
**BEFORE THE MINNESOTA OFFICE OF 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. G-011/M-15-895
OAH Docket No. 68-2500-33101**

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

**INITIAL BRIEF
OF THE OFFICE OF THE ATTORNEY GENERAL—
RESIDENTIAL UTILITIES AND ANTITRUST DIVISION**

October 11, 2016

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INITIAL BRIEF OF THE OFFICE OF THE ATTORNEY GENERAL

INTRODUCTION

The Office of the Attorney General – Residential Utilities and Antitrust Division (“OAG”) respectfully submits its Initial Brief regarding Minnesota Energy Resource Corporation’s (“MERC” or “the Company”) Petition for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project (“the Rochester Project” or “the Project”).

The Commission should reject MERC’s request for pre-approval of the Rochester Project. If the Project is built as MERC has proposed, the Company’s captive ratepayers will be forced to pay for far more natural gas capacity than is reasonably necessary: the Project would result in excess reserve margins of 40 to 50 percent in the near-term, with double digit reserves persisting for decades.

The record demonstrates many problems both with the Project that MERC has proposed and the Company’s decision-making. These problems begin with the Company’s single-minded focus on the results of its long-term peak demand forecast. MERC decided on the size and scope of the Rochester Project based solely on the results of this forecast, without any consideration of forecasting risk or moderation. MERC designed its RFP around the results of the forecast, and focused its analysis of alternatives on those RFP responses that matched the forecast. The result

is a project that will provide far more natural gas capacity than is reasonably necessary to serve the demands of firm customers, decades before it will be useful.

The Company's shareholders will not bear any of this risk—if the Project is approved, the shareholders will be paid. Instead, the risk will be borne by captive ratepayers. The Commission should reject MERC's request for approval and rider recovery, and direct the Company to develop a new plan to increase natural gas supply in the Rochester area.

BACKGROUND

According to MERC's Petition,¹ the Company no longer has sufficient natural gas supply to meet current or future peak demand in the Rochester area.² While MERC has sufficient supply to meet demands for natural gas on a normal day, the Company states that it does not have sufficient gas supply to satisfy demand on a Design Day, which predicts the peak demand for natural gas on the coldest possible day. For that reason, MERC states that it must take action to increase the supply of natural gas in the region. In its Petition, MERC clarifies that the Company seeks to increase natural gas supply in the region because it “now has a limited ability to provide firm and reliable natural gas service to new commercial and industrial customers.”³

The Company states that the primary barrier to acquiring more natural gas capacity is that there is only one natural gas supplier in the region, Northern Natural Gas (“NNG”), and NNG's interstate transmission system is fully subscribed. In order for MERC to increase the amount of firm capacity it has available, new interstate capacity must be constructed by either NNG or a competing supplier.

¹ Ex. 1, at 2 (Petition).

² For purposes of this case the Company has described the Rochester area as including Olmsted County and the communities of Kasson and Blooming Prairie. *Id.* at 20.

³ *Id.* at 2.

To determine how much additional natural gas capacity would be necessary, MERC conducted a forecast. According to MERC, the historical average annual compound growth rate, which measures the total change over the time period, was 0.27 percent per year from 2007 to 2015.⁴ The simple average annual growth rate year over year was 0.46 percent.⁵ Using historical data as a basis, MERC estimates that peak demand in the Rochester area will grow by 1.5 percent per year from 2015 to 2042.⁶ A growth rate of 1.5 percent per year results in a peak demand forecast of approximately 91,000 dekatherms per day (“Dth/day”) in 2042.⁷ To this figure, MERC added a 5 percent reserve margin, and then rounded up to reach 100,000 Dth/day.⁸ MERC’s current firm capacity in the Rochester area is approximately 55,000 Dth/day. As a result, to reach its forecasted peak demand estimate for 2042, MERC would have to nearly double its firm capacity by adding 45,000 Dth/day of incremental capacity.

Based on this forecast, MERC created and distributed a Request for Proposals (“RFP”) requesting bids to provide 100,000 Dth/day of firm capacity to the Rochester area under two different scenarios.⁹ The first scenario asked bidders to propose a new pipeline to deliver 100,000 Dth/day, and the second scenario asked bidders to work with NNG to provide an incremental 45,000 Dth/day to the area.¹⁰ MERC received responses to the RFP from three

⁴ Ex. 11, at 6, Table 1 (Clabots Surrebuttal).

⁵ Ex. 300, at 29 (Urban Amended and Corrected Direct). Amended and Corrected versions of Dr. Urban’s testimony were filed by the Court Reporter after the evidentiary hearing as a result of an agreement by MERC to remove trade secret designations from the testimony. The versions in the record are marked as Amended to refer to the agreed-upon changes to Trade Secret designations, while Corrected to refer to corrections made in an errata filing on September 2, 2016.

⁶ Ex. 9, at 8, Table 3 (Clabots Direct); Ex. 12, at 21, Table 1 (Mead Direct).

⁷ Ex. 17, Sexton Direct, at 39.

⁸ *Id.*

⁹ *Id.* at 39 (Sexton Direct).

¹⁰ *Id.*

companies: NNG, Northern Borders Pipeline, and Twin Eagle.¹¹ After reviewing the bids, MERC proceeded to negotiate with NNG.

The negotiations resulted in a Precedent Agreement between MERC and NNG to upgrade NNG's infrastructure to provide 45,000 Dth/day of incremental capacity in the Rochester area. The Precedent Agreement was initially executed on October 26, 2015, and an Amended Precedent Agreement ("PA") was executed on March 30, 2016 to reflect a change in the proposed in-service date and associated cost increases.¹²

The primary feature of the PA will increase the natural gas capacity available to MERC in the Rochester area to 100,000 Dth/day for 25 years, for a cost of about \$60 million.¹³ MERC states that it was able to negotiate additional conditions that provide value to ratepayers. These include: 1) an agreement to fix the NNG rate at the current tariff maximum;¹⁴ 2) approximately 8,000 Dth/day in additional capacity for thirty additional markets in Southeast Minnesota at NNG's maximum tariff rate; 3) the opportunity for MERC to use up to 20% of the entitlement designated for the Rochester area at other delivery points without giving up the fixed rate; 4) the opportunity for MERC to increase its capacity in the Rochester region by an additional 2,000 Dth/day in every odd-numbered year during the length of the PA; and 5) the right for MERC to elect to extend the term of the PA an additional five years at discounted rates.¹⁵

In order to take advantage of this new natural gas capacity, MERC states that it must make upgrades to the distribution system in the Rochester area. The first phase of distribution

¹¹ *Id.* at 41.

¹² Ex. 306, Highly Sensitive Trade Secret Schedule JAU-7 (Urban Direct HSTS Schedules). The change in schedule was related to the time necessary to obtain regulatory approval from the Commission.

¹³ Ex. 5, at 2 (Lee Direct).

¹⁴ This condition would protect MERC and MERC's shareholders from rate increases that could result if NNG files a rate case or a modernization rider at the Federal Energy Regulatory Commission that would increase the tariffed rate.

¹⁵ Ex. 17, at 46–50 (Sexton Direct).

upgrades is being resolved in MERC's pending rate case, and MERC seeks approval and recovery of costs for Phase II in this proceeding. The Rochester area currently uses two town border stations ("TBS"): 1D and 1B. Phase II will upgrade TBS 1D, and replace TBS 1B with a new TBS.¹⁶ In addition, MERC will construct a new high-pressure distribution pipeline to interconnect the northern and southern portions of the distribution system.¹⁷ These upgrades will "give[] MERC the ability to shift the supply of gas where it is needed on the distribution system within the Rochester area," for an estimated cost of \$44 million.¹⁸

Together, the costs of the NNG upgrades plus MERC's distribution upgrades are approximately \$104 million. MERC seeks to recover these costs through a combination of riders and base rates. MERC proposes that the \$60 million for NNG capacity costs be recovered through the NNG Purchased Gas Adjustment ("PGA") rider from all customers that are subject to the NNG-PGA. MERC proposes that up to 33 percent of the \$44 million for Phase II distribution upgrades be recovered through a Natural Gas Extension Project ("NGEP") Rider authorized under Minnesota Statutes section 216B.1638, and the remaining costs through base rates when rate cases are filed.¹⁹

Ultimately, the question in this proceeding is whether MERC has demonstrated that its proposal for the Rochester Project is a prudent and reasonable way to satisfy the demands of MERC's firm customers in the Rochester area. A thorough evaluation of the facts and evidence demonstrates that it has not, and that the project the Company has proposed would result in

¹⁶ Ex. 7, at 3 (Lyle Direct).

¹⁷ *Id.* at 3.

¹⁸ *Id.* at 5.

¹⁹ Ex. 5, at 17–18 (Lee Direct). In Ms. Lee's Direct Testimony, she states that the rate case revenue requirements would "include any deferred costs," but MERC has provided no further discussion of deferred costs in its filings. The Company has not taken the necessary step of requesting any deferred accounting, so the Commission should not consider any deferred accounting in this proceeding.

significant overbuilding far above and beyond what is reasonably necessary to serve its firm customers.

ANALYSIS

MERC has asked the Commission for at least three distinct determinations in this case. First, MERC requests an advance determination that the Rochester Project is reasonable, prudent, and necessary to provide service to its customers in the Rochester area. Second, MERC requests a determination that the Company may recover up to 33% of the Phase II costs of the Rochester Project through a new NGEP Rider under Minnesota Statutes section 216B.1638. Third, MERC requests a determination that its proposed cost allocations, which would collect the NNG costs from the NNG-PGA customers and the Phase II costs from all of MERC's customers, are reasonable.

This Brief will first address whether the Rochester Project is a reasonable, prudent, and necessary way to provide service to MERC's customers in the Rochester area. Next, this Brief will address the eligibility of the Rochester Project for the NGEP Rider. Third, this Brief will address questions of cost allocation should the Rochester Project be approved. Fourth, this Brief will support the recommendation of the Minnesota Department of Commerce – Division of Energy Resources ("Department") that MERC's distribution costs be capped at the level of cost estimates provided in this proceeding.

I. THE ROCHESTER PROJECT IS NOT A REASONABLE, PRUDENT, AND NECESSARY WAY TO PROVIDE SERVICE TO MERC'S CUSTOMERS IN THE ROCHESTER AREA.

The primary question in this matter is whether the Rochester Project that MERC has proposed is reasonable, prudent, and necessary to provide service to MERC's customers in the

Rochester area.²⁰ MERC's request for an advanced determination of prudence is unusual, however, because the Company does not normally need to obtain approval before proceeding with the project. There is an established process, under the Certificate of Need ("CN") statutes, for obtaining advanced approval of utility construction projects, but MERC is not required to obtain a CN because the Rochester Project is not a Large Energy Facility.²¹ During the evidentiary hearing, MERC witness Ms. Lee confirmed that one reason the Company is seeking Commission agreement is that it is concerned about the risk of proceeding without regulatory approval.²²

Ultimately, the question that must be answered is whether the utility has met its burden of "showing that it would be just and reasonable to include a particular utility expense in rates."²³ And, as with all other instances in which the utility must establish the reasonableness of its rates, the utility must satisfy its burden of proof by the preponderance of the evidence.²⁴ In this proceeding, MERC has failed to meet that bar. Analyzing MERC's proposal demonstrates that the Project will obtain far more natural gas than is reasonable, decades before it will be needed by customers. And a thorough review of MERC's process demonstrates that the proposal was the result of a series unreasonable decisions.

This Section will demonstrate that MERC has not satisfied its burden to prove that its proposal for the Rochester Project is reasonable, prudent, or necessary to provide service to

²⁰ Notice of and Order for Hearing, at 3 (Feb. 8, 2016).

²¹ A natural gas pipeline is not classified as a Large Energy Facility unless it is 50 miles or more in length, and has a maximum pressure of 200 pounds per square inch. Minn. Stat. § 216B.2421 (2015). While the Rochester Project will transport natural gas at greater than 200 psi, there will be less than 50 miles of new construction.

²² Tr. Evid. Hearing, Vol. 1, at 35:17-21 (Lee).

²³ Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes, *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754, at 13 (May 8, 2015).

²⁴ *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722 (Minn. 1987).

customers in the Rochester area. Because of the volume and complexity of the facts in the record, a complete analysis of the reasonableness and prudence of the Project is necessarily lengthy. For that reason, this Section is organized into ten sub-sections, which each addresses a specific issue or decision the Company has discussed as justification for its proposal.

First, reviewing the reserve margins produced by the Rochester Project demonstrates that MERC is obtaining far more natural gas than is reasonably necessary. Second, MERC has relied too heavily on the results of its long-term peak demand forecast, regardless of its quality. Third, MERC has compounded the problems caused by relying on the forecast because the forecast in question is flawed. Fourth, MERC's RFP was not designed reasonably because it was focused too closely on the results of the forecast. Fifth, MERC's analysis of the RFP was insufficient to support the Rochester Project that it designed. Sixth, MERC did not adequately justify its decision to focus on an up-front project rather than a phased or incremental project. Seventh, MERC did not give sufficient consideration to whether conservation or peak shaving alternatives could have reduced demand in the Rochester area. Eighth, this Section will explain why future consumption by interruptible and transportation customers is not a reasonable justification for the Rochester Project investments. Ninth, this Section will compare the problems with MERC's proposal to the Bison Pipeline Project, another MERC pipeline that has been a bad deal for ratepayers. Finally, this Section will present the conclusion that the Rochester Project is not reasonable, prudent, and necessary to provide service to firm ratepayers in the Rochester area.

A. THE ROCHESTER PROJECT WILL RESULT IN UNREASONABLY LARGE RESERVE MARGINS.

The most obvious way to analyze whether MERC's proposal to increase natural gas supplies is reasonable is to look at how much natural gas MERC proposes to obtain compared to

how much natural gas MERC believes is necessary.²⁵ The measurement for this analysis is the “reserve margin.” The reserve margin measures how much capacity the Company has available compared to its Design Day (which is a measurement of peak demand on the coldest possible day). The reserve margin calculates the excess or shortfall of available capacity compared to the Design Day estimate of peak demand.

MERC states that its Design Day for the Rochester area was 60,929 Dth/day in the 2015/2016 heating season, and that its total available capacity is 55,169 Dth/day.²⁶ Using these figures, MERC calculates that it had a reserve margin of negative 9.5 percent during the 2015/2016 heating season.²⁷ Because of this shortfall, MERC reports, it must take action to increase the natural gas capacity available in the area.

The problem is that MERC’s plan to increase capacity will provide far more capacity than is reasonable. In fact, when the Project is initially complete, there will be a reserve margin of more than 50 percent in the Rochester area.²⁸ This means that MERC will have 50 percent more natural gas than is necessary to supply the highest possible demand, on the hypothetical coldest day. And, assuming that MERC’s growth forecast is reasonable, MERC states that the reserve margin will continue to be more than 15 percent through the 2039/2040 heating season.²⁹ MERC witness Ms. Mead produced the following table in her Direct Testimony:

²⁵ In later sections, this Brief will address whether MERC’s assumptions about the demand for natural gas are reasonable. In summary, they are not.

²⁶ Ex. 12, at 21, Table 1 (Mead Direct).

²⁷ *Id.*

²⁸ *Id.*

²⁹ *Id.*

Table 1 - Rochester Staging Plan (Dth/Day)

Winter Period	Rochester Design Day	Capacity 1D	Capacity 1B	Capacity New TBS	Total Capacity	Reserve Margin
2015/2016	60,929	36,707	18,462	0	55,169	-9.5%
2016/2017	61,842	36,707	18,462	0	55,169	-10.8%
2017/2018	62,770	36,707	18,462	0	55,169	-12.1%
2018/2019	63,712	47,207	18,462	0	65,669	3.1%
2019/2020	64,667	40,707	18,462	41,000	100,169	54.9%
2020/2021	65,637	40,707	18,462	41,000	100,169	52.6%
2021/2022	66,622	40,707	18,462	41,000	100,169	50.4%
2022/2023	67,621	40,707	18,462	41,000	100,169	48.1%
2023/2024	68,636	40,707	18,462	41,000	100,169	45.9%
2024/2025	69,665	40,707	18,462	41,000	100,169	43.8%
2025/2026	70,710	40,707	0	59,462	100,169	41.7%
2026/2027	71,771	40,707	0	59,462	100,169	39.6%
2027/2028	72,847	40,707	0	59,462	100,169	37.5%
2028/2029	73,940	40,707	0	59,462	100,169	35.5%
2029/2030	75,049	40,707	0	59,462	100,169	33.5%
2030/2031	76,175	40,707	0	59,462	100,169	31.5%
2031/2032	77,317	40,707	0	59,462	100,169	29.6%
2032/2033	78,477	40,707	0	59,462	100,169	27.6%
2033/2034	79,654	40,707	0	59,462	100,169	25.8%
2034/2035	80,849	40,707	0	59,462	100,169	23.9%
2035/2036	82,062	40,707	0	59,462	100,169	22.1%
2036/2037	83,293	40,707	0	59,462	100,169	20.3%
2037/2038	84,542	40,707	0	59,462	100,169	18.5%
2038/2039	85,810	40,707	0	59,462	100,169	16.7%
2039/2040	87,097	40,707	0	59,462	100,169	15.0%

MERC's table demonstrates that the Rochester Project will result in double digit reserve margins for more than twenty years. In 2040, MERC's customers will be paying for 15 percent more natural gas capacity than they will need at peak demand on the coldest possible day. And MERC's current customers will be paying for even *more* excess gas supply—MERC estimates that customers in the 2019/2020 heating season will be required to pay for 54.9 percent more natural gas than is necessary to serve peak demand.

These reserve margins are unreasonable according to industry standards described by MERC's independent consultant. According to Mr. Sexton, "[M]ost utility distribution companies maintain capacity reserve margins in the 3% to 7% range with targets near 5% with variances in reserve margin targets resulting from unique local conditions."³⁰ Mr. Sexton described the 5 percent reserve margin as the "industry standard."³¹ Based on this standard, MERC should be planning to add at least enough capacity to ensure it can maintain a reserve margin of approximately 5 percent in the Rochester area. Instead, MERC's plan will produce a reserve margin that is approximately ten times this industry standard at the outset, and as high as three times the industry standard in 25 years.

These excessive reserve margins are problematic for several reasons. First, ratepayers simply should not be required to fund the construction of utility infrastructure above and beyond what is reasonably necessary to provide service to firm customers. MERC's proposal would obligate captive ratepayers to purchase fifty percent more natural gas capacity than they require up-front, and continue to pay for more natural gas capacity than they require for decades.

Second, excessive reserve margins create intergenerational inequities. The Rochester Project is designed to ensure that MERC has the full amount of natural gas capacity that is necessary to serve MERC's estimate of peak demand in the 2040s. Said another way, MERC is beginning a construction project that it believes is necessary to serve the customers it will have in about 25 years. But the costs of constructing that project will be paid by MERC's current customers, who do not need the excess capacity that may (or may not) be necessary in the 2040s. In contrast, the costs for the NNG capacity upgrades will be fully recovered by the end of the PA in approximately 25 years. And depreciation will have significantly reduced the financial burden

³⁰ Ex. 17, at 10:14–16 (Sexton Direct).

³¹ *Id.* at 10:19–20.

of MERC's Phase II distribution upgrades. That means that current customers will be the ones who will pay for the majority of the Rochester Project, even though the Company has designed the Project to serve a group of customers far in the future.

Third, the excess capacity created by the Rochester Project will provide a significant benefit for interruptible and transport customers.³² The Rochester Project will, essentially, guarantee that no interruptible customers will ever be curtailed for supply reasons. As a result, every sophisticated natural gas customer will have an incentive to switch to interruptible service. These interruptible customers will be receiving the benefit of reduced distribution rates, but without any real risk of curtailment. Transportation customers will similarly be unlikely to face curtailment. And, above and beyond interruptible sales customers, transportation customers will not share in any of the costs for the NNG upgrades as they do not pay MERC's PGA. As a result, interruptible transportation customers will receive the benefit of a major reduction in curtailment risk without sharing in cost of providing that benefit.

These equity problems between sales, interruptible, and transport customers are the reasons that utilities plan their systems to ensure service to *firm* customers. MERC's planning is based on its Design Day, a measurement of peak demand for firm customers that does not include any consumption by either interruptible or transport customers. Because MERC's proposal will result in such significant overbuilding, those customers will receive significant benefits without fairly sharing in the costs.

At the same time, it is important to recognize that the reserve margin does not represent an actual excess or shortfall. It represents a possibility based on the hypothetical coldest day that could possibly occur—the maximum *possible* demand, rather than the actual demand. MERC

³² This concept will be discussed in more detail in Section III in the context of MERC's proposal for cost allocations.

calculates that if the coldest day on record had occurred during the 2015/2016 heating season, the demand for natural gas would have been 9.5 percent greater than the Company's supply. But no day during the 2015/2016 heating season was as cold as a Design Day—MERC confirms that it did not have any gas supply shortfalls. In fact, the record identifies only one day in which MERC had an actual supply shortfall—January 6, 2014, the height of the polar vortex.³³ And, despite the fact that the Company had a supply shortfall on this day, MERC states that it was able to provide service to all of its firm customers with no penalty from NNG.³⁴ While MERC should plan to meet peak demand, it is worth remembering that on days other than peak days the proportion of unused capacity would be even greater than the reserve margin.

MERC's primary response to the problems with reserve margins appears to be an argument that it would be more cost effective to have a single, massive infrastructure upgrade than it would be to have a smaller upgrade.³⁵ This argument will be thoroughly analyzed in the following subsections, but to summarize briefly the evidence in the record does not support MERC's claim. And, further, the evidence demonstrates that MERC did not conduct sufficient analysis to justify its decision.

MERC also suggests that the reserve margins in this case should be analyzed in the context of the PA condition that allows MERC to deliver 20 percent of total capacity, or 20,000 Dth/day, in the Rochester area to other delivery points at the current tariff maximum. According to MERC, this condition means that the reserve margins are smaller, because the Company can move 20,000 Dth/day to other areas on its system. Using the Company's method, the reserve margin during the 2019/2020 heating season is only 23.0 percent (rather than 54.9 percent),

³³ Ex. 12, at 19 (Mead Direct).

³⁴ *Id.*

³⁵ *Id.* at 14–15.

because the Company would deliver 20,000 Dth/day to other delivery points.³⁶ There are several problems with modifying the analysis in this way.

First, it is important to understand what MERC has actually obtained from this condition. MERC already has the ability to deliver gas from the Rochester area to other points at its delivery system, regardless of this condition. What this condition provides is a guarantee about the price of doing so. And even that is not worth as much as it first appears, because the price that is guaranteed is the current *maximum price*.³⁷ The protection the condition provides is that the price of delivering Rochester capacity to other areas will not increase in the future if NNG files a rate case or a modernization rider.³⁸ It makes little sense to reduce the reserve margin calculations by 20 percent as the result of a price guarantee. As MERC pointed out, the Company could deliver more than 20 percent of the Rochester capacity to other areas—it would just cost more.³⁹

Second, it is not reasonable to assume that reserve margins will be 20 percent lower because there does not appear to be any evidence in the record that other delivery points have demand for that much additional capacity. Being able to deliver 20,000 Dth/day to other delivery points will not provide any value if the other delivery points do not actually need 20,000 Dth/day. During the evidentiary hearing, MERC witness Ms. Mead admitted that she could not identify anywhere in the record that MERC had provided evidence that there is actually a demand for 20,000 Dth/day at other delivery points.⁴⁰ What evidence there is makes this assumption appear unreasonable. In her Direct Testimony, Ms. Mead provided a “few examples

³⁶ Ex. 12, at 23, Table 2 (Mead Direct).

