



Canadian
Gas Association

Association
Canadienne du Gaz

Rate Regulatory Framework

CANADIAN GAS ASSOCIATION

REGULATORY COURSE

PREPARED

BY

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DEFINITION OF A PUBLIC UTILITY

All aspects of the Canadian natural gas industry, from field gathering activities through transportation and distribution are heavily regulated by governmental authorities. The government directly enters into the day-to-day operation of public utilities because public utilities are defined as companies “clothed or affected with a public interest”.⁷ There is no naturally occurring situation which automatically defines an enterprise to be a public utility, and no iron-clad reason for designating all functions of a public utility as being in the public interest. It should be noted, however, that public policy is currently moving towards deregulation, open access between buyers and sellers, denial of full recovery, standard assets, and performance-based rate making in the electric utility business. Natural gas may follow.⁸ Indeed, current market trends indicate that more and more functions performed by a local gas distribution company can be unbundled from the utility and provided within competitive markets.⁹

Notwithstanding the flux in the current regulatory environment facing natural gas companies, there is a strong need to understand the existing regulatory framework.

THE ECONOMIC RATIONALE FOR REGULATION OF PUBLIC UTILITIES

The economic rationale for regulating public utilities encompasses the following three arguments.

1. Public utilities constitute a large part of the economy’s infrastructure of essential services. Competition in the infrastructure of essential services entails a needless waste of resources deemed not to be in the public interest.

⁷ A.E. Kahn, the Economics of Regulation, Wiley, 1970, Volume One, page 3.

⁸ Peter Navarro, “Electric Utilities: The Argument for Radical Deregulation”, Harvard Business Review, January-February 1996

⁹ However, it is clear that the common carrier concept is a more appropriate structure that having many competitors’ distribution pipe attached to a single natural gas customer.



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2. Many public utilities are “natural monopolies”, which are companies with such large economies of scale that their costs of production are lower than any other provider.¹⁰
3. Competition of the provision of the product simply does not work well (e.g., cut-throat competition leads to marketplace instability).¹¹

DIMENSIONS OF REGULATION

The government regulates public utilities along four dimensions:

1. control of entry;
2. price fixing;
3. prescription of quality and conditions of service; and
4. the imposition on an obligation to serve all applicants under reasonable conditions.

REGULATING THE RATE LEVEL

While there are four dimensions in the regulation of public utilities, by far the greatest degree of regulatory effort lies in the control over price. Because of the social importance of the product to consumers, the regulated public utility is given a monopoly franchise and provided with a relatively stable business environment with the opportunity to earn a fair return on its invested capital. The public utility, however, is not guaranteed a return. In addition, most public utilities face competition from substitute products.

¹⁰ Strictly speaking sun-additivity of costs is the condition for the creation of a natural monopoly. See J.C. Bonbright, A.L. Danielsen, and D.R. Kamershen, Principles of Public Utility Rates, Public Utilities Reports, Second Edition, 1988, page 23.

¹¹ A.E. Kahn, The Economics of Regulation, Wiley, 1970, Volume One, page 10.



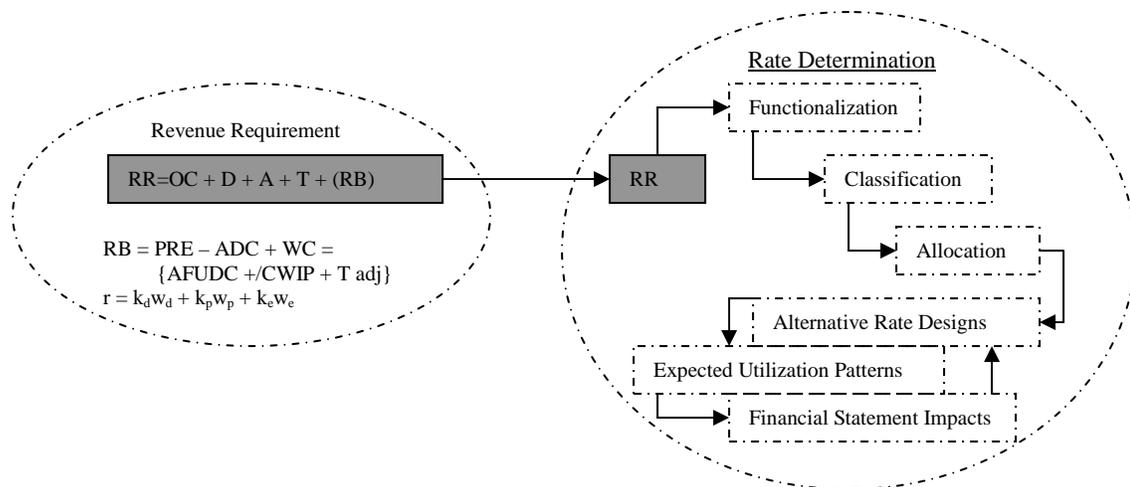
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The basic concept behind traditional rate regulation is the willingness of the regulator to allow the public utility to recover all valid costs through the price setting mechanism. In stark contrast to the private sector, the regulator allows the public utility to explicitly recover a profit. The mechanism for doing so is the addition to total costs of a component called “return on rate base”, where rate base is reflective of the assets of the utility and the return is a percentage applied to the rate base. Together, cost of service plus return is known as revenue requirement and this model of price control is called “rate of return on rate base” regulation. It is still the most common form of price regulation for public utilities in Canada.

RATE OF RETURN ON RATE BASE REGULATION

The regulator uses a two part process in the rate of return on rate base method of price regulation. The first phase determines the utility’s revenue requirement, while the second phase (on cost allocation and rate design) entails determining the specific rates to be recovered from the different customers’ classes served by the utility as noted in figure 1.



