Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

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Introduction

The Natural Gas Act (NGA) requires that rates charged for interstate pipeline services be "just and reasonable." Setting just and reasonable rates requires a balancing of equities between the interests of the pipeline and its ratepayers. The basic methodology we use to establish just and reasonable rates is cost-of-service ratemaking. Under cost-of-service ratemaking, rates are designed based on a pipeline's cost of providing service including an opportunity for the pipeline to earn a reasonable return on its investment.

The Commission sets rates for interstate pipeline services in a number of proceedings. For example, when a pipeline files to increase its rates, it makes a filing with the Commission under Section 4 of the NGA. These types of filings are referred to as general Section 4 rate cases. In these proceedings, the Commission reviews all of a pipelines rates and services. A pipeline can file a general Section 4 rate case anytime it wishes, provided the pipeline did not agree otherwise in a settlement. A pipeline must demonstrate that the new rates it proposes to charge are just and reasonable. When a rate increase filing is made pursuant to Section 4, the application is typically suspended and set for hearing by Commission Order. Once the application is set for hearing, it is processed by the Commission's litigation staff in the Office of Administrative Litigation (OAL). The issues in the application can be settled if parties can reach consensus. However, if the issues cannot be resolved, they will proceed to a hearing before an Administrative Law Judge (ALJ). Whether the case is settled or proceeds to hearing, the Commission will eventually need to act upon the settlement, or upon the record in the hearing.

The Commission also has authority under Section 5 of the NGA to require prospective changes in the rates charged by a pipeline when it can be demonstrated that the rates are no longer just and reasonable. The Commission can initiate a Section 5 proceeding on its own motion, or upon complaint from an interested party. In a Section 5 proceeding, the Commission has the burden of demonstrating that the currently effective rates of the pipeline are no longer just and reasonable, and of establishing just and reasonable rates.

The Commission also sets rates for pipeline services under Section 7 of the NGA. Under Section 7(c) of the NGA a pipeline files to request a "Certificate of Public Convenience and Necessity" to construct a new pipeline or to expand existing facilities, in order to offer new or additional services. The rates established by the Commission under Section 7 for these services are referred to as "initial rates" and generally remain in effect until such time as the pipeline files a Section 4 rate filing in which all of a pipeline's rates are reviewed.

Additionally, the Commission sets rates for intrastate pipelines under Section 311 of the Natural Gas Policy Act (NGPA). Under Section 311, intrastate pipelines are permitted to transport gas for interstate pipelines and local distribution companies (LDC) in interstate commerce without becoming subject to jurisdiction under the NGA (intrastate pipelines are regulated by their State Agencies). The rates established under Section 311 must meet a "fair and equitable" standard, as opposed to a "just and reasonable" standard. When this Commission sets the rates for Section 311 service, the rates are computed using the same cost-of-service methodology used under the NGA. However, an intrastate pipeline may elect to use an approved cost-based rate on file with the State agency that regulates its intrastate business.

Finally, there are "limited" Section 4 filings where pipelines file to add a new service and establish new rates, as well as, complaint proceedings that raise rate issues to be addressed by the Commission.

In order for the Commission's advisory staff to make recommendations to the Commission on all of these types of filings, an understanding of the rate making process is required. This manual is intended to provide a basic understanding of how rates are computed based on the cost-of-service methodology.

The basic tenet that pipeline rates should be based upon the cost of providing service remains unchanged. However, it is worth noting that the Commission has found over the years that other ratemaking methods, in certain situations, can also meet the just and reasonable standard. For example, the Commission has permitted rates to be set using:

(1) selective discounting, where a pipeline is free to charge any rate between the maximum rate, which is set at the pipeline's average cost of providing service, and the minimum rate, which is set at the average variable cost of providing service. The pipeline however, must offer such discounts on a non-discriminatory basis;

(2) market-based rates have been approved when there has been a showing that the pipeline has no market power; and, more recently,

(3) negotiated rates have been permitted when there has been no showing by the pipeline of a lack of market power, but which allows a pipeline and its customers to negotiate a rate for service provided the pipeline has an appropriate "recourse" service on file with cost-based rates that the customer could opt to select.

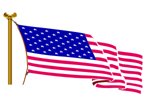
(4) Pending Rate Issues On July 29, 1998, the Commission issued a Notice of Proposed Rulemaking (NOPR) seeking comments from the industry on short-term market issues, such as lifting the cost-based rate cap on short-term transactions that compete in the market place. Short-term market transactions are defined as short-term firm services, capacity release and interruptible services. The Commission has also issued a companion Notice of Inquiry (NOI) requesting comment on whether long term transactions should continue to be priced in the same cost-of-service manner or if other cost-based approaches may be better to set rates, such as incentive regulation,

performance-based rates, or indexed rates. Comment was also sought regarding the future of the Straight Fixed-Variable rate design methodology. Other topics were also explored.

These ratemaking concepts, however, are topics for another discussion but indicate that the market the Commission regulates is very dynamic and the Commission is studying whether traditional cost-of-service ratemaking, is the best way to set rates for pipeline services in the future. The following material is intended to be an introduction to cost-of-service ratemaking which remains the primary methodology used by the Commission to establish just and reasonable rates.

There are essentially 5 steps involved in cost-of-service ratemaking:

(1) Establishing a revenue requirement, or cost-of-service
(2) Functionalizing the cost-of-service
(3) Cost Classification
(4) Cost Allocation
(5) Rate Design



Each of these steps will be explained in further detail below and we will show examples of each step by using an illustrative pipeline, "Pipeline U.S.A."

Pipeline U.S.A.

Pipeline U.S.A. received a Certificate of Public Convenience and Necessity from the Commission to construct and operate a jurisdictional pipeline. In the certificate proceeding (CP), the Commission authorized "initial rates" for firm and interruptible transportation service to be provided by Pipeline U.S.A. Initial rates are established for new services authorized in a certificate proceeding and must meet a public convenience and necessity ("PC&N") standard. Initial rates established in the certificate proceeding remain in effect until such rates are reviewed by the Commission in a rate proceeding (RP). Pipeline U.S.A. has been in operation for the past three years and has now filed a Section 4 (of the NGA) rate filing to have its "initial rates" reviewed under the "just and reasonable" standard. We will be establishing a cost-of-service and designing rates for Pipeline U.S.A. in the following pages. But, first, a few facts about Pipeline U.S.A.:

Pipeline U.S.A. owns 370 miles of transmission pipeline. There are two 30,000 horsepower compressors located on its system. The capacity is 1,000,000 Mcf per day. Pipeline U.S.A. has 4 firm transportation contracts each having 25 year terms and contract demands which total the capacity of its system. Pipeline U.S.A. also provides interruptible transportation service to several customers. The average heat content of the natural gas transported on its system is 1.035 Dth per Mcf.*

**Contract Demand refers to a firm shipper's contractual entitlement to service on any day. Contract Demand levels are expressed in Dth per day. For example, a firm shipper with a contractual entitlement of 50,000 Dth would be able to have up to 50,000 Dth of gas transported on any day of the year. A firm shipper pays a firm reservation charge based on this contractual entitlement to "reserve" capacity to guarantee this level of service on any day. Because firm service is provided on a contract basis, a pipeline is not required to provide service in excess of a shipper's contract demand level.*

A term frequently used to measure a firm shipper's use of its contract demand is <u>load factor</u>. A firm shipper's load factor is calculated by dividing the amount of gas a shipper transports on an average annual day by that shippers contract demand. For example, a shipper who transports 25,000 Dth on an average day and has a contract demand of 50,000 Dth/day, would have a 50% load factor. A shipper that transported its full contract demand every day of the year would be a 100% load factor customer.

The shaded boxes that appear throughout the manual are referencing the Appendices which illustrate the computation of each cost-of-service component, as well as the steps for classifying, allocating and designing rates for Pipeline U.S.A.

Step 1: Computing the Cost-of-Service

Cost-of-service may be defined as the amount of revenue a regulated gas pipeline company must collect from rates charged consumers to recover the cost of doing business. These costs include operating and maintenance expenses, depreciation expense, taxes and a reasonable return on the pipeline's investment. A cost-of-service is a measure of a pipeline's annual "revenue requirement" that will provide a company the opportunity to operate profitably and attract capital for future growth.

This section is devoted to defining each element of the cost-of-service, explaining how each element is computed and explaining the relationship between the various components used to compute the cost-of-service.

The Cost-of-Service Formula

To compute the cost-of-service a basic formula is followed:

Rate Base x Overall Rate of Return = Return
+ Operation & Maintenance Expenses
+ Administrative & General Expenses
+ Depreciation Expense
+ Non-Income Taxes
+ Income Taxes
- Revenue Credits
= Total Cost-of-Service

A cost-of-service includes the product of the pipeline's Rate Base (which is the pipeline's investment) and the Overall Rate of Return, plus its Operation and Maintenance Expenses (O&M), Administrative and General Expenses (A&G), Depreciation Expense, Non-Income Taxes and Income Taxes, less Revenue Credits.

A summary cost-of-service for Pipeline U.S.A. is shown on A-1.

Test Period. Another important concept used in developing a cost-of-service is the test period. The Commission has adopted the test period as a means to develop rates based on current costs, adjusted for known and measurable changes. As defined in the regulations, the test period consists of a base period consisting of 12 consecutive months of most recently available actual experience plus an adjustment period of nine months immediately following the base period. The adjustment period is used to adjust the base period for changes in revenues and costs that are known and are measurable with reasonable accuracy at the time of the Section 4 filing and that will become effective within nine months after the last month of available actual experience. The adjusted base period is an annual period and is usually referred to as the test period. Base period costs and revenues are often adjusted to eliminate non-recurring items, to annualize new costs or revenues, and to amortize costs or revenues that occur periodically, but not annually, i.e. every 2 years, every 5 years, etc.

One example of the test period concept: *Let's assume that for one month of the base period, Pipeline U.S.A. included $5,000 in its O&M expenses to correct for a billing error, which occurred prior to the base period, for field supplies purchased for the operation of certain transmission facilities. This amount should be eliminated to develop an appropriate test period amount for O&M expenses, as this cannot be considered a representative cost of supplies to be purchased during the period in which these rates will be effective. This adjustment reflects the elimination of a non-recurring item.*

Another example of the test period concept: *Let's assume that every two years, Pipeline U.S.A. spends $2,000 to have its meters tested for accuracy. Assume this $2,000 is recorded during one month of the base period. This amount needs to be adjusted to arrive at an appropriate test period expense. Because this expense is only incurred every two years, it needs to be adjusted to an annual expense of $1,000 per year, since the test period upon which we will design rates is representative of one year. If this adjustment is not made, Pipeline U.S.A. will overcollect its costs related to this item. In fact, Pipeline U.S.A. would collect $2,000 every year, rather than $2,000 every other year, if no adjustment is made. This adjustment illustrates an example of an expense that must be amortized as it is incurred periodically but not annually.*

Rate Base

Before actually computing a pipeline's cost-of-service, we must compute the Rate Base. The Rate Base represents the total investment of the pipeline and is used to compute certain components of the cost-of-service. In particular, the Rate Base is used to compute the Return component of the cost-of-service, which permits the pipeline to earn a return on its investment. Additionally, components of Rate Base are used to calculate the Depreciation Expense included in the cost-of-service, which permits the pipeline to recover its investment.

To compute the Rate Base a basic formula is followed:

Gross Plant
-Accumulated Depreciation
= Net Plant
-Accumulated Deferred Income Taxes
+Working Capital
= Rate Base

As shown, Rate Base is calculated by subtracting the Accumulated Reserve for Depreciation from the Gross Investment in Plant to arrive at Net Plant. Net Plant represents the remaining plant balance that is not yet depreciated. From the Net Plant we deduct the Accumulated Reserve for Deferred Income Taxes and add the Working Capital. Below is a description of each of the components of rate base.

Pipeline U.S.A.'s rate base is shown on A-2.

Gross Plant. This is the original cost of the plant, or facilities, owned by the pipeline. Generally, if the pipeline purchases "used" (depreciated) facilities from another utility, only the depreciated original cost of the facilities can be included in rate base, not the amount actually paid by the pipeline (since this may include a purchase premium which is not allowable in rate base). In addition to including the actual amount of the facilities, gross plant can also include amounts permitted to be capitalized (that is, included in rate base) for the cost of land and land rights, right of ways, surveys, line pack, and construction costs including materials, labor, pipe coating, communication equipment, overheads, funds used during construction, and legal fees.

An itemization of Pipeline U.S.A.'s test period gross plant is shown on A-3.

Allowance For Funds Used During Construction (AFUDC) - a pipeline is permitted to include in rate base the cost of financing during the construction period. The cost of financing consists of interest on borrowed funds and equity return on the pipeline's own funds used during the construction period. This computation is based on a prescribed formula contained in Part 201 of the Commission's regulations. These costs are a component of Gross Plant.