³⁷ Ex. 13, at 14 (Mead Rebuttal).

³⁸ *Id.*

³⁹ *Id.* at 14:8–12.

⁴⁰ Tr. Evid. Hearing, Vol. 1, at 107:1–5 (Mead).

of TBSs that are short capacity and benefit from the delivery optionality.”⁴¹ But the table that Ms. Mead provided shows that the shortfall in capacity at these other delivery points is only 1,004 Dth/day.⁴² There is no evidence in the record to support the assumption that 20,000 Dth/day in capacity will be used at other delivery points on the system regularly, much less every day. If the capacity is not necessary to provide service to other TBSs, then it will still represent excess reserve margins that should be considered in deciding whether the Rochester Project is prudent and reasonable.⁴³ MERC cannot muddy the issue by assuming that 20 percent of capacity will be used elsewhere without providing evidence that the demand in question actually exists.

Third, there is no guarantee that MERC will be able to deliver the capacity where it wants on the days that it wants. The times where additional capacity will be most useful are days of peak demand. But days of peak demand are also days in which there are the greatest constraints on the system.⁴⁴ Just as with the Company’s assumption regarding demand for this excess capacity, there is no guarantee that MERC will be able to move capacity where it wants on days of peak demand.

In summary, it is not reasonable to assume that 20 percent of the capacity in the Rochester area will always be used elsewhere. This condition does provide some value to ratepayers, but its value should not be overstated, and it should not be used to hide the large excess reserve margins that would result from the Rochester Project. If the Rochester Project moves forward, ratepayers will be required to pay for that capacity and it should be included in

⁴¹ Ex. 12, at 28:3–4 (mead Direct).

⁴² *Id.* at 28.

⁴³ During the evidentiary hearing, Ms. Mead admitted that if the capacity is not used it will either “sit idle or be released from the capacity release market.” Tr. Evid. Hearing, Vol. 1, at 107:9–16 (Mead). As will be discussed in greater detail in Section III, the likelihood of obtaining good prices in the capacity release market is low.

⁴⁴ Ex. 300, at 39–40 (Urban Amended and Corrected Direct).

the reserve margin analysis used to determine whether the Rochester Project is prudent, reasonable, and necessary to provide service.

Ratepayers should not be subjected to costs above and beyond the costs that are necessary to provide firm customers with safe and reliable service. While it appears that some investments will be necessary to ensure safe and reliable service in the Rochester area, MERC's plan goes so far above and beyond what is necessary to serve its customers that it is unreasonable. MERC's own witness testified that the industry standard for reserve margins is 5 percent—while there may be some reasonable allowances for instances in which large infrastructure investments are necessary, reasonable allowances do not extend to a double digit reserve margin that persists for more than twenty years.

Above and beyond the excessive reserve margin, there are many other reasons that MERC has acted unreasonably in selecting its proposal for the Rochester Project. The first of these is the Company's unreasonable reliance on the results of its long-term peak demand forecast.

B. MERC'S EXTENSIVE RELIANCE ON THE LONG-TERM PEAK DEMAND FORECAST IS UNREASONABLE.

MERC decided how large the Rochester Project should be based on one factor—the results of its long-term demand forecast. By doing so the Company treats the forecast as if it were a prophecy delivered with certainty, rather than an estimate with all the risks that are inherent in forecasts. And with its proposal, MERC would force ratepayers to take on the risk that the dramatic growth it forecasts will not come to pass.

MERC witness Mr. Sexton confirms that the reason MERC chose to obtain 100,000 Dth/day of capacity in the Rochester area was because of the results of its long-term peak demand forecast. Specifically, in his Direct Testimony Mr. Sexton addressed the question,

“Why did MERC request a pipeline design with a capacity of 100,000 Dth/day?”⁴⁵ As Mr. Sexton explains, the Company decided that the Rochester Project must result in 100,000 Dth/day of capacity because, “[The] annual growth rate . . . projects that firm system sales demand in that part of the state will be slightly greater than 91,000 Dth/day at the end of the twenty-five year term in the year 2042. With a 5% reserve margin added, this converts to a capacity requirement of 96,000 Dth/day. *This number was rounded up to 100,000 Dth/day for use in the RFP.*”⁴⁶ In other words, MERC conducted a forecast that said 100,000 Dth/day, and so MERC went out and made sure that it obtained exactly 100,000 Dth/day.

That is the problem. No reasonable analyst would conduct a forecast and then make purchasing decisions as if the results of the forecast were guaranteed to come true, but that is exactly what MERC has done.

By relying exclusively, and so unflinchingly, on the results of its forecast, MERC fails to account for the uncertainty that is inherent in forecasting. Any forecast, even one that is perfectly designed, is, at best, an estimate of what *may* happen in the future. Even MERC’s forecasting witness agreed that there are no guarantees that a forecast will actually be correct.⁴⁷ It is possible that the peak demand in 2042 will be exactly 100,000 Dth/day. In that case, as discussed above, customers may be paying for 15% more natural gas than they actually need. But it is also possible that peak demand in 2042 will be less than 100,000 Dth/day, because there will always be forecast uncertainty. Instead of allowing for the possibility of variance, MERC has made its decisions as if it has complete certainty that the results of its forecast will come true. But, as the Company has agreed, there can be no guarantee of that. If there *is* variance from the

⁴⁵ Ex. 17, at 39 (Sexton Direct).

⁴⁶ *Id.* at 40 (emphasis added).

⁴⁷ Tr. Evid. Hearing, Vol. 1, at 81 (Clabots).

forecast, MERC's shareholders will be earning a windfall return on an overbuilt project paid for by captive ratepayers.

On top of that, the variance from the forecast in this case is likely to be high, because the forecast is for an extremely long time period. As Department witness Mr. Heinen testified during the evidentiary hearing, "there's no guarantee that any forecast will be [correct]," and that "[a]ll else being equal, you would expect a shorter forecast to have less forecasting risk."⁴⁸ That is a problem here because the forecast in this case covers an unusually long period of time. Mr. Heinen pointed out that "this marks the first time that a gas utility has filed a long-range sales forecast" during his extensive tenure with the Department.⁴⁹ Mr. Heinen confirmed that the longest gas forecast he had ever seen filed by a utility was between 18 and 24 months.⁵⁰ The forecasting period for this project is 25 *years*. If a longer forecast means more forecasting risk, and this is the longest natural gas forecast Mr. Heinen has reviewed, then this forecast must contain the most forecasting risk of any natural gas forecast the Commission has ever seen. And yet MERC chose the size of the Rochester Project as if the forecast were guaranteed to come true.

MERC's reliance on the results of its forecast, without controlling for any kind of risk or variance, is inherently unreasonable. It places all of the forecasting risk, the risk of overbuilding, and the risk of building facilities before they are necessary, on ratepayers.

This problem would exist even with a flawless peak demand forecast model. But it will be exacerbated even more in this case, because MERC's forecast contains many problems that led the Company to over-estimate the growth in demand.

⁴⁸ Tr. Evid. Hearing, Vol. 2, at 24:7–12 (Heinen).

⁴⁹ Ex. 405, at 6 (Heinen Direct).

⁵⁰ Tr. Evid. Hearing, Vol. 2, at 25:1–2 (Heinen).

C. MERC’S FORECAST OVERESTIMATES THE GROWTH IN PEAK DEMAND.

MERC relies on its forecast to justify the size of the Project it has proposed, but a thorough analysis of the forecasting methodology raises many concerns. The reasonableness of MERC’s forecast is an important factor in determining the reasonableness and prudence of the Rochester Project because the Company determined the size of the Project, and the resulting cost, based on the forecast. The growth estimate produced by the forecast also impacts the excess reserve margins, or the amount of unnecessary supply that ratepayers would be obligated to pay for. As a result, the methodology and results of MERC’s forecast require a thorough and comprehensive analysis.

MERC conducted a sales forecast using Ordinary Least Squares (“OLS”) regression using historical data from January 2007 through July 2015 to produce a weather normalized estimate of sales growth from 2015 to 2025.⁵¹ The Company states that the “general procedure was mainly utilizing a monthly customer count model and a use-per-customer model to derive total sales by class.”⁵² In the Petition, this process resulted in a sales growth rate of 1.6 percent per year from 2015 to 2025.⁵³ During the testimony process, MERC agreed with the OAG and the Department that the forecast should be conducted using weather data specific to the Rochester region, which reduced the annual sales growth rate from 2015 to 2025 to 1.5 percent.⁵⁴ MERC then applied the ten year sales growth rate of 1.5 percent to its Design Day for a period of 25 years.

The analysis in this case demonstrates that there are several problems with MERC’s forecasting methodology. First, MERC’s growth rate is not supported by the historical data that

⁵¹ Ex. 9, at 4 (Clabots Direct).

⁵² Ex. 1, at 76 (Petition).

⁵³ Ex. 9, at 6 (Clabots Direct).

⁵⁴ *Id.*

is available. Second, MERC's customer count model is not reasonable. Third, MERC unreasonably assumed that Residential use-per-customer would remain constant for the entire 25-year time period. Fourth, MERC used "priori information" to create its forecast. Fifth, MERC assumes, without support, that it is reasonable to apply an estimate of *sales* growth to its Design Day, which measures peak demand. When these problems are addressed, the corrected forecast presents a much lower growth rate that does not support MERC's proposal to acquire 100,000 Dth/day of natural gas capacity for the Rochester region.

1. MERC's Forecasted Growth Rate Is Not Supported By Historical Data.

MERC forecasts that firm peak demand in the Rochester area will grow by 1.5 percent from 2015 to 2042. As discussed above, MERC constructed this forecast using historical sales data from 2007 to 2015. The problem is that the historical sales data simply does not support a growth rate of 1.5 percent, because the historical growth rate has been less than one-third of MERC's forecasted growth rate.

MERC did not clearly state the historical growth rate in its initial Petition, so the OAG asked the Company to do so in an information request.⁵⁵ The results of that information request demonstrate that the historical average annual growth rate in the Rochester area has been 0.46 percent.

⁵⁵ Dr. Urban introduced that Information Request into the record as Schedule JAU-10. As a result of a miscommunication between the OAG and MERC, the OAG updated Schedule JAU-10 in an errata filing to use weather normalized data. The schedules to Dr. Urban's Amended and Corrected Direct Testimony, which are filed as Exhibits 304, 305, and 306, include the correct, weather normalized version of this information.

MERC Rochester Pipeline Expansion Project					
OAG-155 Question 2					
Rochester Weather Normalized Calendar Sales Data					
Units: Therms					
Weather Normalized Calendar Sales Data					
	Residential	SC&I	LC&I	Total	% Chg
2007	33,617,022	839,311	14,799,596	49,255,929	
2008	34,431,489	880,932	15,106,799	50,419,220	2.36%
2009	35,410,050	1,016,451	15,112,268	51,538,769	2.22%
2010	33,655,403	1,060,105	14,473,411	49,188,919	-4.56%
2011	35,161,983	1,220,915	15,686,775	52,069,673	5.86%
2012	35,287,597	1,058,178	16,434,231	52,780,006	1.36%
2013	35,619,126	1,367,791	16,601,029	53,587,946	1.53%
2014	38,121,516	1,691,545	17,872,702	57,685,764	7.65%
2015	33,297,050	1,182,199	15,838,890	50,318,139	-12.77%
Average Annual Percentage Change					
					0.46%

This weather normalized data, provided by MERC, demonstrates that the average annual change in sales growth in the Rochester region is 0.46 percent. Over the entire time period, sales changed from 49,255,929 to 50,318,139—an increase of only 2.1 percent over an eight year period.

In contrast, MERC estimates that its sales will grow by 1.5 percent *each year* for the next twenty five years. If spread over the same eight year period covered by historical data, MERC forecasts its sales will grow by 12.6 percent in the next eight years, even though sales have grown by only 2.1 percent over the last eight years. There is no rational understanding of these facts except to conclude that MERC's forecast estimates dramatically higher levels of growth than is supported by *all* of the historical data.

The disconnect between the historical levels of growth in the Rochester area and the levels of growth MERC uses to support the Rochester Project stand out as a red flag regarding

the reasonableness of MERC's proposal. As discussed above, the Rochester Project will lead to unreasonably high reserve margins *even if* MERC's forecast is 100 percent correct. If growth is closer to historical levels, though, the reserve margins, and the unnecessary costs forced on captive ratepayers, will be significantly greater. The fact that MERC's forecast departs dramatically from historical data is not the only problem with the forecast; MERC also made unreasonable assumptions about the data it used to produce the results of its forecast.

2. MERC's Customer Count Model Is Unreasonable.

According to MERC, the two main components of the forecast were the customer count model and the use-per-customer model.⁵⁶ The customer count model attempts to estimate how many customers MERC will be in each class in a given year in the future. As with other issues regarding the Company's forecast, though, the forecast estimates are significantly greater than historical growth rates.

MERC's customer count model estimates that its total number of customers in the Rochester area will grow by 2.0 percent each year.⁵⁷ But, according to MERC witness Mr. Clabots, the historical growth rate in customer count was 0.77 percent.⁵⁸ In other words, MERC is assuming that over the next 25 years the number of customers in the area will grow approximately 2.5 times faster than it has grown in the past. MERC's customer count model appears to be completely unreasonable compared to historical data.

Further analysis identified additional problems with the comparative results of the customer count model. In following up on this problem, Department witness Mr. Heinen also noticed that MERC's customer count estimates were higher than the population growth estimates

⁵⁶ Ex. 1, at 76 (Petition).

⁵⁷ Ex. 9, at 9, Table 5 (Clabots Direct).

⁵⁸ *Id.* at 10, Table 6. $0.77 = (0.91 + 0.91 + 0.73 + 0.37 + 0.58 + 0.99 + 0.90) / 7$

provided by the Rochester-Olmsted Council of Governments (“ROCG”).⁵⁹ While MERC estimates a 2 percent growth in customer counts, ROCG estimated population growth of only 1.5 percent.⁶⁰

Mr. Heinen also compared MERC’s estimated customer count growth to historical household data from the United States Census Bureau and the Minnesota State Demographic Center. Using historical data from Olmstead County, Mr. Heinen estimated that average household growth since 1990 is approximately 1.65 percent, with a noticable downward trend.⁶¹ As Mr. Heinen testified, “the Company’s Residential customer count projections assumed significant increases in population and household growth, above current conditions.”⁶²

Following his testimony regarding these concerns, Mr. Heinen conducted an alternate customer count forecast using an OLS regression.⁶³ The results of this analysis suggested a growth rate in customer counts of approximately 0.75 percent per year, which was significantly less than MERC’s estimate.⁶⁴ Dr. Urban reviewed Mr. Heinen’s analysis and agreed that MERC had significantly over-estimated the customer counts that went into its forecast—and that, as a result, MERC’s forecast would materially overstate growth in peak demand.⁶⁵

In addition to this problem, Dr. Urban identified problems with MERC’s assumptions regarding use-per-customer.

⁵⁹ Ex. 405, at 15–16 (Heinen Direct).

⁶⁰ *Id.*

⁶¹ *Id.* at 17.

⁶² *Id.* at 18.

⁶³ *Id.* at 26.

⁶⁴ *Id.* at 27.

⁶⁵ Ex. 307, at 4–5 (Urban Amended and Corrected Rebuttal).

3. MERC Unreasonably Assumes That Residential Use-Per-Customer Will Remain Constant.

As noted above, the main parts of MERC's forecast were the customer count model and the use-per-customer model.⁶⁶ Like the customer count model, the Company's use-per-customer model is also flawed. While MERC did not clearly explain it in its Petition, Dr. Urban's analysis discovered that the Company's use-per-customer assumed that Residential use-per-customer would remain constant for the next 25 years.

As a result of conservation and improvements in efficiency in both housing and appliances, natural gas use per customer has been trending downward for many years.⁶⁷ In the face of this trend, MERC assumes that use-per-customer will remain constant for the entire forecast period—but only for some of its customers. One way to reflect a decreasing use-per-customer for a customer class is to include a time trend variable. MERC appears to recognize this analytical tool, because the Company included a time trend variable in its use-per-customer model for the Small C&I customer class.⁶⁸ The Company did not include a time trend variable, however, for the Residential class.⁶⁹ Including a time trend variable in the regression analysis can be used to investigate whether there is a downward trend in residential use-per-customer, and whether the trend variable is a significant explanatory variable in the model.⁷⁰ In other words, a time trend variable can be added to the model to investigate whether residential use-per-customer is flat, as MERC assumes, or if there is a downward trend as observed in historical data.

Dr. Urban investigated MERC's use-per-customer model through discovery requests to the Company. In OAG IR 155.7, the OAG asked MERC to include a time trend variable in the

⁶⁶ Ex. 1, at 76 (Petition).

⁶⁷ Ex. 314, at 2 (Urban Opening Statement).

⁶⁸ Ex. 300, at 30 (Urban Amended and Corrected Direct).

⁶⁹ *Id.*

⁷⁰ *See id.*

residential use-per-customer model.⁷¹ When that step was taken, the results of the residential use-per-customer model were reduced. While MERC estimated an average growth rate in residential sales of 1.87 percent without a time trend variable, including the time trend variable reduced the estimate to 1.34 percent—a reduction of 28 percent. To verify whether the time trend was a significant explanatory variable, Dr. Urban asked MERC to calculate the p-value for the time trend coefficient.⁷² The p-value measures the level of confidence as to whether an explanatory value is significant.⁷³ A p-value of zero indicates that the variable is “highly significant.”⁷⁴ And, as MERC identified in its information request, the p-value for the time trend variable was 0.00 percent—indicating that its inclusion in the model is highly significant.⁷⁵

In other words, including the time trend variable in the residential use-per-customer model is highly significant, and when the time trend variable is included in the model the growth rate result of the model is reduced by 28 percent.

Department witness Mr. Heinen also discussed the use of time trend variables. During the evidentiary hearing, Mr. Heinen pointed out that he included a time trend variable in his analysis of peak demand.⁷⁶ Mr. Heinen concluded, though, that the time trend was not significant because the T-statistic was less than two, but greater than one.⁷⁷ What Mr. Heinen did not acknowledge, however, was that his T-statistic is based on a different model with different data. MERC’s model estimates use-per-customer by customer class using sales data. Mr. Heinen’s model estimates *peak day* use-per-customer, not sales use-per-customer. Further, Mr.

⁷¹ Ex. 300, at 30 (Urban Amended and Corrected Direct); Ex. 304, JAU-15 (Urban Direct Schedules).

⁷² Ex. 304, JAU-14 (Urban Direct Schedules).

⁷³ Tr. Evid. Hearing, Vol. 1, at 19–20 (Urban).

⁷⁴ Ex. 10, at 14:15 (Clabots Rebuttal).

⁷⁵ Ex. 304, JAU-14 (Urban Direct Schedules).

⁷⁶ Tr. Evid. Hearing, Vol. 2, at 63 (Heinen); *see also* Ex. 405, Schedule AJH-13 (Heinen Direct).

⁷⁷ Tr. Evid. Hearing, Vol. 2, at 63 (Heinen).

Heinen's model is an estimate of all firm and non-firm customer data,⁷⁸ while the model discussed by the OAG and MERC is estimated by specific customer class. In other words, Mr. Heinen and Dr. Urban are conducting a different analysis, and Mr. Heinen's discussion does not rebut Dr. Urban's conclusion that a time trend variable is a significant explanatory variable for estimating residential use-per-customer. MERC admitted in its response to information requests that the time trend variable was a significant explanatory variable in the residential use-per-customer sales model, and Mr. Heinen's analysis on a different model does not change that fact.

In his opening statement, Mr. Clabots attempted to criticize the inclusion of a time trend variable by arguing that it is merely a "time index variable."⁷⁹ What Mr. Clabots fails to acknowledge, though, is that *MERC* chose to include a time trend variable in its Small C&I use-per-customer model.⁸⁰ It is unreasonable for the Company to criticize including a time trend for one group of customers, when the Company has already determined that it is reasonable to include it for another group. MERC has not provided any explanation for why it would be reasonable to include a time trend variable for Small C&I customers, but exclude it for Residential customers.

MERC's residential use-per-customer model assumes that residential use will remain constant for the next 25 years. This assumption flies in the face of historical trends, and ignores Minnesota's clear policy goals in favor of conservation and efficiency. When the model is modified to include a time trend variable, which controls for the downward trend in use-per-customer, the variable is highly significant, and results in a growth rate that is 28 percent less

⁷⁸ *Id.* at 62:23–63:3 (Heinen).

⁷⁹ While Mr. Clabots discussed the time trend variable in his Rebuttal Testimony, he did so only to question the magnitude of the time trend variable, not the mechanics of doing so.

⁸⁰ Ex. 300, at 30 (Urban Amended and Corrected Direct).

than MERC's initial results. This evidence clearly demonstrates that MERC's assumptions regarding the use-per-customer model are unreasonable.

4. MERC Unreasonably Uses "Priori Information" In Its Forecast.

In addition to concerns with MERC's customer count and use-per-customer models, Dr. Urban identified concerns with the use of "Priori Information." The use of *a priori* information is significant because it represents a departure from historical growth—the analyst uses his or her judgment to create expectations of future growth that is different from what would be supported by historical data.⁸¹ While all forecasts involve the use of some judgment, when using *a priori* information it is essential to understand what the impact of that judgment has been in order to determine whether it is reasonable. In other words, it is essential to be able to understand what *a priori* information MERC used, and what impact it had on the forecast, because that is the only way to determine whether MERC's use of the *a priori* information was reasonable. But that is impossible in this case because MERC has not been transparent about what outside information it used, or what it used that information for.

In its Petition, MERC stated, "The Rochester Residential and Small C&I customer count models are based on the "Priori Information" methodology. In other words, based on information that was gathered regarding expected future growth prior to preparing the model."⁸² MERC clarified that the "information" that was gathered did not come from outside sources, but from MERC's employees: "The anticipated growth rate is based on information from MERC's Gas Planning Committee and from other MERC personnel who are directly involved with planning system needs resulting from Mayo Clinic's expansion plans."⁸³ Under the heading

⁸¹ Ex. 311, at 1 (Urban Amended Surrebuttal); Ex. 300, at 31 (Urban Amended and Corrected Direct).

⁸² Ex. 1, at 77 (Petition).

⁸³ *Id.*

“Data / Modeling Risks,” MERC states, “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.”⁸⁴

Based on these statements, the OAG attempted to determine what changes had resulted from the “Prior Information” that the Company used. The OAG sent the Company an information request requesting that the Company “reproduce MERC’s growth estimates for the Rochester area without the DMC program.”⁸⁵ Despite the fact that MERC had already filed documents stating that it had “based” its customer count numbers on “information from MERC’s Gas Planning Committee,” in its response to the Information Request the Company stated that the forecast “did not incorporate growth assumptions specific to the Destination Medical Center.”⁸⁶ The Company agreed that it had used data from Moody’s Analytics that “presumably reflect some assumptions about the impact of the DMC plan,” but stated that it could not “determine the degree of that impact.”⁸⁷ And later, in testimony and opening statements, MERC testified that it “used a priori or external information as a check on the reasonableness of its forecast assumptions.”⁸⁸

MERC initially provided signed documentation that it used “priori information” to adjust customer count figures, then contradicted that statement in an information request, then admitted that it did not know the impact of DMC-related priori information, and then testified that it used priori information only as a check on the reasonableness of its forecast. That is not the level of transparency that ratepayers should expect from their utilities. MERC has provided no

⁸⁴ *Id.* at 78.

