



June 2, 2008

MEMOTO: Thomas Brocato, Georgia Crump
FROM: Karl Nalepa
SUBJECT: CenterPoint Energy Entex, Texas Coast Division
2008 Rate Case Report

On March 6, 2008, CenterPoint Energy Entex, Texas Coast Division (“Entex” or “Company”) filed with its cities a request to increase its annual revenues from standard rate classes by \$7,357,609.¹ The proposed revenue increase by class² is summarized in Table 1:

Table 1

Customer Class	Proposed Change
Residential	\$7,011,627
Small General Service	\$345,990
Large Volume General Service	\$0
Total (1)	\$7,357,617

(1) Difference between \$7,357,609 and \$7,357,617 due to rounding.

This revenue increase also includes a reduction of \$415,818 for the special contract classes that is included in the increase to the standard rate classes.³

RJ Covington Consulting (“RJC”), on behalf of the Gulf Coast Coalition of Cities (“GCCC”), was retained to address the following issues related to the rate filing:

- ◆ class cost allocation
- ◆ rate design
- ◆ select cost of service issues
- ◆ tariffs, including Cost of Service Adjustment (“COSA”), Purchased Gas Adjustment (“PGA”), and Tax Adjustment (“TA”)
- ◆ other issues as directed by legal counsel

¹ Schedule 1, line 7.

² DePena Direct, p. 11, Table 3.

³ Schedule 1. Difference between total pro forma revenue increase and Standard Service pro forma revenue increase = \$6,941,791-\$7,357,609 = (\$415,818).

RJC's cost allocation and rate design recommendations are based on recommendations of GCCC consultants Connie Cannady for plant, expense and revenue adjustments and Randy Woolridge for rate of return adjustments.

Class Cost Allocation

RJC recommends two adjustments to Entex's method of allocating costs between customer classes. First, the Company's peak design-day method to allocate capacity-related costs should be replaced by the Seaboard method. Second, the Company's Minimum System method to allocate customer-related costs should be revised to reflect a more reasonable cost allocation.

Entex proposes to allocate the capacity-related component of distribution mains costs using a peak design-day. The Seaboard method is an alternative method to allocate these costs. This method is a commonly used capacity allocation method for gas utilities which apportions the fixed capacity-related costs equally between annual volumes and design-day demands. Equal apportionment using these two usage characteristics is based on the notion that both peak-day and annual volumes of gas use have significant impacts upon the costs of providing service, and that neither one is more important than the other. The facilities are sized to supply the maximum demand but are built to supply service not only on the few peak days but on all days throughout the year.

Stated another way, the capital outlay is made and justified not only for service on peak days but for service throughout the year. If costs are assigned wholly to the capacity function, the gas service used by off peak users will not share in any of the fixed costs. The impact on the allocation of mains investment under the Company's approach and RJC's recommendation is shown in Table 2:

Table 2

Customer Class	Company Adjusted Design-Day	RJC Seaboard
Residential	80.557%	70.145%
Small Commercial & Industrial	7.979%	9.934%
Large Commercial & Industrial	8.514%	12.157%
Transport	2.950%	7.764%
Total	100.000%	100.000%

Entex classifies distribution mains as a function of both the number of customers and distribution system peak demands.⁴ To determine the customer component, the Company employed the Minimum System methodology. Using the most commonly installed 2 inch pipe, it calculated that approximately 74% of mains costs are customer-related and 26% are capacity-related.⁵

⁴ DePena Direct, p. 22.

⁵ DePena Direct, p. 22-23.

The American Gas Association’s *Gas Rate Fundamentals* cost allocation manual defines the minimum system as a “skeleton” system adequate to supply a usable pressure to the customers⁶. When asked in discovery whether the Company’s proposed methodology reflected normally installed facilities or a “skeleton” system, it responded that the 2 inch main is the “predominant” size installed over the Texas Coast Division.⁷ Company data suggests that 2 inch pipe accounts for over 77% of the system’s footprint.⁸

However, the data also shows that the Company has over 150 miles (795,992 feet) of installed mains with a diameter of 1¼ inch.⁹ RJC contends that these facilities can reasonably represent the skeletal system required to deliver an adequate supply of gas to customers at a usable pressure. Using the 1¼ inch pipe as representative of the minimum system results in a customer-related component of approximately 29% of the cost of distribution mains.

