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Robert G. Towers
Basil L. Copeland, Jr.
David E. Peterson

June 22, 2007

via eMail and US Mail
David A. Jacobson, Utility Analyst
South Dakota Public Utilities Commission
500 E. Capitol Avenue
Pierre, South Dakota 57501

RE: Report and Consulting Services Proposal
NorthWestern Energy - Proposed Increase in Gas Service Rates
SDPUC Docket No. NG07- 013

Dear Dave:

Thank you for sending NorthWestern Energy's recent rate filing for our review and preparation of the following proposal. Basil Copeland has reviewed the Company's cost of capital evidence and I now have examined all of the other testimony, exhibits and filing statements.

OVERVIEW OF THE FILING

By letter dated June 1, 2007, NorthWestern Energy ("NWE" or "the Company") filed with the Commission an Application seeking an increase in rates for gas service to its approximately 42,500 customers in South Dakota. Based on a 2006 calendar year Test Year, normalized and adjusted for ratemaking purposes, the proposed rates were designed to increase its annual revenue from these customers by $3,682,377, representing an increase in customer bills – which include PGA charges that are not affected by the filing -- of 5.5%. Measured against the non-PGA portion of customer bills (i.e. the Company's "base rate" charges), the proposed increase is 31.61%. (Decker testimony, p. 16). The proposed effective date for the new rates is August 1, 2007.

The Company's presently-effective base rates were made effective on December 1, 1999 as a result of the Commission's approval of a Settlement

Agreement between the Company (then Northwestern Public Service Company, or "NWPS") and Commission Staff in Docket No. NG99-002. That filing and the Settlement Agreement were based on a 1998 test year.

The Company provides both gas and electric service to customers in South Dakota but only its gas rates are addressed in this filing. The Company also provides gas service to customers in Nebraska and, as a result of acquisitions from the former Montana Power Company in 2002, the Company provides transmission and distribution services to both electric and gas customers in Montana.

The revenue requirement determination filed in support of NWE's proposed rates is developed from a "per books" base year ended December 31, 2006 with adjustments to normalize the effects of abnormal weather conditions, to treat the former Nekota Pipeline customer loads and facilities' investments as part of NWE's regular gas utility operations and to reflect the recent acquisition of the gas system of the City of Freeman and the related pipeline system of Associated Milk Producers, Inc.. Other adjustments are made to eliminate certain advertising, organization dues and lobbying costs and costs associated with non-utility activities. Labor costs are increased by 3% based on historical experience; a net reduction in depreciation expense is made to reflect the implementation of revised depreciation rates (with significant reductions in the rates used for Distribution Mains; a reduction in South Dakota Ad Valorem taxes charged to gas operations is made to reflect a change in the method of allocating these taxes between gas and electric operations; a five-year amortization of the estimated cost of this rate case is provided for; and, expenses are increased to reflect a three-year amortization of long-term incentives granted in 2006 to officers and management employees. An allowance for Federal income taxes is determined by applying the statutory 35% corporate rate to South Dakota gas utility taxable income determined on a "stand-alone" basis. (Statement N, pp. 3-6)

After these normalizing and other adjustments, South Dakota gas utility Operating income with existing rates is claimed to be $2,392,948, equivalent to a 4.50% rate of return on an adjusted (primarily for the plant acquisitions as shown on Statement N, p. 6) average rate base. Using the NorthWestern capital structure ratios and South Dakota senior capital costs, the Company claims that this rate of return is equivalent to a 2.52% return on common stockholders' equity. Claiming that its cost of common equity is 11.25%, requiring an 8.99% return on rate base (see Statement N, p. 2), the Company calculates that the additional income required and the associated income taxes on the revenue required to produce that income establishes its request for a rate increase that will generate an additional $3,682,377 of revenue. (Statement M; Statement N, p. 1).

The Company has presented a class cost of service study ("CCOSS") for the South Dakota jurisdiction and has relied on the study results to allocate the requested increase among the three classes of gas service customers – Residential, Small Commercial and Large Commercial. Revenues from Transportation service customers having "Contracts with deviations" (CWD) are not increased and are treated as a credit to the overall revenue requirement and allocated to the gas service and other transportation service classes (Statement O, p. 9, line 25). The Company's allocations result in an approximately uniform 31% increase in base rate (non-gas cost) charges to each class. However, the unit charges within the rate schedules are not uniform and include much larger increases in the fixed monthly Customer Charges. For example, the existing Residential Customer Charge of \$6.00 is proposed to be increased to \$8.00 based on a claim that relevant costs amount to \$14. Corresponding amounts for Small Commercial customers are \$7 (present), \$9 (proposed) and \$16 (underlying cost). Revenues not recovered by these changes would be recouped through higher delivery charges – primarily in the initial volumetric block. (Decker testimony, pp. 15-18).

In addition to the tariff changes arising out of the claimed revenue requirement and CCOSS, the Company is proposing new rules that would determine customer responsibilities for the cost of new attachments to the system and, separately, connection/reconnection charges.