As shown on A-3, Pipeline U.S.A. has included in its Gross Plant an amount of $33,452,754 which is attributable to AFUDC.

Accumulated Reserve for Depreciation. The cost of the investment in gross plant is recovered through the cost-of-service as Depreciation Expense. Accordingly, the depreciation expense is accumulated and is credited against the gross plant to reduce the remaining investment to be recovered. The remaining balance is the **Net Book Plant.** The net book plant represents the portion of gross plant that is not depreciated.

Pipeline U.S.A. has been in operation for 3 years. The accumulated reserve for depreciation balance computation is shown on A-4. The annual depreciation expense is added for each of the three years of operation to arrive at this balance. The net book plant is computed by subtracting the accumulated reserve for depreciation from the gross plant (See computation on A-2).

Also, as shown by A-4 and A-11, the facilities of Pipeline U.S.A. are 12% depreciated after 3 years of operation (3 yrs divided by 25 years, or $75,490/$629,080). In year 25, assuming Pipeline U.S.A. adds no additional rate base and that the depreciation rate remains unchanged, Pipeline U.S.A. would be fully depreciated, or in other words, Pipeline U.S.A. would have fully recovered its investment.

Over time, if the pipeline does not continue to add plant to its pipeline system, the time will come when the balance in the accumulated reserve for depreciation account will equal the gross plant. At this point, the investment is fully recovered and net plant will be zero. If the pipeline is continuing to operate after its investment is fully recovered, the Commission may consider a management fee. Otherwise, the pipeline would only be able to recover operating expenses and taxes other than income taxes and would have no opportunity to earn a profit as there would be no investment (rate base) to calculate a return.

Management Fee. When a pipeline is fully depreciated and the pipeline continues to provide service, the Commission has permitted rates which provide for the recovery of operating expenses, taxes and a reasonable management fee that is equivalent to no more than 10% of the pipeline's average pre-tax return during the years prior to when the pipeline became fully depreciated.

Accumulated Deferred Income Taxes (ADIT). This is the amount of income taxes collected by the pipeline but not yet needed to pay current income taxes. ADIT arise from differences in the methods of computing taxable income for the various taxing bodies and income for financial statement purposes. In ratemaking, ADIT associated with depreciation expense is the main component of total ADIT. ADIT associated with depreciation expense results because of differences due to the amount of depreciation expense recovered in a pipeline's rates versus the amount of depreciation expense that the pipeline can claim for tax purposes.

For tax purposes, a pipeline can choose an accelerated method of depreciation which produces a higher depreciation expense in the early years compared to the straight-line method which is used for rate purposes. A higher depreciation expense used as a deduction for income tax purposes in the early year's results in a lower tax base and thus, the pipeline actually pays taxes in an amount less than the taxes collected in rates. This difference in the amount of taxes collected in rates and the amount of taxes actually paid are accumulated each year and are deducted from a pipeline's rate base as ADIT.

In essence, ratepayers are prepaying the income taxes and the pipeline will have use of these extra dollars until it has to pay more income taxes in subsequent years as its taxable deduction for depreciation decreases. That is, there will be a point in time when the depreciations expense computed on an accelerated basis for tax purposes will be less than the depreciation expense under the straight-line method. At this point, a pipeline will be collecting less taxes in rates than it needs to pay for income tax purposes. Thus, the monies accumulated as ADIT will be used to pay these taxes and the ADIT balance will start to decline.

We deduct ADIT from rate base because we perceive these "prepaid" dollars to be an investment by the ratepayers which is used by the pipeline to finance its capital investment. The effect of this credit is to reduce the cost of providing service to ratepayers by an amount equal to the deferred income taxes multiplied by the overall rate of return. ADIT associated with other cost and revenues affecting the cost of service are also deducted from rate base.

Schedule A-5 shows a method for computing ADIT when the only tax timing difference results from the difference in computing depreciation expense for tax purposes versus computing depreciation expense for rate purposes. The schedule shows that you can simply take the difference between the depreciation expense computed for rate purposes and the depreciation expense computed for tax purposes, for each year of operation, and multiply these differences by the effective tax rate. The cumulative total for each year represents the surplus, or excess taxes collected by Pipeline U.S.A. in rates but not yet payable for tax purposes.

Note: If we were to compute the ADIT through year 25, the economic life of the pipeline, the balance at year 25 would be 0. For the initial years, the ADIT balance increases each year until it reaches the "crossover" point and then starts to decline. The crossover point is reached when the accelerated depreciation method begins producing a depreciation expense lower than the straight-line method, at this point, the balance starts to decline each year until it reaches 0.

Working Capital. The Commission recognizes working capital as an additional investment by the pipeline upon which it is entitled to earn a reasonable return. This item includes cash working capital, prepayments, and materials and supplies.

Cash working capital is the amount of cash which a pipeline needs in daily operations to pay operating expenses. This is the amount claimed to bridge the timing gap between when expenses are incurred and when revenues are received. In order to include cash working capital in rate base, the Commission requires the pipeline to provide a "lead-lag" study to show that the company actually has a lag between expenses and receipts of revenue.

Pipeline U.S.A. has not submitted a lead lag study, therefore, there is no allowance included in rate base for cash working capital. Most pipelines choose not to file lead-lag studies.

Materials and Supplies, and Prepayments. Under the regulations, pipelines may include an allowance in rate base for the average of 13 monthly balances of materials and supplies and prepayments. These items are included in rate base because they represent investments paid for by the pipeline, which have not been used by the pipeline. For example, a pipeline keeps an inventory of materials and supplies on hand for future use. This inventory is considered an investment by the pipeline upon which it should be allowed to earn a return. Once the materials and supplies are used, they are expensed (removed from a capital account, and charged to an expense account). Similarly, prepayments represent payments for services in advance, such as insurance premiums. These monies are considered an investment by the pipeline for future coverage/service, as with insurance premiums. Once the prepayments are "used" they are amortized over the period that the prepayment covers and expensed based on the amortization schedule.

A-6 shows the average of thirteen monthly balances for materials and supplies, and prepayments to be included in Pipeline U.S.A.'s rate base.

Cost-of-Service

Following is a description of the components of the cost-of-service.

Return. Under cost-of-service ratemaking, pipelines are given the opportunity to earn a reasonable return on their investment. As discussed previously, a pipeline's rate base represents the total investment of the pipeline. Thus, the Return component of the cost-of-service is calculated as follows:

Rate Base
x Rate of Return
= Return

The Return that we include in a pipeline's cost-of-service represents the **After Tax Return**. The Return includes an amount which provides a return on the pipeline's equity investment, as well as including an amount to recover the interest on a pipeline's debt. That is, it represents the amount of profit we are permitting the company to earn, after payment of all of its expenses (except interest on long term debt), including taxes, allowed in the cost-of-service. As shown, the Return allowance is determined by multiplying Rate Base by the overall **Rate of Return (ROR)**.

A-7 shows the calculation of Pipeline U.S.A.'s return allowance of $53,067.

The Overall Rate of Return is computed as a function of the following three components: the capitalization ratio of the pipeline, the cost of debt, and the allowed rate of return on the pipeline's preferred and common equity.

As shown on A-8, to arrive at the rate of return of 9.975%, the "weighted" cost of debt of 5.775% is added to the "weighted" cost of equity of 4.20%. The "weighted" cost of debt is the actual cost of debt of 8.25% weighted by the percentage of debt in the capital structure of 70% (i.e. 8.25% times 70% = 5.775%). Similarly, the "weighted" cost of equity represents the equity return of 14.00% weighted by the percentage of equity in the capital structure (14.00% times 30% = 4.20%). More explanation follows regarding the components which appear on this schedule.

Following is a more detailed explanation of each of the components necessary to calculate the Overall Rate of Return.

Capitalization or Capital Structure: A pipeline's capital structure is a representation of how a pipeline has financed its investment (rate base). It is represented as a ratio of a pipeline's debt, common equity and preferred equity. For example, a pipeline which has financed its investment with $6 million debt and $4 million in common equity, is referred to as having a 60%/40% debt-equity capitalization ratio.

We generally accept the pipeline's actual capital structure. However, more recently the Commission determined that it was only reasonable to use a subsidiary pipeline's actual capital structure when the subsidiary pipeline issues its own debt which is not guaranteed by its parent, has its own bond rating, and its equity ratio is comparable to other equity capitalizations approved by the Commission. If the pipeline does not meet these criteria, the parent company's capital structure will be used in instances where the parent issues stock and incurs debt for the pipeline.

In the past, if the pipeline proposed a capital structure of 100% equity and no debt (or a very high equity ratio), staff often proposed use of a hypothetical capital structure that establishes a lower equity component and imputes a debt component. We do this because it is more costly to the rate payer to finance a pipeline's investment with equity.

As shown on A-8, Pipeline U.S.A.'s own capital structure of 70% debt and 30% equity is used to compute the overall rate of return. It is common that newer companies, such as Pipeline U.S.A. which has only been in service for three years, have high debt ratios. As shown by columns (1) and (2), 70% of Pipeline U.S.A.'s investment (rate base), or $372,403,000 is debt financed as Pipeline U.S.A. issued debt to bondholders to finance this portion of its investment. Also, note that 30% of Pipeline U.S.A.'s investment, or*

$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure represents the amount the company receives from the rate payers. This includes the after-tax return (both debt and equity) and related income taxes. In order to compute the pretax return the following information is needed: The overall rate of return (ROR), the combined effective income tax rate, and the weighted interest deduction.

A-9 shows the steps and formula's necessary to compute Pipeline U.S.A.'s pretax return. First, you need to calculate the combined effective tax rate which will be used as a component in the pretax formula computation. Next, you calculate the pretax return percentage using the formula as shown. The resulting 12.53% represents Pipeline U.S.A.'s before tax, or pretax return. The formula is adding the pipeline's overall (after tax) rate of return percentage of 9.975% to the grossed up taxes expressed on a percentage basis. This sum is the pretax return of 12.53%. This formula computes on a percentage basis the same pretax return which is arrived at by adding the Federal and State Income Taxes and the Return components of Pipeline U.S.A.'s cost-of-service, as shown on A-1, the sum of which is $67,265,000 and dividing by the Rate Base of $532,005,400 (A-2). The resulting pretax return is 12.64%. This percentage differs from the pretax return computed using the pretax formula because the pretax formula does not include tax adjustments, such as the AFUDC tax adjustment included in Pipeline U.S.A.'s tax computation on A-12.

Operation and Maintenance Expenses (O&M). These expenses represent the pipeline's cost of operating and maintaining its utility plant and equipment, or the cost of running the physical pipeline system.

Schedule A-10 shows Pipeline U.S.A.'s transmission O&M and A&G expenses by account. Each account contains costs related to Labor and Non-Labor (Materials and Supplies) amounts. This distinction will be important later, when we classify costs as fixed or variable. The Non-Labor, or Materials and Supplies, portion of the accounts related to compressor station *operation and maintenance are traditionally classified as variable costs. (See A-17).*

Administrative and General Expenses (A&G). These expenses include salaries and wages, office supplies, outside services, regulatory commission expenses, rents and general plant maintenance. In cases where the pipeline is a subsidiary or owns other pipeline systems, the parent company or main office may incur overhead expenses on behalf of the subsidiary, or for all systems. In such a case, it is necessary to directly assign, or allocate, to the particular subsidiary, or system, a portion of these overhead costs. Next, we must directly assign, or allocate, a pipeline's total A&G expenses, including the overhead assigned or allocated from the parent, to the various functions of the pipeline, such as the transmission function. Typically, A&G expenses are not easy to directly assign to a particular function. Therefore, most A&G expenses must be allocated to each function.

At the bottom of A-10, the transmission A&G expenses for Pipeline U.S.A. are shown by account. These costs were allocated to the transmission function using the Commission approved K-N methodology which will be discussed under Step 2: Cost Functionalization. Also, these A&G costs include an amount of costs allocated from Pipeline U.S.A.'s parent which shares certain executive personnel. A portion of these executive's salaries are allocated to Pipeline U.S.A.

Depreciation Expense. This is the return of investment in the pipeline facilities over the estimated useful life of the facilities. This amount represents the recovery of the investment in facilities as opposed to profits from the investment. We typically use the straight line depreciation method for computing the depreciation rate. Under the straight-line method the depreciation rate can be calculated by dividing the estimated useful life of the facility into the ratio of the undepreciated gross plant to total gross plant. For example, if the facility is yet to be depreciated, the calculation for would be 100% divided by the remaining life, which will yield the depreciation rate.

