NRRI 00-08

COST ALLOCATION AND RATE DESIGN FOR UNBUNDLED GAS SERVICES

by

Mohammad Harunuzzaman, Ph.D.
Senior Research Specialist

Sridarshan Koundinya, Ph.D.
Associate

THE NATIONAL REGULATORY RESEARCH INSTITUTE
The Ohio State University
1080 Carmack Road
Columbus, Ohio 43210
Website: www.nrri.ohio-state.edu

May 2000

This report was prepared by the National Regulatory Research Institute (NRRI). Funding was provided by the member commissions of the National Association of Regulatory Utility Commissioners (NARUC). The opinions expressed herein are the authors' and do not necessarily reflect the views, opinions, or policies of the NRRI, the NARUC, or any NARUC-member commissions.

EXECUTIVE SUMMARY

About half of the state public utility commissions (PUCs) in the United States have introduced unbundling of gas services for residential and commercial customers. Most of these states currently offer pilot choice programs for a selected sample of small customers for a limited number of services. A number of states have introduced state-wide unbundling and choice for all customers, and for a relatively larger menu of services.

The success of the unbundling programs depends critically on the accompanying regulatory policy choices. Among the policy choices, allocation of costs for unbundled gas services and designing of end use tariffs have significant impacts on whether and how much customers benefit from the unbundling process. Regulators face the twin tasks of facilitating a market for services that are believed to be competitive or potentially competitive, and adjudicating fair and reasonable rates for the remaining services. To perform these tasks, regulators are confronted with decisions about which services to unbundle, how to allocate and separate costs of unbundled services, which services to deregulate, and how to establish rates for regulated services.

To assist state regulators in developing rate-making policies for unbundled gas services, this report provides a comprehensive study of these issues. The report examines considerations that would dictate the identification of services to be unbundled and identifies services that can be unbundled. It provides overviews of cost allocation, cost separation, and rate design principles, and discusses how these principles can be applied to the design of rates for unbundled gas services. It also provides a comparative evaluation of

alternative cost separation and tariff design options, based on selected criteria of regulatory objectives. Finally, the report offers recommendations on rate-making policy options for unbundled gas services.

The study focuses on the application of the principles of cost allocation, cost separation and end-user tariff design to unbundled gas services. It discusses how the traditional rate design process needs to be changed to address the rate design of unbundled services (see Figures ES-1 and ES-2).

The study concludes that no combination of cost separation and end-use tariff design options can be unambiguously recommended to state regulators.

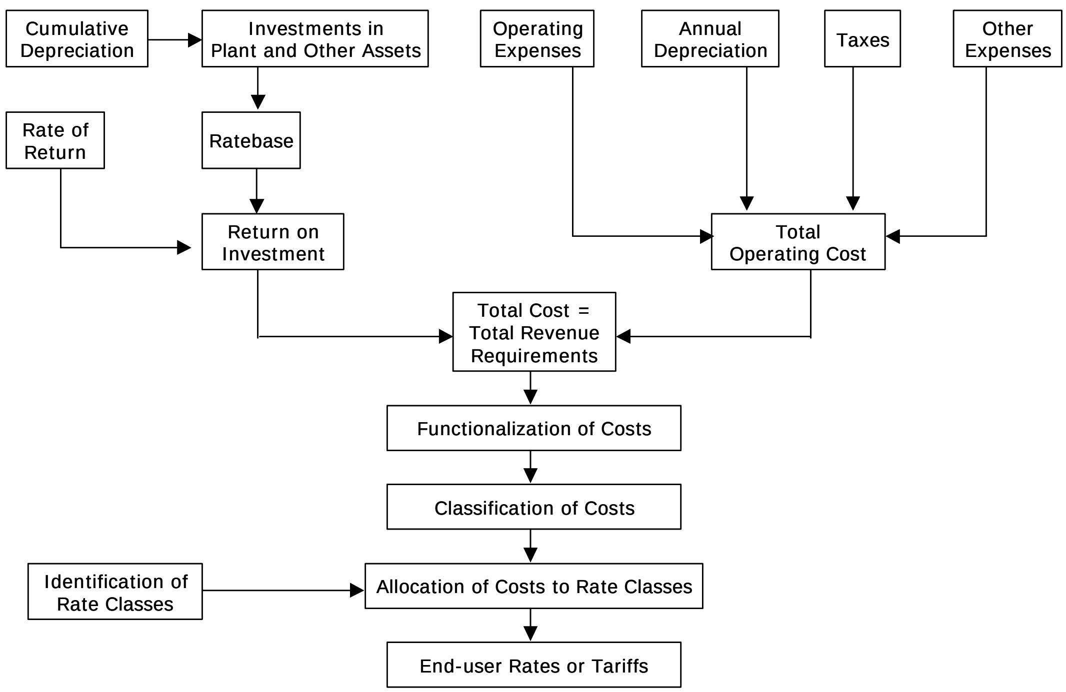

Fig. ES-1. Overview of the traditional rate design process.
Source: Author's Construct.