POTENTIAL ISSUES

Operating Income

NorthWestern Energy's filing raises issues similar to those which Staff has dealt with in most other general rate filings – the development of a revenue requirement determination based on actual experience but reflecting a myriad of adjustments purported to reflect known and measurable changes. Each of the major adjustments needs to be evaluated to determine its validity and to assess whether or not it maintains the balance of test year sales levels, operations productivity, price levels and investments. Adjustments here that are not routinely encountered include the requested changes in depreciation rates (a net reduction); the new allocations of the cost of activities shared by operations in other jurisdictions, utility and non-utility operations and by gas and electric operations in South Dakota; and, the possible effects of accounting changes made as the Company emerged from Chapter 11 bankruptcy in 2004.

And, additional adjustments should be explored. For example, while the Company calculates a Federal income tax liability as if the utility were a single, stand-alone taxpayer, taxed at the corporate rate of 35% of its own "taxable income", the fact is that it is but one member of a group on whose behalf only one tax return is filed with the IRS -- the tax return filed by NorthWestern Corporation. The tax paid by NWCorp. in 2006 amounted to $825,000 – about one-half of the $1.657 million the Company claims it requires for its South Dakota gas operations alone. (Statement M, column g). Moreover, the Company reports that, as of December 31, 2006 NWCorp. has $418.1 million in past losses that may be carried forward to reduce taxable income in future years (see Application – Notes to Financial Statements, Note 14). In other cases in South Dakota and other jurisdictions, we have recommended an adjustment to recognize consolidated tax savings if such savings are a recurring phenomenon.

Rate Base

The Company claims no rate base allowance for Cash working capital but acknowledges that its own analyses indicate that those requirements for *investor-supplied* capital are negative, i.e. that customers payments relative to service rendered are received prior to the related cash required for disbursements to suppliers. The negative allowance should be determined and used to reduce rate base.

Cost of Capital

Testimony on rate of return and cost of capital is presented by Michael J. Vilbert, who recommends an 11.25 percent ROE, the midpoint of a range from 10.75 percent to 11.75 percent. Basil Copeland believes that Mr. Vilbert has substantially overstated the cost of equity. Superficially, Mr. Vilbert uses two common methods of estimating cost of equity capital for public utilities -- the Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) -- but implements each in rather distinctive and unusual ways. The following discussion highlights some of the issues with Mr. Vilbert's analyses.

Discounted Cash Flow (DCF) -- In its simplest form, the DCF method imputes a utility's cost of equity capital from the sum of its stock dividend yield and expected dividend growth rate. In practice, this is usually applied to a sample of "comparable" companies. Mr. Vilbert employs a sample of nine (9) natural gas distribution companies. His Table 1, on Page 26 of his Direct Testimony, conveniently summaries the characteristics of the sample companies. Where possible, we prefer to utilize the same sample of companies as the Applicant to minimize the range of issues or distinctions between our evidence and the Applicant's. The sample of companies chosen by Mr. Vilbert appear to be broadly representative of market traded natural gas distribution companies, and probably will not be an issue.

Mr. Vilbert's DCF results are summarized on his Table 3, Page 31 of his Direct Testimony: 9.1 percent for a "simple" DCF model, and 9.7 percent for a "multi" (meaning "multiple stage") DCF model. Individual company results are presented in his Table MJV-6, and range from 6.5 to 10.1 percent for the "simple" model, and 7.4 to 9.8 percent for the "multi" model. These estimates are biased upwards because they fail to take into consideration evidence of lower dividend growth. This is a common shortcoming of applicant-sponsored DCF evidence. The "cash flow" in the DCF model comes from dividends. But when dividend streams are factored into DCF analyses, the results are typically much lower: as much as 100 basis points lower. Thus instead of DCF estimates in the 9 to 10 percent range, we believe that a correct DCF analysis will produce estimates in the 8 to 9 percent range.

Capital Asset Pricing Model (CAPM) -- Mr. Vilbert refers to his implementation of CAPM as a "risk positioning" approach. In CAPM, the cost of equity is normally inferred from the sum of a risk free rate, and a risk premium that represents a security's systematic risk (measured by "beta"). Mr. Vilbert employs a variant of the CAPM known in the literature as the "empirical" CAPM, or ECAPM, model. We've critiqued this approach when used by witnesses in other cases. Without going into detail (we would provide the necessary detail in filed testimony), the empirical evidence for this version of CAPM does not apply to companies with beta's (the measure of "systematic risk" employed in CAPM) less than 1.0. But as shown on Mr. VIlbert's Table 1, the beta for all the companies in his sample is below 1.0. Thus the ECAPM is inapplicable, and his "risk positioning" adjustment to CAPM should be rejected.

The other major problem with Mr. Vilbert's CAPM/ECAPM approach is his use of a 6.5 to 8 percent market risk premium for which we have found no support in the filing. In recent cases we have presented a comprehensive review of recent studies of the market risk premium that lead to a consensus view that the market risk premium is substantially less than this, probably no more than 2 to 3 percent at the present time. When the CAPM is employed using this lower, consensus estimate, of the market risk premium, the resulting cost of equity is closer to 8 percent, in line with correctly derived DCF estimates.