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PHASE I: DETERMINATION OF REVENUE REQUIREMENT

It is important to note that the revenue requirement process described below is a cost plus method of pricing and not the method of pricing used by firms in a fully competitive market place.

As noted earlier, the revenues the public utility is allowed to recoup are known as “revenue requirement”. Revenue requirement is defined as the sum of all operating costs, depreciation expense, administration expense, taxes, and return on rate base, as specified in equation 1 below.

$$\text{Equation 1: } RR = OC + D + A + T + r(RB)$$

Where:

RR is revenue requirements⁶

OC is operating costs

D is depreciation expense

A is administration expense

T is tax cost

r is fair rate of return on rate base (expressed as a decimal)

RB is rate base

To determine revenue requirement, all costs of service are first ascertained, then equation 1 adds a total dollar return obtained by multiplying the “rate base” (approximately the firm’s fixed assets) by a percentage cost of capital known as the “return”.

⁶ RR is also equal to price times quantity (QxP), where Q is output and P is the average price level set equal to RR/Q. In the regulatory economics literature this process is called “average cost pricing”; while in the accounting literature it is known as “fully distributed costing” since all costs plus profit are fully distributed to customer classes.

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Expect for the return portion, the elements of revenue requirement in equation 1 are typically found in an income statement. The regulatory agency decides on an appropriate level of earnings (return) and then approves or authorizes a target revenue requirement and forecast, the prices will produce sufficient revenues to produce the desired level of earnings after all expenses have been deducted.

The revenue requirement is determined by examination of all annual costs the utility is obliged to recover. Rates should be designed to be appropriate for a specified future time period known as a “test” period. The test period is usually of one year’s duration and should be the same future twelve month period over which rates are expected to be valid. Forecast test year data is often developed using historical “base year” data. Historical data offers the advantage of verification, but may not show improvements in technological conditions. As technological change lowers average cost, customers should be given the opportunity to benefit from such progress and regulators do examine this issue. In addition, many regulators make specific adjustments to test year data in order to “normalize” it or make it normal for the future. Adjustments are made to eliminate extraordinary events or transactions which are not anticipated to occur under normal operating conditions. For example, adjustments can be made for weather conditions and seasonality.

Operating Costs

Estimation of operating costs for a test year may encompass elaborate engineering studies of natural gas transmission, storage, and distribution operations or entail simple calculations of inflation applied to a prior year operating expense amount.

Depreciation and Amortization

Depreciation expense in any particular year is the amount of original cost of a tangible asset which will be recorded as an expense. Depreciation is a process of cost allocation, matching the benefits of a resource to its costs for a specific accounting period. In the regulated world depreciation is a return *of* capital and not a return *on* capital. Based on depreciation policies established from depreciation studies which examine expected asset life, the depreciation expense for the test year can be forecast with a high degree of certainty.



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Provision for Income Tax

In regulation, there are two ways to record the provision for income tax. The provision for income taxes may be calculated on taxable income as defined by the Income Tax Act, or on the basis of accounting income resulting from the application of generally accepted accounting principles (GAAP).

The taxable income method is known as flow through. Here, tax is computed using the legislated standard and all accelerated write-offs and other benefits are recognized immediately in rates. This method flows through to all customers the benefits arising from fast tax writ-offs.

The second method, based on GAAP, is called the “normalized” method as it uses the normal tax provisions applied to accounting income. It is essentially taxes payable (as opposed to taxes paid under flow through).

The difference between the normalized provision and the flow trough provision is deferred tax. The rate impact of flow through is lower rates in the early years of operation and higher in later years.

Rate Base

Rate base is composed of the aggregate of plant and equipment less accumulated depreciation plus working capital, as noted in equation 2.

$$\text{Equation 2: } RB = PPE - ACD + WC = \{AFUDC \text{ and/or } CWIP, \text{ Tax adjustments, and deferred charges if any}\}$$

Where:

PPE is property, plant and equipment

ACD is accumulated depreciation

WC is working capital

AFUDC is an allowance for funds used during construction

CWIP is construction work in progress



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Not all assets are included in rate base. Rate base does not include current assets although it generally includes an allowance for working capital. The components of rate base are described below.

Property, Plant and Equipment

Property, plant and equipment is the sum of long term assets purchased by the utility in order to produce its own outputs. Long-term assets are recorded on the accounting books at their historic costs of acquisition.

Accumulated Depreciation

Accumulated depreciation is a balance sheet item reflecting the sum of the depreciation charges incurred to date on the acquired assets.⁷ The shareholder is entitled to a fair return on “used and useful” assets and the rates paid by utility users are intended to recoup the asset costs of the period.⁸ The depreciation amortization process ensures that asset values are being reduced through time. Depreciation expense also reflects the reality that long term assets wear out. Accordingly, accumulated depreciation must be subtracted from property, plant, and equipment to ensure rates reflect this.

⁷ Depreciation expense is an income statement charge intended to reflect the amortized cost of assets for that accounting period. The cumulative sum of depreciation charges is found as a contra account on the balance sheet. (See J. C. Bonbright, A.L. Danielsen, and D.R. Kamershen, Principles of Public Utility Rates, Public Utilities Reports, Second Edition, 1998, page 270).

⁸ The used and useful criterion for rate base determination ensures that only assets properly in the employ of utility customers are in the rate base. Observe that some assets such as reserve plant are not used, but they are certainly useful since they improve a utility’s reliability. Also note that some plant and equipment may be used, but due to obsolescence, should be retired with the regulator excluding such assets from the rate base thereby lowering the allowed return portion of revenue requirement. (Shareholders do not earn a return on assets excluded from rate base).

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Working Capital

Working capital in accounting terms is usually noted as the difference between current assets and current liabilities. However, the way working capital for a regulated utility is computed is different. It is the addition to the rate base the regulator provides “to bridge the gap between the time when costs are incurred in providing the service and the time the utility is paid for that service”.⁹ Such a definition requires a separate determination for each utility.

