Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: June 12, 2015 ....*Agenda Item #**_2_**

Company: CenterPoint Energy (CenterPoint or CPE)

Docket No. G-008/M-14-561
In the Matter of CenterPoint's Request for a Change in Demand Units Effective November 1, 2014

Issues: Should the Commission approve CenterPoint's proposed level of demand entitlement effective November 1, 2014?

Should the Commission approve CenterPoint's proposed allocation of the fixed costs of two new storage contracts?

Should the Commission grant CenterPoint a variance to Minn. Rules, Part 7825.2700, Subp. 5, to allow for a one-month delay in implementing rate case test year demand volumes?

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Relevant Documents

CenterPoint – Initial Filing (Non-Public) .... July 1, 2014
CenterPoint – Corrected Exhibits (Non-Public) .... August 22, 2014
Department – Comments (Public) and Non-Public Attachment............................. October 2, 2014
CenterPoint – Reply Comments... October 13, 2014
CenterPoint – Supplemental Request (Non-Public) .... October 31, 2014
CenterPoint – Other Supplemental Information (Non-Public) .... December 30, 2014
Department – Response Comments .... March 18, 2015
CenterPoint – Supplemental Reply (Non-Public).. March 30, 2015
Department – Supplemental Response Comments .... April 24, 2015

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

Statement of the Issues

Should the Commission approve CenterPoint Energy's (CenterPoint of CPE) proposed level of demand entitlement effective November 1, 2014?

Should the Commission approve CenterPoint's proposed allocation of the fixed costs of two new storage contracts?

Should the Commission grant CenterPoint a variance to Minn. Rules, Part 7825.2700, Subp. 5, to allow for a one-month delay in implementing rate case test year demand volumes?

Introduction

CenterPoint requested to change its demand entitlements beginning with the November 1, 2014 start of the 2014-2015 heating season. Due to growth in the Lexington and Buffalo/Monticello areas, CenterPoint added 499 Dkt of 12-month and 853 Dkt of Winter-only daily capacity at Lexington, and 1,699 Dkt of 12-month and 2,301 Dkt of 5-month winter daily capacity at Buffalo/Monticello. CenterPoint also decreased its daily propane peak-shaving capacity by 1,033 Dkt. Additionally, CenterPoint extended its Tenaska storage contract at a lower rate, purchased BP and FDD storage capacity/service, updated its Firm Transportation base/variable split, updated pipeline rates, added backhaul entitlement on the Trailblazer Pipeline (needed to move NGPL gas from storage), updated the seasonal reservation schedule, updated the NGPL cost allocation between Firm and Small Volume Dual Fuel customers due to changes in sales estimates, updated the propane costs to rate case values, and updated annual firm sales volume to Rate Case Firm sales estimate.

In its October 31, 2014 update, CenterPoint stated it will increase overall total demand cost from October 2014 by about $12.3 million, due mainly to the end of off-system sales credits ($6.5 million), the increase in seasonal reservation charges ($1 million), and additional storage services ($4.2 million). In its December 30, 2014 update, CenterPoint stated it will increase overall total demand costs from December 2014 rates by an additional approximately $575,000. The total annual effect on a typical residential heating customer using 922 therms of gas per year is an increase of about $15.40 from October 2014 rates.

CenterPoint also increased its estimated design day requirements, including a physical reserve of 36,000 Dkt, from 1,324,000 Dkt to 1,326,0000 Dkt.

The Minnesota Department of Commerce, Division of Energy Resources (Department) performed a comprehensive review of CenterPoint's request, including asking for additional information in reply comments. The Department concluded that CenterPoint's proposed level of demand entitlements is reasonable and the Company's design day is reasonable. Further, the Department stated that it was satisfied with CenterPoint's response regarding the allocation of new storage contracts and agreed with CenterPoint's proposal to allocate the storage contract fixed costs 75% to demand and 25% to commodity. The Department also stated that it would continue to assess the reasonableness of CenterPoint's approach to using the upper-bound of its design-day analysis, rather than the regression point estimate, to determine the appropriate total entitlement level in future demand entitlement filings.