RJC also surveyed other cost of service analyses to benchmark the reasonableness of Entex’s minimum system analysis. In its recent filing, Texas Gas Service calculated a customer-related component of 62.04% using the minimum system method. The Final Order compliance cost of service study by Atmos Energy Corporation, Mid-Tex Division in GUD 9670 determined that 46.06% of mains costs are customer-related. Considering these results along with that proposed by Entex, RJC recommends that the average of the three, yielding a customer-related percentage of 60.72%, be used for the allocation of the customer component of distribution mains. Table 3 shows this average:

Table 3

Company	Customer Related Component
Entex	74.05%
Atmos	46.06%
TGS	62.04%
Average	60.72%

Rate Design

Entex currently does not have uniform rates for customers having similar operating characteristics in the Texas Coast Division. Residential customers in one city may have a different set of rates applied than a similar residential customer in a different city. These differences are also true for the commercial classes. RJC agrees that the

⁶ *Gas Rate Fundamentals*, American Gas Association, 1960, page 133.

⁷ Entex response to GCCC 3-16.

⁸ DePena Exhibit TxC-2.

⁹ DePena Exhibit TxC-2.

Company's proposal to establish division wide base rates be adopted if possible.¹⁰ RJC also agrees with Entex's proposal to remove the summer/winter rate differential for residential rates.¹¹ Finally, Entex's base rates include an embedded amount of \$3.8311 per Mcf in gas costs,¹² and RJC agrees with Entex's proposal to move the base rate portion to the Purchased Gas Adjustment ("PGA") and recover all purchased gas costs through the PGA rather than through base rates.¹³

RJC's own cost of service study supports the retention of current customer charge levels. For the preponderance of residential customers, the current customer charge is \$11.98 per month, and RJC proposes that this charge be applied to all residential customers within the Texas Coast Division. In addition, the current residential commodity charges include up to five declining blocks. While the Company simply proposes reducing the number of blocks, RJC proposes a flat commodity charge for all gas usage. Table 4 compares the Company's proposed residential rate design with the RJC recommendation.

Table 4

Residential Rate Comparison	Company Proposed	RJC Recommended
Customer Charge Based on Cost Study	\$14.57	\$11.98
Design Customer Charge	\$14.50	\$11.98
Block 1: 0 - 30 Ccf	\$ 0.0704	\$ 0.0486
Block 2: 31+ Ccf	\$ 0.0536	\$ 0.0486

* Average usage = 38 Ccf per month

RJC proposes similar rate adjustments for the commercial classes. That is: 1) establish division wide base rates, 2) retain current customer charge, and 3) eliminate declining block rates. Tables 5 and 6 provide comparisons of the Company's proposed rates with the RJC recommendation for small and large commercial customers.

Table 5

Small Commercial Rate Comparison	Company Proposed	RJC Recommended
Customer Charge Based on Cost Study	\$11.85	\$10.90
Design Customer Charge	\$12.50	\$12.48
Block 1: 0 - 150 Ccf	\$ 0.1103	\$ 0.0543
Block 2: 151+ Ccf	\$ 0.0367	\$ 0.0543

* Average usage = 138 Ccf per month

¹⁰ DePena Direct, p. 15.

¹¹ DePena Direct, p. 18.

¹² See, for example, Entex rate schedule R-2042-1.

¹³ DePena Direct, p. 15.