⁸⁵ Ex. 311, at 1 (Urban Amended Surrebuttal); Ex. 313, JAU-SR-1 (Urban Surrebuttal Schedules).

⁸⁶ *Id.*

⁸⁷ *Id.*

⁸⁸ Ex. 26, at 2 (Clabots Opening Statement).

clarification for these inconsistencies, but the simplest explanation is that MERC used prior information in exactly the way the Company described in its initial Petition to the Commission: as the basis for its Residential and Small C&I customer count models. This may be one reason that MERC's customer count models are so significantly overstated.

Department witness Mr. Heinen also discussed whether outside information from the DMC was included in MERC's forecast. In his Direct Testimony, Mr. Heinen stated that his customer count projections could be a "placeholder for the lack of inclusion of the DMC" in MERC's forecast.⁸⁹ In other words, Mr. Heinen believed that, while his modifications would produce a lower forecast, MERC's forecast might still be reasonable since the Company had not accounted for the DMC.

Mr. Heinen appears to have disregarded the record evidence indicating that the Company did consider the DMC. When questioned during the evidentiary hearing Mr. Heinen agreed that he had seen and reviewed the Information Request in which MERC admitted that the data from Moody's analytics "presumably" included consideration of the DMC could, but that he did not care to follow up with them to determine the impact of that consideration.⁹⁰

Mr. Heinen also testified that the customer count data on which he relied for his customer count modifications did account for the DMC. Specifically, Mr. Heinen stated that the information from the Rochester Olmsted Council of Governments "includes a job impacts from the Destination Medical Center [which] I would assume that they've incorporated impacts from the DMC into their population projections."⁹¹ Mr. Heinen also appears to have ignored the clear statement in MERC's Petition that "[t]he assumptions made on Rochester Residential and SC&I

⁸⁹ Ex. 405, at 19 (Heinen Direct).

⁹⁰ Tr. Evid. Hearing, Vol. 2, at 41–43 (Heinen).

⁹¹ *Id.* at 44 (Heinen).

are primarily based on the Mayo Clinic expansion,” and that “[t]hese assumptions do have significant impact on the forecasts.”⁹² In sum, while Mr. Heinen provided written testimony that consideration of the DMC was not used as *a priori* information, the evidence in the record and his testimony during the evidentiary hearing contradicted his earlier statements completely.

Ultimately, the reason that it matters whether or not MERC considered *a priori* information is that it is important to understand what impact that consideration had on the forecast to determine whether it was reasonable to do so. If MERC used the fact that the DMC may lead to growth in the future to increase the results of its customer count model, it is important to know *how much*. Because we do not know *how much*, it is impossible to tell whether doing so is reasonable. According to MERC, their Residential and Small C&I forecasts are “primarily based” on *a priori* information about the Mayo Clinic expansion, and those “assumptions do have significant impact on the forecasts.”⁹³ The problem, here, is that MERC has not been transparent about what “information” it actually had, or about what it did with that information. This concern is especially significant when MERC’s forecast is so much greater than historical trends. MERC’s estimated growth rate is 1.5 percent—more than three times the historical growth rate. While it may be reasonable to incorporate some expectations about the DMC into the forecast, using it to justify tripling the historical growth rate is not reasonable.

5. MERC Did Not Support The Reasonableness Of Applying A Sales Forecast To Design Day, Which Measures Peak Demand.

In addition to the concerns above, MERC did not provide any testimony to support a fundamental aspect of their forecasting methodology. As described above, MERC conducted a

⁹² Ex. 1, at 78 (Petition).

⁹³ *Id.*

sales forecast and determined that retail sales would grow by 1.5 percent from 2015 to 2025.⁹⁴ MERC then applied this sales forecast to its measurement of peak demand—the Design Day. But it is not clear that annual retail sales and the Design Day, which measures peak demand on the coldest single day, are equivalent. MERC has not provided any testimony or evidence in the record to support its assumption that a 1.5 percent growth in sales would cause a 1.5 percent growth in peak demand. In fact, Mr. Heinen from the Department testified that “that’s not a preferred method of doing it.”⁹⁵ While the record does not suggest any changes that could be made to correct this matter, the lack of evidentiary support for MERC’s assumption goes to the weight that the forecast should receive, and the reasonableness of MERC’s decision to rely on it so heavily when deciding the appropriate size of the Rochester Project.

6. The Corrected Forecast Does Not Support MERC’s Proposal To Add 100,000 Dth/Day.

In light of all these problems, the OAG asked MERC to recreate its forecast with three changes.⁹⁶ First, the OAG asked MERC to use the Rochester specific weather data, which MERC had already agreed to. Second, the OAG asked MERC to use Mr. Heinen’s customer count growth model. And third, the OAG asked MERC to incorporate a time trend variable in the residential use-per-customer model. With these changes, the forecast estimated growth of *negative* 0.1 percent—essentially, the forecast estimates that growth will be flat for the next ten years.

⁹⁴ *Id.*

⁹⁵ Tr. Evid. Hearing, Vol. 2, at 59:18–19 (Heinen).

⁹⁶ Ex. 313, JAU-SR-2 (Urban Surrebuttal Schedules).

This change has an extremely significant impact on reserve margins—using the modified growth rate produced in this information request, the Rochester Project would continue to produce *reserve margins in excess of 50 percent for the next 25 years*:⁹⁷

Rochester Area NNG Reserve Margin

	No Capacity to other TBSs		20% Capacity to other TBSs	
	Company	OAG	Company	OAG
	Forecast	Forecast	Forecast	Forecast
Winter	Reserve	Reserve	Reserve	Reserve
Period	Margin	Margin	Margin	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%

This table demonstrates that when some of the problems in MERC's forecasting methodology are controlled, the unreasonable size of the Rochester Project becomes an even bigger problem.

⁹⁷ Ex. 311, at 4, Table 2 (Urban Amended Surrebuttal).

Even when assuming that the reserve margin should be reduced to account for 20 percent of capacity delivered to alternate points, a reserve margin of more than 40 percent would persist for more than 25 years.

In the Information Request where MERC discussed the new forecast, MERC raised concerns about the modified forecast. Primarily, MERC states that it “has concerns with just adding a trend variable in isolation of other adjustments or variables,” because “[c]hanging variables in isolation risks inconsistent and potentially skewed results.”⁹⁸ As discussed above, though, MERC ignores the fact that *the Company* chose to include a time trend variable for Small C&I customers, but then chose not to include one for Residential customers. The OAG raised this issue in Dr. Urban’s Direct Testimony⁹⁹—and the Company has still provided no reason that it would be reasonable to add a trend variable for one group of customers, but not for another.

Second, MERC states that it “took an extra step” and replaced the 2015 forecast with 2015 weather normalized actual sales.¹⁰⁰ But it is important to recognize what MERC is actually suggesting. MERC is not suggesting that the forecast should be re-run using new actual data from 2015. Instead, MERC is suggesting that *after* conducting a forecast for the time period of 2015 to 2025, the forecasted results for 2015 should be removed and replaced with actual data.¹⁰¹ This is a nonsensical comparison between an actual 2015 number and a forecasted 2025 estimate. And MERC provides no explanation as to why it would be reasonable to replace forecasted results with actual results for one year in a forecasted time series. It is also worth

⁹⁸ *Id.*

⁹⁹ Ex. 300, at 30:8–10 (Urban Amended and Corrected Direct) (“Unlike the small commercial and industrial average use model, the residential average use model does not include a time trend variable.”).

¹⁰⁰ Ex. 313, JAU-SR-2 (Urban Surrebuttal Schedules).

¹⁰¹ Ex. 11, Clabots Surrebuttal Schedules at 227–279 (Clabots Surrebuttal).

noting that if the modified forecast *is* changed to account for 2015 actuals, the result is a growth rate of 1.1 percent—nearly thirty percent lower than MERC’s initial growth rate.¹⁰² In other words, even if the modified forecast is changed in this absurd manner, it still results in a growth rate that is significantly less than the growth rate that MERC uses to justify the Rochester Project.

In either event, the point is that Dr. Urban has raised significant concerns about the assumptions that went into MERC’s forecast. When those concerns are addressed to create a modified forecast, the result is a growth rate somewhere between 50 percent and 100 percent less than MERC’s forecast. This analysis provides useful information about the *magnitude* of the problems in MERC’s forecast. Dr. Urban’s analysis demonstrates that MERC’s forecast overstates the growth in peak demand, and also demonstrates that the magnitude of MERC’s errors are significant.

7. MERC’s Forecast Significantly Overestimates The Growth Of Peak Demand In The Rochester Area.

The combination of all of the problems discussed above clearly demonstrate that MERC’s forecast overestimates the growth in peak demand for Rochester area customers. When some of those problems are controlled, the changes in growth rate lead to reserve margins greater than 50 percent for decades. MERC’s forecast model is flawed, and MERC’s decision to select the size of the Rochester Project based exclusively on that forecast is unreasonable. The modified growth rates that result from correcting the problems with MERC’s forecast demonstrate that a more moderate, phased or incremental proposal would be a more prudent, reasonable, and appropriate way to meet demand. The Project that MERC has proposed is excessive, and would result in unreasonable costs being recovered from captive ratepayers.

¹⁰² Ex. 11, at 13 (Clabots Surrebuttal).

While a forecast is an exercise in technical analysis, it is important to recognize the crucial role it plays in this case. The most obvious instance is MERC's RFP, which was intentionally designed so that it would *only* seek proposals for the Rochester Project that provided the full 100,000 Dth/day supported by MERC's forecast.

D. MERC'S RFP WAS NOT DESIGNED TO CONSIDER ALL ALTERNATIVES.

MERC's RFP was issued on December 31, 2014.¹⁰³ In the RFP, MERC sought bids for two different options to increase the available natural gas capacity in the Rochester region. The first option would be to provide 100,000 Dth/day of firm capacity at new TBS on the northwest side of Rochester, while the second option would be to work with NNG to provide 45,000 Dth/day of incremental capacity for a total of 100,000 Dth/day of firm capacity. Both options had the same goal—provide 100,000 Dth/day of firm capacity to the Rochester area.

In its initial Petition, MERC did not provide any explanation as to why the RFP was targeted to 100,000 Dth/day. The first time the Company addressed the issue was in the Direct Testimony of Mr. Sexton, as follows:

Q. WHY DID MERC REQUEST A PIPELINE DESIGN WITH A CAPACITY OF 100,000 DTH/DAY?

A. Utilizing its current projected 1.50% per year annual growth rate in the Rochester area as supported by MERC witness Mr. David Clabots, MERC projects that firm system sales demand in that part of the State will be slightly greater than 91,000 Dth/day at the end of the twenty-five year term in the year 2042. With a 5% reserve margin added, this converts to a capacity requirement of about 96,000 Dth/day. This number was then rounded up to 100,000 Dth/day for use in the RFP.¹⁰⁴

According to Mr. Sexton, MERC requested a pipeline design with a capacity of 100,000 Dth/day because that was the result of MERC's forecast.

¹⁰³ Ex. 316, Schedule JAU-4 (Urban Direct Schedules HSTS).

¹⁰⁴ Ex. 17, at 39:21–40:6 (Sexton Direct).

Designing the RFP to obtain bids for 100,000 Dth/day is a problem because it means that MERC relied exclusively on the results of its forecast to determine how large the Rochester Project should be. As described above, it is not reasonable to give that much weight to *any* forecast. While a forecast can be a very useful tool in making decisions about future needs, no reasonable analyst would assume that a forecast provides certainty. In fact, both Mr. Clabots and Mr. Heinen agreed that there could be no guarantee that a forecast would be correct.¹⁰⁵ This problem is not academic—the record demonstrates that MERC flatly rejected some responses to the RFP because they did not satisfy the demand from the forecast. Mr. Sexton noted that Phased Proposal 2.3 was rejected because it did not “provide MERC with sufficient capacity to meet long-term demand” as shown in MERC’s forecast.¹⁰⁶ MERC effectively decided that its only option was to obtain exactly 100,000 Dth/day, simply because that was the result of its forecast. In doing so, MERC places the full weight of any forecast risk on the ratepayers.

MERC was aware that there was risk that their forecast would not pan out. In the Company’s initial Petition, their description of the sales forecasting methodology included a section titled “*Data / Modeling Risks.*”¹⁰⁷ In that section, MERC states:

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.

The risk of unanticipated national economic weakness could have adverse effects on the Minnesota economy, and impact sector growth.

Further, unanticipated milder weather conditions, increases in energy prices, and downward trends in Moody’s Analytics’

¹⁰⁵ Tr. Evid. Hearing, Vol. 1, at 81:14–19 (Clabots); Tr. Evid. Hearing, Vol. 2, at 24 (Heinen).

¹⁰⁶ Ex. 19, at 13 (Sexton Direct).

¹⁰⁷ Ex. 1, at 78 (Petition).

economic and demographic forecasts would adversely impact the forecast of increased future sales growth.¹⁰⁸

In other words, MERC acknowledged the risk that the DMC plan will not move forward as the Company has assumed, the risk that there could be a downward turn in the economy, that the price of gas could increase, or that the weather could be different than the Company expects. These are all reasons that the results of the Company's forecast may not come to pass, and they are all risk factors that the Company should have accounted for when deciding the appropriate size of the Rochester Project. Instead, MERC has placed the full risk of each of these factors on captive ratepayers.

MERC was also warned of forecasting risk by NNG, in the interstate pipeline company's response to the RFP. Specifically, NNG explained that some of its phased in proposals would provide benefits to ratepayers even though they did not immediately provide 100,000 Dth/day of capacity. According to NNG, these proposals would "eliminate the need for MERC to make construction decisions now based on forecast growth requirements that may occur over a 20-year or longer time period."¹⁰⁹ NNG noted that this approach would "reduce[] the risk to MERC's customers for costs associated with overbuilding facilities for forecasts of unknown growth."¹¹⁰ NNG pointed out that a smaller or phased option could "reduce[] risk for MERC and its customers by ensuring that it does not overbuild pipeline facilities before they are required while maintaining the ability to serve the growth needs of the community," and that the advantage would "protect[] customers from upfront costs and potential rate shock due to a large single

¹⁰⁸ *Id.*

¹⁰⁹ Ex. 300, at 18–19 (Urban Amended and Corrected Direct); *see also* Ex. 306, Schedule JAU-5 (Urban Direct Schedules HSTS). NNG's response to the RFP is marked as Highly Sensitive Trade Secret, but MERC agreed to remove the designation for the quoted sections, which are contained in Dr. Urban's Amended and Corrected Direct Testimony.

¹¹⁰ *Id.*

build-out of capacity when the capacity may not be needed until a future time period.”¹¹¹ To clarify *when* MERC should have been aware of these concerns, these are statements that NNG provided in the introduction to its response to the RFP. Instead of listening to the advice of its supplier, a company that has significantly more experience in building interstate pipeline infrastructure, MERC ignored the warning and focused on projects that would immediately add the full amount of natural gas predicted by its forecast.

After the OAG raised its concerns about the design of MERC’s RFP, the Company came up with new arguments in an attempt to justify the large size of the RFP. In its Rebuttal Testimony, MERC argued for the first time that the RFP needed to be designed at a large size in order to attract competitive bids from pipeline companies other than NNG.¹¹² According to Mr. Sexton, permitting smaller responses to the RFP “would not have fostered the competitive environment.”¹¹³ This argument is suspect, however, because MERC did not mention the concept of a “competitive environment” until the RFP was challenged.

In addition, MERC also fails to take note of the fact that the only bids that came from NNG were decidedly non-competitive. As Mr. Sexton himself determined, the cost of the “competitive” bids received from third parties were all [HIGHLY SENSITIVE TRADE SECRET BEGINS]

[HIGHLY SENSITIVE TRADE SECRET ENDS] A process is not “competitive” if it does not produce competitive results, and bids that are [HIGHLY SENSITIVE TRADE SECRET BEGINS]

¹¹¹ *Id.*

¹¹² Ex. 19, at 6 (Sexton Rebuttal); Ex. 14, at 12 (Mead Rebuttal).

¹¹³ Ex. 19, at 6 (Sexton Rebuttal).

[HIGHLY SENSITIVE TRADE SECRET ENDS] are not competitive.

MERC also does not acknowledge that an RFP that was more open-ended could have achieved both results. If MERC designed an RFP that accepted bids “up to 100,000 Dth/day,” then the Company may have received bids from NNG’s competitors, in addition to bids that would allow the Company to account for forecasting risk by considering smaller projects or phased projects. Instead, the Company forged ahead with considering only the projects that were fully consistent with the results of their 25-year forecast. That design was unreasonable because it prevented the Company from considering options that could insulate ratepayers from forecasting risk.

E. MERC’S ANALYSIS OF THE RFP WAS FLAWED.

In addition to the concerns related to the design of the RFP, the evidence in the record demonstrates that MERC did not analyze the responses to the RFP in a reasonable manner. The primary problem is that MERC’s analysis of the responses was not sufficiently rigorous to justify the Project that has been proposed.

1. MERC’s Analysis Of The RFP Responses Was Insufficiently Rigorous.

MERC did not provide a full discussion or explanation as to its analysis of the responses to the RFP in either its Petition or Direct Testimony. Instead, the parties had to obtain MERC’s analysis of the RFP responses through an information request—Department Information Request 38, which is attached as a Highly Sensitive Trade Secret exhibit to Mr. Ryan’s Direct

Testimony.¹¹⁴ The information that MERC provided is not sufficient to demonstrate a complete analysis of the responses to the RFP for several reasons.

First, MERC does not provide any narrative explanation of its process. Instead, MERC's analysis comprises a single page spreadsheet.¹¹⁵ In this analysis, [HIGHLY SENSITIVE TRADE SECRET BEGINS]

¹¹⁴ Ex. 403 (Ryan Direct HSTS Attachment).

¹¹⁵ *Id.* The following information is all drawn from this spreadsheet.

[HIGHLY SENSITIVE TRADE

SECRET ENDS]

Second, MERC's analysis addresses only four proposals, despite the fact that NNG provided more than ten proposals. Each of those proposals included detailed descriptions for different projects, at different levels of cost and benefit for ratepayers. MERC was asked to provide its analysis of the responses to the RFP, and the only document they provided was this single spreadsheet. The only possible conclusions to be inferred from that set of facts is that MERC either ignored the other bids without conducting any analysis, or declined to provide that analysis to parties when it was requested.

Third, MERC did not even select the bid that received the highest score. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS] MERC proceeded to negotiate with NNG using Proposal 3.0 as the basis for the negotiations. While MERC has been careful to point out

that they made modifications to Proposal 3.0, those modifications did not address the “reserve margin issue,” or the reasons that a phased in option would provide value to ratepayers. MERC obviously thought these were important enough that they needed to have their own category, but the Company ignored their value by moving forward with an up-front option that did not provide those benefits to ratepayers.

This is not the type of analysis that should be required before demanding that ratepayers fund construction of a \$100 million construction project. MERC should have produced a full analysis of the costs and benefits of each of the proposals, including a narrative description of how it performed its analysis and the results. Instead, MERC has handed over a single sheet of paper to justify a significant expenditure of ratepayer dollars.

2. MERC Did Not Obtain Independent Review Of Its Analysis Until After All Of The Decisions Were Made.

After this matter was referred to the Office of Administrative Hearings for a contested case, the Company provided the Direct Testimony of Mr. Sexton, an independent consultant who was retained to provide analysis on “the request for proposals (“RFP”) undertaken by MERC to assess alternatives . . .,” “the proposals received in response to MERC’s RFP and whether MERC,” and “the final negotiated proposal between MERC and NNG versus the other alternatives available to MERC.”¹¹⁶

The problem is that Mr. Sexton’s analysis was conducted *after* all of the important decisions were made. During the evidentiary hearing, Mr. Sexton confirmed that he first spoke to representatives of MERC about providing testimony in January of 2016.¹¹⁷ But the RFP was

¹¹⁶ Ex. 17, at 5 (Sexton Direct).

¹¹⁷ Tr. Evid. Hearing, Vol. 1, at 155 (Sexton).

issued on December 31, 2014, and the Company received responses in January, 2015.¹¹⁸ The PA was executed sometime in the fall of 2015.¹¹⁹ The timing of these important decisions, and its relationship to Mr. Sexton's analysis, are important for two reasons.

First, while it appears laudable for MERC to seek an independent opinion to check its decisions, the Company did not do so until after the decisions were already made. By the time Mr. Sexton heard about the Rochester Project, it had been a year since the RFP was issued and the responses were obtained, the Company had already negotiated for months, and, in fact, the PA had already been executed. The deal was done before Mr. Sexton ever heard of it. To the extent that Mr. Sexton had the opportunity to provide MERC with valuable insight on the decision-making process, his input came months too late to be useful.

Second, Mr. Sexton's analysis of MERC's decision-making is questionable because he was aware of MERC's final decision when he began his review. It is not surprising that a consultant selected by MERC, paid by MERC, and who knew the decision that MERC had already made, produced an analysis agreeing that the Company had made the right decision. While Mr. Sexton is careful to point out that he did not have MERC's analysis, such as it is, when he reviewed the Rochester Project, it is clear that he *was* aware of the Project that MERC had negotiated with NNG.

In addition to these problems, Mr. Sexton's analysis does not provide a direct comparison of all of the different RFP responses. According to Mr. Sexton, he did not provide this analysis because he chose only to compare proposals that "ultimately led to the same facilities and service," and so did not perform an analysis that compared proposals where facilities and

¹¹⁸ Ex. 306, Schedule 5, 7 (Urban Direct Schedules HSTS).

¹¹⁹ Tr. Evid. Hearing, Vol. 1, at 30:15–17 (Lee).

services were not consistent.¹²⁰ Mr. Sexton's analysis focused on comparing the "transaction actually completed versus the original conforming bid,"¹²¹ and, as a result, was not a complete analysis of all of the responses to the RFP.

These flaws all indicate that, despite initial appearances, the independent analysis performed by Mr. Sexton adds little value to the case.

3. MERC Did Not Provide An Analysis Of Distribution System Costs.

While much of the analysis in this case has focused on the costs of the NNG upgrades, MERC's ratepayers are being asked to bear significant costs for upgrading MERC's distribution system. According to MERC, the cost to prepare the Rochester system for receiving increased gas supply from the NNG PA will be approximately \$44 million.¹²² What MERC did not provide was an estimate of the distribution costs for a more moderate interstate capacity solution.

The information in the record indicates that MERC estimates its costs to upgrade the distribution system will be \$44 million. But there is no information about how much distribution upgrades would have cost if MERC had proceeded with a more moderate Rochester Project. If the Company were planning to increase natural gas capacity by 20,000 Dth/day, instead of 45,000 Dth/day, it is entirely possible that the cost of upgrading the distribution system to accept the new capacity would be similarly reduced. But MERC has not provided any information of that nature.

This is also problematic because the particular configuration of the distribution system led MERC to reject several bids. For example, Mr. Sexton testified that NNG Proposal 2.2 and 2.3 were rejected because they did not deliver incremental capacity to the correct TBSs at the

¹²⁰ Ex. 19, at 18 (Sexton Rebuttal).