We typically use a minimum life of 25 years (4.0% per year), or 20 years (5.0% per year), for transmission and storage facilities. If a facility is 50% depreciated, and the remaining useful life is estimated to be 25 years, the depreciation rate would be 50% divided by 25, or 2%. Depreciation is a method of recovering the investment in gas plant over its estimated useful life. As consumers are charged for depreciation in the cost-of-service, the amounts recovered are accumulated annually (monthly) and deducted from gross plant investment in arriving at net (undepreciated) plant yet to be recovered by charges to consumers. These accumulated amounts of depreciation expense are shown as a reduction to gross plant as the Accumulated Reserve for Depreciation .

A-11 shows the calculation of Pipeline U.S.A.'s annual depreciation expense. First, the depreciable plant must be computed. Note that land is not depreciable and must be deducted from gross plant to arrive at depreciable plant. Next, the depreciable plant of $629,080 is multiplied by a 4% annual depreciation rate to arrive at the annual depreciation expense of $25,163. The 4% depreciation rate is based on a depreciable life of 25 years (100% divided by 25 years). This rate was authorized at the time Pipeline U.S.A.'s initial rates were approved by the Commission.

Federal and State Income Taxes. These are amounts included in the cost-of-service to allow the pipeline to recover federal and state income taxes. Income taxes are assessed on the equity portion of the return allowance. The current federal income tax rate is 35% of taxable income. State tax rates vary by state, but usually fall between 4% and 8%. Some states including Texas and South Dakota, have no state tax rate.

To compute the tax allowance we begin by computing taxable income. To compute taxable income we start with the total return dollars and deduct the interest expense, or the cost of debt. Interest expense is computed by multiplying the weighted cost of debt by the rate base. The remaining amount is the after tax return, or the equity return after taxes. To this, we add an amount for the permanent tax timing differences such as for the Allowance for Funds Used During Construction (AFUDC), the necessity of which is described in more detail below. This gives us the Taxable Income.

We cannot simply multiply the Taxable Income by the appropriate tax rate. This is because the company receives, as permitted in its cost-of-service, an additional revenue stream which includes an amount for taxes. Therefore, the pipeline must pay taxes on this tax allowance. In order to be completely reimbursed so that it receives its equity return, the company must also receive an amount to pay the taxes on the tax allowance included in its rates. This is accomplished by a tax on tax formula which is the tax rate divided by one minus the tax rate. For Federal Income Taxes it would be .35 divided by 1 minus .35. For State Income Taxes the Taxable Income must be increased for the amount of the Federal Tax Allowance because the company must pay taxes on this allowance. Then a similar formula using the state rate is applied to the State Taxable Income. In this case it is .0429 divided by 1 minus .0429. Another way to compute total income taxes (both State and Federal) is to multiply the Taxable Income using the Combined Effective Tax Rate in the tax on tax formula. The combined effective tax rate is 37.79% (See A-13 and description below) so the formula would be .3779 divided by 1 minus .3779.

AFUDC - the equity portion of AFUDC which is included in depreciation expense is not considered deductible by the Internal Revenue Service (IRS). However, for rate purposes we consider all expenses, including 100% of the depreciation expense, to be deductible when we calculate the income tax allowance. Because the IRS does not permit this deduction, we must add the AFUDC portion of the depreciation expense to the tax base in order to compute the proper income tax expense for the pipeline. Otherwise, the pipeline will not be permitted to collect the proper income tax allowance.

A-12 shows the computation of Pipeline U.S.A.'s Federal Income Taxes and State Income Taxes to be included in the cost-of-service. This schedule also shows the computation of these taxes on a composite (combined) basis.

Effective Tax Rate or Combined Tax Rate or Composite Tax Rate - When computing a cost-of-service we must include both federal and state income taxes. The federal income tax rate is 35% and the state rate for Pipeline U.S.A. is 4.29%. However, these rates are not additive. That is, we cannot conclude that Pipeline U.S.A. is paying taxes equivalent to 39.29% of taxable income. Because state taxes are considered to be appropriate deductions when computing federal income taxes, the actual combined federal and state tax rate is less than the sum of the two tax rates.

A-13 shows the formula for computing the effective combined tax rate for Pipeline U.S.A. The first step is to multiply the state tax rate by the federal tax rate. The product is then subtracted from the federal rate, producing the effective federal tax rate given that state taxes are a deduction. Next, the state tax rate is added to the reduced federal rate. The sum of which is the combined effective tax rate of 37.79%.

Limited Liability Companies, or partnerships are not subject to federal taxation and thus special rules apply. However, if the members of a partnership are corporations subject to corporate income taxes on their allocated shares of the partnership's income, the Commission permits the partnership a tax allowance in the cost-of-service.

Non-Income Taxes. These include property taxes or ad valorem taxes, franchise taxes and employment taxes. These vary from state to state. Property or ad valorem taxes are taxes on the value of real estate, and personal property. These taxes are often assessed on the plant investment a pipeline has in a given state. Franchise taxes are sometimes assessed by a city in return for allowing the pipeline to provide service to the city. Employment taxes are assessed on the payrolls of the pipelines to pay for FICA taxes, which include social security and Medicare, and unemployment insurance.

A-14 shows the test period property and employment taxes for Pipeline U.S.A.

Credits to the Cost-of-Service. There are many items that could be credited to a pipeline's cost-of-service. A credit to the cost-of-service is a reduction to the cost-of-service. If the pipeline has processing facilities, it may extract salable liquids from the gas stream. We attempt to project the level and the price for the products and we credit this amount to the cost-of-service. If the pipeline rents out facilities, or receives payment from leased facilities, staff may recommend a credit to the cost-of-service for these amounts. If the pipeline has been collecting excessive revenue from the imposition of penalties such as penalties for violating Operational Flow Orders (OFO's), staff may recommend that these monies be credited to the cost-of-service. Additionally, one method for computing a discount adjustment is to credit the revenues from the discounted services to the cost-of-service while removing the associated volumes from the rate design determinants. Discount adjustments and revenue crediting will be discussed later in this manual.

Pipeline U.S.A. does not have any revenues that will be credited to the cost-of-service.

Step 2: Computing a Functionalized Cost-of-Service

Prior to Order No. 636, a pipeline's costs were traditionally functionalized into three broad categories; Production, Storage and Transmission, which recognized the functions of the facilities owned by the pipeline. The Production function included the costs associated with a pipeline's own production as well as purchased gas costs and gathering costs. Today, as a result of Order No. 636, pipeline's no longer act as gas merchants. This function has primarily been taken over by the pipeline's affiliated marketer. Additionally, many pipelines have sold or assigned their gathering facilities to non-jurisdictional entities. Thus, today a pipeline primarily has two functions, Storage and Transmission.

A functionalized cost-of-service is computed by directly assigning or allocating operation and maintenance expenses and other costs incurred by the company to the various functions, e.g. storage function and/or transmission function, of the particular pipeline company.

How are costs functionalized?

O&M expenses are directly assigned to the function for which they are incurred. In fact, pipelines are required to book their expenses to particular accounts under the Commission's Uniform System of Accounts. These accounts are set up on a functionalized basis.

A&G expenses include wages and salaries, rent expense, insurance premiums, supplies, charitable contributions, expenses for outside services employed and regulatory commission expenses. These expenses are not set up on a functionalized basis under the Uniform System of Accounts as these items often cannot be directly assigned, nor easily identified with a particular function. Thus, for ratemaking purposes, the costs that cannot be directly identified with a function must be allocated among the functions. The *Kansas-Nebraska Method* (K-N) is the preferred methodology used by the Commission to allocate these A&G costs to functions as described in more detail below.

> **K-N Method.** The K-N Method is a Commission approved method for allocating a pipeline's A&G expenses that are not directly assigned among the various functions--today, those are primarily storage and transmission, using cost causation principles. That is, the method uses functionalized labor and plant ratios as allocation factors. In theory, when applied, this method is designed to prevent cross subsidization of one service over another.

The K-N Method involves the following steps:

1) First, the pipelines total A&G expenses are listed by account.

2) Second, these expenses are then classified as being related to "labor", "plant" or "other." The expenses related to labor include A&G Salaries, Office Expenses, and Pension and Benefit Expenses. A&G expenses related to plant, include Property Insurance and General Plant Maintenance. The expenses that are not particularly related to plant or labor are listed as "other" and these expenses include Outside Services, Regulatory Commission Expense and Miscellaneous General Expenses.

3) Third, the costs classified to "other" are then allocated between the labor and plant categories.

4) Fourth, the total labor related amount of A&G is then allocated to the pipeline's storage and transmission functions based on the percentage of direct labor associated with each function. Similarly, the plant-related amount of A&G is allocated to the functions based on the percentage of gross plant associated with each function.

Depreciation expense is functionalized on the basis of the gas plant devoted to each function.

Taxes Other Than Income are functionalized by first directly assigning the costs that are specifically related to a specific function. Second, the remaining costs are identified as either being related to plant or labor. Plant-related costs, such as property taxes, are functionalized on the basis of the gas plant ratios. Those taxes related to labor, such as unemployment taxes, are functionalized on the basis of the direct labor ratios.

Income Taxes are a function of the return allowance associated with the rate base computed for the function.

Return for each function is the product of each functions rate base multiplied by the rate of return.

Revenue Credits are typically directly assigned to the function to which they relate.

When all expenses and return have been functionalized, the items are totaled for each function. The result is a functionalized cost-of-service for each function of the pipeline.

The transmission cost-of-service appearing on A-1 represents a functionalized transmission cost-of-service for Pipeline U.S.A. Note that Pipeline U.S.A. only owns transmission facilities. Therefore, developing a functionalized cost-of-service is easy because there is only one function. However, let's assume that Pipeline U.S.A. owns both transmission and storage facilities. Now, we must develop functionalized transmission and storage cost-of-services.

Illustrative functionalized cost-of-services appear on A-15. The amounts for each function were derived as discussed above. Most costs are directly assigned to the appropriate function, such as O&M and revenue credits. Other costs such as return and taxes are a function of the rate base for each function. Depreciation expense is derived by multiplying the depreciable plant for each function by the annual depreciation rate for each function. One of the most involved calculations in developing a functionalized cost of service is the allocation of A&G expenses among or between the various functions.

The A&G expenses cannot be directly assigned to the storage and transmission functions as these costs are incurred to support both functions.

Therefore, these costs must be "allocated" to each function. Schedule A-16 shows the allocation of total A&G costs between the storage and transmission functions based on the K-N methodology. As shown, the total A&G expenses of Pipeline U.S.A. are listed by account. Then they are classified as related to Labor, Plant or Other. The Other costs are then allocated between the Labor and Plant columns based on the ratio of the Labor and Plant column total, respectively, to the total of these two columns. In this case, 76% of "Other" costs are allocated to the Labor column and 24% are allocated to the Plant column. Next, these allocated amounts are added to the Labor and Plant column totals to arrive at new totals.

Next, the Allocation Factors for allocating these Labor and Plant related costs between the transmission and storage functions are calculated. First, as shown, 30% of Labor related costs will be allocated to the Storage function and 70% to the Transmission function. Similarly, as shown, 59% of the Plant related costs will be allocated to the Storage function and 41% will be allocated to the Transmission function.

Finally, at the bottom of A-16 , the Direct Labor related costs and the Gross Plant related costs are then allocated to each function based on the above allocation factors. These amounts are then totaled for each function to arrive at the total A&G costs allocated to each function.

Step 3: Cost Classification

Cost classification is a two step process. First, functionalized costs are classified as either fixed or variable. Next, fixed and variable costs are then classified as reservation (demand) or usage (commodity). Prior to Order Nos. 436 and 636 when pipelines offered primarily bundled sales service, the rate components were referred to as "demand" and "commodity." After Order Nos. 436 and 636, which paved the way for pipeline's to become solely transporters of natural gas, the Commission started using the terms "reservation" and "usage" rates which are more akin to transportation terms. However, in practice these terms are synonymous and will be used interchangeably in this manual and in the Appendices.

Classification of Costs Between Fixed and Variable

In cost classification, the costs that make up the cost-of-service are identified as either fixed or variable, depending on their characteristics. Fixed costs are costs which remain constant regardless of the volume of throughput and are predominately associated with capital investment in the pipeline system. Fixed costs include investment related costs such as depreciation, return and taxes, as well as certain O&M expenses, including labor, A&G expenses and as-billed third party reservation costs.

Variable costs are costs which vary with the volume of throughput. Prior to Order No. 636, variable costs primarily consisted of purchased gas costs and compressor fuel costs. Many companies also traditionally have classified the non-labor portion of certain O&M expense accounts as variable costs. Non-labor costs include materials and supplies. Since Order No. 636, pipelines are no longer sellers of gas, thus purchased gas costs are no longer collected in a pipeline's rates. As for fuel, many pipelines retain fuel as a percentage of total receipts of gas, thus, pipeline's today often do not include fuel costs in their rates.