In its March 18, 2015 Response Comments, the Department raised a concern with CenterPoint's November 1, 2014 implementation of the rate case estimated annual demand volumes in the PGA and recommended that CenterPoint request a variance to Minn. Rules, Part 7825.2700, Subp. 5 to allow for the November 1, 2014 implementation.

In its March 30, 2015 Supplemental Reply, CenterPoint provided a discussion on the uncertainty in the Viking rate case leading up to its decision to extend its current forward haul capacity on Viking for one year. CenterPoint also responded to the Department's recommendation that it request a variance to Minn. Rules, Part 7825.2700, Subp. 5. CenterPoint explained why it did not think implementing the rate case sales forecast in November, rather than December, required a rule variance. However, if the Commission agrees with the Department that a rule variance is required, CenterPoint requested a variance to the rule and discussed how its request meets the requirements for granting variances found in Minn. Rules, Part 7829.3200.

In its April 24, 2015 Supplemental Response Comments, the Department recommended that the Commission:

- approve CenterPoint's proposed level of demand entitlement;
- approve the design-day level proposed by CenterPoint; and
- approve the variance to Minn. Rules, Part 7825.2700, Subp. 5, to allow a one month delay in implementing CenterPoint's test year demand volumes.

As stated above, the Department performed a comprehensive review. Staff agrees with and supports the Department's recommendation to approve CenterPoint's proposed level of demand entitlement and CenterPoint's proposed design-day level for the 2014-2015 heating season.

Staff believes the two areas which may warrant some further discussion are: (1) the proposed allocation of the new storage contracts fixed costs between demand and commodity costs; and (2) the recommendation to approve a variance to Minn. Rules, Part 7825.2700, Subp. 5 to allow a one month delay in implementing CenterPoint's test year demand volumes. The briefing papers summarize and discuss these two items below.

Minnesota Rules

The Commission's Automatic Adjustment of Charges rules (Minnesota Rules, Chapter 7825, Parts 2390 through 2920) require gas utilities to make a filing whenever there is a change in their entitlement to the demand-related services provided to them by a supplier or transporter of natural gas.

Specifically, Minnesota Rules, Part 7825.2910, Subp. 2, Filing upon a change in demand, requires gas utilities to file to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.

Minnesota Rules, Part 7825.2400, Subp. 13a. Demand, defines demand as "the maximum daily volumes of gas that the utility has contracted with a supplier or transporter to receive."

Background

On July 1, 2013, CenterPoint requested to change its demand entitlements, effective November 1, 2014.

On August 22, 2014 CenterPoint filed revisions to several exhibits in its initial filing.

On October 2, 2014, the Minnesota Department of Commerce, Division of Energy Resources (Department), filed comments recommending approval subject to supplemental filings by CenterPoint and requesting further information from CenterPoint.

On October 13, 2014, CenterPoint filed reply comments providing additional information and discussion on its design day modeling and on its proposed allocation of storage costs.

On October 31, 2014, CenterPoint filed a supplement revising several exhibits from its initial filing for updated information and subsequent changes.

On December 30, 2014, CenterPoint filed another supplement again revising several exhibits to update its costs to reflect a revision in the Northern Natural Gas Base/Variable calculation, and the Viking Pipeline rate effective January 1, 2015.

On March 18, 2015, the Department filed response comments. The Department responded to CenterPoint's reply comments and its supplemental filings. Additionally the Department raised two concerns and requested that CenterPoint:

- Provide further discussion on why the uncertainty in the Viking rate case which, according to the Company, led to a shorter and more expensive contract; and
- Request a variance to Minn. Rules, Part 7825.2700, Subp. 5.

On March 30, 2015, CenterPoint filed supplemental reply comments in which it responded to the Department's requests.

On April 24, 2015, the Department filed supplemental response comments making its recommendations to the Commission.

Allocation of Fixed Storage Costs - Should the Commission approve CenterPoint's proposed allocation of the fixed costs of two new storage contracts?

CenterPoint added an additional 5 Billion Cubic Feet of storage capacity with BP Storage with a maximum daily withdrawal of 50,000 Dkt.

CenterPoint also added an additional 500,000 Cubic Feet of Northern Natural Gas Company's FDD Storage, with a maximum daily withdrawal of 8,647 Dkt.