¹²¹ *Id.*

¹²² Ex. 7, at 5 (Lyle Direct).

correct pressures.¹²³ As such, they did not “conform to the RFP requirements, did not meet operational requirements, and [were] not evaluated further.”¹²⁴ But, as Ms. Lyle agreed, the distribution upgrades the Company plans to build will allow the Company to “move [the gas] wherever [MERC] need[s] it,” once the interconnection is complete.¹²⁵ The facts in the record indicate that the planned distribution upgrades would allow MERC to accept gas anywhere on the system and move it where it was needed, but that MERC still rejected at least one proposal because it would not bring gas to the right place.

It is likely that each of the proposals for the Rochester Project would have required a different distribution configuration. It is also likely that MERC could have chosen different investments to upgrade the distribution system in the Rochester area. But MERC has either not conducted any analysis on the different options, or has declined to provide it in this case. As a result, it is not possible to determine whether any of the different interstate pipeline proposals could have been selected to minimize distribution costs.

4. MERC Has Misrepresented The Facts Regarding The Responses To The RFP.

These substantive problems with MERC’s RFP should be reviewed in consideration of the distinct lack of transparency in MERC’s discussion of the RFP and the responses to the RFP. There are several instances in which the statements MERC has made about the RFP are not consistent with the facts in the record.

The first time MERC discussed the responses to the RFP was in its initial Petition. In the Petition, MERC stated that “NNG responded with two proposals. One was to build a new 600 psig transmission pipeline in the Rochester area. The other proposal was to upgrade the capacity

¹²³ Ex. 19, at 11 (Sexton Direct).

¹²⁴ Ex. 19, at 11 (Sexton Direct).

¹²⁵ Tr. Evid. Hearing, Vol. 1, at 62:4–7 (Lyle).

of its existing area pipeline system to 600 psig.”¹²⁶ This statement is materially false. NNG actually provided as many as thirteen different proposals. NNG also made clear that each of the proposals was only a starting point for negotiations.¹²⁷ The statement in MERC’s Petition is simply untrue, and the truth of the matter was not discovered until the Department and the OAG conducted the appropriate discovery.

Dr. Urban also identified inconsistencies in MERC’s Direct Testimony. In her Direct Testimony, Ms. Mead testified that, “NNG advised us that the only available alternative was to make a major expansion of the pipeline system into the Rochester area. This proposal, while larger than we needed in the near term, compared favorably against other proposals that would have required an equivalent major expansion by building a new pipeline into the area.”¹²⁸ As Dr. Urban pointed out, though, Ms. Mead’s statement is “directly contradictory to NNG’s response to the RFP.”¹²⁹ Dr. Urban noted,

NNG went out of its way to propose phased proposals that would *not* have required ‘major expansion of the pipeline’ in the short term, as Ms. Mead suggests. In fact, NNG took pains to point out that a phased approach could ‘eliminate the need for MERC to make construction decisions now based on forecast growth requirements that may occur over a 20-year or longer time period,’ ‘reduce[] the risk to MERC’s customers for costs associated with overbuilding facilities for forecasts of unknown growth,’ and ‘protect customers from upfront costs and potential rate shock due to a large single build-out of capacity when they capacity may not be needed until a future time period.’¹³⁰

In light of these warnings by NNG, Ms. Mead’s statement that the “only available alternative was to make a major expansion” appears disingenuous at best.

¹²⁶ Ex. 1, at 26 (Petition).

¹²⁷ Ex. 306, Schedule 5 (Urban Direct Schedules HSTS).

¹²⁸ Ex. 12, at 27 (Mead Direct).

¹²⁹ Ex. 300, at 50 (Urban Amended and Corrected Direct).

¹³⁰ *Id.*

This concern is compounded by the fact that the Company did not provide either the Precedent Agreement, the RFP or the responses to the RFP until they were demanded in discovery. Dr. Urban pointed out that, “It is unclear [] how the Commission could be expected to approve of MERC’s proposal without a thorough understanding of how MERC’s RFP was designed and what responses it received.”¹³¹ During the evidentiary hearing, MERC witness Ms. Lee confirmed that the Company had asked the Commission for approval of this \$100 million infrastructure project without providing the Precedent Agreement, the text of the RFP, or the responses to the RFP in either its initial petition or its direct testimony.¹³² While the OAG and the Department eventually made sure that this information was made part of the record, this distinct lack of transparency, and MERC’s repeated misrepresentations about the responses it received to the RFP, reflect poorly on MERC’s decision-making process.

5. The Department’s Agreement With The RFP should Be Given Little Weight Because The Department Did Not Actually Analyze The Responses To The RFP.

In his Direct Testimony, Department witness Mr. Ryan testified that his responsibility was to review the RFP conducted by MERC, and that the purpose of his review was to determine “a) whether MERC selected the least cost alternative to meet the proposed need . . . and b) whether MERC met the statutory requirement to show that ‘project costs are reasonable and prudently incurred.’”¹³³ Mr. Ryan testified that he had “access to the RFP responses,” and “review[ed] MERC’s comparative evaluation of the competitive bids.”¹³⁴ Based on this, Mr. Ryan concluded that MERC’s RFP process was fair and reasonable.¹³⁵

¹³¹ *Id.* at 15–16.

¹³² Tr. Evid. Hearing, Vol. 1, at 28–29 (Lee).

¹³³ Ex. 402, at 2 (Ryan Direct).

¹³⁴ *Id.* at 9–10.

¹³⁵ *Id.* at 14.

During the evidentiary hearing, though, Mr. Ryan admitted that he did not actually perform any analysis of the responses to the RFP. Specifically, Mr. Ryan confirmed that he did not do his own independent analysis of the bids.¹³⁶ Instead, all that Mr. Ryan did was “read the RFP responses and [] review MERC’s analysis of them.”¹³⁷ Further, Mr. Ryan admitted that he was not sure where or how MERC was deciding what scores different bids received in the comparative analysis.¹³⁸ And Mr. Ryan also agreed that **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS] even though Mr. Ryan concluded that it was reasonable for MERC to proceed to negotiate on the basis of Proposal 3.0, which did not include the attributes which MERC decided should lead Phased Proposal 4.2 to receive a higher score.

On top of all of this, Mr. Ryan stated in his Opening Statement that he did not “address[] the size and timing of the project.”¹³⁹ In other words, Mr. Ryan’s conclusion is that the RFP process is reasonable, except that Mr. Ryan did not consider whether MERC’s proposal is the proper size—the single most important factor in the reasonableness of the project. The lack of analysis was not limited to Mr. Ryan. Department witness Mr. Heinen also confirmed during the evidentiary hearing that he did not do a detailed analysis of the RFP, because it was Mr. Ryan’s responsibility.¹⁴⁰

¹³⁶ Tr. Evid. Hearing, Vol. 1, at 213 (Ryan).

¹³⁷ *Id.* at 214:2–6 (Ryan).

¹³⁸ *Id.* at 217:2–3 (Ryan).

¹³⁹ Ex. 409 (Ryan Opening Statement).

¹⁴⁰ Tr. Evid. Hearing, Vol. 2, at 46–47 (Heinen).

The Department's concurrence with MERC's RFP and the RFP process should be given little weight in this proceeding, because the Department did not conduct its own analysis of either the RFP or the RFP responses.

6. MERC's Analysis Of The RFP Was Not Sufficient.

The facts in the record demonstrate that MERC did not conduct a sufficient analysis of the responses it received to the RFP. The independent analysis MERC obtained came too late to be useful, and under questionable circumstances. The combination of these concerns, and the others discussed above, indicates that MERC's analysis of the RFP is not sufficient to support the direction it chose for the Rochester Project.

F. MERC'S DECISION TO FOCUS ON UP-FRONT PROJECTS INSTEAD OF PHASED OR INCREMENTAL PROJECTS WAS NOT REASONABLE.

One consequence of all of these problems with MERC's analysis of the RFP is that the Company did not give sufficient consideration to phased proposals that could have provided significant protections for ratepayers. MERC was presented with multiple phased proposals, but did not give them any serious consideration because of the Company's single-minded focus on only pursuing options that would immediately meet their long-term demand forecast. The record demonstrates that these proposals could have provided ratepayers with significant benefits, but that MERC discarded them to focus on up-front proposals that will lead to overbuilding infrastructure, intergenerational inequities, and excess supply that will provide unreasonable levels of benefit to interruptible and transportation customers.

1. Phased Proposals Could Have Provided Significant Protections For Ratepayers.

As discussed above, one of the primary problems with the Rochester Project is that MERC is proposing to acquire more capacity than is necessary, long before it is needed. One obvious way to deal with problems related to the timing of capacity additions would be to phase

capacity additions in over time, or to add capacity incrementally. In fact, the bid responses from NNG provide a list of ratepayer protections that could have resulted from a phased or incremental approach: **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS] ¹⁴¹

NNG provided further discussion of its phased in options: **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS] ¹⁴²

NNG repeated these concerns in its supplemental response to the RFP. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

¹⁴¹ Ex. 306, Schedule 5, at 2 (Urban Direct HSTS Schedules).

¹⁴² *Id.* at 5.

[HIGHLY SENSITIVE TRADE
SECRET ENDS]¹⁴³

Northern also made sure to note that its phased proposals [HIGHLY SENSITIVE TRADE
SECRET BEGINS]

[HIGHLY SENSITIVE TRADE SECRET ENDS]¹⁴⁴

These descriptions lead to three important benefits that ratepayers could have obtained from a phased proposal. First, some of the proposals that NNG made would have allowed MERC the *option* of future capacity additions when they were needed, without any obligation to do so if the need did not materialize. This would obviously insulate ratepayers from a significant amount of forecasting risk. In a phased proposal without obligation for future upgrades, ratepayers are not required to pay for capacity additions if the forecasted levels of growth do not materialize. And, if the forecasted growth *does* materialize, the utility has a plan in place to address it. The benefits of this approach are readily apparent.

Second, a phased or incremental proposal would more closely link the timing of when the costs of a project are paid by ratepayers to when the infrastructure is useful to ratepayers. In other words, some of the costs for a phased or incremental proposal would be incurred later.

¹⁴³ *Id.* at 26.

¹⁴⁴ *Id.* at 37.

This would be more equitable because current ratepayers would be shouldering less of the burden required to provide service for ratepayers who might need the infrastructure upgrades in twenty or thirty years.

Third, because a phased in proposal will not result in such high reserve margins there would be less problems with ensuring that costs are shared equitably between all customers. As discussed in more detail in Section III, the extremely high reserve margins that would result from MERC's proposal would provide significant benefits to interruptible and transportation customers, but not all of those customers would share fully in the costs. A phased proposal could reduce these equity complications by reducing the reserve margins created up-front while still allowing MERC to pursue further upgrades in the future if demand grows as the Company predicts.

Several of the proposals NNG offered to MERC would have provided these benefits.

2. MERC Received Multiple Phased Proposals In Response To The RFP.

In response to the RFP, NNG provided multiple phased proposals that would have provided these benefits to ratepayers. Phased Proposal 2.3 would have increased capacity in the Rochester area by 10,000 Dth/day immediately, and then permitted MERC to add another 35,000 Dth/day in the future when growth materializes.¹⁴⁵ The total cost of Phased Proposal 2.3 would have been [HIGHLY SENSITIVE TRADE SECRET BEGINS]

[HIGHLY SENSITIVE TRADE SECRET ENDS].

Phased Proposal 4.1 would have increased capacity by approximately 17,669 Dth/day up-front, and given MERC the option to add an additional 27,331 Dth/day in the future when growth

¹⁴⁵ Ex. 303, at 22 (Urban Amended and Corrected HSTS Direct).

materializes.¹⁴⁶ The up-front costs for Phased Proposal 4.1 would be **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS].

Phased Proposal 4.2 would have also increased capacity by approximately 17,669 Dth/day up-front, and given MERC the option to add an additional 27,331 Dth/day in the future, for a total of 100,000 Dth/day.¹⁴⁷ As compared to Phased Proposal 4.1, this proposal would install a compressor earlier in the process, which would be more efficient and permit long-term cost reductions in return for greater up-front costs.¹⁴⁸ The up-front cost would be **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS].

These Phased Proposals would have allowed MERC to address short term needs, with no obligation to pursue deferred upgrades. Specifically, in Phased Proposal 4.1 NNG states, **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]¹⁴⁹ MERC would have a similar option to **[HIGHLY**

¹⁴⁶ *Id.* at 23.

¹⁴⁷ *Id.* at 24.

¹⁴⁸ *Id.*

¹⁴⁹ Ex. 306, Schedule 5, at 38 (Urban HSTS Direct Schedules).

SENSITIVE TRADE SECRET BEGINS]**[HIGHLY SENSITIVE****TRADE SECRET ENDS]** deferred construction for Phased Proposal 4.2.¹⁵⁰

As discussed above, the options to defer, or possibly terminate, future capacity growth would provide significant value for ratepayers. First, deferring some of the capacity would mean that the initial cost to ratepayers would be less burdensome. Second, deferring some of the capacity, and thus the cost, to the future would more closely tie the costs to the ratepayers who may need the facilities. Third, the option to defer or terminate the project would remove a significant portion of the forecasting risk from both ratepayers *and* shareholders, because the Company would have no obligation to move forward if growth does not materialize. On top of these benefits, it is important to note that the estimated costs for both Phased Proposal 4.1 and Phased Proposal 4.2 are comparable to the cost of the Rochester Project that MERC has proposed. The PA is estimated to cost approximately \$60 million,¹⁵¹ while the Phased Proposals had total cost estimates of **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS],

respectively. The initial phase of construction for the phased proposals would be significantly less. The information in the record shows that by choosing one of these Phased Proposals, MERC could have obtained these benefits and protected ratepayers from forecasting risk, without significant additional expenditures.

MERC's explanation for focusing on up-front proposals does not hold up under scrutiny.

¹⁵⁰ *Id.* at 41.

¹⁵¹ Ex. 5, at 2 (Lee Direct).

3. MERC Has Not Provided A Reasonable Justification For Failing To Give Serious Consideration To The Phased Proposals.

The record in this proceeding demonstrates that MERC did not give any serious consideration to the benefits that ratepayers could have obtained from a phased proposal. As noted above, in MERC's internal analysis, [HIGHLY SENSITIVE TRADE SECRET BEGINS]

[HIGHLY SENSITIVE TRADE SECRET ENDS]¹⁵² NNG also described the benefits of phased proposals at length in its response to the RFP. Despite being aware of these benefits, MERC negotiated a PA that does not mitigate forecasting risk or reserve margin problems like the Phased Proposals provided by NNG.

MERC did not provide clear reasons that it did move forward with a Phased Proposal at the outset of its case, but later attempted to raise a series of arguments as to why its decision was reasonable. None of them hold up under scrutiny.

a. MERC did Not Conduct A Reasonable Analysis To Justify Its Decision To Pursue An Up-Front Project Instead Of A Phased Or Incremental Approach.

The primary reason that MERC claims that it was reasonable for the Company to focus on an up-front project because it would have cost more for the Company to obtain the same amount of capacity in an incremental manner.¹⁵³ To support this claim, MERC relies upon a "good faith estimate" of the costs of adding 100,000 Dth/day of capacity in an incremental capacity that was conducted by their independent consultant, Mr. Sexton.¹⁵⁴ According to Mr.

¹⁵² Ex. 403, Schedule MR-1 (Ryan HSTS Direct Attachments).

¹⁵³ Ex. 19, at 6–7, 12 (Mead Rebuttal).

¹⁵⁴ *Id.* at 7.

Sexton, the Net-Present-Value (“NPV”) cost of obtaining 30,000 Dth/day in incremental capacity would actually be \$1 million greater than the NPV cost of obtaining 45,000 Dth/day from the PA.¹⁵⁵ The Company states that “an incremental or smaller capacity project would result in greater costs for lower capacity volumes.”¹⁵⁶ The Department, through its witness Mr. Heinen, appears to be convinced by MERC’s analysis.

The problem is that MERC’s analysis is not consistent with reality. In conducting its “analysis” of more moderate incremental or phased projects, MERC asked its consultant to conduct a “good faith estimate” of the costs of adding new capacity. But Mr. Sexton’s estimates are absurd when compared to the results of the competitive bidding process that was conducted. Mr. Sexton estimates that the cost of adding 45,000 Dth/day in an incremental manner will be

[HIGHLY SENSITIVE TRADE SECRET BEGINS]

[HIGHLY SENSITIVE

TRADE SECRET ENDS].¹⁵⁷ But the competitive bidding process resulted in bids for phased proposals that are *much* lower than Mr. Sexton’s “good faith estimate.” As discussed above, the *total* construction costs for adding 45,000 Dth/day in Phased Proposal 4.2 was estimated to be

[HIGHLY SENSITIVE TRADE SECRET BEGINS]

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[HIGHLY SENSITIVE TRADE SECRET ENDS]. MERC’s argument that a phased or incremental approach would cost significantly more than an up-front project is simply untrue—in fact, the evidence demonstrates that there were multiple phased proposals that were cost-competitive with the PA that was negotiated, even assuming that the deferred costs ultimately

¹⁵⁵ *Id.*

¹⁵⁶ *Id.*

¹⁵⁷ Ex. 22, at 17 (Sexton Rebuttal Schedules HSTS).

¹⁵⁸ Ex. 303, at 24 (Urban Amended and Corrected HSTS Direct).

became necessary. And the phased projects could have provided the additional benefits if the deferred costs were ultimately not necessary—in that instance, the costs for the phased proposal could end up being significantly *less* than the cost of the PA. That is, in fact, the point of the phased proposals—because of their phased nature, ratepayers would not be required to pay for all 45,000 Dth/day in incremental capacity until it was actually needed.

On top of those problems, the timing of when Mr. Sexton was hired makes clear that MERC did not conduct this incremental analysis before the PA was executed. As discussed above, Mr. Sexton was not contacted about this proceeding until January, 2016. But MERC negotiated with NNG throughout 2015 and executed the PA in the fall of 2015. Regardless of the quality of Mr. Sexton’s analyses, MERC had never seen them when it made its decision to focus on up-front projects instead of phased or incremental projects. And MERC has not produced any similar analysis of its own. That means that when MERC decided to forego phased or incremental approach, Mr. Sexton’s analysis did not exist, and the Company either did no analysis of its own to justify the decision or has declined to provide it in this case.

b. MERC’s Claim That It Had To Pursue A Large Project In Order To Attract Competing Bids Is Not Reasonable.

MERC also argues that it was necessary to pursue a large, up-front project because an RFP that permitted smaller bids would “not have attracted any non-incumbent third party service providers to submit proposals.”¹⁵⁹ As discussed above, MERC’s argument makes no sense for several reasons.

First, MERC ignores the fact that it could have designed an RFP that allowed for both large bids and smaller bids. That would have allowed competing pipelines to propose large projects that could take advantage of economies of scale to justify significant new pipeline

¹⁵⁹ Ex. 13, at 12 (Mead Rebuttal).

investments, but it also would have allowed bidders to propose incremental or phased proposals that could have been analyzed to determine the proposal that provided the most benefits and protections to ratepayers.

Second, MERC ignores the fact that its RFP did not actually result in competitive bids from competing suppliers. As pointed out above, the bids from third parties were not competitive compared to the bids from NNG. In other words, the RFP process was not really competitive at all.

Third, MERC ignores the fact that it did actually receive bids for more moderate phased projects that could have provided significant protections to ratepayers. While the idea of an RFP large enough to allow competition is attractive, it does not justify ignoring phased or incremental approaches when those options were already on the table regardless of how the RFP was designed.

c. MERC's Argument Regarding Additional Negotiated Conditions Is Not Relevant To The Decision To Focus On An Up-Front Project.

MERC claims that it was reasonable to move forward with an up-front project only, rather than a phased or incremental project, because the PA included fixed-rate conditions from NNG, which were not included in the phased proposals.¹⁶⁰ The PA includes conditions that the capacity rates paid to NNG will be set at the current tariff maximum, even if NNG's tariff rates are increased in the future as a result of a FERC rate case or a modernization rider proposal.¹⁶¹

What MERC does not acknowledge, though, is that the fixed rate conditions were not included in *any* of the initial proposals from NNG. Instead, they were conditions that MERC was able to obtain through negotiation with its supplier. Mr. Ryan, for the Department, agreed

¹⁶⁰ *Id.* at 13.

¹⁶¹ *Id.* at 13–14.

during the evidentiary hearing that there does not appear to be any reason that MERC could not have requested the same new conditions in concert with a phased proposal.¹⁶²

It is also clear that NNG went out of its way to make clear that the proposals in its response to the RFP were not exhaustive and that the supplier was open to discussing different conditions if MERC was interested in them.¹⁶³ NNG was obviously open to discussing fixed-rate conditions, since it agreed to them even though they were not included in any of the initial offers. And, yet, MERC's witness Ms. Mead confirmed that MERC never attempted to negotiate additional conditions for a phased proposal.¹⁶⁴ While it is true that the Phased Proposals did not initially include fixed-rate guarantees, neither did any of the other proposals. There does not appear to be any reason that MERC could not have requested fixed-rate conditions with a phased or incremental proposal.

d. MERC's Argument That Phased Proposals Did Not Provide Cost Certainty Is Not Reasonable.

MERC also states that one reason it did not consider the Phased Proposals was that MERC would be responsible for actual construction costs for any deferred upgrades, while the up-front proposals provided cost certainty.¹⁶⁵ While the first "phase" of NNG's phased proposals had a firm cost, NNG provided a cost estimate of the second "phase" and made clear that MERC would ultimately be responsible for the actual cost of construction. According to the Company, these proposals "[were] not considered as a viable alternative" because they did not provide long-term cost certainty.¹⁶⁶

¹⁶² Tr. Evid. Hearing, Vol. 1, at 221–222 (Ryan).

¹⁶³ Ex. 306, Schedule 5, at 2 (Urban Direct HSTS Schedules).

¹⁶⁴ Tr. Evid. Hearing, Vol. 1, at 128:4–5 (Mead).

¹⁶⁵ Ex. 13, at 13 (Mead Rebuttal).

¹⁶⁶ Ex. 19, at 16 (Sexton Rebuttal).

MERC's statements are not reasonable. The lack of cost certainty is, surely, one factor that MERC should have considered in deciding how to move forward. But it is a factor that should have been weighed against the benefits that ratepayers would receive from a phased proposal. In addition, as Mr. Sexton pointed out, "NNG did provide an estimate" of the deferred costs.¹⁶⁷ MERC had a full opportunity to review the estimated costs and determine whether the estimates were reasonable or whether there was a likelihood of cost increases. The possibility, and the likelihood, of increasing costs in the future should have been weighed against the possibility that deferred costs would never be necessary as a result of reduced growth, and against the benefits of more closely linking expenditures and the ratepayers who require facilities. MERC did not conduct any analysis of this sort.

In addition, MERC's concern with cost certainty appears to be inconsistent because the Company has made clear that it does not offer a fixed price guarantee to ratepayers for *its* costs. As Ms. Lyle pointed out, MERC's estimate of \$44 million for distribution costs is not a "firm or fixed price and it should not be considered a guaranteed or not-to-exceed estimate."¹⁶⁸ MERC argues that it could not consider phased options from NNG because they did not provide "cost certainty," but MERC does not offer cost certainty to ratepayers for the distribution costs. In fact, MERC has made it clear that the Company will seek to recover additional costs from ratepayers if the distribution upgrades are subject to cost overruns.

e. MERC's Decision To Reject Proposals That Delivered Gas To Existing TBSs Is Not Consistent With MERC's Distribution Upgrades.

MERC states that it rejected some proposals because they did not deliver gas to the correct TBS or because the pressure would not be sufficient. In particular, Ms. Mead states that

¹⁶⁷ *Id.*

¹⁶⁸ Ex. 8, at 3 (Lyle Rebuttal).

