Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: March 6, 2014 .... *Agenda Item **# 5**

Company: CenterPoint Energy (CPE)

Docket No. G008/M-13-578
In the Matter of CPE's Request for Changes in Demand Entitlements

Issues: Should the Commission approve CPE's proposed level of demand entitlement effective November 1, 2013 and allow CPE to recover the associated demand costs through the monthly Purchased Gas Adjustment?

Staff: Sundra Bender 651-201-2247

Relevant Documents

CPE – Initial Filing (Public) .... July 1, 2013
DOC – Comments .... August 19, 2013
CPE – Reply Comments .... September 9, 2013
CPE – Supplemental Demand Entitlement .... October 31, 2013
CPE – Supplemental Adjustments .... December 18, 2013
DOC – Response Comments .... February 4, 2014

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 proposed level of demand entitlement effective November 1, 2013 and allow CenterPoint Energy (CPE or the Company) to recover the associated demand costs through the monthly Purchased Gas Adjustment (PGA)?

Minnesota Rules

Minnesota Rules 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.

Minnesota Rule part 7825.2910, Subp. 2, Filing upon a change in demand, is included in the Automatic Adjustment of Charges rule parts 7825.2390 through 7825.2920 and requires gas utilities to file to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.

Minnesota Rule 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 and Party Positions

On July 1, 2013, CPE requested approval to implement changes in its Demand Units effective November 1, 2013. CPE added 2,625 dekatherms (DT) of entitlements for the winter season, with a corresponding increase of 1,740 DT in the summer. The majority of these additions were off of Northern Natural Gas' (NNG) Willmar branch line where capacity is tight and growth is expected. Additionally, a one-year capacity release of 1,500 units expired, which was added back to the Company's entitlement portfolio. CPE also retired its Coon Rapids Propane Peaking Plant in June 2013, decreasing its propane peak day capacity by 9,167 DT. The Company determined that this facility is not required for supply purposes at the Coon Rapids location because that location has sufficient demand entitlement (pipeline) capacity. With all of these changes combined, CPE proposed an overall decrease in peak day capacity of 5,042 DT from 1,344,981 DT to 1,339,939 DT.

Further, CPE allowed 30,000 dekatherms/day, or 50%, of its SMS service for protection against out of balance charges on NNG to expire on October 31, 2013. The Company's filing did not reflect the updated NNG Base/Variable split or the final Reservation Fee cost estimate. CPE stated that updates will be noted in supplemental filings.

On August 19, 2013, the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC), filed comments. The Department concluded that CPE's proposed level of demand entitlement is reasonable. However, the Department requested that CPE provide, in Reply Comments, the cost/benefit analysis the Company used to arrive at the decision to allow the contract for 30,000 dekatherms/day of SMS expire. The Department also concluded that CPE's decision to retire the Coon Rapids Peaking Plant is reasonable and stated, "Since the Coon

Rapids TBS[1] currently has sufficient capacity, there should be no replacement costs for fuel or facilities." [Footnote added.] The Department recommended that the Commission:

- Approve CPE's proposed level of demand entitlement subject to supplemental filing(s) by the Company related to the reallocation of units between TF-12 Base and TF-12 Variable services and the final Reservation Fees cost estimate;
- Accept the proposed changes to non-capacity items;
- Accept the design-day level proposed by CPE; and
- Approve the proposed demand costs with an effective date of November 1, 2013.

On September 9, 2013, CPE filed reply comments. The Company accepted the Department's recommendations and explained the analysis it performed when it decided to let the System Management Service (SMS) contract expire. CPE provided a comparison of the actual SMS and penalty (daily delivery variance charges, or DDVC) costs ($8,247,212) it incurred over the past 5 years with 60,000 Dth/day of SMS, to the SMS and DDVC costs it would have incurred over the same period ($5,359,700) had it had only 30,000 Dth/ day of SMS as it proposes in this docket.

CPE also provided a discussion about using the coldest temperature in the past 20 years for forecasting the design day. CPE stated that it uses a temperature of minus 25 degrees, which is based upon the coldest days that have occurred during the last 100+ years. The Company believes relying on the lowest daily temperature from only the last 20 years is too risky for this type of forecast.

On October 31, 2013, CPE filed a supplement including updated schedules incorporating changes since its initial filing. Specifically, CPE:

- Updated the allocation of NNG TF 12[2] entitlements between TF-12 Base and TF-12 Variable rates effective November 1, 2013;
- Contracted for additional entitlement in Springfield, MN where customer demand necessitated additional units;
- Updated the seasonal supply reservation schedule for the upcoming winter season;
- Updated the NGPL[3] cost allocation between Firm and Small Volume Dual Fuel (SVDF) customer classes due to changes in sales estimates;[4] and
- Updated annual firm sales volume used as the denominator in purchased gas demand rate calculations.

On December 18, 2013, CPE provided revised exhibits and supplemental information including minor corrections to the NNG Base/Variable split and backhaul charge calculations, as well as

[1] Town Border Station
[2] NNG TF 12 refers to a year-round (i.e. 12-month) firm transportation contract on the Northern Natural Gas Company pipeline.
[3] NGPL refers to the Natural Ga7s Pipeline company, an interstate pipeline located upstream from the Northern Natural.Gas Company pipeline.
[4] In its February 28, 2012 Order in Docket Nos. G008/M-07-561 and G008/M-11-1078, the Commission approved CPE's proposal to allocate 65.69% of NGPL storage costs to firm and small volume dual fuel customers based on sales volumes, with the remaining 34.31% to be included in commodity costs and allocated to all sales customers based on sales volumes.

the shifting of SMS charges from demand costs to commodity charges in the December PGA pursuant to the Commission's November 14, 2013 Order in Docket G-999/AA-12-756.