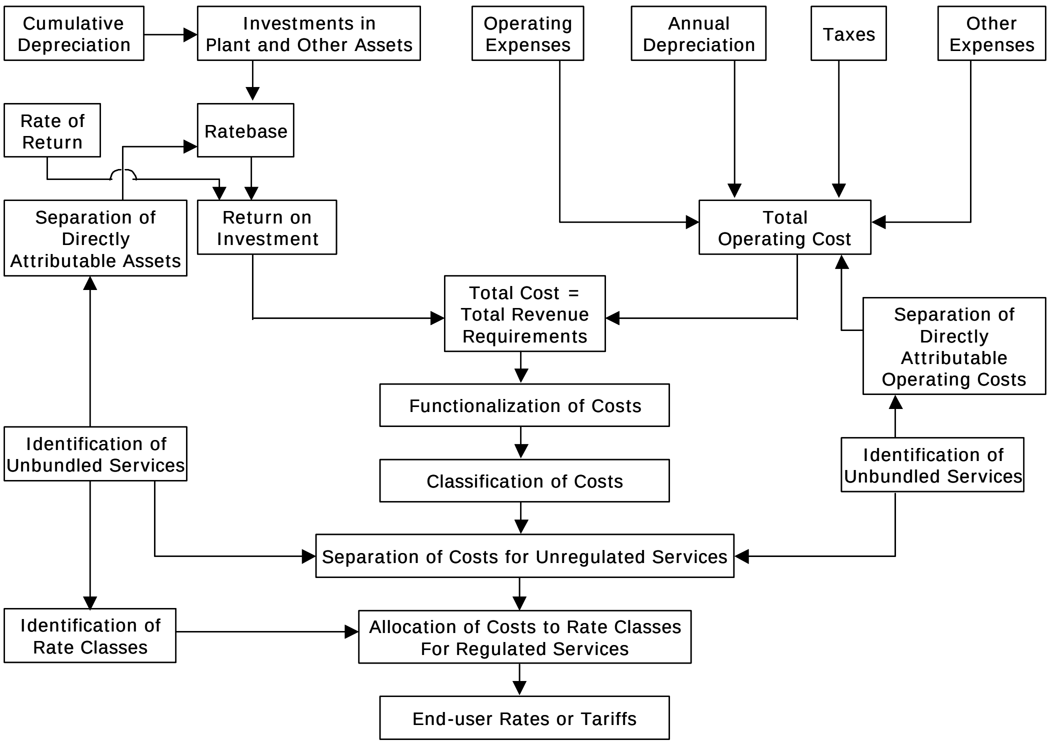

Fig.ES-2. Overview of rate design under unbundling.
Source: Author's Construct.

The reason for this is that no unique combination of options has all the desirable properties to satisfy most of the regulatory objectives. For example, some options may be economically efficient but inhibit competition. Also, the public interest compulsions and preferences of each PUC may be different, and the desirable set of options for one PUC may be an inferior choice for another. The study proposes a strategic framework that can help the state regulator evaluate alternative cost separation and end-use rate design options compatible with actual conditions and the regulator's policy preferences.

TABLE OF CONTENTS

TABLE OF CONTENTS – *continued*

LIST OF TABLES and FIGURES

Page

Table

LIST OF TABLES and FIGURES – *continued*

Page

Figures

FOREWORD

Gas unbundling has become a major area of interest for state public utility commissions (PUCs). Of particular concern are the methods available for cost separation and rate design. This report provides a comparative evaluation of these methods, based on longstanding regulatory objectives. It is hoped that this report will assist PUCs in their ongoing efforts to restructure the retail gas market.

Sincerely,

Raymond W. Lawton
Director, NRRI
April 2000

ACKNOWLEDGMENTS

The authors wish to thank Dr. John Cita and Dr. Michael Proctor for useful comments on an earlier draft of this report. The support and helpful comments of Mr. Ken Costello and Dr. Vivian Witkind Davis are thankfully acknowledged.