Often the regulator requires the utility to conduct a “lead-lag” study intended to determine the investor supplied funds which a utility effectively should set aside to ensure all liabilities are paid when they fall due. An alternative approach, sometimes used when a lead-lag study has not been conducted, is the 45-day rule where 1/8 of a year (45 days) of the utility’s operating and maintenance expenses is designated as the working capital allowance.

Allowance for Funds Used During Construction (AFUDC or Construction Work In Progress (CWIP))

The used and useful concept becomes problematic when a utility is rapidly expanding. The regulator can include some or all assets under construction into the rate base (CWIP) as they are constructed to benefit current consumers. The regulator can also allow carrying charges on a debt interest plus a reasonable rate of return on equity used in funding construction to be added to the rate base once the plant goes into service (AFUDC). This is a more conservative treatment as only when a plant goes into service does it enter rate base. However, when AFUDC is used, the full amount of AFUDC is added to plant acquisition costs which will then be recovered from consumers via the mechanism of depreciation.

Both methods are intended to provide an opportunity to recover financial carrying costs. They are different primarily from the point of view of timing. With AFUDC, carrying costs are recovered only after the plant goes into service, while with CWIP, recovery occurs as new assets are being built.

⁹ J.C. Bonbright, A.L. Danielsen, and D.R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Second Edition, 1988, page 242.



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Tax Adjustments

Permanent differences between taxable income and accounting income are adjustments to revenue requirement. Some accounting costs (such as depreciation on the equity component of ADUDC) for example are not deductible for tax purposes and revenue requirement must be increased in order to recover the underlying cost.

If flow through tax accounting is used, the existence of rapid depreciation write-offs (capital cost allowance) presents the regulator with a problem. The regulator must decide what treatment should be given to the revenues recouped from consumers in excess of taxes actually paid in the earlier years. These phantom taxes are segregated in special reserve for “deferred taxes”, in recognition of the fact that taxes will in later years exceed these “normalized” recoveries from customers.¹⁰ The regulator has to decide if the deferred tax reserve should be deducted from rate base or not allow a return on the assets represented by this tax reserve.

Other Deferred Charges or Credits

Deferred charges or credits are some items which are not due in a legal sense of being owed, but will be paid in the future.

Rate of Return

In setting rates, the regulatory authority (usually a government-run quasi-judicial tribunal) tries to strike a balance between the prices to be paid by customers and the rate of return which shareholders of the utility are allowed to earn on their equity investment. The return is a percentage applied to the rate base producing an absolute dollar value sufficiently large enough to discourage all financing costs incurred in funding the rate base.

The financial costs incorporate costs for each of three component costs of capital raised. Capital is raised primarily from three sources, debt, preferred shares, and equity. The regulator selects a fair rate of return to be large enough to discharge the cost of interest on short and long term debt, to satisfy the dividend requirements of preference shareholders, and to provide common shareholders with an attractive equity return. The return is thus a blended or composite cost of capital. Too high a return and equity shareholders may receive an equity return in excess of that required to attract new equity capital. Similarly, too low a return and utility shareholders become reluctant to continue investing and the utility has difficulty attracting any form of capital for future expansion.

¹⁰ A.E. Khan, The Economics of Regulation, Wiley, 1970, Volume One, page 33.

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The determination of the rate return (cost of capital) entails considerable judgment on the part of the regulator. The regulator attempts to establish a return which:

- ❑ attracts future capital into the utility;
- ❑ encourages managerial effectiveness;
- ❑ encourages customer rationing of a scarce resource;
- ❑ ensures fairness to investors; and
- ❑ provides a reasonably stable and predictable rate level to rate payers.¹¹

The regulator recognizes that each of the sources of capital has different risk profiles and different risk adjusted component costs of capital (expressed as a percentage). The overall return is therefore a weighted average of the component costs of capital (WACC).¹² The weights are each component's proportion in the total capital structure of the utility. The return is specified in equation 3.

Equation 3.

$$r = k_d w_d + d_p w_p + k_e w_e$$

Where:

r is the return or overall cost of capital (WACC) expressed as decimal

k_d is the actual (embedded) cost of debt

k_p is the actual (embedded) cost of preferred shares

k_e is the component cost of equity (return on equity)

w_d is the weight for debt

w_p is the weight for preferred shares

w_e is the weight for the firm's equity

¹¹ J.C. Bonbright, A.L. Danielsen, and D.R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Inc. Second Edition, 1988, page 203

¹² The literature on the cost of capital is substantial. A recent general text is M.C. Ehrhardt, The Search for Value: Measuring the Company's Cost of Capital, Harvard Business School Press, 1994. Two texts which are specific to public utilities are M. J. Gordon, the cost of Capital to a Public Utility, Michigan State University Public Utilities Studies, 1974, and R.A. Morin, Utilities' Cost of Capital, Public Utilities Reports, Inc., 1984

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To operationalize equation 3, the regulator must first determine the rate base and then determine the sources of capital used to fund the rate base and their weights. The traditional convention is to vary the short term debt proportion in order to equate total capitalization to rate base. Total capitalization is then expressed as 100 per cent and is divided into percentage weights representing the proportion of capital raised by debt, preferred shares, and equity, respectively.

Alternative Methods of Determining the Cost of Equity

The determination of cost of equity is the most critical portion of the return calculation. Two standards are used: the standard of comparable earnings, and the standard of capital attraction.¹³ The comparable earnings standard calculates a return on equity by examining the rate of return on the book value of firms with comparable risk. The standard of capital attraction is a market based approach in that the equity return is assumed to be fair if new equity investors are attracted to the public utility.

There are two methods of determining the equity return based on the notion of capital attraction.