Phased Proposal 4.2 was rejected, in part, because “the new capacity would be provided at TBS 1B, which is not where MERC’s substantial growth is.”¹⁶⁹ There are several problems with this argument.

First, MERC has also clearly explained that the purpose of the distribution upgrades it plans to make will “interconnect” the northern and southern portions of the distribution system in Rochester.¹⁷⁰ As Ms. Lyle confirmed during the evidentiary hearing, after the distribution upgrades are complete, MERC will be able to move the gas wherever it is needed.¹⁷¹ In her own words, Ms. Lyle stated that the “project will take all capacity from the two town border stations and can be moved north or south where the demand is.”¹⁷² As such, it is clear that the distribution upgrades would permit MERC to receive the new capacity at any point along the distribution system and still be able to move the gas wherever it is needed.

During the evidentiary hearing, MERC claimed for the first time that if the new capacity was delivered to the existing TBSs, MERC would have had to increase the size of the pipe used for the interconnection.¹⁷³ But there is no information in the record as to what the cost differential would be. And, more concerning, there is no information in the record that MERC did a thorough comparison of the costs and benefits before it discarded this option.¹⁷⁴ If the additional costs were minimal, and the benefits of not having to build a new TBS significant, then it may have been reasonable to proceed with a larger interconnection pipe. But MERC either did not conduct that analysis, or chose not to provide it to support its request or in response

¹⁶⁹ Ex. 16, at 17 (Mead Surrebuttal).

¹⁷⁰ Ex. 25, at 2 (Lyle Opening Statement).

¹⁷¹ Tr. Evid. Hearing, Vol. 1, at 62:4–7 (Lyle).

¹⁷² *Id.* at 62:1–3 (Lyle).

¹⁷³ *Id.* at 67 (Lyle).

¹⁷⁴ For that matter, it is worth noting that MERC did not ever raise this point until the evidentiary hearing.

to discovery requests. Instead, it appears that MERC decided that it would not consider any proposals that did not conform entirely with the design of the RFP.

Second, NNG made clear that the Phased Proposals were not exhaustive, and that they had the flexibility to work with MERC to modify any of the proposals to meet the Company's needs. In fact, MERC points out that the PA was an amalgamation of several proposals. As a result, it is clear that the fact that one of the phased proposals delivered gas to an area that MERC did not prefer was not a deal breaker—MERC could certainly have attempted to negotiate a different delivery point, or to propose a new phased project at a different delivery point. The fact that one of the proposals did not deliver gas to the right place is not a justification for failing to give careful consideration to the benefits that ratepayers would have received from a phased or incremental approach.

f. MERC's Argument That An Incremental Or Phased Proposal Would Not Satisfy Short-Term Growth Is Factually Incorrect.

MERC also states that it did not prefer phased projects because they would not provide incremental capacity quickly enough for MERC's preferences. In particular, the Company states that it rejected at least one proposal, Phased Proposal 2.3, because the incremental addition of 10,000 Dth/day would not serve near-term growth requirements.¹⁷⁵ According to Ms. Mead's Direct Testimony, though, adding 10,000 Dth/day would completely solve the existing supply shortage, and ensure a positive reserve margin until the 2020/2021 heating season.¹⁷⁶ And that figure assumes that MERC's forecast is completely accurate—when modified to account for the forecasting problems addressed above, it is likely that an adequate reserve margin would persist further into the future.

¹⁷⁵ Ex. 19, at 13 (Sexton Rebuttal).

¹⁷⁶ Ex. 12, at 21, Table 1 (Mead Direct).

g. MERC Has Not Demonstrated That It Was Reasonable To Focus On Up-Front Proposals.

A phased proposal could have provided clear benefits to ratepayers that would have addressed some of the primary concerns raised with MERC's proposal for the Rochester Project: the extremely high reserve margins, which represent capacity purchased by ratepayers for which there is no current demand, and the concerns with intergenerational inequity. By deferring some upgrades to a future time period when growth in demand has actually materialized, a phased proposal could have mitigated both of these problems. And the record also makes clear both that NNG advanced phased proposals that were not significantly more expensive than the PA, and that NNG was willing to negotiate different conditions using the initial phased proposals as a baseline.

While MERC did not squarely address its focus on an up-front construction plan in its initial filings, later in the proceeding the Company attempted to justify its decisions. But, as discussed in this section, MERC has still not produced any explanation or documentation of the decision making process it used when it decided not to pursue a phased proposal, and none of the Company's arguments explain why the Company moved forward without a cost benefit analysis of some kind that recognized the unique benefits ratepayers could have received from phased proposals.

The record also shows that MERC did not give sufficient consideration to other alternatives, such as peak shaving facilities, which could have reduced the peak demand in the Rochester area and led to cost savings.

G. MERC DID NOT CONSIDER THE POSSIBILITY THAT CONSERVATION AND PEAK SHAVING FACILITIES COULD REDUCE THE MAGNITUDE OF NEED FOR THE ROCHESTER PROJECT.

In its Initial Petition, MERC described the alternative approaches it considered for the Rochester Project. MERC stated that it considered 1) transmission pipeline alternatives, 2) distribution modification alternatives, 3) conservation alternative, and 4) a no build alternative.¹⁷⁷ There are several problems with MERC's analysis.

First, MERC should have provided significantly more information about the possibility that conservation could have reduced peak demand in the Rochester area and reduced the need for the Rochester Project. From MERC's discussion in the Petition, it appears that the Company investigated whether conservation could have eliminated the need for the Rochester Project entirely.¹⁷⁸ That analysis is obviously incomplete—the more rational and important question is whether increased conservation efforts could reduce the size of the Rochester Project that is necessary. If MERC could assist its customers in improving conservation, it may be possible to reduce the growth in peak demand. And, if the growth in peak demand is reduced, then the amount of additional capacity that is necessary, and the cost, would also be reduced. By discussing the matter as an all-or-nothing proposition, MERC has not effectively addressed whether increased conservation could have mitigated the cost of any upgrades that are needed.

MERC made the same error in its analysis of peak shaving facilities. In her Direct Testimony, Dr. Urban raised the concern that MERC had not provided any discussion or analysis of the possibility that peak shaving facilities could be used to mitigate peak day demand.¹⁷⁹ As Dr. Urban explained, peak shaving facilities, such as propane-air or liquefied natural gas

¹⁷⁷ Ex. 1, at 26–28.

¹⁷⁸ *Id.*

¹⁷⁹ Ex. 300, at 50–52 (Urban Amended and Corrected Direct).

facilities, can be “used to meet the ‘needle peaks’ of gas demand that occur during the coldest days of the season.”¹⁸⁰ MERC witness Ms. Lyle explained that “during periods of extreme usage, peaking facilities . . . can be utilized to supplement system and underground storage supplies.”¹⁸¹

Ms. Lyle also provided a reference to the U.S. Energy Information Administration, which explained that “The objective of [peak shaving facilities] is to maintain sufficient local underground natural gas storage capacity . . . to meet large shifts in daily demand, *thereby minimizing capacity reservation costs on the supplying pipeline.*”¹⁸² In other words, the point of a peak shaving facility is to deal with large increases in daily demand, because that can reduce the costs of interstate pipeline capacity—like the Rochester Project. Based on MERC’s own description of peak shaving facilities, it appears that they are specifically designed to address *this* situation—avoiding capacity reservation costs on interstate pipelines by addressing peak demand with other facilities. Dr. Urban noted that both CenterPoint Energy and Xcel Energy use peak shaving facilities for this purpose.¹⁸³ In fact, some utilities in Minnesota use peak shaving facilities to satisfy more than 20 percent of their demand on peak days.¹⁸⁴

It appears that needle peaks also occur on very cold days in the Rochester area. As Dr. Urban described, the “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.”¹⁸⁵ In other words, on average days MERC is using somewhere between 33 percent and 40 percent of the capacity in the

¹⁸⁰ *Id.* at 51.

¹⁸¹ Ex. 8, at 7 (Lyle Rebuttal).

¹⁸² *Id.* (quoting U.S. Energy Information Administration, About U.S. Natural Gas Pipeline—Transporting Natural Gas (available at http://www.eia.gov/pub/oil_gas/analysis_publications/ngpipeline/process.html) (emphasis added)).

¹⁸³ *Id.*

¹⁸⁴ Ex. 300, at 50–52 (Urban Amended and Corrected Direct) (citing Review of 2013–2014 Annual Automatic Adjustment Reports, *Natural Gas Utilities’ 2013–2014 Purchased Gas Adjustment (PGA) True-Up Filings*, Docket No. G-999/AA-14-580, at 71, Table G16 (May 5, 2015)).

¹⁸⁵ Ex. 311, at 16 (Urban Amended and Corrected Surrebuttal).

Rochester area. It is likely that some of the difference between this level of demand and peak demand is a brief, significant increase during very cold days—a needle peak. In fact, Ms. Lyle agreed during the evidentiary hearing that the Design Day, which is the focus of MERC’s forecast, actually “measures the highest possible needle peak.”¹⁸⁶ This is exactly what peak shaving facilities are designed to deal with.

The record makes very clear that MERC did not perform any substantive analysis of peak shaving facilities. During the evidentiary hearing, MERC witness Ms. Lyle admitted that the possibility of a peak shaving facility was “an option that was dismissed early,” and without a “full analysis.”¹⁸⁷ That is consistent with the state of the record—despite the fact that the OAG raised the issue in Direct Testimony, MERC has never produced any documents analyzing the cost and benefits of a peak shaving facility. On top of that, the reasons that Ms. Lyle raises for failing to consider a peak shaving alternative are obviously insufficient.

In her Rebuttal Testimony, Ms. Lyle argues that the reason she did not consider peak shaving facilities is that it “does not solve the capacity constraints MERC is experiencing in the Rochester area.”¹⁸⁸ Ms. Lyle first argues that peak shaving cannot solve the capacity constraints because peak shaving facilities “are not intended to meet base load demand.”¹⁸⁹ Ms. Lyle’s statements do not make any sense. This proceeding is not about meeting base load demands in the Rochester area—it is about meeting peak demand. And meeting peak demand is exactly what peak shaving facilities are designed to do. In fact, the references *provided by Ms. Lyle*

¹⁸⁶ Tr. Evid. Hearing, Vol. 1, at 65:21–24 (Lyle).

¹⁸⁷ *Id.* at 64:11–17 (Lyle).

¹⁸⁸ Ex. 8, at 8 (Lyle Rebuttal).

¹⁸⁹ *Id.*

actually state that the purpose of peak shaving facilities is to control peak demand *in order to reduce the costs of interstate pipeline capacity*.¹⁹⁰

Second, Ms. Lyle argues that MERC did not do a full analysis on peak shaving facilities because it “would not effectively serve the deficit we have in the Rochester area.”¹⁹¹ In other words, MERC did not consider peak shaving facilities because they would not have solved the problem completely. But that is not a reasonable way to conduct analysis, because peak shaving facilities are not an all-or-nothing concept. While peak shaving facilities may not have been able to completely eliminate the need for additional capacity, it is possible that they could have reduced *how much* additional capacity was needed. For example, other Minnesota gas utilities meet 20 percent of their peak demand with peaking facilities.¹⁹² If MERC could serve 20 percent of demand in the Rochester area with peaking facilities, then that is 20 percent that would not have to be served by interstate pipeline capacity that will be unused on all but the coldest days. But it is clear that MERC did not conduct any cost benefit analysis on the possibility of reducing the magnitude of the Rochester Project using peaking facilities.

Third, Ms. Lyle argues that a peak shaving facility would not resolve the distribution constraints. But this also misses the point—even if MERC still had to construct some distribution upgrades, it is possible that a peak shaving facility could have reduced the costs of interstate pipeline upgrades. On top of that, there is evidence in the record from a Maryland Public Service Commission report that peaking facilities *can* reduce distribution system costs

¹⁹⁰ *Id.* at 7 (citing U.S. Energy Information Administration, About U.S. Natural Gas Pipeline—Transporting Natural Gas (available at http://www.eia.gov/pub/oil_gas/analysis_publications/ngpipeline/process.html)).

¹⁹¹ *Id.* at 8.

¹⁹² Ex. 300, at 50–52 (Urban Amended and Corrected Direct) (citing Review of 2013–2014 Annual Automatic Adjustment Reports, *Natural Gas Utilities’ 2013–2014 Purchased Gas Adjustment (PGA) True-Up Filings*, Docket No. G-999/AA-14-580, at 71, Table G16 (May 5, 2015)).

when designed properly.¹⁹³ Dr. Urban produced this information in her direct testimony, but Ms. Lyle did not take advantage of any of her several opportunities to respond.

In summary, it is possible that a peaking facility could have reduced the scale of the Rochester Project by serving some portion of demand on peak days. But MERC did not complete any kind of cost benefit analysis to determine whether it would be in the interests of ratepayers to do so. MERC has similarly ignored the possibility that increased conservation efforts could reduce growth in peak demand, and thus reduce the scale required for the Rochester Project. These failures indicate that MERC did not exercise the necessary care and thoroughness in its decision-making process before embarking on its plan for the Rochester Project.

H. THE ROCHESTER PROJECT SHOULD NOT BE JUSTIFIED BY INCREASED CONSUMPTION BY INTERRUPTIBLE AND TRANSPORT CUSTOMERS.

In his Direct Testimony, Department witness Mr. Heinen explained that estimates of peak demand measure the demand for firm customers:

[W]hen a utility estimates peak demand for demand entitlement purposes, it focuses only on throughput for firm sales customers. It does not include interruptible load in this analysis because interruptible customers receive the benefit of lower non-gas margins knowing that they will be interrupted if load must be curtailed to maintain system integrity. Transportation load is also not included in estimates of peak day demand for demand entitlement purposes because these customers procure their entitlement level through a third-party vendor, not the gas utility.¹⁹⁴

According to Mr. Heinen, a measurement of peak demand should include consumption by firm customers, and should *not* include consumption by interruptible or transportation customers.

Nearly every witness in this proceeding agrees. During the evidentiary hearing, MERC witness Ms. Lee agreed that the Design Day measurement of peak demand does not include any

¹⁹³ Ex. 300, at 55, n.91 (Urban Amended and Corrected Direct).

¹⁹⁴ Ex. 405, at 9 (Heinen Direct).

use by interruptible or transport customers.¹⁹⁵ Mr. Clabots confirmed that the Design Day forecast represents the demand of firm customers, and contains no usage for any interruptible or transport customers.¹⁹⁶ Ms. Mead agreed that the Design Day includes firm customers only.¹⁹⁷ MERC further confirmed this principle in OAG Information Request 156, where Ms. Lyle and Ms. Lee stated that “interruptible and transport volumes do not factor into MERC’s peak-day planning and therefore do not directly affect MERC’s planning for its Rochester Project.”¹⁹⁸

The problem is that both MERC and the Department have suggested that future consumption by interruptible and transportation customers provides justification for the Rochester Project. In particular, both MERC and the Department argue that growth in consumption by Rochester Public Utilities (“RPU”) should be a factor in deciding whether the Rochester Project is prudent and reasonable.

But any increased consumption from RPU will be *interruptible transportation* service, not firm service. In fact, RPU made this very clear when it stated, “Overall, RPU anticipates that its firm natural gas usage from Minnesota Energy Resources will remain relatively constant for the next decade. However, RPU’s use of interruptible transportation service is likely to increase dramatically in the coming years.” According to the vast majority of witnesses in this case, the fact that RPU will take interruptible transportation service means its consumption should not be considered when planning to serve peak demand. And, yet, both the Department and MERC have used RPU’s future plans to justify the Rochester Project.

MERC did not mention RPU in its initial Petition or in its Direct Testimony. In fact, MERC did not raise the matter of RPU until its Rebuttal testimony. In Rebuttal, MERC witness

¹⁹⁵ Tr. Evid. Hearing, Vol. 1, at 24 (Lee).

¹⁹⁶ *Id.* at 79 (Clabots).

¹⁹⁷ *Id.* at 111:2–6 (Mead).

¹⁹⁸ Ex. 304, Schedule 32, at 3 (Urban Direct Schedules Public).

Ms. Mead discussed the possibility that RPU would increase its consumption of natural gas in the future, but was careful to point out that “under existing tariffs . . . MERC is unable to dictate whether RPU takes service as a firm, interruptible, sales, or transport customer.”¹⁹⁹ In her Surrebuttal testimony, though, Ms. Mead argued that RPU’s plans to increase natural gas consumption is one reason to approve the Project. This is obviously inconsistent with Ms. Mead’s other testimony that interruptible and transport service should not be included in peak demand planning.

Mr. Heinen makes the same mistake. Despite the statement in his Direct Testimony that peak demand does not include transportation service, in his Surrebuttal Testimony Mr. Heinen suggested that the reserve margin analysis should be modified to account for RPU’s future consumption. To complete his reserve margin analysis, Mr. Heinen assumed that the level of excess capacity would decrease by “10,000 to 20,000 Dkt/day” as a result of increased consumption by RPU.²⁰⁰ During the evidentiary hearing Mr. Heinen confirmed that he used this figure because it was an estimate of daily use from RPU’s planned West Side Energy Station.²⁰¹ But the record makes clear, and Mr. Heinen acknowledges, that the West Side Energy Station plans to take “interruptible transport service.”²⁰² That means, according to Mr. Heinen’s earlier testimony, that the additional consumption from RPU should *not* be included in calculation of reserve margins because it will be transportation service. Mr. Heinen’s reserve margin analysis directly conflicts with his own principles of planning for peak demand.

The utility’s obligation is to ensure that firm customers receive safe and reliable service, not to plan to ensure service for interruptible and transportation customers. As Ms. Lee

¹⁹⁹ Ex. 13, at 6 (Mead Rebuttal).

²⁰⁰ Ex. 407, at 18 (Heinen Surrebuttal).

²⁰¹ Tr. Evid. Hearing, Vol 2, at 34 (Heinen).

²⁰² *Id.* (Heinen); Ex. 309, R-2 (Urban Rebuttal Schedules).

confirmed during the evidentiary hearing, MERC plans its natural gas system to provide service to firm customers, and “measure[s] the system based on the firm load.”²⁰³ MERC does not plan to ensure that interruptible and transport customers can receive service at all times,²⁰⁴ and “interruptible and transport volumes do not factor into MERC’s peak-day planning and therefore do not directly affect MERC’s planning for its Rochester Project.”²⁰⁵ Based on these principles, it would be unreasonable to justify a significant infrastructure investment because of an expected increase in consumption by interruptible or transportation customers.

There are good policy reasons for these distinctions. As Mr. Heinen points out, the reason that interruptible consumption is not included in peak demand planning is that “interruptible customers receive the benefit of lower non-gas margins knowing that they will be interrupted if load must be curtailed to maintain system integrity.”²⁰⁶ Similarly, Mr. Heinen notes that, “Transportation load is also not included in estimates of peak day demand for demand entitlement purposes because these customers procure their entitlement level through a third-party vendor, not the gas utility.”²⁰⁷ Those principles should not be reversed in this case in order to justify overbuilding facilities that are not necessary to serve firm customers in the Rochester area.

In addition to those problems, it would be unreasonable to consider increased consumption from RPU as a justification MERC’s proposal because MERC had no idea that RPU would be increasing natural gas use when the Company made its decision. As discussed above, MERC issued its RFP in December, 2014, received responses in January, 2015,

²⁰³ Tr. Evid. Hearing, Vol. 1, at 26:1–10 (Lee).

²⁰⁴ *Id.* at 26:11–13 (Lee).

²⁰⁵ Ex. 304, Schedule 32, at 3 (Urban Direct Schedules Public).

²⁰⁶ Ex. 405, at 9 (Heinen Direct).

²⁰⁷ *Id.*

negotiated the PA throughout 2015, and executed the PA in the fall of 2015.²⁰⁸ MERC did not learn about any increased consumption for RPU until months later. In fact, MERC has gone out of its way to confirm that its forecast “did not model” any additional sales to RPU.²⁰⁹ In other words, MERC decided to move forward with the Rochester Project as described in the PA *before* it was aware of any increased consumption from RPU. It is very clear that any increased consumption from RPU was not a significant factor supporting the Project when the Company was not even aware of it when the important decisions were made.

I. THE BISON PIPELINE PROJECT PROVIDES AN EXAMPLE OF THE PROBLEMS THAT CAN RESULT FROM PIPELINE CONTRACTS.

The Rochester Project is not the first time MERC has asked the Commission to approve an interstate pipeline contract. In fact, the Company is currently recovering nearly \$14 million per year for a pipeline that is barely being used—the Bison Pipeline Project.

In June, 2008, MERC filed a Petition requesting Commission approval of MERC’s plan to contract for capacity on the Bison Pipeline Project.²¹⁰ The Bison Project was a proposed pipeline that would deliver natural gas from the Powder River Basin in Wyoming to Northern Border Pipeline Company in North Dakota, and then to MERC.²¹¹ MERC contracted with Bison to deliver 50,000 Dth/day to the Northern Border pipeline at a rate of \$0.55 per Dth, and then contracted with Northern Border to deliver 49,690 Dth/day to MERC’s system at a rate of \$0.23 per Dth.²¹² The total cost over the ten year duration of the contracts was estimated to be approximately \$140 million, or \$14 million per year.²¹³ MERC asked the Commission for

²⁰⁸ Ex. 306, Schedule 5, 7 (Urban Direct Schedules HSTS); Tr. Evid. Hearing, Vol. 1, at 30:15–17 (Lee).

²⁰⁹ Ex. 10, at 7 (Clabots Rebuttal).

²¹⁰ Petition, *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 (June 11, 2008).

²¹¹ *Id.* at 3, 12

²¹² *Id.* at 3.

²¹³ $(\$0.55 + \$0.23) * 50,000 \text{ Dth/day} * 365 \text{ days} = \$14.23 \text{ million per year.}$

approval of its plan to contract for 50,000 Dth/day in capacity on the Bison Pipeline in order to diversify the utility's natural gas supply options.²¹⁴ Just as with the Rochester Project, MERC did not need approval from the Commission before contracting with Bison but sought the Commission's agreement to "ensure recovery of all reasonable and prudent costs associated with the project."²¹⁵ In three pages of comments and analysis, the Department, through Mr. Heinen,²¹⁶ recommended that the Commission approve MERC's request.²¹⁷

In its Briefing Papers, Commission staff raised several concerns about the Bison Project investment. Staff noted that the Commission does not normally pre-approve cost recovery of contracts, and that gas utilities routinely enter into precedent agreements without Commission approval.²¹⁸ While Staff noted that there may be some merit to the concept of diversifying supply sources, the Briefing Papers concluded that the concerns about "cost and unreliability of Canadian supplies is probably exaggerated."²¹⁹ Staff also noted that the more typical approach for pipeline supply would be for the utility to contract for supply closer to the company's service area,²²⁰ and that MERC's cost savings estimate was based on being able to exploit price differentials between pipelines when those prices appeared to be converging.²²¹ In light of these concerns, the Staff recommended that the Commission decline to take action on MERC's proposal. In support of its decision, Staff noted that there should be some incentive for the utility

²¹⁴ *Id.* at 3.

²¹⁵ *Id.*

²¹⁶ Despite Mr. Heinen's statements during the evidentiary hearing, Tr. Evid. Hearing, Vol. 2, at 68:21–24 (Heinen), Mr. Heinen signed the Department's recommendation to approve the Bison contract.