A-17 shows Pipeline U.S.A.'s transmission costs classified between fixed and variable costs. As shown, the variable costs represent the Non-labor or Material and Supplies portion of the O&M accounts related to compressor and meter stations (See A-10). The remainder of the costs are classified as fixed costs.

Classification of Costs Between Demand and Commodity

After functionalized costs are classified as fixed and variable, they are then classified as demand or commodity. The demand and commodity components have generally been associated with providing peak and annual services. Variable costs have always been classified to the commodity component in order to match their recovery with the level of throughput. Sometimes an issue may arise as to whether a cost is variable. However, the basic premise that variable costs are classified to the commodity component is relatively uncontroversial. However, the classification of fixed costs between demand and commodity components has historically been a controversial issue. The issue becomes particularly heated because the choice of a cost classification method can have direct effects not only on the rates paid, but also on the revenue responsibility of a particular class of customer. For example, a particular cost classification method could result in more costs being allocated to a particular service. Additionally, depending on a customer's load factor, a particular cost classification method may mean a customer pays a higher unit rate per dekatherm of gas transported. Because these decisions have a direct monetary impact on individual customers, or classes of customers, it is the cause for much debate.

The Commission has used various cost classification methods to classify costs in response to particular industry trends and situations. In most cases, the cost classification method used will be followed for allocating costs and designing rates.

In 1938, the Natural Gas Act was passed and the transportation and sale of natural gas in interstate commerce became subject to the jurisdiction of the Commission. During this time period, rates were designed on a volumetric basis, that is, all costs were collected in commodity rates. This made sense at the time as pipelines had contractual obligations to serve a customer's total requirements. Contracts did not specify a specific contract demand level for service to a particular customer. Instead, a pipeline was obligated to supply all of a customer's requirements, whatever those requirements were and customers were required to pay a rate per unit of gas transported. This was known as the Volumetric method.

A-18 shows the classification of costs for the design of a 100% volumetric, or commodity rate. Here, 100% of the costs are classified to the commodity component.

In 1942, the Commission used the "peak responsibility" or Fixed-Variable method for classifying costs. Under the Fixed-Variable method all fixed costs are assigned to the demand component. Variable costs are included in the commodity component. During this time period, service obligations became more centered on defining a peak level of service to be offered as opposed to the pipeline having an open ended commitment for service. At that time, the Commission reasoned that because pipeline capacity and pending expansions controlled service levels, it was reasonable to place all fixed costs in the demand component to reflect the importance of capacity costs.

A-19 shows Pipeline U.S.A.'s transmission costs classified under the Fixed-Variable or Straight Fixed-Variable (SFV) methods.

In 1952, the Commission determined that both peak and annual use were of equal importance in determining cost responsibility and thus established the Seaboard methodology. Under Seaboard, fixed costs associated with transmission and storage functions were apportioned 50 percent to the demand category and 50 percent to the commodity category. All production costs were assigned to the commodity category.

A-20 shows the classification of Pipeline U.S.A.'s transmission costs to the demand and commodity components using the Seaboard methodology. Remember that Pipeline U.S.A. does not have storage or production functions.

In 1973, the Commission adopted the United methodology. Under United, 25% of fixed storage and transmission costs are classified to the demand component and 75% of the storage and transmission fixed costs are classified to the commodity component. Production costs remained in the commodity charge. During this time period, gas shortages and resulting curtailments prevailed. The Commission found that a change from the Seaboard methodology was warranted. In Seaboard, the Commission concluded that neither peak nor annual usage predominated. In United, the Commission reasoned that peak usage was no longer a valid measure of a customer's responsibility for capacity costs. Given the gas supply situation in the early 1970's, a customer's payment of a demand charge for capacity rights did not assure the customer of receiving gas. Thus, the Commission concluded annual usage represented a more reasonable way to collect fixed costs. Thus, more costs were shifted to the commodity component. Additionally, the Commission found that the result of the shift of costs to the commodity component, which would increase the cost to industrial high load factor customers, was not unreasonable given that these industrials were the least favored customers in the curtailment plans and many were capable of using alternative fuels. To date, other than a purely volumetric rate, the United methodology classifies the most fixed costs to the commodity component compared to other classification methods used by the Commission.

A-21 illustrates the classification of Pipeline U.S.A.'s transmission costs between demand and commodity components using the United methodology.

In 1983, the Commission adopted the Modified Fixed-Variable (MFV) method. Under MFV, all fixed costs in the transmission and storage functions are classified to the demand category, except for return on equity and related income taxes which are classified to the commodity component along with all variable costs. All production costs except for as-billed pipeline supplier demand costs were classified to the commodity category. During this time period, pipelines were underutilized on an annual basis due to competition from alternative fuels. The MFV method was intended to provide an opportunity for market enhancement and increased rate flexibility and to maximize the use of system capacity. In most cases, depending on the pipeline's capital structure, less fixed costs are classified to the commodity component than under either the Seaboard or United methods. The lowering of the commodity rate was intended to increase gas sales. Also, by placing the pipeline's return on equity, or its profit, in the commodity component of rates, it was theorized that pipelines would be more aggressive in their effort to market and sell gas services.

A-22 shows Pipeline U.S.A.'s transmission costs classified using the MFV methodology. The fixed costs classified to the commodity component include $22,344,000 in equity return (A-8) plus income taxes of $14,197,000 (A-12), for a total fixed costs of $36,541,000. These fixed costs plus variable costs of $2,600,000 equal the total costs of $39,141,000 classified to the commodity component.

In 1992, with the issuance of Order No. 636, the Commission adopted the Straight Fixed-Variable method (SFV). Under SFV, all fixed costs are classified to the demand component and all variable costs are classified to the commodity component. The Commission reasoned that a change from MFV was necessary because each pipeline, depending on its capital structure, had different levels of fixed costs in the usage (commodity) rates, thus hindering gas on gas competition in the marketplace. The purpose of SFV was to promote the development of a competitive market for natural gas at the wellhead by eliminating transportation rate differentials.

A-19 shows the classification of Pipeline U.S.A.'s transmission costs using the SFV methodology.

1998 and 1999. Now that Order No. 636 and the SFV rate design have been in effect since 1992 and 1993, the Commission has been faced with proponents that request a movement away from SFV. These proponents promote a move toward incorporating or shifting more fixed costs to the commodity (usage) component of rates arguing that this is necessary to encourage short-term markets, to market freed-up capacity and to keep costs low. The Commission will need to address these issues. In select cases, or in approving settlements, the Commission has already approved deviations from the SFV rate design. Also, as mentioned at the beginning of this manual, the Commission has requested comments from the industry on several rate matters (and specifically on SFV) as well as other policy issues regarding the best way to regulate the new markets that have developed since the issuance of Order No. 636.

Step 4: Cost Allocation

Cost allocation entails apportioning the functionalized and classified costs between jurisdictional and non-jurisdictional services, among zones and among jurisdictional services. Costs are allocated between services using volumes usually expressed in dekatherms (Dt, Dth, Dkt) as allocation factors. Costs are typically allocated among zones using Mdt-miles as allocation factors.

Mcf's and Dth's

Gas is measured by volume in cubic feet (cf). Pipeline capacity is expressed in Mcf, or 1,000 cubic feet.

1 Mcf = 1,000 cubic feet
1 MMcf = 1,000,000 cubic feet
1 Bcf = 1,000,000,000 cubic feet

Gas is sold, and rates are designed, based on the heat content of the gas. The heat content of gas is measured in British thermal units (Btu) or dekatherms (Dth, Dt, or Dkt).

1 MMBtu = 1 Dth

To Convert Mcfs to Dths (or MMBtus) you need a conversion factor. The conversion factor will vary depending on the heat content of the gas. Let's assume the heat content of the gas to be transported is 1,035 Btu per cubic foot. The conversion factor is:

1 cf = 1,035 Btu, or
1 Mcf = 1.035 MMBtu, or 1.035 Dth

Example:

1,000,000 Mcf = ? Dth

1,000,000 Mcf x 1.035 Dth/Mcf = 1,035,000 Dth

A-23 shows the conversion of Pipeline U.S.A.'s firm contractual entitlements of 1,000,000 Mcf, which equates to the capacity of the pipeline, to dekatherms.

Allocation Factors and Billing Determinants

Allocation factors are used to allocate costs among services. Billing determinants are used to design rates. Both are based on some measure of service level to a particular customer, or class of customers. In some instances, allocation factors and billing determinants can be the same. For example, commodity or usage costs are usually allocated between services using commodity volumes. These commodity volumes are also used to design the commodity (or usage) rates for each service. In other circumstances, they can be different. For example, one could allocate demand, or reservation, costs between services based on consecutive-three day peak volumes. The demand rates, however, would be designed on contract demand levels.

A-23 shows the firm and interruptible service levels for Pipeline U.S.A. As described earlier, Pipeline U.S.A. has 4 firm customers with contract demand entitlements which total the capacity of the pipeline system 1,000,000 Mcf per day. This schedule shows the total contractual entitlements of these four firm customers, as well as their average day use of the pipeline system. This schedule also shows the annual interruptible (IT) quantities transported, and the average day IT quantities.

Load Factor

Load factor is a measure of a customer's, or group of customer's, use of their contractual entitlements (or peak usage). A firm customer's load factor is the ratio of his average day use to his daily contract demand. If a customer transported 10,000 dth on average each day of a year and his daily contract demand is 20,000 dth per day, that customer's load factor is 50%. If a customer's average day were equal to his daily contract demand, the customer would be a 100% load factor customer. In some instances you will see load factor defined as a measure of a customer's annual use compared to peak use. Here, for purposes of this manual, we are using contract demand for a customer, or group of customer, to be an accurate representation of peak day use.

A pipeline's "system average load factor" is computed by computing the average annual day of total firm and interruptible transportation on the pipeline and dividing by the pipeline's total firm daily contract demand. Typically, the contract demand for firm customers on a pipeline system is equivalent to the pipeline's total capacity. However, if it is not, the system average load factor can be computed using the pipeline's capacity as the denominator rather than the firm contract demands. This provides a measure of the actual use of a pipeline system.

A-24 shows the firm service average load factor computed for Pipeline U.S.A.'s firm customers. It also shows the computation of Pipeline U.S.A.'s system average load factor.

Allocation of Costs Between Jurisdictional and Non-jurisdictional Services

Prior to Order No. 636, an important allocation issue involved the allocation of costs between jurisdictional and non-jurisdictional services. Non-jurisdictional services consisted primarily of direct sales to end-users which are not "sales for resale" under the NGA, and thus, the Commission has no authority to set the rates for these services. Instead, the Commission would allocate costs to these services and the pipelines were free to charge any rates necessary to recover the allocated costs. To allocate demand costs between jurisdictional and non-jurisdictional services the basis used was peak utilization of the system, such as the three-day sustained peak deliveries. Variable costs, or commodity costs, were allocated on the basis of annual throughput of the system. However, as a result of Order No. 636, which required pipelines to offer unbundled sales and transportation services, and pipelines subsequent assignment of their sales business to marketing affiliates, has essentially eliminated the need for allocating costs to non-jurisdictional business, as pipelines today do not make sales for resale or direct sales.

Pipeline U.S.A. does not have any non-jurisdictional business. Therefore, there is no allocation between jurisdictional and non-jurisdictional services.

Allocation of Costs Among Zones

When a pipeline system is divided into geographic regions, or zones, costs are usually allocated to the zones based on Dth-miles. A detailed discussion regarding the allocation of costs between zones and the design of zoned rates, appears later in this manual on Pages 53-57.

Pipeline U.S.A. does not have zones. Therefore, we can skip this step in allocating costs. For now, we are merely allocating costs and designing postage stamp rates for Pipeline U.S.A. A "postage stamp" rate is a rate that is paid by all shippers regardless of the distance the gas is transported on the system. A one mile haul would be subject to the same maximum transportation rate as a 200 mile haul under postage stamp rates.

Allocation of Costs Among Jurisdictional Services

Once costs are classified between demand and commodity components, the costs are allocated to the pipeline's services.

Transmission costs are allocated between a pipeline's transportation services, such as firm and interruptible transportation services. Previously, prior to Order No. 636, pipelines offered firm and interruptible sales services. At that time, transmission costs were allocated between sales and transportation service. Now, as a result of Order No. 636, pipelines are no longer in the sales business. Therefore, there is no longer a need to allocate transmission costs between sales and transportation services. Transmission costs are now allocated among the various types of transportation services offered by the pipeline (i.e. no-notice transportation, short-term firm transportation, interruptible transportation services, overrun services, etc.)