Errors that may remain are, of course, the responsibility of the authors.

CHAPTER 1

INTRODUCTION

This report provides a comprehensive study of the issues related to the cost allocation and rate design of unbundled gas services, and presents policy options for state regulators.

Background

Over the last two decades, the gas industry has been moving toward a increasingly competitive regime, characterized by greater unbundling of gas services and expanded customer choice.[1] Starting with the deregulation of wellhead gas in the late seventies, the industry has moved through unbundling of the gas commodity and transportation services of the interstate pipeline, to unbundled gas services at the retail level offered by the local distribution company (LDC).

LDCs started offering unbundled transportation and gas commodity services to large customers in the mid-eighties. Over the years, large customer retail unbundling has proliferated. Beginning in the mid-nineties, pilot programs to unbundle gas services for small customers were adopted in a few state jurisdictions. The unbundling process has generally exhibited the following patterns: (1) services are unbundled first at the upstream segment of the gas

[1] Whether or not the gas industry is actually transformed into a truly competitive regime depends critically on the interaction of state regulatory policies and industry players.

delivery system followed by unbundling at the downstream segments, and (2) large customers are offered unbundled services first followed by similar offerings for smaller customers. At the time of writing this report, twenty-one states and the District of Columbia have introduced either small customer pilot programs or broader customer choice programs. Utilities in eleven states have provided or are in the process of providing all of their customers with the ability to purchase their gas from a nonutility supplier.[2] Table 1.1 shows the current status of residential pilot programs and unbundling initiatives.

Overview of Issues

The emergence of retail unbundling warrants a policy response from state regulators. The introduction of retail unbundling and customer choice by themselves do not guarantee efficiency benefits.

Regulators face the twin tasks of facilitating a competitive market for gas services that are believed to be competitive, and adjudicating fair and reasonable customer rates for the remaining services. To perform these tasks, regulators will be confronted with decisions about which services to unbundle, how to separate the costs of unbundled services, which services to deregulate, and how to establish rates for regulated services.[3]

---

[2] Broader customer choice has been introduced in California, Georgia, Iowa, New York, Ohio, and Pennsylvania. Utilities in Maine, Massachusetts, Montana, New Mexico, and Oklahoma are in the process of introducing broader customer choice. See American Gas Association, *Providing New Services to Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives: Issue Brief 1999-05.*

[3] Most states that have unbundled gas services have chosen not to significantly adjust revenue requirements or rates. However, as more services (other than gas commodity) get unbundled or when the next rate cycle begins, changes to revenue requirements and rates are likely.

Table 1.1: Residential Pilot Programs and Unbundling Initiatives

State	Company	Potential # of Homes	Potential Demand (Bcf)	In-service Date	Pending or Completed Government Action*
Arizona					Commission Docket
California	Pacific Gas & Electric	3,454,000	190.9	8/91	CPUC rulings issued,
	San Diego Gas & Electric	68,000	3.6	8/91	State law delays further residential choice until 2000
	Southern California Gas	455,000	24.0	In-Service	
Colorado					State law passed; allows utilities to voluntarily file customer choice programs
Connecticut					PUC hearings held; draft study
Delaware	Conectiv Power Delivery	14,500	1.4	11/99	
Dist. of Columbia	Washington Gas	130,000	17.3	1/99	
Georgia	Statewide	1,538,000	127.7	11/98	State law passed
Illinois	Central Illinois Light Co.	10,000	1.5	10/96	ICC hearing
	Nicor Gas	250,000	18.3	1999	
	Peoples Gas Light & Coke	20,000	7.0	11/97	
Indiana	N. Indiana Public Svce.	150,000	18.3	05/98	URC study completed
Iowa	Statewide	770,000	87.8	2/99	IUB rulemaking
	MidAmerican Energy	875	.1	11/95-10/96	
Kansas					Legislation introduced; NOI
Kentucky	Columbia Gas of Kentucky	124,000	11.9		Proposed legislation
Maine	Northern Utilities				State law; PUC inquiry
Maryland	Baltimore Gas & Electric	525,000	52.5	11/97	PSC recommendations issued
	Columbia Gas	29,000	2.9	11/96	
	Washington Gas	100,000	10.0	11/96	