²¹⁷ Comments of the Minnesota Office of Energy Security, *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 (Aug. 1, 2008).

²¹⁸ 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 3 (Aug. 21, 2008).

²¹⁹ *Id.* at 5.

²²⁰ *Id.*

²²¹ *Id.* at 6.

to ensure it is making good decisions “so that utilities have an incentive to enter into best-cost gas supply arrangements.”²²² There does not appear to be any Commission Order disposing of MERC’s request, but the Commission’s minutes indicate that the Commissioners voted unanimously to take no action on the Petition.²²³

The Bison Pipeline has not been a good investment for MERC’s ratepayers. In its Briefing Papers for the 2015–2016 Demand Entitlement filing, Commission Staff noted that “the Bison/NBPL contract option may not currently be the best or least cost gas option.”²²⁴ In fact, MERC explained in an e-mail to Mr. Heinen that MERC has utilized only half of the Bison capacity from 2011 to 2015.²²⁵ As of December, 2015, MERC has *no* supply contract in place for the pipeline.²²⁶ And, during that time, MERC has been unable to release any of the excess capacity because there were no takers in the capacity market.²²⁷ According to Mr. Heinen, the average residential ratepayer is on the hook for approximately \$38.09 per year for the Bison contract,²²⁸ and it looks like at least half of that cost (and possibly more) serves no purpose. Despite these concerns, Staff noted in their Briefing Papers that MERC has no ability to get out of the costs for the Bison Pipeline because of the contract that was executed.²²⁹

The facts of the Bison case are different from the facts surrounding the Rochester Project. The Rochester Project primarily concerns gas supplies, while the Bison pipeline appears to be

²²² *Id.* at 8.

²²³ Minutes, *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 (Oct. 8, 2008).

²²⁴ Briefing Papers, *In the Matter of a Petition by Minnesota Energy Resources Corporation for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan effective November 1, 2015*, Docket No. G-011/M-15-722, at 12 (Apr. 12, 2016).

²²⁵ Ex. 405, Schedule AJH-20 (Heinen Direct).

²²⁶ *Id.*

²²⁷ *Id.*

²²⁸ Ex. 405, at 36 (Heinen Direct).

²²⁹ Briefing Papers, *In the Matter of a Petition by Minnesota Energy Resources Corporation for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan effective November 1, 2015*, Docket No. G-011/M-15-722, at 12 (Apr. 12, 2016).

focused on gas sources. But there are enough similarities between the two pipeline projects to draw several conclusions.

First, like the Bison Pipeline, it does not appear that the Commission has a legal obligation to take action on the Rochester Project. While MERC has requested approval, the Company does not require that approval to move forward and there does not appear to be any requirement for the Commission to make a decision. But the facts of the Bison Pipeline show that taking no action on a pipeline contract petition does not provide sufficient protection for ratepayers. In fact, it can make it extremely difficult to challenge the reasonableness of expenses in the future. The decision not to act, when the Commission has the opportunity to do so, can be taken as tacit approval. And once a utility has executed a pipeline contract, it can be extremely difficult to insulate ratepayers from unreasonable costs that a utility has a contractual obligation to pay.

Second, the Bison Pipeline is an example of how important it is to review whether the assumptions used to justify a pipeline contract are reasonable. In its review of the Bison Pipeline, Staff noted that the costs and benefits were “largely based on MERC being able to exploit a difference in cost” for gas purchased from different area, but that concerns about the cost and unreliability of gas from Canada were “probably exaggerated.”²³⁰ Ultimately, it appears that a thorough investigation of these assumptions may have been able to protect ratepayers from unnecessary pipeline costs. In this case, the core assumptions used to justify MERC’s proposal for the Rochester Project are the Company’s 25-year growth forecast, the Company’s decision that it must obtain exactly the amount of gas the forecast estimates will be demanded in the 2040s, and the Company’s decision to move forward with a fully up-front project rather than a

²³⁰ *Id.* at 5.

phased or incremental project. The evidence in this record demonstrates that these assumptions and decisions were not reasonable.

J. FOR ALL OF THESE REASONS, THE ROCHESTER PROJECT IS NOT PRUDENT, REASONABLE, AND NECESSARY TO PROVIDE SERVICE TO CUSTOMERS IN THE ROCHESTER AREA.

In its Notice of and Order For Hearing, the Commission asked the Administrative Law Judge and the parties to investigate whether the Rochester Project investments are “prudent, reasonable, and necessary to provide service to MERC’s Rochester service area.”²³¹ The foregoing analysis demonstrates that the answer to this question is “no.”

MERC based its decision on how large the Rochester Project should be solely on the results of its long-term demand forecast, a decision that places all of the risk inherent in long-term forecasts on ratepayers. The effect of that decision is compounded because there are significant errors in MERC’s forecast. Namely, the two primary inputs into the forecast—the customer count model and the use-per customer model—were not reasonable. This resulted in a forecast that predicts continuous growth of 1.5 percent every year for the next 25 years—a figure that is more than three times the historical average for the region. MERC then tied the design of its RFP exclusively to the results of its forecast, and performed a flawed analysis on the RFP responses it received. In the course of that analysis, the Company effectively focused only on proposals that would provide, up-front, the full amount of natural gas that the forecast estimated would be needed in the 2040s, instead of giving full consideration to phased or incremental proposals that could have provided significant protections to ratepayers. And, on top of that, MERC categorically did not consider whether increased conservation or peak shaving facilities could have reduced the magnitude of need in the Rochester area. The result is a Rochester

²³¹ Notice of and Order for Hearing, at 5 (Feb. 8, 2016).

Project that will provide fifty percent more natural gas than is needed when the upgrades are complete, and will continue to provide double digit reserve margins for decades—a massively overbuilt project that MERC knows will be paid for by its captive ratepayers.

The Commission should reject MERC's request for pre-approval of the Rochester Project. Instead, the Commission should direct MERC to pursue a different, more moderate plan for the Rochester area that improves the forecast methodology, does not expose ratepayers to the full extent of forecasting risk, and that takes advantage of the benefits of phased or incremental proposals to deal with the problems of unreasonably high reserve margins, intergenerational inequities, and unreasonable benefits for interruptible and transportation customers.

If the Commission does approve the Project, it should take steps to protect ratepayers from costs related to unreasonably high reserve margins and intergenerational inequities. If the Project moves forward, the Commission should find that a portion of the Rochester Project, related to the exceedingly high level of excess reserve margins, is not used and useful because it is not reasonably necessary to meet the demand of existing customers. The Commission should not allow recovery of this portion of the Project until the Company later demonstrates that growth has made it necessary to provide this amount of capacity to firm customers. The evidence demonstrates that the most appropriate resolution of this proceeding is for the Commission to find that the Rochester Project is not prudent and reasonable. As an alternative, however, the Commission could take these steps to protect ratepayers from the costs of MERC's unreasonable proposal.

II. THE ROCHESTER PROJECT IS NOT ELIGIBLE FOR COST RECOVERY UNDER THE NEGP RIDER.

The Rochester Project is not eligible for cost recovery under the Natural Gas Extension Project Costs (“NGEP”) Rider Statute in Minnesota Statutes section 216B.1638.²³² The NGEP Rider Statute was enacted following the harsh winter and propane shortage in 2013–14, and is intended to be utilized to promote the extension of natural gas service to propane-dependent areas of the state. But MERC interprets ambiguity in the NGEP statute to permit recovery of a project designed to serve customers in the Rochester area—an area that has been served by natural gas for over 80 years. Such a broad interpretation of the statute is not supported by legislative intent and would upend traditional revenue recovery for gas utilities in the state. Instead, the legislative history of the NGEP Rider Statute demonstrates that the Legislature intended the statute to be a new tool to encourage expansion of natural gas service in response to the propane shortage of 2014.

The question of rider eligibility is separate from the question of reasonableness and prudence discussed in Section I. The Commission and the ALJ should consider the issues separately. This Section proceeds in three sections. First, this Section will provide an overview of the terms and structure of the NGEP statute. Second, this Section will discuss the ambiguity of the statute, and demonstrate that applying the statute properly requires an analysis of legislative intent. Third, this Section will demonstrate that the Legislature intended for the NGEP Rider Statute to supplement and expand existing policies for natural gas line extensions,

²³² In her Direct Testimony, Dr. Urban clearly stated that the question of NGEP Rider eligibility was a question of legal interpretation that would be addressed in the OAG’s Initial Brief. Ex. 300, at 70 (Urban Amended and Corrected Direct). Dr. Urban stated that she raised the issue in her Direct Testimony “because the OAG wants to ensure that MERC is aware that the issue of rider eligibility may be raised in the future.” *Id.*

not to allow recovery of costs for distribution projects intended to continue to provide service to existing customers.

A. THE NGEPRIDER STATUTE.

The NGEPRIDER statute provides that a utility “may petition the commission outside of a general rate case for a rider that shall include all of the utility’s customers, including transport customers, to recover the revenue deficiency from a natural gas extension project.”²³³ A natural gas extension project is “construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas.”²³⁴

The NGEPRIDER Statute provides that the Commission “shall approve” the petition if two criteria are satisfied: “1) the project is designed to extend natural gas service to an unserved or inadequately served area; and 2) the project costs are reasonable and prudently incurred.”²³⁵ Unserved or inadequately served area is defined as “an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers.”²³⁶ If approved, the utility is not permitted to recover more than 33 percent of the costs of the natural gas extension project through the rider.”²³⁷

When a utility files a petition, the statute requires the petition to include specific information, including 1) a description of the project, including the number and location of new customers to be served; 2) the construction schedule; 3) the proposed budget; 4) the amount of any contributions in aid of construction (“CAIAC”); 5) a description of the efforts made by the utility to obtain CAIACs; 6) the amount of the revenue deficiency and the proposed allocation;

²³³ Minn. Stat. § 216B.1638, subd. 2(a) (2015).

²³⁴ *Id.* at subd. 1(e).

²³⁵ *Id.* at subd. 3(b).

²³⁶ *Id.* at subd. 1(i).

²³⁷ *Id.* at subd. 3(c).

7) the proposed cost recovery mechanism; 8) the proposed termination date of the rider; and 9) a description of the benefits that will accrue to existing natural gas customers.²³⁸

The NGEP Statute explicitly provides that the Commission has the authority to “issue orders necessary to implement and administer” the Statute.²³⁹

B. THE NGEP STATUTE CONTAINS AMBIGUITY THAT REQUIRES INVESTIGATION OF LEGISLATIVE INTENT USING CANONS OF STATUTORY CONSTRUCTION.

This is the first proceeding before the Commission to deal with the NGEP Rider Statute and, as such, is the first time that the Commission must decide what the statute means. According to the Minnesota Supreme Court, “When interpreting the meaning of a statute, [the] primary goal is to ‘interpret and construct laws so as to ascertain and effectuate the intention of the legislature.’”²⁴⁰ While MERC would have the Commission believe that the NGEP Rider is simple and straightforward, a more careful analysis reveals that some terms in the statute are unclear.

In particular, one of the key provisions in the statute—the meaning of an “unserved or inadequately served area”—is ambiguous for two reasons. First, Minnesota law instructs that the Legislature intends technical terms, like “unserved” and “inadequately served” areas, to be read in concert with the special meaning they are given as terms of art. And, second, the NGEP Rider Statute is ambiguous because accepting MERC’s proposed interpretation would lead to an absurd and unreasonable result that the Legislature did not intend.

²³⁸ *Id.* at subd. 2(b).

²³⁹ *Id.* at subd. 4.

²⁴⁰ *Lietz v. Northern States Power Co.*, 718 N.W.2d 865, 870 (Minn. 2006).

1. The NGEP Statute Is Ambiguous Because It Must Be Read In Concert With The Technical Definitions Of “Unserved” And “Inadequately Served” Areas.

According to the Minnesota Supreme Court, “[I]f a statute is susceptible to more than one reasonable interpretation, then the statute is ambiguous and we may consider the canons of statutory construction to ascertain its meaning.”²⁴¹ The NGEP Rider Statute is susceptible of more than one reasonable interpretation because “unserved” and “inadequately served” areas are technical words that must be considered in the context of their special meanings in the industry.

MERC correctly notes that the NGEP Rider Statute includes a definition of “unserved or adequately served area.” But that is not the end of the investigation, because according to Minnesota law, “when “technical words and phrases and such others as have acquired a special meaning . . . [they] are constructed according to such special meaning.”²⁴² And “unserved or inadequately served area” is exactly that—a technical term of art that has a specific meaning within the realm of natural gas extension policy. The technical meaning of “unserved or inadequately served area” envisions a far narrower conception of eligible projects that does not include already-served communities like Rochester.

“Unserved areas” have a specific meaning in the natural gas extension context. According to a publication from the National Regulatory Research Institute (“NRRI”) titled *Line Extensions for Natural Gas: Regulatory Considerations*, “unserved areas” mean “areas remote from the nearest utility’s gas system.”²⁴³ This definition is supported by MERC’s New Area Surcharge tariff, which limits the New Area Surcharge rider to “geographical areas that have not

²⁴¹ *State v. Rick*, 835 N.W.2d 478, 482 (Minn. 2013).

²⁴² Minn. Stat. § 645.08 (2015); *see, e.g., Minn. v. RSJ, Inc.*, 552 N.W.2d 695, 701 (Minn. 1996) (noting that in reviewing legislative intent, a court will “construe technical words according to their technical meaning and other words according to their common and approved usage . . .”).

²⁴³ Ken Costello, Nat’l Regulatory Research Inst., *Line Extensions for Natural Gas: Regulatory Considerations* 3 (Feb. 2013) [hereinafter “NRRI Report”].

previously been served by the Company.”²⁴⁴ There is also an industry definition for “inadequately served” or “underserved” areas. According to NRRI, “inadequately served” or “underserved” areas are areas that “may have main [gas] lines nearby but [also have] many households and businesses that consume other forms of energy.”²⁴⁵

Minnesota law requires that these technical terms be constructed according to their special meaning,²⁴⁶ which is different from the way that MERC has suggested they be interpreted. Because they are susceptible of different interpretations, their meaning is ambiguous and must be ascertained using a more searching analysis.²⁴⁷

2. The NGEF Statute Is Ambiguous Because MERC’s Proposed Interpretation Would Lead to An Absurd And Unreasonable Result.

Another reason that the meaning of “unserved or adequately served area” is ambiguous is that applying MERC’s definition would lead to an absurd and unreasonable result. The Minnesota Supreme Court has held that courts, and commissions, are “obliged to reject a [statutory] construction that leads to absurd results or unreasonable results which utterly depart from the purpose of the statute.”²⁴⁸ MERC’s interpretation of the NGEF would lead to an absurd and unreasonable result. That means that according to Minnesota law, MERC’s interpretation is not permissible.²⁴⁹

If the Rochester Project were deemed to be eligible for recovery under the NGEF rider statute, then the effect of the law would be so broad as to consume the vast majority of natural gas utilities’ projects, rendering them eligible for non-rate case recovery via the NGEF rider.

²⁴⁴ Minnesota Energy Resources Corporation Tariff, 2d Revised Tariff Sheet No. 9.14.

²⁴⁵ NRRI Report, at 3.

²⁴⁶ Minn. Stat. § 645.08 (2015); *see, e.g., Minn. v. RSJ, Inc.*, 552 N.W.2d 695, 701 (Minn. 1996) (noting that in reviewing legislative intent, a court will “construe technical words according to their technical meaning and other words according to their common and approved usage . . .”).

²⁴⁷ *State v. Rick*, 835 N.W.2d 478, 482 (Minn. 2013).

²⁴⁸ *Wegener v. Commissioner of Revenue*, 505 N.W.2d 612, 617 (Minn. 1993).

²⁴⁹ Minn. Stat. § 645.17(1) (2015).

Such an outcome would present an unprecedented change to the utility regulatory process in Minnesota.

MERC is proposing NGEP rider recovery for a project “designed to improve the operation and efficiency of MERC’s distribution system to ensure that all available firm gas on the system can be delivered across the system’s entire footprint in southeastern Minnesota.”²⁵⁰ Put simply, the Rochester Project is a project designed to meet the needs of firm customers in one of, if not the most populous, longest-served areas in MERC’s service territory. The Company may have said it best when it stated: “As a system integrity and reliability project, the Rochester Project can be considered similar to other infrastructure projects included in rate base and recovered through base rates [many of the upgrades] are therefore comparable to the many other system repairs and upgrades MERC makes every year.”²⁵¹ Under this logic, the Rochester Project would be no different than a routine distribution upgrade undertaken by CenterPoint in Minneapolis or Xcel in Saint Paul. The problem is that when applied to MERC’s interpretation of the NGEP Rider Statute, this would mean that almost *any* distribution system project *anywhere* would be eligible for rider recovery. This interpretation stretches the intent of the Legislature far beyond the breaking point.

If MERC can recover one-third of the Rochester Project through the NGEP Rider, when MERC has been very clear in explaining that the Rochester Project will not actually extend service to any new areas or connect to any new customers, then there do not appear to be any infrastructure investments that would not be eligible for the NGEP Rider. Under that interpretation, natural gas utilities in Minnesota would begin recovering one-third of all of their

²⁵⁰ Ex. 5, at 10 (Lee Direct).

²⁵¹ *Id.* at 23.

investments through NGEP Riders. There is no indication in the NGEP Statute that the Legislature intended such a major regulatory shift.

To allow utilities to recover up to one-third of the cost for typical distribution system projects, especially larger projects such as the Rochester Project, could allow a utility to significantly increase revenue recovery without subjecting itself to review under a rate case.²⁵² Such an outcome would upend the traditional rate recovery process for natural gas utilities in Minnesota and could not possibly be what the Legislature intended when it enacted this statute in response to the severely-cold, propane-stressed winter of 2013–14. Instead, as will be discussed in greater detail below, the NGEP rider statute was enacted with a very specific purpose: to promote expansion of natural gas to areas of the state where existing policies still left some communities short. The NGEP Rider Statute was *not* meant to upend decades of policy by allowing every natural gas utility to perform an end-run around normal regulatory procedures in order to recover one-third of most of its investments through a rider. Such a result would be absurd, and is an indication that there is ambiguity in the statute. As the Minnesota Supreme Court has pointed out, decision-makers are “obliged to reject a construction that leads to absurd results or unreasonable results which utterly depart from the purpose of the statute.”²⁵³ When the literal language meaning put forward by one party would lead to this result, “it is necessary to look to the purpose for which the statute was enacted.”²⁵⁴

²⁵² Under the interpretation of the NGEP rider statute advanced by MERC, and with the availability of the Gas Utility Infrastructure Costs (“GUIC”) rider in Minnesota Statutes section 216B.1635, a utility could conceivably recover all “safety-related” infrastructure costs via a GUIC rider and one-third of any non-safety-related, distribution system costs via the NGEP rider. It is unclear, at that point, exactly which costs would *not* be recoverable through one of the recently enacted rider mechanisms.

²⁵³ *Wegener v. Commissioner of Revenue*, 505 N.W.2d 612, 617 (Minn. 1993).

²⁵⁴ *Id.*

3. Because The NGEP Statute is Ambiguous, The Commission Must Determine The Legislature's Intent.

The language in the NGEP Rider is ambiguous for two reasons. First, the technical terms “unserved” and “inadequately served” area must be considered in the context of their special meanings according to Minnesota law. And, second, interpreting the NGEP Rider Statute as MERC proposes would produce an absurd and unreasonable result that the Legislature did not intend.

As a result of this ambiguity, the Commission must “consider the factors set forth’ by the Legislature for interpreting a statute.”²⁵⁵

C. THE LEGISLATURE INTENDED THE NGEP STATUTE TO LIMIT ELIGIBILITY TO SPECIFIC PROJECTS DESIGNED TO EXTEND NATURAL GAS SERVICE.

As discussed above, the Minnesota Supreme Court has declared that the “the primary goal is to ‘interpret and construct laws so as to ascertain and effectuate the intention of the legislature.’”²⁵⁶ The Legislature has provided a series of factors that must be used in doing so. Minnesota Statutes section 645.16 provides eight factors that are used to investigate legislative intent, including: 1) the occasion and necessity for the law; 2) the circumstances under which it was enacted; 3) the mischief to be remedied; 4) the object to be attained; 5) the former law, if any, including other laws upon the same or similar subjects; 6) the consequences of a particular interpretation; 7) the contemporaneous legislative history; and 8) legislative and administrative interpretations of the statute.

A fair review of each of these factors demonstrates that they all weigh against MERC’s proposed interpretation of the NGEP Rider Statute. Instead, the mandatory factors demonstrate

²⁵⁵ *State v. Peck*, 773 N.W.2d 768, 772 (Minn. 2009).

²⁵⁶ *Lietz v. Northern States Power Co.*, 718 N.W.2d 865, 860 (Minn. 2006) (quoting *Olmanson v. LeSeur County*, 693 N.W.2d 876, 879 (Minn. 2005)).

that the Legislature intended the NGEPRider Statute to be used to promote the expansion of natural gas service in Minnesota to communities where it is otherwise uneconomical to extend service. The historical context and legislative history provides support and an explanation for the occasion and necessity of the law, the circumstances under which it was enacted, and the mischief to be remedied, in accordance to the statutory guidance on legislative intent.²⁵⁷

1. The NGEPRider Statute Was Intended To Continue Minnesota's Policy Goal To Encourage Expansion Of Natural Gas Service.

It has been a long-held state policy goal to encourage expansion of natural gas service across the state to areas that are otherwise reliant upon other fuels such as propane for heating. In 1992, the Commission acknowledged the “significant benefits” to both customers and communities conferred by the “expansion of the availability of natural gas in areas of Minnesota not currently served.”²⁵⁸ Over the years, policymakers have developed policies that promote expansion of natural gas while also balancing the interests of existing customers. This section describes the foundation concepts behind this incremental expansion approach.

Generally, a utility will extend gas service to a new community if it is economical to do so.²⁵⁹ That means that the incremental cost of adding that community must equal or surpass the benefit of additional revenue provided by the new customers. In theory, communities that are economical to serve will have already been served by a utility.²⁶⁰ For example, it was

²⁵⁷ Minn. Stat. § 645.16 (2015).

²⁵⁸ Order Rejecting Proposed Tariffs and Requiring Report, *In the Matter of a Request by Peoples Natural Gas for Approval of a New Town Least Cost Energy Rate et al.*, Docket Nos. G-011/M-91-296, G-007/M-91-460, G-008/M-91-575 2 (Mar. 10, 1992).

²⁵⁹ See Minnesota Energy Resources Corporation Tariff, at 2nd Revised Tariff Sheet Nos. 9.05–06 (stating that the “Company will apply the general principal [sic] that the rendering of service to the applicant shall not result in undue burden on the other customer” and that the Company may refuse to extend service “if in the Company’s judgment it is not economically feasible”).

²⁶⁰ See Order Rejecting Proposed Tariffs and Requiring Report, *In the Matter of a Request by Peoples Natural Gas for Approval of a New Town Least Cost Energy Rate et al.*, Docket Nos. G-011/M-91-296, G-007/M-91-460, G-008/M-91-575 2 (Mar. 10, 1992) (“At this time, however, it appears that most of the communities that can be economically served by existing LDC networks under current gas tariffs are being served.”).

presumably economical to serve the Rochester area in 1932, when a predecessor of MERC first began buildout of the system.²⁶¹ In contrast, a potential new community where the incremental cost of extending service outweighs the expected additional revenue, would be uneconomical to serve.²⁶² Extending service to this uneconomical community would be inequitable to the utility's current ratepayers, who would be asked to subsidize the uneconomic costs of the new area customers. Figure 1 illustrates this concept.