Class Cost Allocations and Rate Design

The South Dakota allocation methods employed in the Company's class cost of service study (CCOSS) presented in Statement O purport to be consistent with studies relied on in the resolution of prior cases. This appears to be correct but needs to be verified by a detailed review. Also requiring verification is the allegation that the proposed increase in customer service charges is cost-justified. But, even if cost support can be found, the Company can be made whole by recovering the same revenues in its delivery charges to the same customer group and "rate shock" can be minimized.

Related to the CCOSS and rate design issues is the Company's proposed treatment of contracts with deviations. Costs are not allocated to these customers; the so-called "Margins" (i.e. revenues at the discounted rates) are treated as an offset to other class revenue requirements (see Exhibit JDD-1, Schedule 2.1, p. 14 and Statement O, p. 9, line 25). The "Margin" should recover both the incremental cost of serving these customers and a share of other system costs.

Finally, the proposed changes to the tariff's General Terms and Conditions, including the proposed extension footage allowance and fixed payment requirement for heating and water heating customers and the economic feasibility test to be applied to other new customers, should be justified as reasonable, non-discriminatory and consistent with the Commission's policies or practice in other cases.

DIVISION OF WORKLOAD

With precedent to guide the Staff on the recurring revenue requirement issues, it would be most efficient to have Staff review and develop positions on the recurring operating revenue and expense adjustments and rate base adjustments for plant additions and working capital. We would provide assistance to Staff in defining and developing positions on these issues, as needed.

We propose to address the cost of capital, income tax, overhead cost allocations and the Class cost of service allocation/rate design issues discussed above. All of our activities would be carried out with as much participation as possible by Staff.

PROPOSAL

As you know, we have considerable experience with general rate increase requests by electric and gas utilities including experience with the types of issues that we have identified here. In addition to our participation with the South Dakota Staff in more than thirty formal rate proceedings since 1976, we are presently engaged by the Colorado Consumer Counsel, the New Jersey Rate Counsel, Maryland People's Counsel and the Staff of the Delaware Public Service Commission as consultants in gas, electric and water rate cases before the regulatory commissions in those states.

In this proceeding, we propose to assist the Staff as described above. Basil Copeland would analyze and testify on the cost of capital and capital structure issues. I would be responsible for any accounting issues that are delegated to me by your Staff, the depreciation rate, income tax and intra-company cost allocation issues, and the jurisdictional and class cost of service determination. Dave Peterson has considerable experience with intra-company, jurisdictional and class cost allocations as well as income tax issues and would participate with me.

We will prepare the necessary data requests to obtain the information needed for our analyses; review the Company's responses, and confer with their witnesses as necessary; and prepare testimony and supporting exhibits describing our analyses, and recommendations. As needed, we will assist Staff witnesses in developing issues on which they will testify. We will also assist Staff Counsel in preparing for hearing and with the preparation of post-trial briefs and other pleadings.

For the purposes of preparing a cost estimate, I have assumed that two or three days will be required for participation in hearings in Pierre.

We estimate that the cost of performing these services would amount to approximately $57,375. including out-of-pocket expenses. Of course we would bill only for time actually spent working on the assignment and for our actual out-of-pocket costs, principally for air fare for 2 man-trips to Pierre, per diem expenses in Pierre, long distance telephone, copier and courier services. Our estimate is derived as follows:

Tasks	Hours: Towers	Hours: Copeland	Hours: Peterson
! Analyze the filing, identify issues, discovery;	40	8	40
! Developing positions; preparation of testimony and exhibits, including coordination with other Staff witnesses;	48	40	48
! Review rebuttal testimony and preparation for hearing;	30	14	30
! Participation in hearing	30	20	10
! Assisting counsel with briefs	12	8	12
Total hours	160	90	140

Cost Summary

Fees: Towers	160 hrs. @ $140		$22,400
Copeland	90 hrs @ $140		12,600
Peterson	140 hrs. @ $140		19,600
Total fees			$54,600
Out-of-pocket expenses:			
Air fare		$2,000	
Hotel		200	
Courier		125	
Data base charges for ROE analysis		300	
Other		150	
			2,775
Total cost			**$57,375**

Please let me know if you have any questions about my discussion of the issues, division of the workload between Staff and our firm or any other aspect of this report and proposal. We look forward to working with you again.

Sincerely,

/s/
Robert G. Towers
President

Attachment: Fee Schedule (January 2007)

Chesapeake Regulatory Consultants, Inc.

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FEE SCHEDULE

		Hourly Rate
Robert G. Towers Annapolis, MD	Senior Consultant	$ 140.00
Basil L. Copeland, Jr. Maumelle, AR	Senior Economist	$ 140.00
David E. Peterson Dunkirk, MD	Senior Consultant	$ 140.00

January 1, 2007