CenterPoint proposed to allocate the two new storage contracts' fixed costs by allocating 75 percent to demand costs and 25 percent to commodity costs. CenterPoint stated that this allocation is like the allocation used for reservations fees as detailed in Docket No. G-008/M-11-1078.

The Department questioned why the allocation would be similar to reservation fees, rather than to other storage contracts currently held by the Company. The Department noted that in Docket No. G-008/M-07-561, the Commission ordered CenterPoint to allocate costs associated with NGPL Storage 65.69 percent to firm and small volume dual fuel customers based on sales volumes, and to include the remaining 34.31 percent in commodity costs allocated to all sales customers based on sales volumes. Additionally, costs associated with CenterPoint's Tenaska storage contract are allocated 25 percent to demand and 75 percent to commodity [Docket No. G008/M-11-1078.]. The Department requested that CenterPoint provide a detailed discussion in its Reply Comments regarding its proposal to allocate its two new storage contracts 75% to demand and 25% to commodity.

In its October 13, 2014 reply, CenterPoint explained that applying the NGPL cost allocation did not seem appropriate as the services on the new agreements were expected to be different from the NGPL storage service.

CenterPoint further explained that:

> In its November 1, 2011 Demand Entitlement filing, Docket No. G-008/M-11-1078, the Company proposed an allocation of fixed costs for its then-new storage contract with Tenaska as part baseload (75.8% Commodity) and part swing (24.2% Demand) based on the services the Company contracted from Tenaska. The costs being allocated represent the fixed fees added on top of the commodity gas costs to provide the contracted services to get the commodity to our market area. At that time, the company explained that part of the service was arranged to provide baseload gas throughout the winter, which delivers the same quantity of gas each day of the month (the 75.8% portion). The remaining gas was proposed to be Demand (24.2%), because the service provided swing, or variable, daily quantities depending upon CPE's needs. The PUC approved the allocation for that storage agreement on September 6, 2013. Unlike the new storage contracts proposed for the upcoming winter (2014-2015) that allow for all of the stored gas to be delivered on a swing supply basis each day, the Tenaska contract had the

> greater portion of its gas to be delivered as baseload supply. On the Tenaska storage contract, only 24.2% of the stored gas could be used to provide swing supplies.
>
> CenterPoint Energy proposed the 75 percent demand / 25 percent commodity cost allocation for the two new storage agreements because the costs represent the fixed-cost (demand) portion of the new storage services that were contracted to serve swing supplies. Under the terms of this storage contract, gas is brought to CenterPoint Energy's distribution system as needed, just like swing supplies that have a reservation component. In the February 28, 2012 order in the G-008/M-07-561 and G-008/M-11-1078, this kind of cost was ordered to be split 75% demand and 25% commodity to reflect that some of the fixed-cost portion of the storage costs should be borne by dual fuel customers as they use some of the storage supplies throughout the winter when not required for firm supply (ordering point 7).

The Department was satisfied with CenterPoint's response regarding the allocation of new storage contracts and agreed with CenterPoint's proposed approach.

<u>Staff Discussion</u>

Gas costs classified as demand are charged to firm customers, whereas costs classified as commodity are allocated between firm and interruptible sales service customers based on use. Staff has some concern that CenterPoint's proposed allocation of 75% to demand and only 25% to commodity would still allocate the majority of the costs to firm customers.

Previously, the Commission expressed an interest in the possibility of having gas utilities allocate some demand costs to interruptible customers. In Docket No. E,G999-AA-06-1208 (2006 AAA docket) the Department ultimately concluded that, with a few exceptions,

> the costs associated with supplier Producer Demand[1] and Contract Storage Service (Storage) [2] have traditionally been recovered as demand costs from firm sales customers. Historically, these types of costs were primarily used as tools to maintain distribution system reliability for the utility's firm customers. As noted above, the Commission has reviewed the utilities' unique set of circumstances and found that it was reasonable to allocate such costs as demand costs and assign them to firm customers.

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[1] Producer Demand costs are the contracted, per-unit fees paid by the utility to reserve third-party supplies to guarantee (reserve) gas supplies at either a fixed-rate or an index-rate.