Discounted Cash Flow: Dividend Growth Model

The market based capital attraction test is often determined using a specific discounted cash flow model formulation known as the “dividend growth” model. It is specified in equation 4.

$$\text{Equation 4: } k_e = D_1/P_0 = g$$

Where:

k_e = is the cost of new equity

D_1 is the current period's dividend per share

P_0 is the price of equity share at the beginning of the period

g is the growth rate of dividends per share

¹³ J.C. Bonbright, A. L. Danielsen, and D.R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Inc. Second Edition, 1988, page 316

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The Capital Asset Pricing Model (CAPM)

The second capital attraction test is the CAPM, a risk premium approach, which explicitly measures the anticipated risk premium the equity market places on a given equity stock reflective of its systematic risk. The overall risk of a specific equity share is comprised of systematic risk, which is unique to the company itself and cannot be diversified away, and unsystematic risk which is market related risk and can be diversified away by including the equity in a portfolio of other equities.

This model shows that combining equity assets into a portfolio enables an equity investor to diversify risk and reduce total portfolio risk by so doing. Since investors can diversify away company specific risk, they should not be compensated for it. To apply the CAPM model, a measure of market risk is required. This measure of market risk is referred to as beta and is identified in the fundamental CAPM equation 5.

Equation 5:
$$k_e = r_f + e(k_m - r_f)$$

Where:

k_e is the cost of new equity

r_f is the risk free rate of return expected in the market

e is the equity stock's expected market risk beta

k_m is the expected rate of return on a stock market portfolio.¹⁴

¹⁴ E.F. Brigham, A.L. Kahl, W.F. Rentz and L.C. Gapenski Canadian Financial Management, Fourth Edition, Dryden, 1994, chapter six.

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Table 1 illustrates the way cost of capital is calculated by the Ontario Energy Board (OEB) as applied to Consumers Gas.

Table 1: 1995 Cost of Capital for Consumers Gas in EBRO 490¹⁵

Capital Component¹⁶	(1) % of Total Capital	(2) Annual Cost	(3) Weighted Component Cost of Capital
Medium and Long-term debt	56.21%	9.77%	5.540%
Short-Term debt Preferred	4.77%	7.19%	0.340%
stock Common equity Total	4.02%	6.45%	0.269%
	<u>35.00%</u>	11.875%	<u>4.150%</u>
	100%		r=10.25%

PHASE II: DISTRIBUTION OF REVENUE REQUIREMENT AND RATE DETERMINATION

Phase II has two sub-components: distribution of revenue requirement and rate determination as noted earlier in figure 1.

Distribution of Revenue Requirement

There are three steps involved in distributing revenue requirements: functionalization, classification, and allocation.

1. Functionalization is the process of separating revenue requirements into the basic functions performed by a natural gas utility such as:
 - Transmission
 - Storage
 - Distribution

¹⁵ OEB partial decision for rates, EBRO 490, August 29, 1995, Appendix C

¹⁶ Deferred taxes are either deducted from rate base and not considered part of capitalization, or included as part of capitalization but a zero weighted component cost of capital. The OEB does not consider deferred taxes part of capitalization as it uses the “flow through” method.

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The revenue requirement is distributed to these functional categories based on assessments of activities performed and then allocated out to classes of service by allocation factors.

Table2: Illustrative Functionalization

Function Revenue Requirement	Transmission (Tr)	Storage (S)	Distribution (D)	Total	Allocation Basis
Operating Costs (OC)	OC-Tr	OC-S	OC-D	. OC	
Depreciation (Dn)	Dn-Tr	Dn-S	Dn-D	. Dn	
Administration (A)	A-Tr	A-S	A-D	. A	
Tax (Tx)	Tx-Tr	Tx-S	Tx-D	. Tx	
Return (rRB)	(rRB)-Tr	(rRB)-S	(rRB)-Dr	.(rRB)	
Total Revenue Requirement (RR)	. RR-Tr	. RR-S	.RR-D	. RR	

Note: . is a summation operator

2. Classification entails relating the functionalized costs into categories of cost attribution. The three cost classifications are:
 - Capacity related
 - Commodity related
 - Customer related

Capacity components are those which vary in proportion to the maximum gas demanded on the system in the various customers segments. It is the load at a point in time. Capacity related costs are allocated to classes of service by peak responsibility. This requires study of a customer's load characteristics and load characteristics of the system as a whole.

Commodity related components are those which relate directly to natural gas usage and are allocated on the basis of gas consumption.

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The customer related component includes the portion of distribution plant and expense necessary to serve load at the customer's location. It also includes metering, customer accounting and sales plant and expenses. Customer cost should vary in proportion to the number of customers served and the customer density on the system. These costs are allocated to customers on the basis of number of attachments on the system. For example, a residential customer has one attachment. A large industrial customer may have a great many attachments.

The process of classification entails examining all functionalized costs and determining the splits based on cost causation. For example, transmission and distribution functions may be classified as being capacity related. Meters, on the other hand may be assigned to the customer component. Table 3 illustrates the process for just one of the functions noted in table 2.

Nature of Variation	Capacity Related (Cap)	Commodity Related (Comm)	Customer Related (Cust)	Total	Allocation Basis
Function: Transmission (Tr)					
OC-Tr	OC-Tr (Cap)	OC-TR (Comm)	OC-TR (Cust)	. OC-Tr	
D-Tr	D-Tr (Cap)	D-Tr(Comm)	D-Tr (Cust)	. D-Tr	
A-Tr	A-Tr(Cap)	A-Tr (Comm)	A-Tr(Cust)	. A-Tr	
Tx-Tr	Tx-Tr(Cap)	Tx-Tr (Comm)	Tx-Tr (Cust)	. Tx-Tr	
(rRB)-Tr	(rRB)-Tr(Cap)	(rRB)-Tr (Comm)	(rRB)-Tr(Cust)	. (rRB)-Tr	
. RR-Tr	. RR-Tr(Cap)	. RR-Tr(Comm)	. RR-Tr (Cust)	. RR-Tr	

For logical completeness, similar tables are required for the storage and distribution functions

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3. Allocation entails distributing the functionalized and classified costs to each customer class based on cost incidence or on a reasonable allocation basis designed to reflect the actual behavior of costs in response to changes in rates of output of different classes of utility service.¹⁷

Capacity related costs are allocated to customers on the basis of the following allocation factors:

- ❑ Coincident demand is the demand that occurs simultaneously with any other demand at the time of annual system peak.
- ❑ Non-coincident demand is the sum of all individual maximum demands regardless of time of occurrence within a specified period. This can be either by class of customers in a class.