A-25 shows the total transmission reservation and usage costs under the SFV cost classification allocated between the firm and interruptible transportation services of Pipeline U.S.A.

As shown, the reservation cost allocation factor for firm service of 1,035,000 Dth, is equivalent to the firm contract demand of Pipeline U.S.A.'s 4 firm customers. The interruptible reservation allocation factor of 32,878 Dth is imputed at a 100% load factor. To arrive at the imputed allocation factor at 100% load factor, the projected annual interruptible service volume of 12,000,000 Dth is divided by 365 days (365 days times 100%). (If the load factor for designing the interruptible rate were 50%, the reservation cost allocation factor would be derived by dividing the 12,000,000 Dth by 182.5 days (365 times 50%). The usage cost allocation factors for firm and interruptible service are equivalent to the annual projected volume for these services.

To arrive at the allocated costs for firm service, the total reservation costs are multiplied by the ratio of the firm reservation allocation factor of 1,035,000 dth divided by the total reservation allocation factor of 1,067,878 Dth, or 96.92%. The remaining 3.08% of reservation costs are allocated to interruptible service. Similarly, the same calculation is used to allocate the usage costs between firm and interruptible service. As shown, 95.43% of the *total usage costs are allocated to firm service, the remaining 4.57% of usage costs are allocated to interruptible service.*

Next, these allocated costs are used to design rates. As shown on A-26, the firm reservation rate is derived by dividing the reservation costs allocated to firm service (from A-25) by the firm billing determinants. The firm billing determinants are derived by multiplying the firm contract demands of Pipeline U.S.A.'s four firm customers by 12 months. This is necessary to develop a monthly reservation charge. Similarly, the firm usage rate is derived by dividing the usage costs allocated to firm service (from A-25) by the projected annual units of firm transportation service.

Next, A-27 shows the derivation of the interruptible transportation rate. The reservation and usage costs allocated to interruptible service (from A-25) are totaled and divided by the projected annual interruptible transportation volumes to arrive at the interruptible transportation rate per Dth of gas transported.

Note: *We have shown for illustrative purposes how costs can be allocated between firm and interruptible transportation services (A-25) and how rates are then designed based upon these allocated costs (A-26 and A-27). However, when the allocation factors are equivalent to the billing determinants, as the case is here, a separate cost allocation step does not need to be performed. Instead, cost allocation can be combined into the rate design step. With the Commission's current policy regarding the design of the interruptible rate as the 100% load factor derivative of the firm rate, we allocate costs to the interruptible rate in the rate design step as discussed below in Step 5: Rate Design.*

Step 5: Rate Design

Rate design is the final step and is used to directly translate the costs allocated to the jurisdictional customers into unit charges or rates. Rates are designed to recover the jurisdictional cost-of-service which consists of the demand and commodity costs as determined by the cost classification and cost allocation for each service.

Firm Service Rates

Rates for firm service are usually two-part rates; that is, they contain a reservation charge and a usage charge. The reservation charge is usually a monthly charge per Dth of daily contract demand (CD). It represents the amount that a firm customer must pay monthly to guarantee service on any day up to the CD. For example, a customer with a CD of 200,000 Dth per day would pay $2,000,000 per month, if the firm reservation charge were $10.00. The $2,000,000 must be paid every month regardless of the amount of gas actually transported. Even if the customer does not transport any gas the customer must pay the reservation charge. The payment of the reservation charge reserves a right to the customer to receive service up to 200,000 Dth on any day. In addition to the monthly reservation charge, the customer is also billed a usage charge per unit of gas actually shipped.

The usage charge is a charge per Dth of gas actually transported. For example, if the customer with the CD of 200,000 Dth per day, actually transported 3,000,000 Dth during one month, that customer would pay reservation costs of $2,000,000 plus usage costs of $150,000, assuming a usage rate of $0.05 per Dth, for that month.

Interruptible Service Rates

Interruptible rates are designed as volumetric rates and charged per unit of gas transported. The Commission has had a long-standing policy that, in most cases, interruptible transportation rates should be designed as the 100% load factor derivative of the firm transportation rates. A discussion of the 100% load factor rate follows.

Interruptible Rate Computed as Derivative of Firm Rate

As mentioned, long-standing Commission policy requires that the interruptible rate be the 100% load factor derivative of the firm transportation rate. That is, the interruptible rate is derived from the firm transportation rate. The Commission determined that the 100% load factor rate was the appropriate rate for interruptible services as it makes a reasonable contribution to the fixed costs of the pipeline system, yet adequately recognizes the inferior quality of interruptible service compared to firm service.

The Commission concluded that the 100% load factor rate recovered a reasonable share of both reservation and usage costs and thus met the criteria of being a "fully allocated" rate as required by the regulations. The Commission found it was reasonable that interruptible shippers should contribute to the fixed costs of the system - since interruptible customers on most pipelines are only able to receive transportation in instances where firm customers are not using all of their firm entitlements.

Also, by paying the lowest unit rate that a firm shipper could pay for firm service, appropriately recognizes the inferior quality of interruptible service. A firm shipper would actually pay a unit rate equivalent to the 100% load factor rate if that shipper took 100% of his contact demand every day of the year.

The first step in designing the interruptible rate as a derivative of the firm transportation rate, is to design the firm transportation rates. To design the firm reservation fee, the reservation costs are divided by the contract demand volumes for firm services plus an imputed volume for interruptible service (in this case interruptible volumes are imputed at 100% load factor), multiplied by 12 months (multiplying by 12 months is necessary to compute a monthly reservation fee). The resulting reservation rate is charged to firm customers per unit of their contract demand per month. Next, the firm usage rate is computed by dividing the total usage costs by the projected annual firm and interruptible transportation volumes. This rate is charged per unit (Dth) of gas transported. Now that the firm reservation and usage rates have been computed, the 100% load factor interruptible rate is derived by dividing the firm reservation rate by 30.4 days (30.4 days represents the average days for each month of the year, 365 days/year divided by 12 months). This converts the monthly firm reservation fee to a unit daily charge. This unit daily charge is added to the firm commodity rate. The total represents the 100% load factor derivative of the firm transportation rate. This interruptible rate is charged per unit of interruptible service.

A-28 shows the derivation of the firm and interruptible transportation rates under the SFV methodology as a "one-step" process. The firm reservation rate is derived by dividing the total reservation costs by the total firm billing determinants, which include an imputed amount for interruptible service at 100% load factor. The firm billing determinants are derived by multiplying the firm contract demands of Pipeline U.S.A.'s four firm customers, plus a daily volume imputed at 100% load factor for interruptible service, by 12 months. Multiplying by 12 months is necessary to develop a monthly reservation charge.

Similarly, the firm usage rate is derived by dividing the total usage costs by the total annual projected units of firm and interruptible transportation service. This yields a firm usage rate per Dth of gas transported.

Once the firm rates are derived, we can calculate the 100% load factor interruptible rate. The interruptible rate is calculated by dividing the firm reservation rate by 30.4 days (30.4 days time 100%). This recognizes that we are designing a 100% load factor interruptible rate. If we were designing an interruptible rate equivalent to the 50% load factor derivative of the firm rate, we would divide the firm reservation rate by 15.2 days (30.4 days times 50%). The resulting rate per Dth represents the amount of reservation costs to be included in the interruptible rate. Next, to this unit reservation rate we *add the firm usage rate. The total represents the 100% load factor interruptible rate. This rate is collected per Dth of interruptible volumes transported.*

Schedules A-29 through A-32 show the calculation of firm rates, and interruptible rates computed as the 100% load factor derivative of the firm rates, using other rate design methodologies such as MFV, Seaboard, United and the Volumetric method. A-33 shows a summary sheet of the firm and interruptible rates computed under each method.

Revenue Check

Once you have designed rates, to ensure their accuracy, a revenue check must be done. To do a revenue check, the rates for each service are multiplied by the respective billing determinants. The product should "equal" the cost-of-service (revenue requirement) established for the company. Note however, the revenues generated by the revenue check will not "exactly" equal the cost of service due to rounding. Rounding errors should be negligible. The difference between the revenues generated by the rates and the cost of service generally should not differ by more than 1/100th of a percent. If the revenue check does not produce revenues that are within this guideline, there is an error in the calculation of the rates. The error needs to be found and corrected.

A-34 shows the revenue check for Pipeline U.S.A. under the SFV methodology. Due to rounding the revenues generated do not exactly equal the cost-of-service. Note, that the rounding error here is minimal $1,000/$120,430,000 = 0.00083%.

Rate Design and Load Factors

The revenue responsibility of a particular customer, or group of customers, is impacted by the rate design methodology used to design rates and the particular load factor of the customer, or group of customers. For example, a low load factor customer will have a high unit rate. A high load factor customer will have a low unit rate. A rate design which includes more costs in the commodity component of the rate, such as volumetric rates, or rates designed under the United methodology, is beneficial to low load factor firm customers. High load factor firm customers are better off under rate designs which include more costs in the demand or reservation charge, as with SFV and MFV. In order of decreasing negative impact on costs to low load factor customers, the cost classification and rate design methods can be listed as follows: SFV, MFV, Seaboard, United and Volumetric rates.

A-35 through A-38 show calculations of customers unit rates at various load factors, under each of the rate design methodologies. A-39 shows a comparison of the unit rates a firm customer would pay under various rate designs at different load factors in order of decreasing impact on low load factor customers and increasing impact on high load factor customers.

Small Customer Rates

Prior to Order No. 636, pipelines often offered bundled sales service to small customers on their systems at subsidized rates. Small customers were often defined as those that had contract demands of less than 10,000 Dth per day, although it varied by pipeline. Small customers are often low load factor customers. That is, they do not take gas at a constant amount each day of the year but tend to have seasonal fluctuations. Most pipelines had specific rate schedules on file to serve small customers. The rate was often designed on a volumetric basis and was designed at an "imputed" load factor above the actual load factor of the group of small customers. For example, if the small customer groups' load factor was 40%, the rate would be designed on something higher, like a 60% load factor. The higher the load factor, the lower the unit rate. Therefore, the small customers benefited from the rate subsidy, as well as the fact that they did not have to pay a demand charge. The volumetric rate permitted small customers to pay only when they received service.

In Order No. 636, the Commission required that pipelines that offered sales or firm transportation services to small customers on a one-part volumetric basis, at an imputed load factor, were required to continue to offer firm and no-notice service on the same basis. This grandfathering of the small customer rate was intended as a mitigation measure from the shift to the SFV rate design as required by Order No. 636. A rate design such as SFV, which includes all fixed costs in the firm reservation charge has the effect of shifting costs to low load factor customers.

A-40 shows an example of how to compute a small customer rate as a 60% load factor derivative of the firm rate. Note that demand costs are allocated to the small customer service at an imputed load factor of 60%. A-40 also shows what the small customer rate would be if the actual load factor of 40% were used to allocate costs the small customer service and design rates. As shown, the small customer rate designed at 60% is less than the rate designed at the actual load factor of 40%, and thus represents a rate subsidy.

Discounting and Discount Adjustments

As part of the move to open access transportation under Order No. 436, the Commission permitted pipelines to selectively discount their rates between an established maximum rate and established minimum rate. The maximum rate is established as the pipelines average cost of providing service. The minimum rate is the variable costs of providing the service. The Commission found this was necessary to permit pipelines to lower their rates in an effort to retain load or to capture new load in an increasingly competitive market.

The Commission later determined that if a pipeline discounted its rates for competitive reasons, pipelines could receive a "discount adjustment" when designing their rates in a rate proceeding. The Commission reasoned that if the pipeline could offer a competitive rate to retain or gain new customers, all customers of the pipeline would be better off. That is, by retaining or gaining new customers, throughput would increase and, designing rates on higher throughput would mean lower rates for all, even when those volumes were added at a discounted rate. Under this policy, the pipeline was better off as it received more revenues, and customers were better off because their rates were reduced, albeit not at the maximum rate.

There are essentially three methodologies the Commission has used in deriving an appropriate discount adjustment. These are the (1) Revenue Crediting Method, (2) Proportional/Fractional Method, and (3) Iterative Method. These will be briefly discussed in turn.

Revenue Crediting Method

Under this method, the revenue generated from discounted transactions is computed. For example, if 25,000,000 Dth of throughput were transported at a discounted rate of 40 cents per Dth, then the revenue generated from discounted transactions would be $10 million. This amount would then be credited to the pipeline's cost-of-service. Next, the discounted volumes of 25,000,000 Dth would be deducted from the total rate design determinants. Thus, rates would be computed by dividing the total cost of service adjusted for discounted revenues, by the total billing determinants adjusted for discounted volumes.