State	Company	Potential # of Homes	Potential Demand (Bcf)	In-service Date	Pending or Completed Government Action*
Massachusetts	Bay State Gas	‘83,000	8.0	11/96	Unbundling collaborative workshops
	Boston Gas	479,000	46.0	11/97-2000	
Michigan	Battle Creek Gas	1,000	.1	04/97	PSC hearings held; legislation pending
	Consumers Energy	300,000	42.8	04/98	
	Michigan Consolidated Gas	1,078,000	162.0	04/97	
	SEMCO Energy	23,500	3.8	04/99	
Minnesota					PUC working groups; PUC inquiry closed
Montana	Great Falls Gas	22,600	2.4	09/99	State law, PSC proceeding
	Montana Power	120,000	13.0	Winter 1999	
Nebraska	KN Energy	100,000	22.0	6/98	Localities regulate utilities
New Jersey	Statewide	2,196,000	192.0	12/99	State law
New Mexico	Public Ser. of New Mexico	361,000	28.5	12/97	
New York	Statewide	4,048,000	404.8	In-Service	PSC regulations issued
Ohio	Cincinnati Gas & Electric	360,000	30.0	10/97	State law passed
	Columbia Gas of Ohio	1,150,000	143.8	04/97	
	Dayton Power & Light	25,000	3.1	Pending	
	East Ohio Gas	1,034,000	129.3	04/98	
Oklahoma	Oklahoma Natural Gas	670,000	59.0	05/98	Proposed rulemaking
Oregon					Issued statement of PUC objectives
Pennsylvania	Statewide	2,453,000	262.5	7/2000	State law

State	Company	Potential # of Homes	Potential Demand (Bcf)	In-service Date	Pending or Completed Government Action*
South Dakota	Mid American Energy	54,000	5.4	1995	
	N.W. Public Svc	33,000	3.5	1995	
Virginia	Columbia Gas of Virginia	26,000	2.5	12/97	State law
	Washington Gas	58,000	5.6	07/98	
West Virginia	Statewide	362,432	36.0	1986	State law
Wisconsin	Wisconsin Gas	23,532	24.0	11/96	PSC report
Wyoming	KN Energy	10,000	.9	06/06	PSC study completed
	Questar Gas	19,000	1.9	1999	
TOTAL		22,728,439	2,219.8		

Source: American Gas Association, *Providing New Services to Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives: Issue Brief 1999-05,* November 30, 1999 and *Gas Utility Report,* December 31, 1999.

Identifying Services To Be Unbundled

Choosing a service to be unbundled entails two major issues: whether it is (1) *operationally feasible* and (2) *economically beneficial* to offer the service separately.

For a service to be unbundled, it must be operationally feasible to offer it independently of other services. This means that there are no physical or engineering constraints (such as system safety) that would preclude a service from being unbundled. Further, it must be economic to offer the service separately. In other words, the cost savings from providing the service separately must offset the increase in transaction costs and foregone economies of scope of previously bundled services.

Separating Costs of Unbundled Services

One of the most thorny issues state regulators and LDCs will face is how to separate costs of different unbundled services. The separation has to be accomplished through the use of one or more cost allocation mechanisms. Generally speaking, the separations process can be divided into two broad categories: (1) separation of investments and (2) separation of operating and other expenditures.

Costs of investments or values of assets used to provide an unbundled, deregulated service will have to be allocated to the service. The cost or value of the asset have to be determined and subtracted from the regulated asset base of the LDC. Such a determination involves choosing among competing methodologies (historical vs. replacement cost, alternative methods for depreciation rates and economic lives, and so forth) to calculate value or cost. For an asset that is used to provide multiple services, one needs to choose a method (fully distributed, incremental, stand-alone) to allocate the cost or the value of the asset to a particular service.

Likewise, the operating costs, previously aggregated for different services, have to be separated and allocated to each unbundled service. While some costs can be directly attributed to specific services, many of the costs are common or joint among services. As is true for investments, one needs to choose a method (fully distributed, incremental or stand-alone) to allocate common or joint costs to a particular service.

The allocation of investments and operating costs are subject to another degree of difficulty if an unbundled service is to be deregulated. For regulated services, it may be possible to treat certain common costs using some accounting contrivance, such as using a separate account for chosen categories of common costs, and imposing a common charge on all users that use the related services. For a deregulated service that shares costs in common with a regulated service, such an option is not viable. In such a case, the choice of cost allocation methodologies and the treatment of data become very critical.

