8,541	7,625	7,626	7,625	7,116	(509)
Forecasted DD Requirement	8,112	8,135	**7,420**	**6,891**	**7,292**	**6,851**	(441)
Surplus/Deficient	791	406	205	735	333	265	(68)
Reserve Margin	**9.75%**	**4.99%**	**2.76%**	**10.67%**	**4.57%**	**3.87%**	

Transportation Demand Entitlements PGA Costs, as adjusted

MERC-NMU	06-1535	07-1402	08-1329	09-1282	10-1166	11-1088	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	$	$	$	$	$	$	$
							(6) - (5)
NNG TF 12 B&V 112495	1,299,191	1,338,116	966,064	1,255,236	812,428	744,855	(67,573)
NNG TF 5 112495	157,398	150,848	412,995	150,848	264,647	247,524	(17,123)
NNG TFX 5 112486	412,888	465,121	465,121	465,121	682,554	638,343	(44,211)
NNG TFX 12 112486	0	0	0	0	236,539	221,287	(15,252)
TFX	0	0	0	0	0	1,148	1,148
TFX	0	0	0	0	0	1,148	1,148
LS Power	0	36,211	36,211	35,531	41,059	0	(41,059)
Bison	0	0	0	0	993,135	1,061,386	68,251
NBPL	0	0	0	0	397,254	424,554	27,300
NNG Zone GDD Call Option	0	0	0	0	0	3,453	3,453
GLGT FT FT0016	420,354	420,354	420,354	420,354	420,354	258,562	(161,792)
GLGT FT (12) FT0155	48,882	48,882	48,882	48,882	48,882	91,872	42,990
GLGT FT (5) FT0155	36,966	36,966	36,966	36,966	36,966	38,695	1,729
GLGT FT FT8466	0	186,732	165,984	124,488	124,488	0	(124,488)
GLGT FT FT15782	0	0	0	0	0	229,722	229,722
VGT FT-A AF0012	331,427	331,427	331,427	331,427	331,427	320,818	(10,609)
Wadeena Delivery Option	0	0	0	0	15,935	0	(15,935)
VGT FT-A	0	0	111,167	88,934	0	0	0
VGT FT-A AF0014	0	0	0	0	0	7,052	7,052
VGT FT-A AF0102	0	0	0	0	0	51,341	51,341
VGT FT-A AF0183	0	0	0	0	0	34,883	34,883
VGT – Cap. Release RF0361	80,177	68,222	0	0	0	0	0
Balancing Agreement	0	0	0	0	0	55,284	55,284
NNG-TF 12 B Chisago 112495	163,654	71,130	84,181	124,431	0	0	0
NNG-TF 12 V Chisago	0	0	0	104,232	0	0	0
NNG-TF 5 Chisago 112495	33,049	133,755	158,296	42,672	0	0	0
NNG-TFX12Chisago 112486	82,847	226,869	268,494	241,411	0	0	0
NNG-TFX 5 Chisago 112486	122,597	36,057	42,672	70,141	0	0	0
Centra FT-1	489,742	536,214	536,214	531,532	540,057	662,537	122,480
Union Balancing	54,000	54,000	54,000	54,000	54,000	54,000	0
Centra MN Pipelines	145,634	145,634	145,634	145,634	145,634	210,330	64,696
Total Demand Entitlement	**3,878,806**	**4,286,538**	**4,284,662**	**4,271,840**	**5,145,359**	**5,358,794**	**213,435**

Transportation Demand Entitlements PGA Costs

MERC-PNG GLGT	06-1535	07-1402	08-1329	09-1282	10-1166	11-1082	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	$	$	$	$	$	$	$
							(6) - (5)
FT-A FT0017	170,341	170,341	170,341	170,341	170,341	161,793	(8,548)
FT-A FT0075	81,872	81,872	81,872	81,872	81,872	0	(81,872)
FT-A FT0155	100,503	100,503	100,503	100,503	100,503	57,513	(42,990)
FT-A FT0155	25,935	25,935	25,935	25,935	25,935	24,206	(1,729)
FT-A FT8466	0	0	25,935	62,244	62,244	0	(62,244)
FT-A FT15782	0	0	0	0	0	143,752	143,752
Total Demand Entitlement	**378,651**	**378,651**	**404,586**	**440,895**	**440,895**	**387,264**	**(53,631)**