The classified functions are assigned to classes of service by allocation factors. Table 4 continues the illustration of table 3 by allocating costs to customer classes.

Table 4: Illustrative Cost Allocation to Customer Classes for Capacity Related Costs in the Transmission Function

Customer Class Capacity Related (Cap) Transmission (Tr)	Residential (Res)	Commercial (Com)	Industrial (Ind)	Total	Allocation Basis
OC-Tr (Cap)	OC-Tr (Cap) (Res)	OC-Tr (Cap) (Com)	OC-Tr (Cap) (Ind)	. OC-Tr (Cap)	
Dn-Tr (Cap)	Dn-Tr (Cap) (Res)	Dn-Tr (Cap) (Com)	Dn-Tr (Cap) (Ind)	. Dn-Tr (Cap)	
A-Tr (Cap)	A-Tr (Cap) (Res)	A-Tr (Cap) (Com)	A-Tr (Cap) (Ind)	. A-Tr (Cap)	
Tx-Tr (cap)	Tx-Tr (cap) (Res)	Tx-Tr (cap) (Com)	Tx-Tr (cap) (Ind)	. Tx-Tr (cap)	
(rRB)-Tr	(rRB)-Tr (Res)	(rRB)-Tr (Com)	(rRB)-Tr (Ind)	. (rRB)-Tr	
. RR-Tr (Cap)	. RR-Tr (Cap) (Res)	. RR-Tr (Cap) (Com)	. RR-Tr (Cap) (Ind)	. RR-Tr (Cap)	

A similar table is required for commodity related costs in transmission and customer related costs in transmission. Then another family of such tables would be required for the two other functions of storage and distribution in order to complete the total distribution of revenue requirement to all customer classes.

¹⁷ F.C. Bonbright, A. L. Danielsen, and D.R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Inc. Second Edition, 1988, page 487



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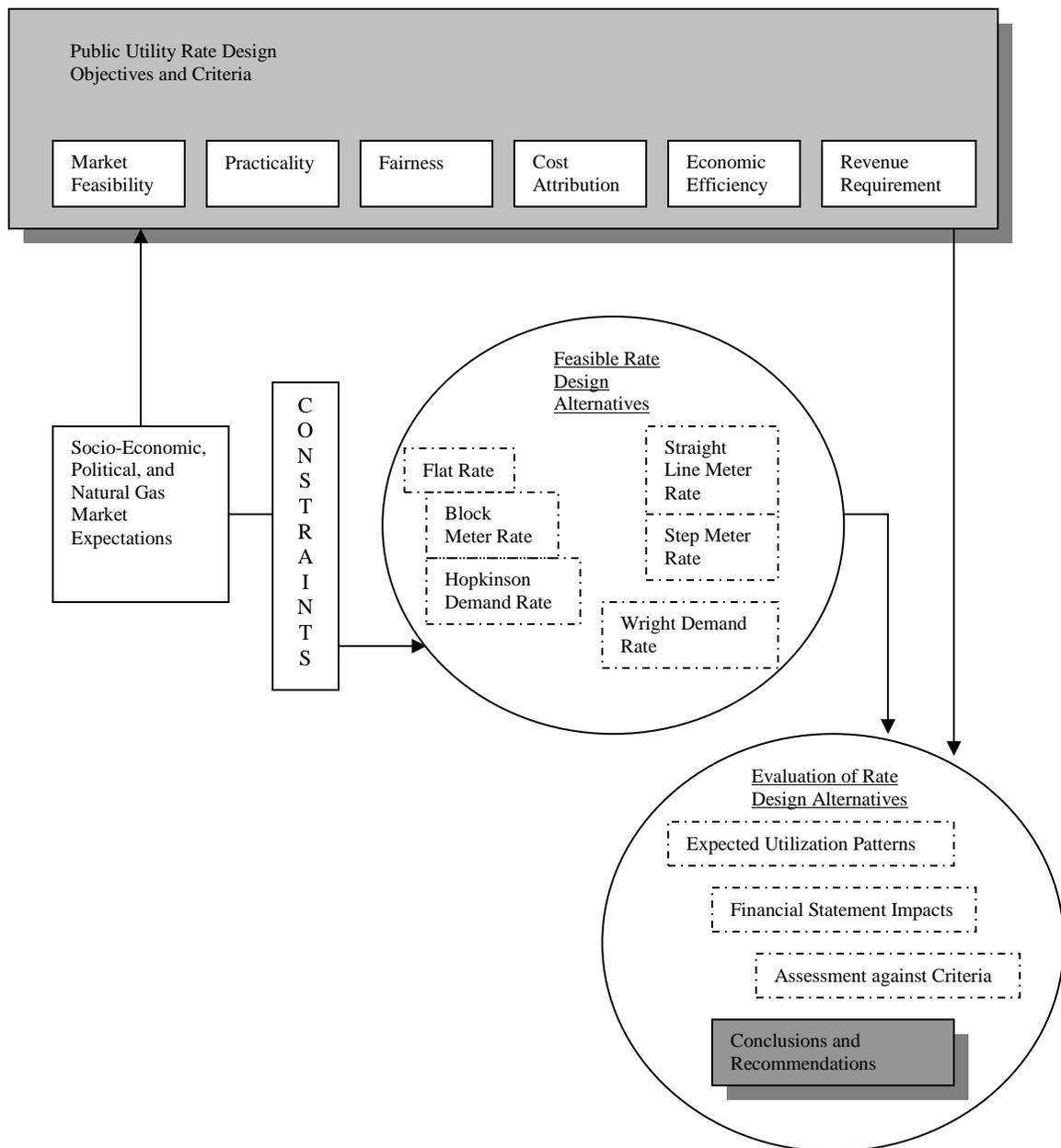
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Rate Determination

The process of designing rates is noted in figure 2.