Deregulating An Unbundled Service

The decision to deregulate a service is predicated on a judgment on whether the service is currently or potentially competitive. This requires an examination of the characteristics of the service (economies of scale, economies of scope with other services, sunk costs, etc.) and the characteristics of the relevant market (market share, barriers to entry, etc.). Services that are judged to be clearly and currently competitive (such as gas commodity) can be immediately deregulated and opened to market competition.

Among the remaining services, some may have a natural monopoly character (such as local distribution) while others may be potentially, but not currently, competitive (such as gas peaking service). Services with a natural monopoly character will continue to be regulated. A potentially competitive service may continue to be regulated until workable competition develops, at which time it may be deregulated.

Designing Rates for Unbundled Regulated Services

Monopoly services will continue to be regulated to meet traditional regulatory objectives (e.g., economic efficiency, reliability of service, equity among parties and social goals). The regulator has the choice of using either traditional (cost-plus) or performance-based rate-making mechanisms, or some combination thereof, to accomplish these objectives. For potentially competitive services, the rate-making policies need to be crafted and implemented to facilitate ultimate development of full competition, besides accomplishing traditional regulatory objectives.

The rate design of unbundled gas services, with associated regulatory ramifications and policy options, confronts the regulator with difficult and complex challenges. One of the challenges is to balance conflicting regulatory objectives and interests. For example, there may be a conflict between providing cost-minimizing incentives for a currently regulated, but potentially competitive, service and facilitating competition for the service. Although the balancing of conflicting objectives and interests is hardly new to regulators, the current transition toward gas industry restructuring and unbundling introduces perhaps an order magnitude increase in those difficulties.

Objectives and Organization of the Study

This study attempts a comprehensive examination of issues related to the pricing and rate design of unbundled gas services. To this end, it discusses the identification of services to be unbundled, examines allocation of costs among services, and evaluates alternative rate design options. This study is intended to assist state regulators in evaluating rate unbundling schemes.

Chapter 2 of this report provides an overview of the rate unbundling process. First, the rate design process for traditionally bundled services is summarized. Next, issues introduced by unbundling are discussed and necessary revisions to the traditional rate design process are examined. Finally, the rate bundling process is summarized. Chapter 3 provides a discussion on the identification of unbundled services. Chapter 4 provides an in-depth examination of allocation and separation of costs for unbundled services. Chapter 5 provides an examination of end-user rate design concepts and schemes. Chapter 6 provides an evaluation of cost allocation and rate design schemes. Chapter 7 summarizes the findings of this study, draws conclusions based on the findings, and offers policy recommendations for state regulators.

CHAPTER 2

AN OVERVIEW OF THE RATE UNBUNDLING PROCESS

The mechanics of rate design for unbundled services (also referred to as rate unbundling) are fundamentally and conceptually similar to those for the traditionally bundled services. However, the rate unbundling process may require additional cost allocation and cost separations analyses to account for the unbundling of previously bundled services. To develop a basic framework for rate unbundling, it may be helpful to review the traditional rate design process, examine implications introduced by unbundling, and introduce the needed revisions or adjustments for an unbundled rate design process.

Traditional Rate Design Process: Review of Basics

The traditional rate design process is shown in Figure 2.1. The process consists of the following steps.

- Determination of total costs and revenue requirements
- Functionalization of costs
- Classification of costs
- Identification of rate classes
- Design of end-user rates