Table 6

Large Commercial Rate Comparison	Company Proposed	RJC Recommended
Customer Charge Based on Cost Study	\$47.37	\$54.59
Design Customer Charge	\$12.50	\$12.48
Block 1: 0 - 1,500 Ccf	\$ 0.09040	\$ 0.06710
Block 2: 1,501 - 10,000 Ccf	\$ 0.05880	\$ 0.06710
Block 3: 10,001+ Ccf	\$ 0.04980	\$ 0.06710

* Average usage = 4,206 Ccf per month

Select Cost of Service Issues

RJC was asked to assist in evaluating the impact of recovery of natural gas storage costs in rates. Entex entered into a natural gas storage agreement during the test year and is seeking recovery of a return on its average cost of gas in storage. Entex has proposed recovery of a return in two ways. First, as an inventory item reflected in rate base, or second, as a component of the PGA mechanism.¹⁴

As a base rate item, Entex's 12 month average storage inventory balance during the test year was \$6,632,355.¹⁵ Entex then adjusted the test year amount to reflect a pro forma rate year by projecting monthly storage balances and cost of purchased gas through December 2008.¹⁶ The proposed pro forma 12 month average storage balance is \$21,584,014.¹⁷ As a component of the PGA, Entex proposes to include a carrying charge based on the average monthly balance of gas in storage inventory. The carrying charge is calculated using the pre-tax rate of return as determined in this proceeding.¹⁸

RJC agrees that recovery of a return on the average storage inventory balance is reasonable, but recommends that storage inventory be included only in rate base and not the PGA. Materials and Supplies ("Inventories") are a rate base item in traditional rate of return ratemaking.¹⁹ The typical accounting method for determining natural gas storage inventories is using a 13 month average test year amount. Entex, however, entered into new storage agreements in May 2007,²⁰ so a 13 month average would not accurately

¹⁴ DePena Direct, p. 15-16.

¹⁵ Schedule 2e, line 2.

¹⁶ Workpaper 2e/1, page 1.

¹⁷ Schedule 2e, line 1.

¹⁸ Exhibit A, Rate Schedule No. PGA-5.

¹⁹ See, for example, *Rate Case and Audit Manual*, NARUC Staff Subcommittee on Accounting and Finance, 2003.

²⁰ Entex response to GCCC 6-3.

reflect the actual usage of the storage capacity since there were only minimal volumes of gas in storage prior to May, and the winter withdrawal period had not yet occurred.²¹

GCCC consultant Connie Cannady estimated the appropriate value for gas in storage inventory to be \$11,589,099. This amount reflects the value of the actual January 2008 ending balance for gas in storage.²² Until the Company experiences adequate operating data regarding its storage capacity, using the most recent ending balance is a reasonable estimate for ratemaking purposes.

RJC recommends that the Cities reject Entex's alternative proposal to collect a return on the average monthly storage balances through the PGA. Return on inventory items is not appropriate for recovery through the PGA, as the PGA should be limited only to the flow-through of part or all of a utility's gas costs.²³ "Return on an asset" is a rate base concept not a gas cost concept. Furthermore, as the PGA is proposed, the return component would be included in a deferred purchased gas cost account, with a carrying charge or credit applied to the average monthly balance in the account. Therefore, there is the possibility that the Company will collect both a return on the inventory balance AND a carrying charge on the return, if return is in the PGA.

However, recognizing that the actual return on storage inventory may be difficult to accurately estimate with the limited operational data available, RJC suggests that if the Cities desire, the estimated \$11,589,099 inventory value can be included in base rates, but the return on any incremental amount above or below the base rate amount be recovered through the PGA on a transitional basis. This proposal must be made with the understanding that the PGA component would be removed at the next base rate change.

Cost of Service Adjustment (COSA)

Entex currently has a Cost of Service Adjustment ("COSA") in 37 of 47 cities in the Texas Coast Division. In the 10 cities without a COSA, Entex files an annual statement of intent to change rates.²⁴ The current COSA is the same for 33 of the cities and exists with certain limited notice and review provisions in 4 cities (Alvin, Jones Creek, LaPorte, and Wharton).²⁵ The COSA has been in effect for many of these cities since 1978.²⁶

²¹ Workpaper 2e/1, page 3.

²² Entex response to GCCC 6-2.

²³ 16 Texas Administrative Code § 7.5519.