[2] The American Gas Association defines a Contract Storage Service as:

> Service provided by a pipeline, or other owner of storage facilities, whereby storage customers may lease a portion of the facilities for the purposes of storing customer-owned gas. Contract storage service generally involves the injection of customer-owned gas into the facility during the off-peak period, the holding of the accumulated inventory for the customer, and the withdrawal of gas during the peak heating season.

> However, Producer Demand and Storage costs have recently been identified as tools used to mitigate price. Minnesota natural gas utilities are currently using these tools in developing their general gas supply portfolio, which is designed to provide gas to all system customers. Given what appears to be the evolving use of these tools, and because the Commission's prior decisions were made in 1993 dockets, it may be appropriate for the Commission to revisit the issue of classification and billing for these charges as demand or commodity. If it is indeed the case that utilities use these tools such that they benefit all of a utility's sales customers (i.e., both firm and interruptible sales customers), the Commission may want to note this fact and consider whether it is reasonable to classify Producer Demand and Storage costs as demand charges and assign all related costs solely to firm customers.

In its February 6, 2008 Order,[3] the Commission required all the natural gas utilities to make supplemental filings in their pending, 2007 annual demand entitlements dockets, addressing the issue of the inter-class allocation of Producer Demand (supplier reservation) fees and Storage costs. In that Order, the Commission stated:

> In the past, Minnesota gas utilities and regulators have generally treated Producer Demand and Storage costs as incurred for the benefit of firm customers and therefore properly allocated to and recovered from firm-service customers' rates. As the natural gas marketplace has become more complex, however, gas purchasing practices have changed, and it now appears that, at least in some cases, utilities are incurring Producer Demand and Storage costs not just to ensure reliable supplies for their firm service customers, but also to round out their supply portfolios and to cushion the price volatility associated with serving interruptible customers.

In the present docket, CenterPoint has stated the new storage:

- provides additional flexibility to handle load swings;
- provides price protection; and
- captures the usually favorable difference in summer prices versus winter prices.

Additionally, the FDD storage allows CenterPoint to make real time adjustments to daily supplies and provides for resolution of monthly imbalance volumes.

These features serve both firm and interruptible customers.

The baseline question underlying who should pay for the fixed costs related to the two new storage contracts is: Which customers are using these services?

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[3] ORDER ACTING ON CERTAIN GAS UTILITIES' ANNUAL REPORTS AND TRUE-UP PROPOSALS, DEFERRING ACTION ON OTHERS, AND REQUIRING SUPPLEMENTAL FILINGS IN RELATED DOCKETS, in the 2006 Annual Automatic Adjustment report, docket, Docket No. E,G-999/AA-06-1208 and the 2007 demand entitlement dockets of the individual natural gas utilities.

Staff notes that some storage services such as Northern Natural's FDD service, break their fixed fees down into Reservation fees (to reserve the maximum daily withdrawal amount) and Capacity fees (associated with the annual cycle storage capacity).

In their 2007 demand entitlement dockets, Docket Nos. G-002/M-07-1395 and G-004/M-07-1401, respectively, Xcel Energy and Great Plains Natural Gas Company, proposed allocating the fixed storage charge associated with the contractual share of the total annual cycle quantity to firm and interruptible customers based on sales volumes (like commodity costs are allocated), because they believed that interruptible customers as well as firm customers benefit from the use of storage gas. However, both Xcel Energy and Great Plains proposed to continue charging the fixed cost associated with the maximum daily quantity (MDQ) of gas that may be withdrawn as a demand charge allocated to firm customers only. The reasoning was that the reservation of the MDQ amount was contracted for to ensure availability of a specific volume of firm supply on a peak day to meet firm demand under design-day conditions. The Commission accepted both of their proposals. Minnesota Energy Resources Corporation and Interstate Power and Light both allocate all of their FDD storage fixed costs like commodity, where the costs are allocated to both firm and interruptible sales customers based on sales.

Here, CenterPoint explains that new storage provides added flexibility, price protection, resolution of monthly imbalance volumes, and captures the often favorable difference in summer prices versus winter prices. CenterPoint stated that these contracts serve both firm and interruptible customers with swing gas supplies.

Staff recognizes that the price hedging, flexibility and balancing that storage offers benefits interruptible, as well as firm, sales customers. The Commission could accept CenterPoint's reasoning that the fixed storage costs are like third party supplier reservation fees and should be split 75% to demand, 25% to commodity.