Transportation Demand Entitlements PGA Costs

MERC-PNG NNG	06-1535	07-1402	08-1329	09-1282	10-1166	11-1084	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	$	$	$	$	$	$	$
							(6) - (5)
TF-12 Base and Variable	7,357,729	5,452,825	6,227,986	5,816,707	6,626,048	6,557,069	(68,979)
TF5	2,753,487	2,244,084	2,003,752	2,244,084	2,180,896	2,169,204	(11,692)
TFX-12	1,110,471	1,689,365	1,689,365	1,746,271	1,949,350	1,964,701	15,351
TFX-5	5,074,869	6,303,269	6,303,269	5,656,324	5,625,135	5,662,428	37,293
Bison	0	0	0	0	8,183,865	9,426,614	1,242,749
NBPL	0	0	0	0	3,273,546	3,770,646	497,100
TFX 112486	0	11,366	11,366	11,366	10,138	10,218	80
TFX 112486	4,867	11,366	11,366	11,366	10,138	10,218	80
TFX7 111866	0	168,437	168,437	317,633	0	0	0
Windom	0	0	0	0	0	0	0
Ortonville	0	0	0	0	0	87,360	87,360
NNG Zone GDD Call Option	0	0	0	0	0	30,672	30,672
LSP Peaking Service	349,444	343,217	343,217	343,897	338,369	0	(338,369)
Total Demand Entitlement	**16,650,867**	**16,223,929**	**16,758,758**	**16,147,648**	**28,197,485**	**29,689,130**	**1,491,645**

Transportation Demand Entitlements PGA Costs

MERC-PNG Viking	06-1535	07-1402	08-1329	09-1282	10-1166	11-1083	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	$	$	$	$	$	$	$
							(6) - (5)
FT-A AF0012	146,742	146,742	146,742	146,742	146,742	198,956	52,214
FT-A AF0014	45,683	11,421	11,421	11,421	11,421	4,369	(7,052)
FT-A AF0016	41,605	41,605	41,605	41,605	41,605	0	(41,605)
FT-A AF0102	83,210	83,210	83,210	83,210	83,210	31,870	(51,340)
FT-A AF0183	0	0	0	0	0	21,623	21,623
Wadena Delivery Option	0	0	0	0	2,965	0	(2,965)
NNG-TF 12 Chisago B 11249	35,016	28,712	15,661	23,149	0	0	0
NNG-TF 12 Chisago V 11249	0	0	0	19,391	0	0	0
NNG-TF 5 Chisago 112495	40,730	53,990	29,449	7,939	0	0	0
NNG-TFX12Chisago 112486	17,726	91,576	49,950	44,912	0	0	0
NNG-TFX 5 Chisago 112486	151,093	14,554	7,939	13,049	0	0	0
Capacity Release RF03061	53,130	12,517	0	0	0	0	0
Total Demand Entitlement	**614,935**	**484,327**	**385,977**	**391,418**	**285,943**	**256,818**	**(29,125)**

Summary of demand entitlement costs for all PGA areas

PGA Area	06 Total Costs	07 Total Costs	08 Total Costs	09 Total Costs	10 Total Costs	11 Total Costs	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	$	$	$	$	$	$	$
							(6) - (5)
MERC-NMU	3,878,806	4,286,538	4,284,662	4,271,840	5,145,359	5,358,794	213,435
MERC-PNG Viking	614,935	484,327	385,977	391,418	285,943	256,818	(29,125)
MERC-PNG GLGT	378,651	378,651	404,586	440,895	440,895	387,264	(53,631)
MERC-PNG NNG	16,650,867	16,223,929	16,758,758	16,147,648	28,197,485	29,689,130	1,491,645
Total Demand Entitlement	**21,523,259**	**21,373,445**	**21,833,983**	**21,251,801**	**34,069,682**	**35,692,006**	**1,622,324**