Figure 2: The Rate Design Decision Making Framework



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Socio-economic, Political, and Natural Gas Market Expectations

Rates must anticipate social, economic and political trends and be responsive to changes in the natural gas distribution company's environment. These expectations influence the selections of relevant rate design criteria to be used by gas utility management and their prioritization.

Rate Design Criteria

The second step in decision making is to develop the criteria to be used in evaluating rate design alternatives. (The criteria are the various yardsticks used to measure the attractiveness of alternatives).

Regulation should allow a fair rate of return to shareholders but not reward poor management in a regulated company. Properly designed rates are those which:

“..provide clear, efficient, effective, informative, and cost effective market signals about the present and future cost of service to buyers and sellers”¹⁸

In other words rate design objectives include:

- Recovery of total revenue requirement
- Promotions of economic efficiency
- Equitable distribution of costs to customer classes
- Fairness by avoiding undue price discrimination
- Rate stability, predictability, and practicality to the utility and its customers; and
- Market feasibility

Utility management must also decide upon the weights to be placed on the various criteria and this in essence is the criteria prioritization process.

¹⁸ J.C. Bonbright, A.L. Danielsen, and D.R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Inc. Second Edition, 1988, page 382.

Constraints

Utility management generally is faced with a multitude of constraints. Unlike criteria, which are measurement yardsticks used to evaluate alternatives, constraints limit choice. To be considered feasible, every alternative must meet all constraints. Constraints may be legally imposed, e.g., standards of service.

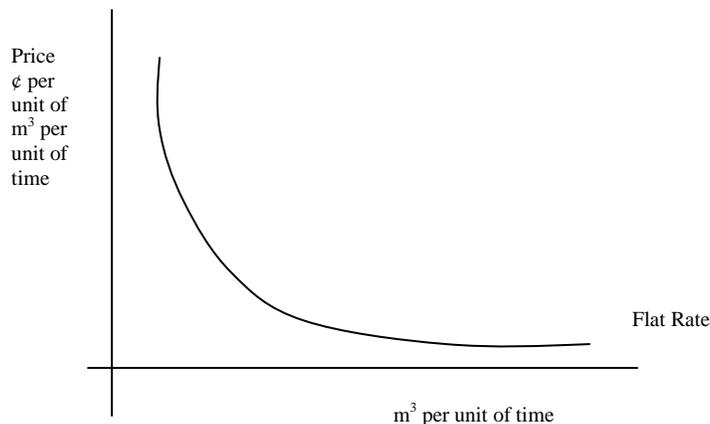
Feasible Rate Design Alternatives¹⁹

Feasible rate design alternatives are those which meet all constraints. They may include the following.

Flat Rate

The flat rate is simply a single rate per unit of time (e.g., \$22 per week) no matter what volume is consumed. The rate curve diminishes with volume increases as noted in figure 4.

Figure 4: The Flat Rate



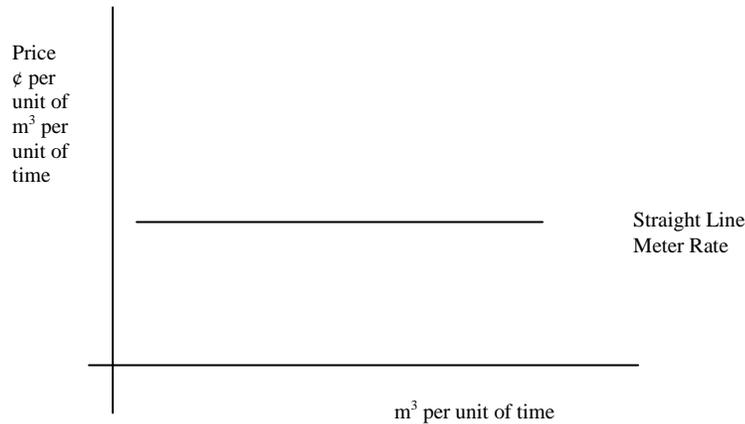
Flat rate is the easiest rate to develop and administer and it does not need a meter. The flat rate, however, is an unfair rate since different customers are charged in the same rate regardless of volume consumed, implying that customers who incur the greatest cost on the system are treated the same way as all other customers. If volumes of gas are unknown by customer, it is also unlikely that forecast revenue requirement can be met.

¹⁹ Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987

Straight Line Meter Rate

The straight line meter rate has constant price per unit of gas consumed and is the simplest of all metered rates. Figure 5 indicates its behavior.