²⁴ Entex response to GCCC 4-1. Cities without a COSA are: Angleton, Baytown, Clute, Freeport, Friendswood, LaMarque, League City, Pearland, Seabrook, and Texas City.

²⁵ Entex response to GCCC 4-2.

²⁶ DePena Direct, p. 16.

The existing COSA is implemented on an annual basis by adjusting the customer charge upward or downward for changes in Entex's cost of providing gas service (including depreciation but excluding cost of gas, gross receipts taxes, income taxes and return). The calculation compares the costs for the previous year ending December 31 to the costs incurred in the second prior calendar year, and the annual adjustments are cumulative. The operating expenses used in this computation are those reported to the Railroad Commission of Texas ("Commission") in the annual report of the Company.²⁷

Entex proposes to revise its COSA to bring consistency among all the Texas Coast Division cities and to include additional items for adjustment, including return and taxes.²⁸ However, the Company has also fundamentally changed its method of calculating the customer charge adjustment. Its proposal would sum the calendar year operating expenses, return on year end investments, and Texas franchise taxes, then subtract calendar year actual non-gas revenue and other revenues. The difference would be divided by calendar year average number of customers, and then by 12 to determine the monthly adjustment to the customer charge. The Company's annual filing would occur no later than May 15. Once filed, the regulatory authority would have 45 days to review the adjustment prior to it taking effect.²⁹

RJC recommends that the COSA be denied for the Texas Coast Division. The COSA as proposed, while providing a limited window for review, does not include sufficient protections to the cities to ensure that the rates set are just and necessary as required by statute.³⁰ The level of detail regarding the components at issue are not sufficient to determine whether the costs and revenues are reasonable, as the only source document provided by the Company would be its summary annual report to the Commission. No supporting testimony would be filed.³¹ Furthermore, none of the costs will be adjusted or normalized to recognize non-recurring or partial year expenses, and revenues will not be normalized to account for weather or customer impacts.³² Even specific details of the proposed COSA raise questions. For example, the return would be calculated on the calendar year ending rate base rather than the average rate base, yet average rate base would be more consistent with the other elements of the calculation. There is no rate cap or other consumer safeguards contemplated in the event there is a large increase in costs. Finally, there are no customer notice provisions anticipated.³³

²⁷ See, for example, Entex rate schedule R-2042-1.

²⁸ DePena Direct, p. 17.

²⁹ Exhibit A, Rate Schedule No. COSA-1.

³⁰ Tex. Util. Code Ann. § 104.003 (Vernon 2007).

³¹ Entex response to TCUC 3-20.

³² Entex responses to GCCC 4-9, 4-10, and 4-11.

³³ Entex response to TCUC 3-17.

It is also important to note that Entex does not consider a COSA filing a “statement of intent” as contemplated in the statutes,³⁴ and suggests that none of the requirements under a statement of intent filing are applicable to a COSA filing.³⁵

Another element to consider in denying the COSA is that Entex does not have a COSA in its Houston,³⁶ Beaumont/East Texas or South Texas Divisions.³⁷ Furthermore, Commission precedent is not to approve a COSA, and in fact, CenterPoint has no COSA in any environs it serves in Texas.³⁸ In a presentation to its Board of Directors in July 2006, Entex suggested that one of the goals of this Texas Coast Division rate case was to make its rate recovery mechanisms consistent with its other Texas divisions, including elimination of the cost of service adjustment.³⁹

Purchased Gas Adjustment (PGA)

Entex’s PGA currently is adjusted up or down to reflect 1) changes in its cost of gas per unit sold and 2) changes in gross receipts taxes resulting from such increases or decreases in the net monthly rate. For purposes of calculating this adjustment, the cost of natural gas includes the cost of gas supplies purchased for resale, upstream transportation charges, storage charges, the cost of gas withdrawn from storage less the cost of gas injected into storage, any transaction related fees, gains or losses and other transaction costs associated with the various financial instruments used by Entex to stabilize prices. If the Company receives any refunds of any increased cost of purchased gas that have been passed on under the PGA, a refund is made to consumers served by the rate schedule.⁴⁰ The current PGA assumes that \$3.8311 per Mcf is included in base rates, as discussed in the Rate Design section of this Report.