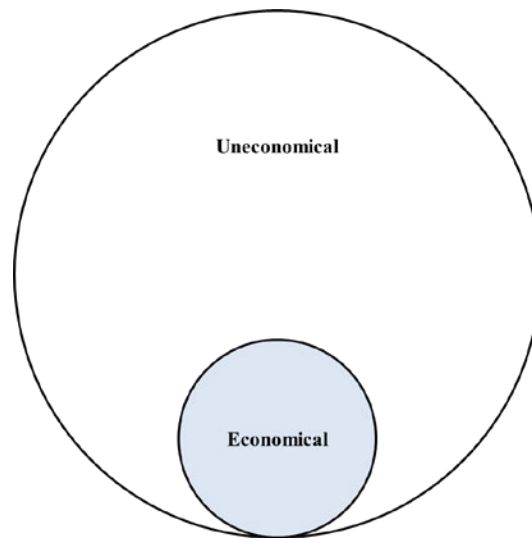


Figure 1: A visual depiction of a pool of potential natural gas customers, some of whom are economical to serve while the rest are not economical to serve.

Under this scenario, potential new area customers may be reluctant to pay the hefty upfront costs of expansion and the utility may be reluctant to extend service without additional revenue certainty. The expansion of natural gas service to these typically remote communities thus “appears unlikely to occur unless the LDCs are allowed to recover their excess extension

²⁶¹ *Our History*, <http://www.minnesotaenergyresources.com/company/history.aspx> (last visited Sept. 30, 2016).

²⁶² The new area community could self-fund the uneconomical costs associated with extension of service, but these high one-time costs can deter potential customers from extending service, even when long-term benefits are high and long-term costs are low. See NRRI Report, at 15–16.

costs directly from customers.”²⁶³ Minnesota was an early adopter of a special policy, the New Area Surcharge (“NAS”), designed to further promote expansion of natural gas service in order to expand the radius of economically-viable communities in the state.²⁶⁴

The first NAS tariffs were implemented in Minnesota in the early-1990s. The purpose of an NAS is to “permit a natural gas company to extend service into a new area it would be uneconomic to serve at tariffed rates, by permitting the company to collect a surcharge [upon new area customers] in addition to the tariffed rate.”²⁶⁵ The NAS is “designed to recover the portion of the cost of service attributable to uneconomic service extensions” as determined by a feasibility model.²⁶⁶ Broadly, the feasibility model takes into consideration the project’s capital costs minus the revenues (based on current rates) collected from the additional customers.²⁶⁷ The difference is the contribution in aid of construction that will be collected via the NAS rider over a specified period of time. By allowing new area customers to pay the uneconomic costs of the extension over time, the NAS incrementally expands the number of communities that can be served by natural gas, as Figure 2 below illustrates.

²⁶³ Order Rejecting Proposed Tariffs and Requiring Report, *In the Matter of a Request by Peoples Natural Gas for Approval of a New Town Least Cost Energy Rate et al.*, Docket Nos. G-011/M-91-296, G-007/M-91-460, G-008/M-91-575 2 (Mar. 10, 1992)

²⁶⁴ NRRI Report, n. 7.

²⁶⁵ Order Approving New Area Surcharge with Modifications and Requiring Revised Tariff Sheet, *In the Matter of Minnesota Energy Resources Corporation’s (MERC) Petition for Approval of a New Area Surcharge Rider 1* (Jul. 26, 2012).

²⁶⁶ *Id.* at 2.

²⁶⁷ See, e.g. Minnesota Energy Resources Company Tariff, at 9.14–16 (describing the “standard model” used in the calculation of an NAS surcharge).

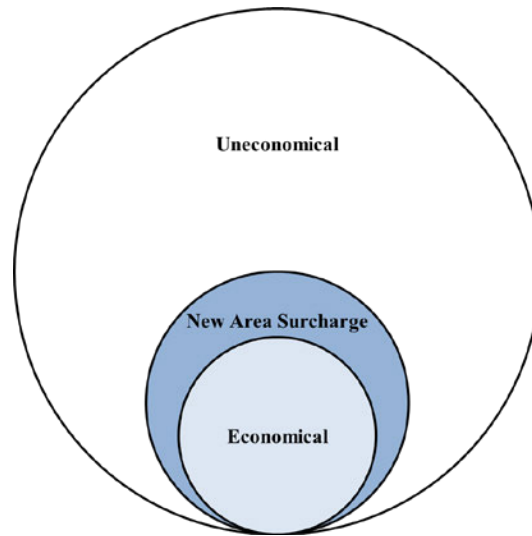


Figure 2 A visual depiction of a pool of potential natural gas customers illustrating the impact that the New Area Surcharge has on the expansion of the pool of potential customers.

This policy change did not extend natural gas service to *all* communities in the state, however, as some areas of the state remained uneconomical to serve even after proliferation of NAS tariffs.

These communities, which remained out of reach even with an NAS surcharge, became the focus of legislative attention following the winter of 2013–14. The winter heating season of 2013–14 was unusually cold, resulting in increased demand for natural gas and other heating fuels. In addition, a propane shortage caused by the high demand and regional supply challenges stressed propane-dependent communities.²⁶⁸ The propane shortage that winter was so acute that Governor Dayton declared a state of emergency across the state on January 27, 2014.²⁶⁹ As a result, policymakers began to explore alternatives that could allow the propane-dependent communities to switch to a cheaper alternative fuel like natural gas. Figure 3 shows the

²⁶⁸ See Legislative Energy Commission, *Propane Conversion Strategies* 5–6 (Jan. 15, 2015) available at <https://www.leg.state.mn.us/docs/2015/mandated/150040.pdf> (noting that unexpectedly high demand and delivery constraints contributed to a propane shortage in Minnesota and more than 30 other states).

²⁶⁹ State of Minn. Executive Dep't, *Emergency Executive Order 14-02: Declaring a State of Peacetime Emergency in the State of Minnesota* (Jan. 27, 2014).

intended goal, which again increased the radius of communities eligible for the extension of natural gas service.

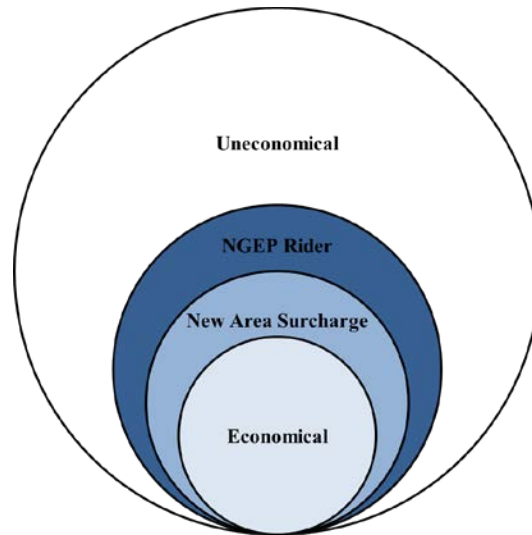


Figure 3 A visual depiction of a pool of potential natural gas customers illustrating the impact that the New Area Surcharge and the NGEP rider statute have on the expansion of the pool of potential customers.

All of the evidence, discussed below, indicates that the Legislature intended for the NGEP Rider Statute to supplement existing line extension policy by allowing existing customers to share in 33 percent of the costs of extending service to new customers.

2. Legislative History Of The NGEP Rider Statute.

Following the winter of 2013–14 and prior to enactment of the NGEP statute, the Legislative Energy Commission (“LEC”), which evaluates state energy policy for the Legislature, issued a report on the propane shortage and identified potential alternatives to relieve stress on propane-dependent communities. One alternative suggested by the LEC report was to develop policies to promote the extension of natural gas service to communities that were

still uneconomical to serve, even with an NAS rider.²⁷⁰ The report noted that the maximum amount of NAS surcharge typically accepted by potential new area customers was about \$25 per month.²⁷¹ Given that NAS policy limits the duration of an NAS rider,²⁷² the \$25 a month charge necessarily limits the amount of revenue that can be collected from new area customers, which can leave some potential new area communities with a revenue deficiency and, thus, no natural gas service. In order to bridge this revenue deficiency, the LEC report suggested that the Legislature “could consider giving state-regulated utilities greater flexibility in how these costs are covered” by building an “expansion fund” via a rider “to subsidize the costs of expansion projects.”²⁷³

The NGEP rider bill was intended to give utilities this flexibility when it was introduced in March 2015.²⁷⁴ The Senate Committee on Environment and Energy held a hearing on the NGEP bill shortly thereafter. At the hearing, a co-author of the NGEP bill explained the rationale behind the bill:

[T]he current process analyzes if there is a revenue deficiency or not and then allows the option of having a New Area Surcharge added on to help cover the deficiency. If that is not enough to cover the deficiency, the project does not go forward. So what we’re proposing . . . is to, in order to cover that deficiency, to allow the current, existing member base to pay part of the cost of the expansion . . . up to 33 percent of the project cost, to help cover

²⁷⁰ Legislative Energy Commission, *supra* note 268, at 13.

²⁷¹ *Id.* at 15.

²⁷² Minnesota Energy Resources Corporation Tariff, at 2nd Revised Tariff Sheet No. 9.15 (limiting the duration of an NAS rider to 30 years). Interestingly, the Department recommended that the Company lengthen the duration of the NAS rider to 30 years from 15 in its 2013 rate case in order to “make it easier for new areas to obtain natural gas service rather than depending on propane service that may not be reliable” in response to the propane shortage of 2013–14. Direct Testimony of Michael Zajicek, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G011/GR-13-617 12 (Mar. 4, 2014).

²⁷³ Legislative Energy Commission, *supra* note 268, at 15.

²⁷⁴ S.F. 1263, 89th Leg. (Minn. 2015) and H.F. 1522, 89th Leg. (Minn. 2015).

the deficiency in order to move natural gas usage forward in Minnesota.²⁷⁵

A representative of MERC also testified at the hearing. He noted that MERC had received calls from 25 towns and townships since the previous winter, seeking help to extend gas service.²⁷⁶ The representative gave two examples of towns—one small and one large, both situated where the additional NAS revenue would *not* fully cover an expansion—and noted that, to cover the revenue shortfall, the average annual increase for a typical MERC customer over the life of the extension would be between \$0.02 and \$0.37.²⁷⁷ No mention was made of utilizing the NGEPR rider to fund a massive distribution upgrade in communities that already had gas service.

The NGEPR statute was enacted in May 2015.²⁷⁸ The new statute incrementally expands the type of communities eligible to receive natural gas extensions and it followed a particularly harsh winter that brought a statewide propane shortage into full relief. Moreover, it fits into decades of policy development in Minnesota to promote extension of natural gas service while balancing equity concerns of existing ratepayers. The language and the structure of the statute also support this intention by the Legislature.

3. The Language And Structure Of The NGEPR Statute Support The Narrower Interpretation Of Eligibility Argued By The OAG.

In addition to the particular policy and legislative history of the NGEPR rider statute, the language and structure show that it is tailored to address the Legislature's specific concerns with encouraging additional expansion of natural gas service following the propane crisis. When

²⁷⁵ Audio: March 17, 2015 hearing of the Senate Committee on Environment and Energy (Statement of Sen. Skoe) available at https://www.leg.state.mn.us/senatemedias/audio/2015/cmte_envenergy_031715a.MP3 (remarks begin at approx. 5:00 minute mark).

²⁷⁶ *Id.* (Statement of Mr. Jeff Larson) (remarks begin at approx. 20:00 minute mark).

²⁷⁷ *Id.*

²⁷⁸ 2015 Minn. Sess. Law Serv. 1st Sp. Sess. Ch. 1 Sec. 20 (H.F. 3) (West).

considered in the correct context, the different parts of the NGEP Rider Statute demonstrate that they are intended to supplement and extend the existing policies for extending natural gas service. In particular, the definition of the applicable areas, the 33 percent cap on recovery, and the inclusion of construction in aid of construction (“CIAC”) and the revenue deficiency all have a specific meaning that is unique to the discussion of line extensions for natural gas service. Under Minnesota law, it must be presumed that “the legislature intends the entire statute to be effective and certain.”²⁷⁹ To give full effect to each of these concepts, the NGEP Rider Statute must be read in understanding with existing line extension policy. First, the “unserved or inadequately served” terms in the NGEP Rider Statute must be understood in the context of existing policies for extending natural gas service. According to the NRRI, unserved areas “refers to areas remote from the nearest utility’s gas system.”²⁸⁰ This understanding is supported by MERC’s NAS tariff, which limits the NAS rider to “geographical areas that have not previously been served by the Company.”²⁸¹ MERC explicitly distinguishes the Rochester Project from typical NAS-eligible projects, likening the project to a system integrity project rather than a gas extension project.²⁸²

In addition, as discussed above, the terms “inadequately served” or “underserved” areas have special meaning in the context of natural gas extensions. According to NRRI, “inadequately served or “unserved areas” “may have main [gas] lines nearby but many households and businesses that consume other forms of energy.”²⁸³ There is no record evidence

²⁷⁹ Minn. Stat. § 645.17(2) (2015).

²⁸⁰ NRRI Report, *supra* note 262, at 3.

²⁸¹ Minnesota Energy Resources Corporation Tariff, at 2nd Revised Tariff Sheet No. 9.14.

²⁸² “Q. Is the Rochester Project more akin to a new customer extension project . . . than to a system integrity project? A. No. Phase II is not being undertaken to connect specific new customers to our distribution system nor to extend the distribution system to new customers in an area that MERC is not already serving.” Ex. 5, at 24 (Lee Direct).

²⁸³ NRRI Report, at 3.

that the Rochester area meets fits this definition either. An “inadequately served area” cannot mean an already-served area that needs additional capacity, as MERC argues with respect to Rochester.²⁸⁴ In addition to resulting in an absurd broadening of eligible projects (discussed above), interpreting “unserved or inadequately served area” as broadly as the Company proposes has the effect of cancelling out other vital elements of the statute.

The 33 percent cap also indicates that the NGEP Rider Statute was intended to supplement the NAS system, rather than allow recovery of distribution costs to existing customers. The 33 percent cap in the NGEP statute has a specific purpose within the natural gas extension policy realm. It is intended to “help cover the deficiency,” as one legislator commented, that the NAS could not fully fund.²⁸⁵ Neither the initial petition nor subsequent testimony submitted by the Company comments in detail on this element of the statute, other than a general restatement that a cap exists.²⁸⁶ Only with the historical context about the NAS and extension policy provided above does the 33 percent cap become meaningful. Prior to enactment of the NGEP rider statute, it was the policy of the Commission to require new area customers to pay the *entire* share of the uneconomic extension costs via the NAS rider. The NGEP Rider Statute is a new tool that allows new area customers to pay only 67 percent of the costs of uneconomic extensions, while the other 33 percent are paid for by existing customers. The 33 percent cap is thus a specific tool designed and intended balance the contribution of *all* of a utility’s ratepayers to fund the uneconomical portion of natural gas extension project costs with the interest of the state to extend natural gas service to unserved or underserved communities.

²⁸⁴ “The Rochester Project is being constructed in an area that MERC already serves but is inadequately served as described in the NGEP statute.” Ex. 5, at 24–25 (Lee Direct).

²⁸⁵ Audio: March 17, 2015 hearing of the Senate Committee on Environment and Energy (Statement of Sen. Skoe) *available at* https://www.leg.state.mn.us/senatemedial/saudio/2015/cmte_envenergy_031715a.MP3 (remarks begin at approx. 5:00 minute mark).

²⁸⁶ *See, e.g.*, MERC’s Initial Petition, at 29 (noting that “only 33% of the revenue deficiency . . . may be recovered through the rider . . .”).

Similarly, contribution in aid to construction (“CIAC”) also plays a very specific role in the statute.²⁸⁷ CIAC reflects the need of the utility to charge certain customers, such as new customers on the system, a special fee when those customers demand reside in an area remote from the utility’s infrastructure.²⁸⁸ Under the NGEP statute, a petition for NGEP rider recovery must contain a description of any CIAC as well as “a description of efforts made by the public utility to offset the revenue deficiency through contributions in aid to construction.”²⁸⁹ In other words, the NGEP Rider Statute is written with the assumption that some CIAC will be collected—that is because the statute is intended to supplement existing natural gas extension policies, and those policies would *always* require a CIAC to be collected.²⁹⁰ Here, MERC acknowledges that, “[w]hile new customers pay a CIAC to connect [via the NAS], customers will *not* be connecting directly to Phase II of the Rochester Project”²⁹¹ As a result, there will be no CIACs to offset the Rochester upgrades. While it is not an explicit requirement that petitioners must have some amount of CIAC, it is clearly envisioned by the Legislature that CIAC from potential new customers would be an important component of an NGEP rider petition and it further requires utilities to describe “efforts made” to offset the deficiency via CIAC.²⁹²

Finally, the revenue deficiency, as defined in the statute, describes the “deficiency in funds” that occurs when the “projected revenues from customers receiving natural gas service as

²⁸⁷ The statute defines CIAC as “a monetary contribution, paid by a developer or a local unit of government to a utility providing natural gas service to a community receiving that service as a result of a natural gas extension project, that reduces or offsets the difference between the total revenue requirement of the project and the revenue generated from the customers served by the project.” Minn. Stat. § 216B.1638 subd. 1(b) (2015).

²⁸⁸ NRRI Report, at n. 76.

²⁸⁹ Minn. Stat. § 216B.1638 subd. 2(b)(4)–(5) (2015).

²⁹⁰ See Mar. 12, 1992 Office Memorandum from Kate O’Connell & Bob Harding to Commissioners, *Issues for new-area rates*, in Docket Nos. G011/M-91-296, G007/M-91-460, G008/M-91-575 2 (noting the recommendation from staff that “the [New Area] surcharges should be considered as CIACs rather than rates”).

²⁹¹ Ex. 1, at 29–30 (Petition) (emphasis added).

²⁹² Minn. Stat. § 216B.1638 subd.2(b)(5) (2015).

the result of a natural gas extension project, plus any [CIAC], fall short of the total revenue requirement of the natural gas extension project.”²⁹³ The total revenue requirement is defined as the “total cost of extending and maintaining natural gas service to a currently unserved or inadequately served area.”²⁹⁴ This formula is functionally similar to the process used for other line extension policies, except it requires the new area customers to pay only 67 percent of the costs, while existing customers would pay 33 percent of the costs. As the legislative history suggests, the whole purpose of the NGEP rider statute is to allow utilities to close the gap between the revenue collected from new customers with the NAS accounted and the project costs. Further, the 33 percent cap reflects the understanding of the Legislature that this deficiency would not be likely to exceed 33 percent of project costs. In other words, where the utility and the new area community fell short of economically extending service, the NGEP rider would allow the utility and all of its current ratepayers to bridge the revenue gap up to 33 percent.

MERC, however, indicates a “revenue deficiency” of more than 70 percent by 2019²⁹⁵ and simply calculates the rider-eligible revenue deficiency as 33 percent of its total revenue requirement. The significant difference between MERC’s revenue deficiency and the one envisioned in the statute further indicates that the Legislature did not intend the NGEP Rider Statute to apply to investments such as the Rochester Project.

There is a presumption that the Legislature intends for the entire statute to be effective and certain.²⁹⁶ But MERC attempts to ignore or write-off important elements of the statute in order to shoehorn the Rochester Project into the eligibility criteria listed in the statute. Instead,

²⁹³ *Id.* at subd. 1(f).

²⁹⁴ *Id.* at subd. 1(g).

²⁹⁵ Ex. 1, Table 9 (Petition) (2019 revenue deficiency \$2,359,549 / 2019 revenue requirement \$3,211,424 = 73.5%).

²⁹⁶ Minn. Stat. § 645.17(2) (2015).

the specific terms in the NGEP rider statute, and the way in which those terms relate to existing line extension policies, demonstrate that the Legislature intended the NGEP Rider Statute to be a new tool to encourage extension of natural gas service to new customers in response to the propane shortages in 2014—and nothing more. In fact, when considered in the proper context, it is clear that the Legislature engaged in a complicated balancing act and determined that the state policy in favor of extending natural gas use, and the problems caused by shortage of other fuels, would justify requiring existing customers to fund one-third of the costs of extending new service in some circumstances. That careful consideration should not be twisted into a different policy that allows a utility to recover 33 percent of the costs of continuing to provide service to existing customers through a rider.

D. THE LEGISLATURE DID NOT INTEND THE NGEP RIDER STATUTE TO APPLY TO INVESTMENTS LIKE THE ROCHESTER PROJECT.

As discussed above, the Legislature has created eight criteria that should be applied to determine the intent of a statute.²⁹⁷ Each of those criteria is satisfied in this case.

The first four criteria deal with the occasion and necessity for the law, the circumstances under which it was enacted, the mischief to be remedied, and the object to be attained.²⁹⁸ These criteria all demonstrate that the purpose of the NGEP Rider Statute was to support, and supplement, existing natural gas line extension policies. A review of the legislative history of the NGEP Rider Statute demonstrates that it was passed in response to the historic problems caused by the propane shortage in 2013–14. In part because of these problems, the Legislature wanted to create a new policy that would encourage natural gas expansion, even in some

²⁹⁷ Minn. Stat. § 645.16 (2015)

²⁹⁸ *Id.*

currently uneconomical circumstances, by allowing existing ratepayers to share in the costs of line extensions for the first time.

The “former law,” to be considered according to the fifth criteria, is existing line extension policy.²⁹⁹ In that light, the NGEPRider Statute is a rational step beyond existing policies. Before the NGEPRider Statute, customers that did not have access to natural gas could get access if they were willing to pay a CIAC to cover the additional costs of extending service. The NGEPRider Statute further encouraged that type of development by reducing the financial burden of CIACs by 33 percent, and spreading it to existing ratepayers.

The sixth criteria instructs that it is important to consider the consequences of different interpretations of a law.³⁰⁰ As discussed above, MERC’s interpretation of the NGEPRider Statute would significantly change the regulatory structure in Minnesota by allowing natural gas utilities to recover up to one-third of *most* of their investments through a new rider. If the Rochester Project is eligible for NGEPRider recovery, then there appear to be few rational reasons that MERC or other utilities could not request that most of their projects go through the NGEPRider in the future. There is no indication that the Legislature intended such a dramatic shift in the regulatory structure from this statute. Instead, there is every indication that the statute was intended to address a single, specific problem related to the economics of line extension policies in the state.

The seventh criteria refers to the contemporaneous legislative history, which has been discussed throughout this section.³⁰¹ In addition to providing insight on the Legislature’s intentions, that legislative history shows that when MERC testified during the hearings on the

²⁹⁹ *See id.*

³⁰⁰ *Id.*

³⁰¹ *Id.*

NGEP Rider Statute, the Company discussed line extension policies, and did not discuss infrastructure investments to existing customers.

The eighth criteria does not apply in this instance, because this is the first-ever interpretation of this statute.³⁰² As such, there are no decisions by legal or administrative bodies from which to draw inspiration. Instead, the Commission must base its decision on the intent of the Legislature.

MERC's interpretation is that the Legislature intended the "Natural Gas Extension Project Rider" statute to recover the costs of projects that are undertaken to ensure continued safety and reliability to existing customers. The obvious conclusion following this interpretation would be that utilities can request recovery of up to 33 percent of normal infrastructure investments through the NGEP Rider. And, as discussed above, there is no requirement to obtain pre-approval before moving forward with such investments or requesting recovery. The Legislature did not intend such a significant change in regulatory policy. Instead, all of the available evidence demonstrates that the Legislature intended the NGEP Rider to supplement and expand existing line extension policies. The NGEP Rider Statute should be used for that purpose, but the Rochester Project is not eligible for recovery under this rider.