Total Cost of Service, unadjusted	$50,000,000
Discounted Revenues	(10,000,000)
Cost of Service, adjusted	$40,000,000
Total Volumes, unadjusted	100,000,000
Discounted Volumes	25,000,000
Total Volumes, adjusted	75,000,000 Dth
Maximum Rate	53.33 cents/Dth

As shown above, assuming the total cost of service adjusted for discount revenues is $40 million ($50 million less $10 million in discounted revenue), divided by the adjusted rate design volume of 75,000,000 Dth, produces a maximum rate of 53.33, or approximately 53 cents per Dth.

Proportional/Fractional Method

Under this method, total volumes transported by the pipeline are adjusted to reflect discounting by including volumes for discounted transactions in proportion to the discounted rate-to-maximum rate ratio. For example, let's say a pipeline transported 100,000,000 Dth of gas during the test period and 25% of these volumes, or 25,000,000 Dth were transported at a discounted rate. The following is an illustrative calculation of a maximum rate, adjusted for discounting using this method.

Total Cost of Service	$50,000,000
Total Volumes, unadjusted	100,000,000 Dth
Maximum Rate, unadjusted	50 cents/Dth
Total Discounted Volumes	25,000,000 Dth
Average Discounted Rate to Maximum Rate (40 cents/50 cents)	80%

Adjusted Discounted Volumes	20,000,000
Total Volumes at Maximum Rates	75,000,000
Total Volumes Adjusted for Discounting	95,000,000
Maximum Rate, adjusted (Total Cost-of-Service divided by Adjusted Volumes)	52.63 cents

As shown above, the discounted volumes that would be included in the rate design determinants would be 20,000,000 Dth (25,000,000 Dth x 80%). The total rate design volume would be 95,000,000 Dth (75,000,000 Dth transported at the maximum rate plus 20,000,000 Dth included as adjusted discounted volumes). Assuming the total cost of service of $50 million, dividing by the adjusted volumes of 95,000,000 Dth, produces a maximum rate of 52.63, or approximately 53 cents.

Iterative Method

Not surprisingly, the iterative method involves iterations in order to generate a more accurate maximum rate adjusted for discounting. This method is iterative because the maximum rate is adjusted and compared to the discounted rates, then a new discount adjustment is derived and used to compute a new maximum rate, and so on.... until the new maximum rate generated is equivalent to the maximum rate generated under the previous iteration. The litigation staff uses a complex computer generated model to compute the maximum rate adjusted for discounting under the iterative method. For a further explanation of the computer generated model, see the "Manual For Gas Pipeline Ratemaking - Introduction to Cost Allocation and Rate Design" (June, 1999) prepared by the Office of Administrative Litigation (OAL). For purposes of this manual, we will show a simplified version of the iterative method. Often, pipeline companies choose this approach. For example, let us use the proportional method example above as the first iteration.

First Iteration

Using the resulting rate derived under the proportional method above, as the first iteration, produces a maximum rate, adjusted for discounting, of 52.63 cents per Dth. To "fine tune" that rate under the iterative method we run the calculations again, this time using the 52.63 cents per Dth as the maximum rate.

Second Iteration

Total Cost of Service	$50,000,000
Total Discounted Volumes	25,000,000
Ave. Discounted Rate to New Max Rate (40 cents/52.63 cents)	76%
Adjusted Discounted Volumes	19,000,000
Total Volumes at Max Rates	75,000,000
Total Volumes Adjusted for Discounting	94,000,000
Maximum Rate, adjusted (Total Cost-of-Service divided by Adjusted Volumes)	53.19 cents

As shown, the Second Iteration produces a new Maximum Rate of 53.19 cents.

Third Iteration

Total Cost of Service	$50,000,000
Total Discounted Volumes	25,000,000
Ave. Discounted Rate to New Max Rate (40 cents/53.19 cents)	75.2 %
Adjusted Discounted Volumes	18,800,000
Total Volumes at Max Rates	75,000,000
Total Volumes Adjusted for Discounting	93,800,000
Maximum Rate, adjusted (Total Cost-of-Service divided by Adjusted Volumes)	53.30 cents

The Third Iteration produces a new Maximum Rate of 53.30 cents.

Fourth Iteration

Total Cost of Service	$50,000,000
Total Discounted Volumes	25,000,000
Ave. Discounted Rate to New Max Rate (40 cents/53.30 cents)	75.05%
Adjusted Discounted Volumes	18,762,500
Total Volumes at Max Rates	75,000,000

Total Volumes Adjusted for Discounting	93,762,500
Maximum Rate, adjusted (Total Cost-of-Service divided by Adjusted Volumes)	53.33 cents

The Fourth Iteration produces a new Maximum Rate of 53.33 cents.

Fifth Iteration

Total Cost of Service	$50,000,000
Total Discounted Volumes	25,000,000
Ave. Discounted Rate to New Max Rate (40 cents/53.33 cents)	75%
Adjusted Discounted Volumes	18,750,000
Total Volumes at Max Rates	75,000,000
Total Volumes Adjusted for Discounting	93,750,000
Maximum Rate, adjusted (Total Cost-of-Service divided by Adjusted Volumes)	53.33 cents

The Fifth Iteration produces the same Maximum Rate of 53.33 cents, calculated in the Fourth Iteration. This is an indication it is time to stop the iterations and use the 53.33 cents as the Maximum Rate adjusted for discounting.

Note: All things being equal, i.e. cost-of-service, discount volumes, average discount rate, maximum unadjusted rate, the three methods produce similar results. As shown above, the maximum rate adjusted for discounting approximates 53 cents per Dth under each method. Note that under the revenue crediting method and the iterative method the same result of 53.33 cents is calculated.

Distance Based Rates

The regulations require that rates be calculated to reasonably reflect any material variation in costs with regard to the distance the natural gas is transported. Distance based rates are used to reflect that the cost of transporting natural gas increases with the distance the gas is transported. With distance based rates, customers close to the source(s) of supply, or points of receipt, pay lower rates. Customers farther away from the source(s) of supply, or points of receipt pay higher rates. Distance-based rates are appropriate for long-line pipeline systems with one directional gas flow and varied load density. There are different methods for calculating distance based rates, such as,

- Mileage Based Rates Under this method a rate per mile of haul, or per 100 miles of haul, is calculated. Customers are billed based on the rate per dth-mile, multiplied by the number of miles the gas is transported, multiplied by the quantities of gas transported.

- Zoned Rates Under this method the pipeline is divided into geographic segments called zones. Zones are often several hundreds of miles in length and usually incorporate one or more load centers (markets). With zoned based rates, in any given zone, each customer is assessed the same relative cost responsibility and are assessed the same rates regardless of where they are located within a zone. Costs are allocated to the zones based on "Dth-Miles." Dth-Miles are calculated by multiplying each customer's volume (Dth) from each source of supply, or receipt point, by the number of miles between each source of supply (receipt point) and the customer's delivery point. The Dth-Miles are totaled for each zone and ratios are calculated based on each zones total Dth-Miles to the total of all zones Dth-Miles. These ratios are then used to allocate costs to the respective zones. Rates are developed for each zone based on these allocated costs. Customers that take delivery of gas in Zone 1 are charged the Zone 1 rates. Customers that take delivery of gas in Zone 2, pay the Zone 2 rates.

Not all costs vary with distance. There are mileage and non-mileage related costs. Only the "Mileage Related Costs" vary with distance and are allocated to the zones based on Mdt-miles.

<u>Mileage Costs</u> Generally all transmission fixed and variable costs, excluding Administrative and General Expenses, are considered to be costs that increase with the distance the gas is transported.

<u>Non-mileage Costs</u> Administrative and General Expenses, which include expenses related to salaries of administrative personnel and office supplies, are not considered to increase with the distance the gas is transported. Supervision and Engineering, Storage costs and Account No. 858 costs, are not considered to vary with distance. All customers pay the same unit rate for these costs, as these costs do not increase with the distance the gas is transported. The non-mileage costs are usually presented in a pipeline's tariff as separately stated "Access Charges," or these costs may be embedded in the total zone of delivery rate under "Matrix Charges." These are different methods for stating, or presenting, the rates in the tariff and often will not result in any rate difference for a shipper.

<u>Access Charges</u>: Some pipelines have separately stated "Access Charges" which collect the non-mileaged costs. These "Access Charges" represent the costs of accessing a pipeline system for service.

In addition to paying the access charge, a shipper would pay a mileage rate for each zone through which the shipper's gas is transported.

Matrix Charges Often pipelines with zone-based rates show these rates in their tariffs in matrix form. A matrix shows the total rate that will be paid by a shipper depending on the zone in which the gas is received and the zone in which the gas is delivered. Under matrix charges, the "access charge" is included in the total rate. For a two zone system such as Pipeline U.S.A., the matrix would include the following combinations of receipt and delivery patterns a shipper could use: Zone 1 to Zone 1; Zone 1 to Zone 2; and Zone 2 to Zone 2. (These represent the forward haul options.) As shown on Page 56, the Zoned Rates/Dth appearing at the bottom of the page represent zoned rates presented in a matrix. Missing from this matrix is rates for transportation where the gas is received and delivered in Zone 2. The rates for a within Zone 2 transportation service in this example would be $5.3400 reservation and $0.0056 usage. The derivation of these rates is described in more detail below.

The following page shows an example calculation of zoned rates for Pipeline U.S.A. First, as shown on Page 56, total reservation and usage costs are shown broken out between mileage and non-mileage related costs. The Mileage costs are allocated to the zones based on the Dth-mile study shown on Page 57. The allocated mileage costs for each zone are divided by the respective zoned billing determinants. These billing determinants are based on delivered amounts to each zone (as opposed to amounts traversing a zone), to arrive at the Mileage component of the rate. Next, the non-mileage rate is computed by dividing the non-mileage costs by the total system billing determinants to arrive at the non mileage rate component. Finally, the zoned "matrix" rates are computed by adding the mileage and non-mileage rate components for each zone. As shown, for deliveries in Zone 1 the customer pays a reservation charge of $5.2299 per Dth of contract demand and a usage charge of $0.0054 per Dth of gas transported. For deliveries in Zone 2 the customer pays a reservation charge of $10.1863 per Dth and a usage charge of $0.0110 per Dth of gas transported. Notice how these rates compare to the postage-stamp rate computed consisting of a $9.1951 reservation fee and a $0.0099 usage rate (A-28).

Calculation of Zoned Rates for Pipeline U.S.A.

		Reservation	**Usage**
Total Costs:		$117,831,000	$2,600,000
Mileage (96%)		$112,915,000	$2,600,000
Non-mileage (4%)		$4,916,000	$0
Allocation Factors (Dth-Miles):			
Zone 1	11%	29,923,680	29,923,680
Zone 2	89%	249,004,520	249,004,520
Total	100%	278,928,210	278,928,210
Allocated Mileage Costs:			
Zone 1		$12,420,650	$286,000
Zone 2		$100,494,350	$2,314,000
Total		$112,915,000	$2,600,000
Billing Determinants:			
Zone 1	20%	2,562,904	52,470,200
Zone 2	80%	10,251,617	209,880,800
Total	100%	12,814,521	262,351,000

Mileage Rates/Dth:

Zone 1	$4.8463	$0.0054
Zone 2	$9.8027	$0.0110
Non-mileage Rate/Dth:	$0.3836	$0.0000
Zoned Rates/Dth:		
Zone 1	$5.2299	$0.0054
Zone 2	$10.1863	$0.0110

Calculation of Dth-Miles - Assumptions

- 370 mile pipeline
- 2 Zones, 185 miles each
- 20% of volumes delivered in Zone 1, 80% delivered in Zone 2
- 100% of volumes enter in Zone 1 at two receipt points, R1 and R2
- 4 customers, 2 in each zone

Zone 1 Customer A

R1	Miles	Dth-Miles
10,402 Dth	90	936,180

R2	Miles	Dth-Miles
93,882 Dth	120	11,258,640

Customer B

R1	Miles	Dth-Miles

51,388 Dth	160	8,222,080

R2	Miles	Dth-Miles
51,388 Dth	185	9,506,780

Total Zone 1 Dth-Miles **29,923,680 (11%)**

Zone 2 Customer C

R1	Miles	Dth-Miles
145,704 Dth	250	36,426,000

R2	Miles	Dth-Miles
339,868 Dth	280	95,163,040

Customer D

R1	Miles	Dth-Miles
308,196 Dth	340	104,786,640

R2	Miles	Dth-Miles
34,232 Dth	370	12,628,840

Total Zone 2 Dth-Miles **249,004,520 (89%)**

Total Zone 1 and Zone 2 Dth-Miles **278,928,210 (100%)**

Storage Services and Rates

This manual has been dedicated primarily to developing a cost of service and designing rates for Pipeline U.S.A.'s transmission function. Many post-Order No. 636 pipeline's have storage functions as well as transmission functions. Storage fields can be used by a pipeline to support system operations (for example, to provide system balancing or support for no-notice transportation services), to provide contract storage service (storage service to third parties), or a combination of both. When a pipeline's storage fields are used entirely to support system operations, the storage costs are classified and allocated in the same manner as transmission costs. However, in situations where the pipeline uses its storage fields to provide both system operations support and contract storage service, or in situations where the pipeline uses its storage fields solely to provide contract storage service, the storage costs are classified and allocated in the manner described below.