On the other hand, it could be argued that a 75% to demand, 25% to commodity split still allocates far too great a percentage to firm customers and that alternatively, all of the costs of the two new storage contracts should be allocated to commodity. This would allocate more of the storage costs to interruptible customers and the cost of the new contracts would be recovered in proportion to CenterPoint's sales to firm and interruptible customers.

Another alternative would be to allocate all of the fixed costs associated with the annual storage capacity to commodity (like Xcel and Great Plains do), and allocate the fixed costs associated with the maximum daily quantity that can be withdrawn from storage (like CenterPoint allocates its supplier reservation fees) with 75% to demand and 25% to commodity. This approach would also allocate more of the costs to interruptible customers than would CenterPoint's proposed allocation.

Variance to Minn. Rules, Part 7825.2700, Subp.5, Demand Adjustment - Should the Commission grant CenterPoint a variance to Minn. Rules, Part 7825.2700, Subp. 5, to allow for a one-month delay in implementing rate case test year demand volumes?

Minnesota Rules, Part 7825.2700, Subp. 5, Demand Adjustment, states the following:

> The demand adjustment is the change in the annual demand rate which results from a difference between the demand-delivered gas cost and the demand base cost. In the event the demand-delivered gas cost does not change, the demand adjustment must be recalculated for each 12-month period from the date of the last change. The adjustment must be computed using test year demand volumes for three years after the end of the utility's most recent general rate case test year. After this time period, the demand adjustment must be computed on the basis of annual demand volume.
>
> If a customer class is billed separately for demand, the demand adjustment must be computed on the basis of the demand component of the rate for that class and applied to the demand charge.

In its March 18, 2015 Response Comments, the Department raised a concern with CenterPoint's November 1, 2014 implementation of the rate case estimated annual demand volumes in the PGA, instead of in the December 1, 2014 PGA when final rates were scheduled to be implemented. The Department recommended that in Supplemental Reply Comments CenterPoint request a variance to Minn. Rules, Part 7825.2700, Subp. 5.

In its March 30, 2015 reply, CenterPoint stated in part:

> At the time of the implementation of the 2014-2015 demand entitlement change, proposed to be effective November 1, 2014, the Company's rate case test year was over. CenterPoint Energy's test year was defined as October 2013 – September 2014. At that point in time, any rate case sales forecast issues in dispute had been resolved for months, and the Company had no reason [to] believe the sales forecast would not be in effect for the next three years.
>
> …
>
> Because there was agreement and a Commission Order approving the Rate Case sales forecast, and the test year had already passed, CenterPoint Energy did not think implementing the rate case sales forecast required a rule variance. However, if the PUC agrees with the Department that a rule variance is required, the Company requests a variance to the rule.

Further, CenterPoint provided the following information to show that it meets the requirements for granting variances found in Minn. Rules, Part 7825.3200:

> *A. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;*
>
> Enforcement of the rule would impose an excessive burden because at this point in time the rates implemented in November cannot be changed. The difference between the costs incurred and the costs recovered are included in the true-up balances. Potential corrections including immediate bill credits or refunds would be complex, given the nature of this cost recovery mechanism.
>
> *B. Granting the variance would not adversely affect the public interest;*
>
> As noted above, granting the proposed variance will not adversely impact the public interest. The per-unit demand rate billed in November would have been lower than what was charged, but because the demand adjustment rule works to balance demand costs over an annual period, not a monthly period, a mismatch on demand costs is not uncommon. The difference impacts only the demand related true up balances, which by the same rule will be corrected as a revenue difference. Demand costs in general are over-collected during winter months and under-collected in non-heating months because the per-unit rate is based on total annual sales estimates, but are actually billed on monthly sales, which vary greatly from month to month.
>
> *C. Granting the variance would not conflict with standards imposed by law*
>
> CenterPoint Energy is not aware of any laws that would be violated by granting this variance.