Figure 5: The Straight Line Meter Rate

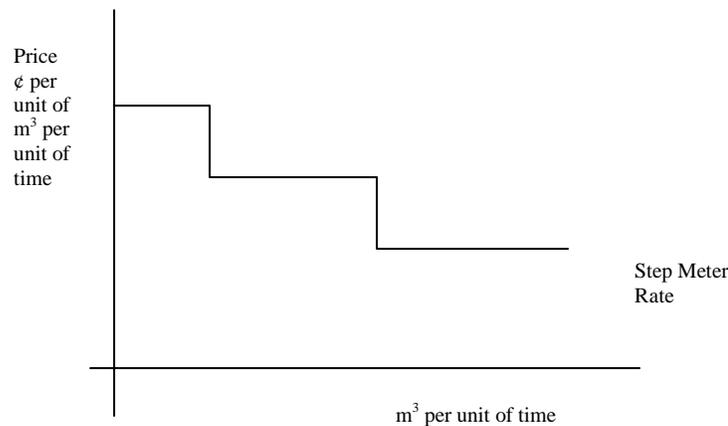


The straight line meter rate is often used for “volumetric” situations. It bills customers on the basis of actual volume used and the customer’s bill is simply the constant rate times the volume used over the billing period. Its major disadvantage is its inability to track cost attribution. A customer who took no gas would not be charged, yet is clear that the utility has incurred significant fixed costs to be able to provide service. Modifications to this rate include adding a fixed customer per month for a small amount of volume consumed.

Step Meter Rate

The step meter rate bills the customer's entire volume of use at a certain price which varies depending upon the rate step in which metered use falls as noted in figure 6.

Figure 6: The Step Meter Rate



The step meter rate differs from the flat rate and the straight line meter rate by encouraging consumers to increase use to obtain a lower unit price. The advantage to the utility of such a concept is that it increases load factor and thus lowers overall system unit costs.²⁰ The disadvantage is that it “wastes” a scarce non-renewable resource. Indeed a consumer may deliberately consume more than is required just to get into the lower step. Another disadvantage is the step meter's inverse load factor bias. For example, a high volume consumers may have a lower than average load factor, yet this customer pays a lower than average price than a low volume high load factor customer. It is the large volume customer, however, who has incurred a greater than average fixed cost onto the system.

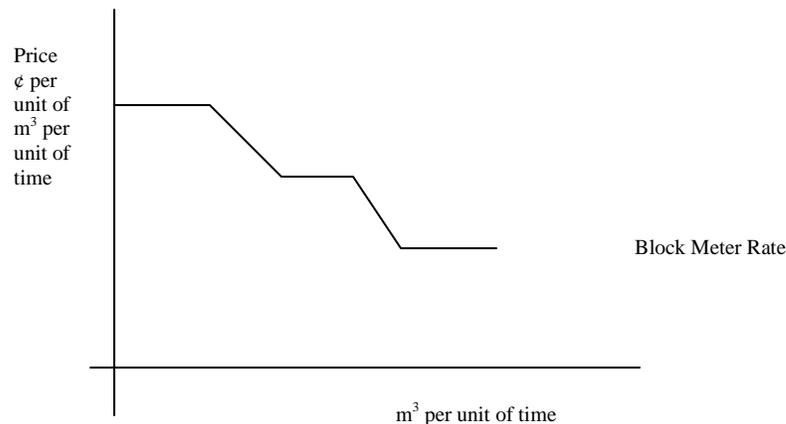
²⁰ Load factor is a measure of constancy of output. It is computed by comparing an average day's gas delivery to the maximum day's delivery over a year, expressed as a percentage. See Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987, page 16.

Another difference is its cost attribution advantage over the other two rate forms considered so far. The low-volume user does pay higher unit price than the large-volume user and thus mirrors cost incurrence patterns (observe that unit cost curves are U-shaped).

Block Meter Rate

The block meter rate has two or more successive blocks with decreasing prices per unit as noted in figure 7.

Figure 7: The Block Meter Rate



Unlike the step meter rate, however, the consumer is charged for use in each successive block of use at the rate applicable to that block with decreasing prices per unit of volume. The charges calculated for each block are added to compute the total bill for the period under consideration. Rates designed this way often recover a substantial portion of customer costs in the initial block. Block-meter rates avoid the problems of the step meter rate and are quite popular. They are simple and avoid undue price discrimination as well as recognizing that in certain volume ranges unit costs decline.

The trend towards energy conservation has led to the creation of some block-meter rates that increase with volume and these are called “inverted rates”. In addition, fewer

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blocks were being allowed with smaller price differentials between blocks. Block-meter rates do not treat customers within a customer class differently if load factors are relatively uniform. Block-meter rates, however, tend to be discriminatory against high load factor customers with small loads while favouring large-use consumers who may have lower than average load factors.²¹ Under this rate form, the high load factor consumer tends to pay for a relatively larger share of fixed charges on production, transmission, storage, and distribution plant.

Demand Rates

Large volume users have great variance in load factors. Because of this, natural gas companies pay particular attention to a consumer's demand and load factor. Two part rate systems impose a *demand charge* based on a customer's maximum demand and a *commodity charge* based on total usage during the period.

A consumer's demand is defined as usage terms (e.g., number of 103m³ units of gas) within a specific time interval. Demand is determined by metering or nameplate rating capacities of equipment. Demand rates can incorporate a ratchet clause stipulating that a consumer's *billing* demand not be less than a stated percentage of maximum demand during a previous period. The ratchet forces a consumer to pay fixed charges related to maximum demand imposed on the system, thereby protecting the utility and providing a benefit to high load factor customers.²² Consumers with low annual load factor are required to bear their share of capacity costs as imposed by their peak demands even though they have infrequent high volume use.

Demand rates are not used extensively by gas companies because demand meters are expensive and periodic inspections to check consumers' equipment capacity is also expensive. In addition, some consumers have difficulty understanding or accepting the demand concept.²³

²¹ Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987, page 168.

²² Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987, page 171.