Classification of Storage Costs For pipelines that offer contract storage service, storage function costs are classified using the Equitable method. Under the Equitable method, all fixed storage costs are classified equally between the "Deliverability" and "Capacity" components; that is, 50% of the total storage fixed costs are classified to the "Deliverability" component and 50% are classified to the "Capacity" component. All storage function variable costs are classified to the "Injection/Withdrawal" component. This storage function classification, which is also used for rate design, recognizes that fixed storage costs are incurred to support the storage field's deliverability and capacity functions. The "Deliverability" function of a storage field refers to the ability of the storage field to withdraw gas on a particular day. The "Capacity" function refers to the storage field's capacity to store gas for a designated customer or for system operations. The "Injection/Withdrawal" component refers to the storage fields function injecting and withdrawing gas for customers or for system operations. Therefore, the Commission has reasoned that such costs are properly apportioned between the deliverability and capacity components. Storage variable costs, however, are incurred as gas is injected into and out of the storage field, therefore, are appropriately assigned to the injection/withdrawal component.

Allocation of Storage Costs If the pipeline uses the storage field for system operations (such as for balancing or no-notice services), and to provide contract storage service to third parties, costs are allocated between system and contract storage services after the costs have been classified to the "Deliverability," "Capacity" and "Injection/Withdrawal" components. The storage costs allocated to "system storage" are then re-classified using the same manner as transmission function costs. Transportation rates, which include the reclassified storage costs, are then designed.

Design of Firm Contract Storage Rates The costs allocated to contract storage service remain classified as "Deliverability," "Capacity," and "Injection/Withdrawal" for rate design purposes. The firm contract storage rates are designed by dividing the Deliverability and Capacity costs by the certificated deliverability (and imputed deliverability at 100% load factor for interruptible storage service) and capacity of the storage field(s) (plus projection for interruptible storage volumes) (multiplied by 12 months), respectively. The result is a monthly Deliverability charge and a monthly Capacity charge, which are similar to a firm transportation reservation charge. These rates are assessed monthly per each firm customer's contract level for deliverability and capacity. The Injection/Withdrawal costs are divided by the annual projection of injection and withdrawal activity. The Injection/Withdrawal charge is assessed per unit of volumes actually injected or withdrawn by each firm and interruptible customer. Volumes are included in the design of the firm storage rates for interruptible storage service, in order to allocate deliverability, capacity and injection/withdrawal costs to the interruptible storage service. The design of interruptible storage rates follows.

Design of Interruptible Contract Storage Rates

As with interruptible transportation rates, interruptible storage rates are typically computed as the 100% load factor derivative of the firm contract storage rates. There are essentially two methods for computing 100% load factor storage rates.

Under the first and most predominate method, the firm monthly deliverability rate is converted to a monthly capacity charge and added to the firm capacity charge. This combined deliverability and capacity charge is assessed per Dth of each interruptible storage customer's average inventory balance in storage for a given month. To convert the firm deliverability charge you need to know the ratio of deliverability to capacity. Let's assume this ratio is 1/50. This represents the Maximum Daily Withdrawal Quantity divided by the Maximum Storage Quantity. This ratio is then multiplied by the monthly deliverability rate and added to the monthly capacity charge. Another way to calculate this combined charge is to add the total Deliverability and Capacity costs together and divide by the Capacity billing determinants. The interruptible storage customer is also assessed an injection/withdrawal charge for each unit of gas injected into or withdrawn from the storage fields.

Under the second method, the firm monthly deliverability charge is converted to a rate per Dth of gas either injected or withdrawn. The unit deliverability charge can then be assessed either per unit of gas injected, or per unit of gas withdrawn. The monthly capacity charge remains unchanged and is assessed each month on an interruptible contract storage customer's average balance in storage for a given month.

Summary Cost of Service A-1

(000's omitted)

Return	$53,067
O & M Expenses	7,900
A & G Expenses	3,416
Depreciation Expense	25,163
Income Taxes	14,197
Non Income Taxes	16,687
Revenue Credits	0
Total Cost of Service	$120,430 *

* Note: If you added the numbers on this page they would total $120,430! The total on this page reflects the rounding up, of the total cost-of-service of $120,430,922 as generated by the computer. You will see instances of rounding throughout these Appendices.

A-2

Rate Base

Gross Plant	$630,580,000
Accumulated Depreciation	-75,489,600
Net Plant	555,090,400
Accumulated Deferred Income Taxes	-24,085,000
Working Capital	1,000,000
Total Rate Base	532,005,400

A-3

Itemized Gross Plant

Land & Land Rights	$1,500,000
Right of Way	28,533,600
Pipeline	500,437,000
Compression	61,593,800
Metering Stations	5,062,846
AFUDC *	33,452,754
Gross Plant	$630,580,000

* For illustrative purposes, AFUDC is shown here separately.
However, AFUDC is subsumed in the gas plant accounts

(for pipeline, compression, and meter stations).

A-4

Accumulated Reserve for Depreciation

(000's omitted)

	Depreciation Expense	Accumulated Reserve for Depreciation
Year 1	$25,163	$25,163
Year 2	25,163	50,326
Year 3	25,163	75,490

Note: Depreciation expense is accumulated for book purposes even if the pipeline finds itself in the unlikely position of not generating enough revenue to cover all of its depreciation allowance.

A-5

Accumulated Deferred Income Taxes (ADIT)
(000's omitted)

Year	Commission Straight-line Depreciation Exp	IRS Accelerated Dep. (DDB) *	Difference Times Composite Tax Rate of 37.79% **	Accumulated Surplus
1	25,163	50,326	9,509	9,509
2	25,163	46,300	7,988	17,497
3	25,163	42,596	6,588	24,085

* Double Declining Balance is computed as twice the straight-line depreciation rate (2 * 4%) times net depreciable plant.
** See A-13 for computation of Composite Tax Rate.

A-6

Working Capital

(000's omitted)

Month	Materials & Supplies	Pre-Payment	Total
Jan	800	230	1,030
Feb	850	290	1,140
March	825	350	1,175
April	799	325	1,124
May	740	400	1,140
June	780	376	1,156
July	735	354	1,089
August	620	300	920
Sept	600	200	800
Oct	596	300	896
Nov	540	300	840
Dec	580	200	780
Jan	635	275	910
13 month Total	9,100	3,900	13,000
13 month Average	700	300	1,000

A-7

Return
(000's omitted)

Rate Base	$532,005
Overall Rate of Return	9.975%
Return	$53,067

A-8

Capital Structure and Rate of Return

(000's omitted)

	Rate Base	Capital Structure	Cost	Weighted Cost	Return	
	(1)	(2)	(3)	(4) Col (2) * Col (3)	(5)	
Long Term Debt	$372,403	70.00%	8.25%	5.775%	$30,723	1/
Common Equity	$159,602	30.00%	14.00%	4.200%	$22,344	2/
Total	$532,005	100.00%		9.975%	$53,067	

1/ $532,005,000 * 5.775%

2/ $532,005,000 * 4.20%

A-9

Pretax Return Calculation

Step 1: Calculate Combined Federal / State Tax Rate

= 37.79% (See A-13)

Step 2: Use Pretax Return Formula:

$$\text{ROR} + \frac{\text{Combined Effective Tax Rate (ROR - Weighted Debt \%)}}{\text{(1-Combined Effective Tax Rate)}}$$

$$9.975\% + \frac{37.79\%\ (9.975\% - 5.775\%)}{(1 - 37.79\%)}$$

$$= 12.53\%$$

Note: This formula calculates pretax return net of tax adjustments i.e. AFUDC.

A-10

Transmission O & M and A & G Expenses

(000's omitted)

		Amount
850	Supervisory & Engineering	$1,500
851	System Control & Dispatching	200
852	Communication System Expense	200
853	Compressor Station Operating Exp (Labor)	500
853	Compressor Stat. Oper. Exp. (Material & Other)	1,000
856	Mains	2,000
857	M & R Station Expense (Labor)	200
857	M & R Station Exp. (Material and Other)	600
Total Operating Expense		**$6,200**
862	Maintenance of Mains	100
864	Maint. of Compressor Station Equipment (Labor)	400
864	Maint. of Comp. Station Equip. (Material and Other)	1,000
865	Maint. of M & R Equipment	100
866	Maint. of Communication Equipment	100
Total Maintenance Expense		**$1,700**
Total Operation & Maintenance Expense		**$7,900**
920	A & G Salaries	$1,072
921	Office Expenses	188
923	Outside Services	1,072
924	Property Insurance	200
928	Regulatory Commission Expense	190
931	Rents	379
935	General Plant Maintenance	315
Total Transmission A & G		**$3,416**
Total O&M and A&G Expenses		**$11,316**

A-11

Calculation of Depreciation

(000's omitted)

Depreciation		
Gross Plant	$630,580	
Less Value of Land	-1,500	(A-3)
Depreciable Plant	629,080	
Depreciation Rate	4.0%	(100% / 25 years)
Depreciation Expense	$25,163	

A-12

Income Taxes

Line		
	Federal Tax Calculation	
1	Return	53,067
2	Less: Interest (5.78 * Rate Base)	-30,723
3	Equity Return	22,344
4	Plus: AFUDC Equity	1,029
5	Taxable Income	23,373
6	Federal Tax Factor (.35/(1-.35))	0.5385
7	Federal Income Tax (Line 5 * Line 6)	12,585
	State Tax Rate	
8	Taxable Income (Line 5)	23,373
9	Plus: Federal Income Tax Allowance (Line 7)	12,585
10	State Taxable Income	35,958
11	State Tax Factor (.0429/(1-.0429))	0.0448
12	State Income Tax (Line 10 * Line 11)	1,612
13	Total Income Taxes (Line 7 + Line 12)	14,197
	Composite Rate Tax Method	
14	Return	53,067
15	Less: Interest	-30,723
16	Equity Return	22,344
17	Plus: AFUDC Equity	1,029
18	Taxable Income	23,373
19	Composite Tax Factor (.3779/(1-.3779))	0.6075
20	Total Income Taxes	14,198

A-13

Computation of Composite Tax Rate or Combined Effective Tax Rate

Formula:

Federal Tax Rate (35%) * the effective State Tax Rate = X

.35 - x = y

y + State Rate = Composite Tax Rate

Calculation:

State Tax Rate = 4.29%

35% * 4.29% = .0150

.35 - .0150 = .3350

.3350 + .0429 = .3779 or 37.79%

A-14

Other Taxes (Non-Income)

(000's omitted)

Property and Employment Taxes	$16,687

A-15

Functionalized Cost of Service

(000's omitted)

	Transmission	Storage
Return	$53,067	$50,893
O & M Expenses	$7,900	3,250
A & G Expenses	$3,416	2,000
Depreciation Expense	$25,163	24,234
Income Taxes	$14,197	12,944
Non Income Taxes	$16,687	8,000
Revenue Credits	$0	-1,000
Total Cost of Service	$120,431	$100,321

A-16

Functionalization of A&G Costs: KN Method

(000's omitted)

A&G Expenses	Total	Labor	Plant	Other
A&G Salaries	$1,700	$1,700		
Office Expense	300	300		
Outside Service	1,700			1,700
Property Insurance	316		316	
Regulatory Comm Exp	300			300
Rents	600	600		
General Plant	500		500	
Total	5,416	2,600	816	2,000
Other 1/		1,520 *	480 **	-2,000
Total	$5,416	$4,120	$1,296	

Allocation Factors:	Total	Storage	Transmission
Direct Labor Costs	2,286	686	1,600
Direct Labor Percentage	100.00%	30%	70%
Gross Plant Costs	1,538,000	907,420	630,580
Gross Plant Percentage	100.00%	59%	41%

Allocation of A&G:			
Direct Labor	4,120	1,235	2,885
Gross Plant	1,296	765	531
Total	5,416	2,000	3,416

1/ The $2,000 of Other Costs are allocated between the Labor and Plant columns in the same ratio as the totals of the Labor and Plant columns (76% Labor*/24% Plant**).