III. THE COMMISSION SHOULD REQUIRE CHANGES TO MERC'S PROPOSED COST ALLOCATIONS.

MERC has proposed to handle the cost allocation of the Rochester Project in two different ways. For those costs incurred by MERC, for Phase II distribution upgrades, MERC proposes to recover the costs from all of its firm customers, including customers who do not live in the Rochester area or the NNG PGA. For those costs related to expanding NNG's interstate

³⁰² *Id.*

pipeline capacity, MERC proposes to recover the costs through the commodity portion of the on a per-therm basis from all customers subject to the NNG-PGA.

If the Commission agrees that MERC has not demonstrated that the Rochester Project is prudent, reasonable, and necessary to provide service to customers then it need not make a decision on the cost allocations. If the Rochester Project is approved, though, the evidence in the record supports the Company's proposal for allocating the costs of the Phase II distribution upgrades. For the costs of the NNG pipeline capacity, however, the Commission should require MERC to ensure that the NNG costs are borne by all customers, including transportation customers, in a manner commensurate with the benefit received.

A. THE EVIDENCE IN THE RECORD SUPPORTS MERC'S COST ALLOCATION PROPOSAL FOR PHASE II COSTS.

MERC proposes to recover its Phase II capital costs from all of its customers via base rates and the NGEPR rider.³⁰³ Thirty-three percent of the Phase II costs would be recovered via the NGEPR rider under the Company's proposal, with the remaining costs recovered through base rates when rate cases are filed.³⁰⁴ The Department recommends, instead, that customers outside the Rochester area should pay for only 50 percent of the costs, with the remaining 50 percent recovered from customers inside the Rochester area.³⁰⁵

MERC disagreed with the Department's recommendation for several reasons. First, MERC states that "spreading costs equally across all customers is consistent with Commission precedent that spreads system upgrade costs across the entire rate base and with the policy

³⁰³ Ex. 5, at 21 (Lee Direct).

³⁰⁴ *Id.* at 25.

³⁰⁵ See Ex. 400, at 3 (Peirce Direct) (noting that Rochester area customers receive the most direct benefits of the distribution upgrades).

underlying the NGEP Rider statute.”³⁰⁶ Second, MERC states that “customers in other locations also benefit from the Project.”³⁰⁷ Third, MERC states that “a disproportionate split would effectively create separate rate zones within the MERC system.”³⁰⁸ Fourth, MERC states that the 50/50 split would be a “potentially excessive cost burden on [Rochester] customers.”³⁰⁹

The record supports several of MERC’s arguments. It is true that the general policy in Minnesota is to spread system upgrade costs amongst all customers. In instances where costs are incurred to add new customers to the system, there are specific policies in place that require new customers to contribute if the connection costs are uneconomical.³¹⁰ But the Phase II distribution upgrades are “not being undertaken to connect specific new customers” nor are they intended to “extend the distribution system to new customers in an area that MERC is not already serving.”³¹¹ Rather, Phase II is a “system integrity and reliability project” that is “similar to other infrastructure projects included in rate base and recovered through base rates.”³¹² The Commission’s general policy is to spread the costs of system integrity and reliability projects among all customers.

One reason for that policy is that there are difficult questions of where to draw the line when assigning system integrity and reliability projects to specific customers. If 50 percent of the Rochester Project costs are assigned to Rochester customers, it is difficult to see why that policy should not be applied to all distribution projects that are intended to serve specific areas, which could be the vast majority. The Rochester Project is unique, but it is unique in the way the Company is seeking approval of the project, not because of the project itself. It is unclear

³⁰⁶ Ex. 6, at 10.

³⁰⁷ *Id.*

³⁰⁸ *Id.*

³⁰⁹ *Id.* at 11.

³¹⁰ Section II contains a more thorough discussion of line extension policy.

³¹¹ Ex. 5, at 24 (Lee Direct).

³¹² *Id.* at 23.

why a system integrity and reliability project in Rochester should be treated differently than a similar project in any other community. Taken to its logical conclusion, directly assigning the costs of distribution projects would lead to a multitude of rate areas across MERC's system. That has not been the Commission's policy, generally. In fact, during the evidentiary hearing Ms. Peirce acknowledged that she was not aware of any instance where the Commission has required customers in a specific area to pay more than all other customers for infrastructure-related costs like the Rochester Project.³¹³

In addition, it appears that the language of the NGEP Rider Statute supports spreading costs to all customers. The NGEP rider statute requires that the rider petition "shall include *all* of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas project."³¹⁴ This comports with the general principle that distribution upgrade projects should be recovered by all customers on the system, not just the customers served by the upgrade.

In contrast, there does not appear to be record support for the 50/50 split suggested by the Department. At the evidentiary hearing, Ms. Peirce clarified that there was no calculation behind the 50/50 split, but rather that it was where she "landed" in her attempt to "balance out the rate impact that . . . those two groups [Rochester and non-Rochester customers] would have in this revenue deficiency."³¹⁵ In addition, as discussed in Section II the Legislature determined that it would be reasonable for all customers to share in 33 percent of the costs of line extensions brought under the NGEP Rider. Assigning half of those costs back to the customers obtaining

³¹³ Tr. Evid. Hearing, Vol. 1, at 207–208 (Peirce).

³¹⁴ Minn. Stat. § 216B.1638 subd. 2(a) (2015) (emphasis added).

³¹⁵ Tr. Evid. Hearing, Vol. 1, at 206:7–19 (Peirce).

the new extension, so that only 16.5 percent of the costs are shared amongst all customers, may contravene the Legislature's intent in the NGEP Rider.

As discussed in Section I, the evidence in the record demonstrates that the Commission should find that the Rochester Project proposed by MERC is not prudent, reasonable, or necessary to provide service to customers in the Rochester area. But if the Commission does approve the Rochester Project, the record supports MERC's proposal to recover the Phase II distribution costs from all customers.

B. MERC'S PHASE II COST ALLOCATION PROPOSAL IS EVIDENCE THAT THE ROCHESTER PROJECT IS NOT ELIGIBLE FOR NGEP RIDER RECOVERY.

The arguments that MERC raises in support of its Phase II cost allocation proposal are also relevant to another issue in this case—NGEP Rider eligibility. In particular, MERC's argument that the Rochester Project is a system integrity and reliability project, rather than a line extension project, demonstrate that the Project is not eligible for NGEP Rider recovery.

As discussed in more detail in Section II, the Rochester Project is not the type of project envisioned by the Legislature when it enacted the NGEP rider statute. As discussed above, MERC states that the Rochester Project is a "system integrity and reliability project" that is "similar to other infrastructure projects included in rate base and recovered through base rates."³¹⁶ MERC further asserts that the Rochester Project "is not being undertaken to connect specific customers to our distribution system nor to extend the distribution system to new customers in an area that MERC is not already service."³¹⁷ And yet, the Company seeks rider recovery under a law enacted to target the very type of project the Company argues the Rochester Project is not. The conflict over cost allocation is simply another symptom of the

³¹⁶ Ex. 5, at 23 (Lee Direct).

³¹⁷ *Id.* at 24.

Company's attempt to fit a square peg into a round hole. For that reason, and for reasons discussed in Section II, the OAG recommends that the Commission find that the Rochester Project is ineligible for recovery under the NGEP statute.

C. INTERRUPTIBLE DISCOUNTS SHOULD BE RECALCULATED.

While the evidence in the record supports MERC's proposal to recover the Phase II distribution costs from all of its customers, there are problems related specifically to interruptible customers. As discussed above, interruptible customers receive a discount to their distribution rates because of their agreement to curtail consumption when called to do so.³¹⁸ As described by Mr. Heinen, "interruptible customers receive the benefit of lower non-gas margins knowing that they will be interrupted if load must be curtailed to maintain system integrity."³¹⁹ For example, MERC's General Service Small C&I customers pay a distribution charge of \$0.18116 per therm, and Large C&I customers currently pay a distribution charge of \$0.16579 per therm.³²⁰ In comparison, Small Volume Interruptible customers pay a distribution charge of \$0.08490 per therm, and Large Volume Interruptible customers pay a distribution charge of \$0.04553 per therm.³²¹ For the benefit they provide to the system, namely their agreement to curtail when it is necessary, the interruptible customers receive rate discounts of somewhere between fifty and seventy percent.

Agreeing to curtail in the face of high demand will not provide any benefit to the system in Rochester, however, because the Rochester Project will create so much excess capacity that it is extremely unlikely that customers' curtailment will be necessary. MERC agrees that "interruptible customers will receive the benefit of firmer service" if the Rochester Project is

³¹⁸ Ex. 300, at 63 (Urban Amended and Corrected Direct).

³¹⁹ Ex. 405, at 9 (Heinen Direct).

³²⁰ Minnesota Energy Resources Corporation Tariff Book, 4th Revised Sheet No. 5.00.

³²¹ *Id.*, 4th Revised Sheet Nos. 5.21 & 5.21.

constructed.³²² In other words, the benefits that interruptible customers provide to the system will be reduced, but the discount that they receive for their agreement will stay the same.

In addition, sophisticated customers will be aware that there will be a significant amount of excess capacity in the Rochester area. That means that they will know that they can transfer from firm to interruptible service with very little risk of facing curtailment. Every customer that does so will increase the cost burden on customers who are unable, aware, or do not have the option to transfer to interruptible service—like captive residential customers.

These concerns indicate that, if the Rochester Project moves forward, changes must be made to ensure that firm customers are treated fairly. Dr. Urban requested that MERC provide information about recalculating the interruptible discount in the face of such an extreme level of excess capacity.³²³ MERC declined to provide a detailed discussion, but did agree that MERC's tariffs "be reviewed to ensure that interruptible customers are not allowed to 'free ride' on the system."³²⁴ As such, it appears that MERC agrees that the Rochester Project may allow interruptible customers to free ride, or avoid sharing the full cost of the Project, but the Company has not offered any solution to the problem. Instead, the Company suggests that such issues be tabled until the Company's next rate case.

Whether these issues are handled in this proceeding or in a future rate case, the Commission should be aware of the problem and the fact that it must be addressed eventually. In addition, the Commission should consider the fact that these equity problems would not exist, or would be much less problematic, if the Rochester Project MERC proposed were sized more appropriately. A more moderate, phased or incremental approach, as discussed above, would

³²² Ex. 6, at 40 (Lee Rebuttal).

³²³ Ex. 300, at 63 (Urban Amended and Corrected Direct).

³²⁴ Ex. 6, at 43 (Lee Rebuttal).

mitigate many of the problems with equity between firm and interruptible customers, as well as the incentive customers will have to shift to interruptible service and concentrate the burden on the remaining firm customers.

D. THE COMMISSION SHOULD ENSURE THAT ALL CUSTOMERS SHARE COST BURDENS IN AN EQUITABLE IF THE ROCHESTER PROJECT IS BUILT.

In addition to the equitable problems with interruptible customers and distribution costs, there is an equity problem with MERC's proposal for NNG capacity costs. MERC proposes to collect the estimated \$58 million in costs from the NNG portion of the Rochester Project on a per-therm basis via the PGA commodity charge from system sales customers (firm and interruptible) in its NNG PGA area.³²⁵ Under MERC's proposal, its transportation customers would not directly pay for NNG-related capacity costs and would only be paying "for their share of improvements to MERC's distribution system," or the Phase II distribution upgrade costs.³²⁶ Transportation customers, unlike sales customers, obtain their natural gas from third parties. As a result, they do not share in the fuel costs that are recovered from the NNG-PGA, and so would not pay for any of the costs of the NNG upgrades that MERC proposes to recover through the PGA (in addition to any distribution rate discounts transportation customers will receive for agreeing to interruptible service).

While they would not share in the costs of the NNG upgrades, transportation customers *will* receive benefit from the newly available capacity if the Rochester Project is built. The new capacity of the NNG system will represent capacity that is available to transportation customers on any days that MERC is not utilizing all of the available capacity. For those customers that

³²⁵ See *Id.* at 29–30 (noting that the cost of NNG's capacity expansion would "generally [be] recovered via the demand portion of the PGA" but that "it would be possible for a portion of those costs to be allocated through the commodity portion of the PGA" in order to recover NNG costs from interruptible sales customers" who pay commodity, but not demand charges within the PGA).

³²⁶ *Id.* at 30.

take interruptible service, there will be an extremely low likelihood of curtailment. And for all customers, there will be a new supply of natural gas capacity available to them. In fact, the amount of excess supply on the system may reduce prices in the capacity market.

Department witness Mr. Heinen raises similar concerns. In his Direct Testimony, Mr. Heinen stated that the new capacity on the NNG line “will be used to serve MERC’s sales customers *and* its transportation customers,” so it is “important to ensure that costs of expanding NNG’s capacity are appropriately charged to both sales and transportation customers.”³²⁷ Mr. Heinen points out that the NGEP Statute requires that transportation customers share in the costs of projects recovered through the rider, and states that, “Without this provision in the NGEP statute, the Company’s sales customers would unfairly subsidize transportation customers, who would not pay for the pipeline capacity costs associated with the Project.”³²⁸

Mr. Heinen concluded, however, that transportation customers would be contributing “either directly or indirectly” to the costs of the NNG expansion because they will have to purchase their capacity through capacity markets. Mr. Heinen states that this may be a reasonable solution because he believes that “MERC should be able to obtain near full, or maximum, rate recovery in the capacity release market because third-party marketers, with which transportation customers contract, can only buy capacity deliverable in the Rochester area from MERC.”³²⁹ But all of MERC’s statements regarding the capacity market indicate that Mr. Heinen’s assumptions about capacity market prices are not reasonable.

³²⁷ Ex. 405, at 49–50 (Heinen Direct).

³²⁸ Ex. 407, at 11 (Heinen Surrebuttal).

³²⁹ *Id.* at 13.

First, during the evidentiary hearing Ms. Lee stated that MERC holds 85 to 90 percent of the existing capacity in the Rochester area.³³⁰ While MERC will acquire 100 percent of the new capacity on the system, it is possible that existing marketers have long-term capacity contracts with NNG. If so, they will be able to serve transportation customers without having to work through MERC.

Second, during the evidentiary hearing Ms. Lee also stated that the prices in the capacity release market are set according to market conditions.³³¹ In other words, MERC does not set the prices—they are set by supply and demand. And, as Mr. Heinen pointed out in his Direct Testimony, “the revenue associated with these releases is typically small compared to the original purchase price of the capacity.”³³² In fact, Mr. Heinen pointed out that while “there is some relief to ratepayers ... [the capacity release market] should not be considered a significant tool to mitigate costs.”³³³ There is reason to believe that the prices could be even lower in the future. The principles of supply and demand indicate that a significant amount of excess capacity in the market would depress prices, because marketers would know that there is far more supply than demand.

Transportation customers will share in the benefits if the NNG upgrades are built, but they would not share in the costs except to the extent that they are recovered through transactions on the capacity market. It is not reasonable to assume that the prices in the capacity release market will reflect the full benefit that transportation customers will receive.

In addition, there is a further concern that the amount of excess capacity may incentivize customers to switch to interruptible transportation service in order to avoid the costs of the

³³⁰ Tr. Evid. Hearing, Vol. 1, at 36–37 (Lee).

³³¹ *Id.* at 37:24–25.

³³² Ex. 405, at 47 (Heinen Direct).

³³³ *Id.*

Rochester Project to the maximum extent. As Ms. Lee pointed out, the Company's tariffs provide a limited ability to control what type of service customers take.³³⁴ Mr. Heinen pointed out that the "excess capacity in the Rochester area will likely result in a decrease in curtailments and a drift to 'firmer' capacity" for interruptible customers.³³⁵ Sophisticated firm service customers will be incentivized to transfer to interruptible or transportation service because they will know that it is very unlikely they will be curtailed. By doing so they will could completely avoid the costs of the NNG upgrade, and receive a discounted rate for all of MERC's distribution costs, including the Rochester Project. And by taking steps to reduce these costs for themselves, transportation would focus the costs all the more heavily on existing firm customers, including captive residential customers. In addition to raising concerns with cost allocations, the fact that the Rochester Project will incentivize customers to switch to discounted interruptible or transportation service is yet another factor that demonstrates that the Rochester Project is not reasonable and prudent.

Ultimately, all customers, including transportation customers, should contribute to the costs of the NNG portion of the Rochester Project in a manner commensurate with the benefits received. MERC's proposal would shield transportation customers entirely from the majority of Rochester Project costs, and the hope that capacity release markets will recoup some of the burden for firm customers is not reasonable. If the project is approved, the Company should be ordered to work with parties to ensure that the burden does not fall on MERC's firm customers.

³³⁴ Ex. 6, at 41 (Lee Rebuttal)

³³⁵ Ex. 407, at 15 (Heinen Surrebuttal).

Instead, the costs should be shared in an equitable manner between firm, interruptible, and transportation customers.³³⁶

IV. IF THE PROJECT IS APPROVED THE COMMISSION SHOULD ESTABLISH A COST CAP AS RECOMMENDED BY THE DEPARTMENT.

In his Direct Testimony, Department witness Mr. Heinen proposed that the future cost recovery for the Rochester Project, if approved, should be limited “only to the amount of costs that the utility proposed in its petition,” and that “the utility would have the burden of proof to show that any costs above the approved level are prudent and why it would be reasonable to recover such costs from ratepayers.”³³⁷ Mr. Heinen explained that such cost caps are important because “[u]tility cost estimates are used extensively throughout the regulatory process and are relied upon by the Commission, particularly when considering alternatives to a proposed project.”³³⁸ Mr. Heinen continued by noting that, “Absent cost recovery caps tied to the evidentiary record . . . utilities have little incentive to expend the effort needed to accurately report project costs in regulatory proceedings, nor to ensure that the actual costs are as reasonable as possible.”³³⁹ Mr. Heinen provided examples of other proceedings in which the Commission had applied such caps, and then recommended that the Commission cap the costs of MERC’s distribution costs for the Rochester Project at the Company’s estimate in this proceeding—\$44,006,607.³⁴⁰

The Department’s analysis is sound and its recommendation is reasonable. Accurate estimates are essential in order for the Commission to ensure that rates are just and reasonable.

³³⁶ Given that MERC is seeking pre-approval of the Project in this proceeding, rather than immediate cost recovery, if the Commission orders the Company to develop a method for ensuring that costs are shared equitably between all customers classes there will be an opportunity to address the issue further in a future cost recovery proceeding.

³³⁷ Ex. 405, at 40 (Heinen Direct).

³³⁸ *Id.* at 41.

³³⁹ *Id.*

³⁴⁰ *Id.* at 43.

Capping costs at the level estimated in the initial petition will incentivize utilities to ensure that their estimates are reasonable, and to control costs once construction begins.

Some of Mr. Heinen's other statements, however, are concerning. In particular, later in his Direct Testimony, Mr. Heinen suggested that the Commission will "have the opportunity to review costs in future rider reviews and in subsequent general rate cases."³⁴¹ It is true that MERC must begin another proceeding to request recovery of costs through the NGEP Rider. But it would not be reasonable to defer a thorough investigation of the prudence and reasonableness of MERC's proposal to the future. First, it is unlikely that a future rider proceeding will be converted into a contested case—in this proceeding the Commission has the benefit of sworn testimony and extensive analysis that would be unusual for an annual rider proceeding. And, second, as a practical matter, once MERC has expended funds on infrastructure investments it would be much more challenging to deny recovery. *This* proceeding is the best avenue to review the prudence and reasonableness of the Rochester Project, and the Commission should not delay that investigation just because it will have another opportunity to review the Project in the future. As demonstrated throughout this brief, the results of that investigation demonstrate that the Rochester Project is not reasonable, prudent, and necessary to provide service to customers in the Rochester area.

CONCLUSION

The Commission should reject MERC's request for pre-approval of the Rochester Project. Based on all of the evidence in the record, the Company has not demonstrated that the Project is prudent, reasonable, and necessary to provide service to customers in the Rochester area.

³⁴¹ *Id.* at 44.

The Rochester Project would produce far more natural gas capacity than is reasonable, decades before it will be useful. The evidence demonstrates that the Company focused too heavily on the results of its flawed long-term peak demand forecast, and ultimately selected a Project that will place all of the forecasting risk and the risk of overbuilding on captive ratepayers. On top of that, the Rochester Project would lead to intergenerational inequities as a result of excess reserve margins, and incentivize large customers to avoid the costs of the Project by switching to interruptible or transportation service. Additionally, the record demonstrates that MERC did not consider phased or incremental approaches that could have provided significant benefit to customers, and also did not consider whether conservation or peak shaving facilities could reduce the need for additional capacity. Ultimately, the evidence shows that the Rochester Project that MERC has proposed is not prudent, reasonable, or necessary to provide service to customers. The Commission should reject MERC's request for pre-approval and direct the Company to develop a new, more moderate plan to increase capacity in the region.

In addition, the Commission should find that the Rochester Project is not eligible for recovery through the NGEP Rider. The NGEP Rider Statute is ambiguous, and a careful review demonstrates that the Legislature did not intend the NGEP Rider Statute to apply to investments like the Rochester Project.

If the Commission approves the Rochester Project, the Commission should approve MERC's proposal for cost recovery regarding the Phase II distribution costs, but should order the Company to work with interested parties to ensure that the NNG costs are shared by all customers in a manner commensurate with the benefits received.

Finally, if the Project is approved the Commission should order a cost cap as recommended by the Department.

Dated: October 11, 2016

Respectfully submitted,

LORI SWANSON
Attorney General
State of Minnesota

s/ Ryan P. Barlow

RYAN P. BARLOW
Assistant Attorney General
Atty. Reg. No. 0393534

445 Minnesota Street, Suite 1400
St. Paul, Minnesota 55101-2131
(651) 757-1473 (Voice)
(651) 297-7206 (TTY)
ryan.barlow@ag.state.mn.us

s/ Joseph A. Dammel

JOSEPH A. DAMMEL
Assistant Attorney General
Atty. Reg. No. 0395327

445 Minnesota Street, Suite 1400
St. Paul, Minnesota 55101-2131
(651) 757-1061 (Voice)
(651) 297-7206 (TTY)
joseph.dammel@ag.state.mn.us

ATTORNEYS FOR OFFICE OF THE
ATTORNEY GENERAL – RESIDENTIAL
UTILITIES AND ANTITRUST DIVISION



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

October 11, 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/M-15-895

OAH Docket No. 68-2500-33191

Dear Judge Cochran:

Enclosed and e-filed in the above-referenced matter please find the PUBLIC and HIGHLY SENSITIVE TRADE SECRET Brief of the Office of the Attorney General – Residential Utilities and Antitrust Division.

The Highly-Sensitive Trade Secret version of this Brief 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/ Ryan Barlow

RYAN P. BARLOW
Assistant Attorney General

(651) 757-1473 (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/M-15-895

OAH Docket No. 68-2500-33191

[illegible]

I hereby state that on October 11, 2016, I filed with eDockets the PUBLIC and HIGHLY SENSITIVE TRADE SECRET *Brief of the Office of the Attorney General – Residential Utilities and Antitrust Division* 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 11th day of October, 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	mittchellabeln@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 400 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 7 h 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	Yes	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 4 h 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	john.lindell@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 Fwy 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	Yes	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 7 h Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List