Entex now proposes several changes to its PGA. First, to move the base rate portion of gas costs to the PGA and recover all purchased gas costs through the PGA rather than through base rates.⁴¹ Second, to include a return on monthly average gas storage inventory, and third, to establish a deferred purchase gas cost account to record the balance of over and under recoveries of the PGA. The balance would be subject to a

³⁴ Tex. Util. Code Ann. § 104.102 (Vernon 2007).

³⁵ Entex response to TCUC 3-22.

³⁶ Entex response to TCUC 1-1.

³⁷ Entex response to Baytown 1-2.

³⁸ Entex response to GCCC 4-6.

³⁹ Entex response to GCCC 8-3, p. 21.

⁴⁰ See, for example, Entex rate schedule R-2042-1.

⁴¹ DePena Direct, p. 15.

carrying charge equal to the rate of interest applicable to customer deposits.⁴² This rate is 4.69% for calendar year 2008.⁴³

RJC agrees with Entex's proposal to move the base rate portion of gas costs to the PGA and recover all purchased gas costs through the PGA rather than through base rates. RJC also does not oppose the proposed deferred purchase gas cost account at the requested carrying charge. This is typical practice among gas utilities maintaining an over or under recovery balance for its PGA and is consistent with the PGA in place in other Entex divisions.⁴⁴ However, as discussed in the Select Cost of Service Issues section, RJC recommends that the Cities reject Entex's proposal to collect a return on the average monthly storage balances through the PGA. Return on inventory items is not appropriate for recovery through the PGA, as the PGA should be limited only to the flow-through of part or all of a utility's gas costs. As discussed earlier, the proposed return on storage inventory should be recovered in base rates, not the PGA. In addition, RJC recommends that the language "if the Company receives any refunds of any increased cost of purchased gas that have been passed on under the PGA, a refund is made to consumers served by the rate schedule," be retained from the current PGA schedules to explicitly require refunds on overpayment for gas to be flowed through to consumers.

Tax Adjustment (TA)

Entex currently recovers its state gross receipts taxes ("GRT") and city franchise fees ("FF") through its base rates, except for certain gross receipts taxes collected on gas revenues through the PGA. These are charged on a division-wide average basis.⁴⁵ Entex now proposes to collect all of its GRT and FF through a separate tax adjustment so that these can be collected specifically from the customers that incurred the taxes and fees, and only the actual amount of taxes and fees are collected.⁴⁶

RJC supports a separate rider as this is typical practice among gas utilities, but because state gross receipts taxes and city franchise fees are collected from different groups of customers, RJC recommends that separate riders be established under which these taxes and fees are collected. Furthermore, the tax adjustment as proposed is much too broad and would allow the Company to include:

⁴² Exhibit A, Rate Schedule No. PGA-5.

⁴³ Railroad Commission of Texas, *Gas Utilities Information Bulletin*, No. 835, January 10, 2008.

⁴⁴ Entex response to TCUC 4-2.

⁴⁵ DePena Direct, p. 18.

⁴⁶ Exhibit A, Rate Schedule No. TA-5.

“any tax, charge, impost, assessment or fee of whatever kind and by whatever name (except ad valorem taxes and income taxes) levied upon the Company by any governmental authority under any law, rule, regulation, ordinance, or agreement.”⁴⁷

This language must be limited to the specific gross receipts taxes contemplated to be collected. The tax adjustment can be revised later if a new tax or fee is imposed.

In the alternative, should the Cities desire, the current levels of GRT and FF can remain in base rates, but any incremental amount above or below the base rate amount be recovered through the tax and franchise fee riders. This allows the Company to collect any new incremental tax, but still ensures that it collects only the actual amount of taxes and fees necessary and also minimizes the effect on rates of moving these costs out of base rates.

We are happy to discuss in more detail any of the findings and recommendations reflected in this Report.

⁴⁷ *Id.*