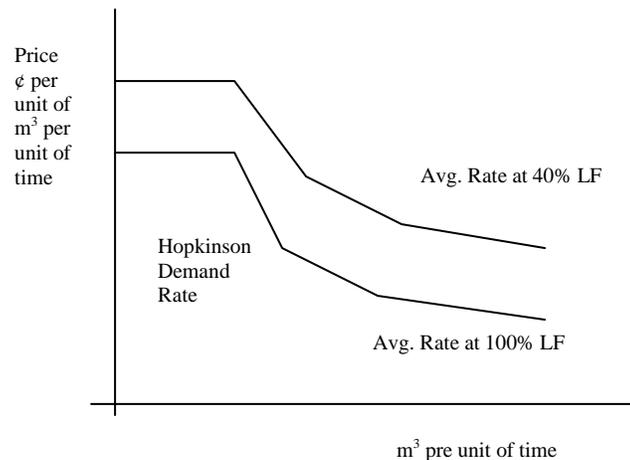
²³ Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987, page 170.



Hopkinson Demand Rate

The Hopkinson demand rate is a two-part rate (often called a demand/commodity rate in pipeline companies). In gas distribution companies the Hopkinson rate is blocked but generally not in pipeline companies. It is illustrated in Figure 8.

Figure 8: Hopkinson Demand Rate



A customer who improves load factor can lower annual costs of gas. A variation of the Hopkinson two-part tariff is a three-part rate, where the third portion is a flat amount per time period customer charge.

Wright Demand Rate

Under a Wright demand rate, the customer pays a different unit charge for use in each successive block. The size of each block is stated in terms of either day's use of the customer's maximum daily demand or hours' use of the customer's maximum hourly demand. Block size is dependent on the customer's maximum demand. In this way the Wright rate form takes load factor into account but without having to use separate demand and commodity charges.²⁴

²⁴ Gas Rate Fundamentals, Fourth Edition, American Gas Association, 1987, page 174.

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Evaluation of Rate Design Alternatives

The final analytical stage in the rate design decision-making process entails attempting to determine that rate form alternative which best suits the objectives of the natural gas company.

The process of distributing revenue requirements produces a matrix of total revenue requirement by customer class as illustrated below in table 5.

Table 5: Illustrative Revenue Requirement by Customer Class

Customer Class Revenue Requirement	Residential (Res)	Commercial (Com)	Industrial (Ind)	Total
Operating Cost (OC)	Oc(Res)	Oc-(Com)	Oc-(Ind)	.OC
Depreciation (Dn)	Dn-(Res)	Dn(Com)	Dn-(Ind)	. DN
Administration (A)	A-(Res)	A-(Com)	A-Tr(Cap)(Ind)	. A
Tax (Tx)	Tx-(Res)	Tx-(Com)	Tx-Tr(Cap)(Ind)	. Tx
Return (rRB)	rRB-(Res)	rRB-(Com)	rRB-Tr(Cap)(Ind)	.(rRB)
Total Revenue Requirement (RR)	. RR-(Res)	. RR-(Com)	. RR-Tr(Ind)	. RR

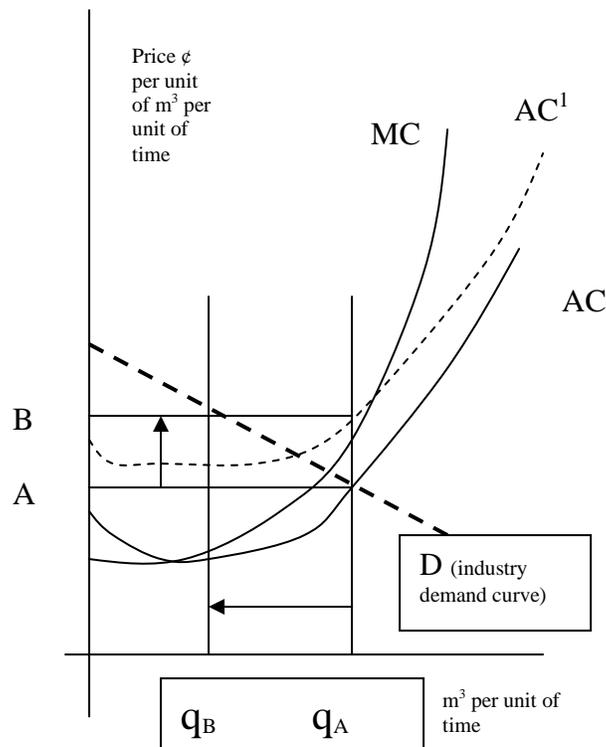
The bottom line of this table indicates the split of revenue by customer class and notes the amount that must be recovered through rates charged each customer class. To avoid charges of undue price discrimination, differences in rates are only allowed if it can be shown that marginal or average costs of service are differently by customer class.

Expected Utilization Patterns

It is important of utilities to test proposed rate structures and designs for effectiveness in achieving rate design objectives. Market place realities may not allow the utility to achieve its desired customer class revenue requirements. Competition due to open access may make the assumption of demand inelasticity unrealistic. An example of inappropriate pricing is shown in figure 9.

Figure 9: Illustration of Inappropriate Pricing

If the utility had its fixed costs rise from AC to AC¹
The regulator sets prices as P=AC
What happens in the ext year if the demand curve is as indicated?
What if price is left unchanged?



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If demand is elastic and alternatives are available to consumers, then as price rises ($P=AC$ in the revenue requirement model), volume sold in the next year will drop and revenues will be lower. If rate relief is not granted, the utility will suffer a significant loss equal to $(B-A)q_A$. In either case, competitive markets play havoc with the standard regulatory model. Accordingly it is important for regulatory analysts to develop price elasticity of demand measures by customer class in order to test the efficacy of any given rate form and resulting rate level.

Financial Statement Impacts

Testing of rate forms will likely entail determination of financial statement impacts. The desired rate form might meet all other rate criteria, but if it does not recover revenue requirement in aggregate, the rate design is likely inferior.

Assessment of Evaluation Criteria

The final step in the decision making process examines all alternatives from the perspective of each evaluation criterion and an assessment is made on which approach to rates is most effective in meeting over-all utility requirements.