On February 4, 2014, the Department filed response comments. The Department stated that it is satisfied with the answers provided in CPE's reply comments and that it has no more comment on the additional information. The Department also indicated it has reviewed CPE's October 31, 2013 and December 18, 2013 supplemental filings. The Department concluded that the proposed changes are reasonable and recommended that the Commission:

- approve CenterPoint's proposed level of demand entitlement;
- accept the proposed changes to non-capacity items;
- accept the design-day level proposed by CenterPoint; and
- approve the proposed demand costs with an effective date of January 1, 2014.

Staff Comment

Coon Rapids Peak Shaving Plant

As discussed above, CPE retired its Coon Rapids Propane Peaking Plant in June 2013. According to CenterPoint, the plant was the last in order of plant dispatch and contained a significant amount of old manual and labor intensive equipment. CenterPoint estimated that $600,000 to $700,000 investment would be needed to reliably count on this facility. Further, CenterPoint stated that this facility is not required for supply purposes because the Coon Rapids location has sufficient capacity.

Staff agrees with the Department that there should be no replacement costs for fuel since the Coon Rapids TBS currently has sufficient capacity. Peak shaving facilities' operating and maintenance costs are generally part of base "non-gas cost" rates, rather than the cost of gas rates adjusted through the PGA.[5] Staff notes that CenterPoint is currently involved in a general rate case proceeding, Docket No. G-008/GR-13-316. Rate recovery of the cost of facilities will be determined in the general rate case, which has a test year of October 1, 2013 through September 30, 2014. Since the Coon Rapids Peaking Plant was retired prior to the beginning of the test year, the facilities costs would not be included in the test year or the interim rates effective October 1, 2013.

It does not appear to staff that any adjustments, to proposed demand gas cost recovery effective November 1, 2013, need to be made in the instant docket to reflect the retirement of the peaking plant.

Reserve Margin

The Department states that CPE's proposed reserve margin is 1.20 percent. CPE's petition

[5] The difference between the cost of propane or fuel consumed in the manufacture of gas during the heating season and the base cost of peak shaving and manufactured gas base cost is recoverable through the automatic adjustment and true-up mechanism, pursuant to Minn. Rules, part 7825.2700, subpart 6, peak shaving and manufactured gas adjustment.

provides a reserve margin range from 1.2% to approximately 4%. The difference between CPE's revised[6] total peak day capacity of 1,340,099 DT and its calculated design day of 1,288,000 DT is 52,099 DT, or approximately 4%. The difference between CPE's revised total peak day capacity and the combined requirements of its design-day plus a physical reserve requirement of 36,000 DT, is 16,099 DT, or approximately 1.2%. Based on its analysis, the Department stated that it believes that CPE likely has sufficient capacity to serve needs on an all-time peak day.

Approvals and Effective Date

One of the Department's recommendations, in its August 19, 2013 comments, was that the Commission approve the proposed demand costs with an effective date of November 1, 2013. In its February 4, 2014 response comments, the Department changed the recommendation and recommended that the Commission approve the proposed demand costs with an effective date of January 1, 2014.

CPE updated its proposed changes in its October 31, 2013 Supplemental filing and its November 2013 PGA. Additionally, in its December 18, 2013 supplement, CPE made a couple of minor corrections in its January PGA[7] due to billing clarifications from Northern Natural Gas. It appears to staff that the demand contract changes went into effect on November 1, 2013, and CPE implemented the changes in its November PGA, with a few minor errors, which it corrected in its January 2014 PGA.

Base gas costs are adjusted monthly through the PGA and are annually reconciled to actual gas costs through the annual PGA true-up. Staff believes the proposed changes in demand are effective November 1, 2013, and that CPE should be allowed to recover the associated costs through the PGA effective November 1, 2013. The fact that CPE needed to make some corrections in its January PGA should not change the allowed effective date of the changes in demand.

Decision Alternatives

1. Approve CenterPoint's requested changes in demand effective November 1, 2013. [CPE]

   or

2. Approve CenterPoint's proposed level of demand entitlement. [DOC]

3. Accept the proposed changes to non-capacity items. [DOC]

4. Accept the design-day level proposed by CenterPoint. [DOC]

5. Approve the proposed demand costs with an effective date of January 1, 2014. [DOC]

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[6] As shown in CPE's October 31, 2013 Update and its December 18, 2013 Supplement.

[7] CPE also decreased demand costs in its December 2013 PGA by shifting $784,800 of SMS (balancing service) charges to commodity charges pursuant to the Commission's November 14, 2013 Order in Docket No. G-999/AA-12-756 (as opposed to a proposed change).

or

6. Approve alternatives 2, 3 and 4 above and replace alternative 5 with the following:

   Allow recovery of the associated demand costs through the monthly PGA, effective November 1, 2013. [Staff]

Staff Recommendations

Staff recommends Alternative 6.