In its April 24, 2015 Supplemental Response Comments, the Department stated that upon reviewing CenterPoint's reply, it realized that the Commission had previously issued an order clarifying the use of rate case test year volumes for the monthly demand adjustment. In its October 17, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-Up Proposals, Clarifying Requirements, and Setting Further Requirements,* Docket No. G999/AA-11-793, the Commission stated the following at page 6:

> When Minn. R. 7825.2700, subp. 5, states "The [demand] adjustment must be computed using test year demand volumes for three years after the end of the utility's most recent general rate case test year," the Commission clarifies that the three year period begins at the conclusion of the utility's rate case test year.

CenterPoint's most recent rate case test year was October 1, 2013 through September 30, 2014. Based on the above described Order, the Department concluded that CenterPoint should have implemented the test year demand volumes in its October 2014 purchased gas adjustment (PGA), not in the November PGA as CenterPoint did, or in the December PGA as the Department previously recommended.

The Department concluded that CenterPoint submitted sufficient information to grant a variance to Minn. Rules, Part 7825.2700, Subp. 5 to accommodate implementing the volume change a month later than required by the rule, even though CenterPoint provided information to vary the rule for implementing its demand volumes a month early, rather than a month late. The Department suggested modifying the request for a variance as follows:

> *A. Enforcement of the Rule Would Impose an Excessive Burden Upon the Applicant or Others Affected by the Rule*
>
> As noted in the Department's March 18, 2015 Response Comments, the adjustment to the demand volumes in the Company's rate case resulted in a demand volume decrease from 1,009,900,000 to 962,546,190 therms. This decrease in volumes results in a higher demand rate, which should have been implemented in October 2014 rather than November 2014. Enforcement of the rule would impose an excessive burden because at this point in time, the rates implemented in October cannot be changed. Imposing a surcharge to correct the October 2014 undercharge is possible but complex given the nature of this cost recovery mechanism, and burdensome given that the costs would otherwise be trued-up in the 2014-2015 Annual Automatic Adjustment (AAA) Report proceeding.
>
> *B. Granting the Variance Would Not Adversely Affect the Public Interest*
>
> As previously noted, the per-unit demand rate billed in October would have been higher than what was charged. This difference in the demand rate billed versus the demand rate that should have been charged was less than five percent and will be trued-up in the 2014-2015 AAA Report.
>
> *C. Granting the Variance Would Not Conflict with Standards Imposed by Law*
>
> CenterPoint Energy is not aware of any laws that would be violated by granting this variance.

<u>Staff Comment</u>
If the Commission determines that a variance to Minn. Rules, Part 7825.2700, subp. 5. is necessary to allow for a November 1, rather than October 1, implementation date, staff agrees with the Department that CenterPoint appears to meet the requirements for a variance.

Decision Alternatives

Should the Commission approve CenterPoint's proposed level of demand entitlement effective November 1, 2014?

1. Approve CenterPoint's proposed level of demand entitlement; and

2. Approve the design-day level proposed by CenterPoint; or

3. Do not approve CenterPoint's proposed level of demand entitlement and design-day level.

Should the Commission approve CenterPoint's proposed allocation of the fixed costs of two new storage contracts?

4. Approve CenterPoint's proposed allocation of the fixed costs associated with the two new storage contracts with 75% allocated to demand and 25% allocated to commodity. or

5. Require CenterPoint to allocate the fixed costs associated with the two new storage contracts 100% to commodity. or

6. Require CenterPoint to allocate:

   a) all of the new fixed storage costs associated with the annual capacity (amount) of gas that can be stored to commodity costs; and

   b) all of the new fixed storage costs associated with the maximum daily quantity that can be withdrawn (peak day deliverability) like supplier reservation fees, with 75% allocated to demand costs (allocated to firm customers only) and 25% allocated to commodity costs (allocated to firm and interruptible sales customers).

Should the Commission grant CenterPoint a variance to Minn. Rules, Part 7825.2700, Subp. 5, to allow for a one-month delay in implementing rate case test year demand volumes?

7. Approve a variance to Minn. Rules, Part 7825.2700, Subp. 5, to allow CenterPoint a one-month delay in implementing its test-year demand volumes. or

8. Decide CenterPoint does not need a variance to Minn. rules, Part 7825.2700, Subpart 5 to implement its test-year demand volumes on November 1, 2014. or

9. Do not approve a variance to Minn. Rules, Part 7825.2700, Subp. 5, to allow CenterPoint a one-month delay to implement its test-year demand volumes.