* ($2,600/($2,600+$816)) = 76% Labor

** ($816/($2,600+$816)) = 24% Plant

A-17

Classification of Costs Between Fixed and Variable

(000's omitted)

	Fixed	Variable
Return	$53,067	
O & M Expenses	5,300	2,600
A & G Expenses	3,416	
Depreciation	25,163	
Income Taxes	14,197	
Non-Income Taxes	16,687	
Revenue Credits	0	
Total	$117,831	$2,600

A-18

Classification of Costs Between Demand and Commodity

(000's omitted)

A. 100% Commodity or Volumetric

- 100% Fixed Costs to Commodity
- 100% Variable Costs to Commodity

Total Costs	Fixed Costs	Variable Costs	Demand Costs	Commodity Costs
$120,431	117,831	2,600		120,431

A-19

Classification of Costs Between

Demand and Commodity

(000's omitted)

B. Straight Fixed Variable Rate Design

- 100% Fixed Costs to Demand
- 100% Viarable Costs to Commodity

Total Costs	Fixed Costs	Variable Costs	Demand Costs	Commodity Costs
$120,431	117,831	2,600	117,831	2,600

A-20

Classification of Costs Between Demand and Commodity

(000's omitted)

C. Seaboard Rate Design

- 50% of Fixed Costs are Classified to Demand
- 50% of Fixed Costs are Classified to Commodity
- 100% of Variable Costs are Classified to Commodity

Total Costs	Fixed Costs	Variable Costs	Demand Costs	Commodity Costs
$120,431	117,831	2,600	58,915	61,515

A-21

Classification of Costs Between

Demand and Commodity

(000's omitted)

D. United Rate Design

- 25% of Fixed Costs are Classified to Demand
- 75% of Fixed Costs areClassified to Commodity
- 100% of Variable Costs are Classified to Commodity

Total Costs	Fixed Costs	Variable Costs	Demand Costs	Commodity Costs
$120,431	117,831	2,600	29,458	90,973

A-22

Classification of Costs Between

Demand and Commodity

(000's omitted)

E. Modified Fixed - Variable (MFV) Rate Design

- All fixed Costs are Classified to Demand Except for Return on Equity and Income Taxes
- Return on Equity and Incomes Taxes are Classified to Commodity
- 100% Variable Costs are Classified to Commodity

Total Costs	Fixed Costs	Variable Costs	Demand Costs	Commodity Costs
$120,431	117,831	2,600	81,289	39,141

A-23

Transportation Service Levels

Allocation Factors and Billing Determinants

Firm Transportation Service

Reservation Billing Determinants:

Conversion to Dth: 1,000,000 Mcf * 1.035 Dth/Mcf = 1,035,000 Dth

Firm Contract Demand:	1,035,000	Dth/day	* 12	=	12,420,000	Dth
Annual Usage Quanitites:	250,351,000	Dth				
Average Day	250,351,000	/	365	=	685,893	Dth

Interruptible Transportation Service

Annual IT Quantities:	12,000,000					
Average Day:	12,000,000	/	365	=	32,877	Dth

A-24

Load Factors

Firm Service Average Load Factor

Average Day		685,893	Dth
		÷	
Daily Contract Demand (capacity)		1,035,000	Dth
Load Factor	=	66%	

System Average Load Factor

Average Day (including IT)		718,770	Dth
		÷	
Daily Contract Demand		1,035,000	Dth
Load Factor	=	69%	

A-25

Cost Allocation (SFV)

Allocation of Costs Between Firm and Interruptible Transportation Services

Total Costs	Reservation Costs	Usage Costs
$120,431	117,831	2,600

Allocation Factors (dth)

Firm	1,035,000	250,351,000
Interruptible	32,878	12,000,000
Total	1,067,878	262,351,000

Allocated Costs:

Firm	$114,203	$2,481
Interruptible	$3,628	$119
Total	$117,831	$2,600

A-26

Firm Transportation Rate Design (SFV)

(000's omitted)

		Reservation	Usage
Allocated Costs		$114,203	$2,481
Billing Determinants		12,420 *	250,351
Rates:	Max	$9.1951	$0.0099
	Min		$0.0099

* Reservation Billing Determinants = 1,035,000 Dth (CD) x 12 months

A-27

Interruptible Transportation Rate Design (SFV)
(000's omitted)

		Reservation	Usage	Total
Allocated Costs		$3,628	$119	$3,747
Billing Determinants				12,000
Rates:	Max			$0.3122
	Min			$0.0099

A-28

Cost Allocation and Rate Design (SFV)

	Reservation	Usage	
Total Costs (000's omitted)	$117,831	$2,600	
Billing Determinants			
Firm	12,420,000	250,351,000	
Interruptible	394,521 *	12,000,000	
Total	12,814,521	262,351,000	
Rates:			
Firm	$9.1951	$0.0099	
Interruptible		$0.3124	**

* (12,000,000/365)*12 = 394,521
** (9.1951/30.4)+.0099 = $.3124

A-29

Cost Allocation and Rate Design (MFV)

	Reservation	Usage
Total Costs (000's omitted)	$81,289	$39,141
Billing Determinants		
Firm	12,420,000	250,351,000
Interruptible	394,521 *	12,000,000
Total	12,814,521	262,351,000
Rates:		
Firm	$6.3435	$0.1492
Interruptible		$0.3579 **

* (12,000,000/365) * 12 = 394,521
** (6.3435/30.4) + .1492 = $.3579

A-30

Cost Allocation and Rate Design (Seaboard)

	Reservation	Usage
Total Costs (000's omitted)	$58,915	$61,515
Billing Determinants		
Firm	12,420,000	250,351,000
Interruptible	394,521 *	12,000,000
Total	12,814,521	262,351,000
Rates:		
Firm	$4.5976	$0.2345
Interruptible		$0.3857 **

* (12,000,000/365) * 12 = 394,521
** (4.5975/30.4) + .2345 = $.3857

A-31

Cost Allocation and Rate Design (United)

	Reservation	Usage
Total Costs (000's omitted)	$29,458	$90,973
Billing Determinants		
Firm	12,420,000	250,351,000
Interruptible	394,521 *	12,000,000
Total	12,814,521	262,351,000
Rates:		
Firm	$2.2988	$0.3468
Interruptible		$0.4224 **

* (12,000,000/365) * 12 = 394,521

** (2.2988/30.4) + .3468 = $.4224

A-32

Cost Allocation and Rate Design (Volumetric)

	Reservation	Usage	Total
Total Costs (000's omitted)	$117,831	$2,600	$120,431
Billing Determinants			
Firm			250,351,000
Interruptible			12,000,000
Total			262,351,000
Rates:			
Firm			$0.4590
Interruptible			$0.4590

A-33

Summary of Rates Under Different Rate Design Methods

	Firm Rates		Interruptible Rates
	Reservation	Commodity	@ 100% Load Factor
SFV	$9.1951	$0.0099	$0.3124
MFV	$6.3435	$0.1492	$0.3579
Seaboard	$4.5976	$0.2345	$0.3857
United	$2.2988	$0.3468	$0.4224
Volumetric		$0.4590	$0.4590

A-34

Revenue Check (SFV)

	Rates		Billing Determinants (000's omitted)		Revenue (000's omitted)	
	Reservation	Usage	Reservation	Usage	Reservation	Usage
Firm	$9.1951	$0.0099	12,420	250,351	$114,203	$2,478
Interruptible		$0.3124		12,000		$3,749

Total Reservation and Usage Revenue	$120,430
Total Cost of Service	$120,431
Difference	($1)

A-35

Effects of Load Factor and Rate Design (SFV)

Assume:

Customer A - Low Annual Load Factor Customer - 10%

							Unit Rates
Reservation	200,000 * 12 *	$9.1951	=	$22,068,263			
Usage	20,000 * 365 *	$0.0099	=	$72,346			
				$22,140,609	/	7,300,000 dt = (20,000*365)	$3.0330

Customer B - Average Annual Load Factor Customer - 50%

Reservation	200,000 * 12 *	$9.1951	=	$22,068,263			
Usage	100,000 * 365 *	$0.0099	=	$361,729			
				$22,429,992	/	36,500,000 dt = (100,000*365)	$0.6145

Customer C - High Annual Load Factor Customer - 100%

Reservation	200,000 * 12 *	$9.1951	=	$22,068,263			
Usage	200,000 * 365 *	$0.0099	=	$723,458			
				$22,791,722	/	73,000,000 dt = (200,000*365)	$0.3122

A-36

Effects of Load Factor and Rate Design (MFV)

Assume:

Customer A - Low Annual Load Factor Customer - 10%

Reservation	200,000 * 12 *	$6.3435 =	$15,224,400			**Unit Rates**
Usage	20,000 * 365 *	$0.1492 =	$1,089,160			
			$16,313,560	/	7,300,000 dt = (20,000*365)	$2.2347

Customer B - Average Annual Load Factor Customer - 50%

Reservation	200,000 * 12 *	$6.3435 =	$15,224,400			
Usage	100,000 * 365 *	$0.1492 =	$5,445,800			
			$20,670,200	/	36,500,000 dt = (100,000*365)	$0.5663

Customer C - High Annual Load Factor Customer - 100%

Reservation	200,000 * 12 *	$6.3435 =	$15,224,400			
Usage	200,000 * 365 *	$0.1492 =	$10,891,600			
			$26,116,000	/	73,000,000 dt = (200,000*365)	$0.3578

A-37

Effects of Load Factor and Rate Design (Seaboard)

Assume:

Customer A - Low Annual Load Factor Customer - 10%

Reservation	200,000 * 12 *	$4.5976 =	$11,034,240			**Unit Rates**
Usage	20,000 * 365 *	$0.2345 =	$1,711,850			
			$12,746,090	/	7,300,000 dt = (20,000*365)	$1.7460

Customer B - Average Annual Load Factor Customer - 50%

Reservation	200,000 * 12 *	$4.5976 =	$11,034,240			
Usage	100,000 * 365 *	$0.2345 =	$8,559,250			
			$19,593,490	/	36,500,000 dt = (100,000*365)	$0.5368

Customer C - High Annual Load Factor Customer - 100%

Reservation	200,000 * 12 *	$4.5976 =	$11,034,240			
Usage	200,000 * 365 *	$0.2345 =	$17,118,500			
			$28,152,740	/	73,000,000 dt = (200,000*365)	$0.3857

A-38

Effects of Load Factor and Rate Design (United)

Assume:

Customer A - Low Annual Load Factor Customer - 10%

							Unit Rates
Reservation	200,000 * 12 *	$2.2988 =	$5,517,120				
Usage	20,000 * 365 *	$0.3468 =	$2,531,640				
			$8,048,760	/	7,300,000 dt (20,000*365)	=	$1.1026

Customer B - Average Annual Load Factor Customer - 50%

Reservation	200,000 * 12 *	$2.2988 =	$5,517,120				
Usage	100,000 * 365 *	$0.3468 =	$12,658,200				
			$18,175,320	/	36,500,000 dt (100,000*365)	=	$0.4980

Customer C - High Annual Load Factor Customer - 100%

Reservation	200,000 * 12 *	$2.2988 =	$5,517,120				
Usage	200,000 * 365 *	$0.3468 =	$25,316,400				
			$30,833,520	/	73,000,000 dt (200,000*365)	=	$0.4224

A-39

Summary of the Effects of
Rate Design and Load Factors

Rate Design	Load Factors 10%	50%	100%
SFV	$3.0330	$0.6145	$0.3124
MFV	$2.2347	$0.5663	$0.3578
Seaboard	$1.7460	$0.5368	$0.3857
United	$1.1026	$0.4980	$0.4224
Volumetric	$0.4590	$0.4590	$0.4590

Note: Rates are in order of decreasing impact on low load factor customers, and increasing impact on high low factor customers.

A-40

Small Customer Rates (SFV) @ 40% and 60% Load Factors

	Reservation		Usage	
Total Costs	$117,831		$2,600	
(000's omitted)				
Billing Determinants				
Firm	12,420,000		250,351,000	
Interruptible	394,521		12,000,000	
Small Customer	547,945	**1/**	10,000,000	
Total	13,362,466		272,351,000	
Rates:				
Firm	$8.8181		$0.0095	
Interruptible			$0.2996	
Small Customer @ 60% Load Factor			$0.4929	**2/**
Billing Determinants				
Firm	12,420,000		250,351,000	
Interruptible	394,521		12,000,000	
Small Customer	821,918	**3/**	10,000,000	
Total	13,636,438		272,351,000	
Rates:				
Firm	$8.6409		$0.0095	
Interruptible			$0.2937	
Small Customer @ 40% Load Factor			$0.7201	**4/**

1/ Reservation volumes are imputed at 60% load factor ((10,000,000 dth/(365*60%) * 12))
2/ $8.8180/(30.4*.60) $0.4929
3/ Reservation volumes are imputed at 40% load factor ((10,000,000 dth/(365*40%) * 12))
4/ $8.6409/(30.4*.40) $0.7201