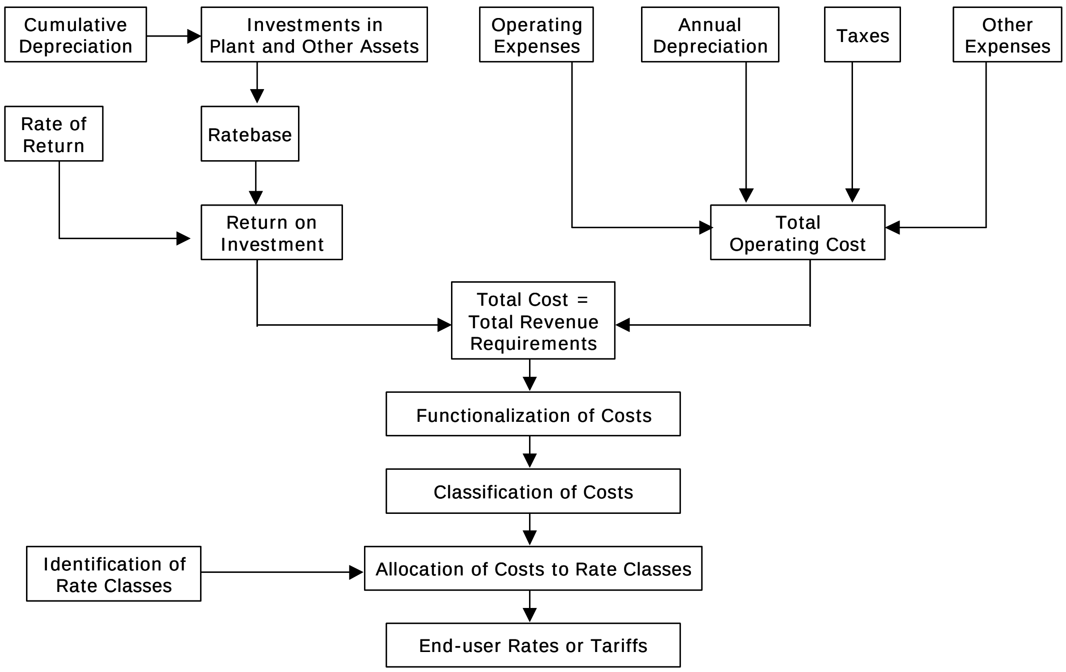

Fig. 2.1. Overview of the traditional rate design process.
Source: Author's Construct.

Total revenue requirements are the total of all costs incurred by the utility in providing its services, and is authorized to recover from its customers. For purposes of determining revenue requirements, the costs are grouped into capital, operations and maintenance, and administrative, and taxes. The revenue requirements, or the total cost of service, is the sum of the return on undepreciated capital investment and all other expenses.[4]

[4] The standard equations for revenue requirements are:

$$RR = (RB) * r + E + D + T + O \quad \text{and} \quad RB = (PV - CD)$$

where RR = revenue requirements; r = allowed rate of return; RB = rate base; E = operating expenses; D = annual depreciation; T = taxes; O = other expenses; PV = plant value (investment in plant); CD = cumulative depreciation.

A utility is required to maintain detailed accounting records of its costs. The major accounting categories include plant, operating expenditures and taxes. Each major accounting category has a number of subaccounts. The gas plant category, for example, may include land and land rights, structures and improvements, boiler plant equipment, field compressor station structures. For purposes of rate design, costs from different accounting categories are grouped into different operating functions, such as production, transmission and distribution. This process is known as *functionalization* of costs.

The costs of each functional category are then classified by their consumption or cost causation characteristics. The *classification* criteria include demand (capacity), energy (commodity), customer and revenues. Demand-related costs, such as the capital cost of reserving capacity on an interstate pipeline, generally correspond to maximum system demand or maximum system capacity (in thousand cubic feet or Mcf). The energy related costs, such as gas procurement costs, correspond to the total consumption volume over a specific period of time (in Mcf). Customer-related costs, such as costs of metering and billing, correspond to services dedicated to customers. Revenue-related costs, such as gross receipts taxes and certain administrative overhead costs, correspond to total sales over a specific period of time (in dollars).

Customers are divided into *rate classes* for purposes of allocating costs of service and designing rates. A rate class is defined by characteristics that are common to all members of a class. Factors that have been used to define a rate class include: (1) size, (2) customer type, (3) type of usage, (4) firmness or interruptibility of service, (5) load factor, and (6) access to alternatives.[5] These

[5] United Nations, *Gas Distribution Rate Design Manual* (New York: United Nations, 1995).

defining factors or criteria are not mutually exclusive and may have various degrees of overlap.

Size refers to the total volume of use over a time period or rate cycle. The size factor, for example, distinguishes the large commercial customer from the small commercial customer.

Customer type refers to types of buildings and other physical facilities for which gas service is used, as well as some demographic characteristics. The broad customer types include residential, commercial, industrial, electric utilities, and government. Residential customers may be further subdivided by demographic characteristics, for example, into general residential customers, senior citizens and low income customers.

Type of usage refers to various end-uses of gas that include space heating, lighting, air conditioning, electricity generation and industrial processes. For example, residential customers may be divided into space heating and non-space heating customers.

Firmness or interruptibility of a service is a well-known criterion to define a rate class. Because firm customers require a full commitment of service up to their peak demand, the utility must acquire and pay for firm capacity. On the other hand, interruptible customers do not require such a commitment, and therefore cost much less to serve.

Load factor is an index of a customer's consumption pattern and is defined as the ratio of average consumption to peak consumption. Low load factor customers, such as residential and small commercial customers, tend to have a spiked consumption pattern, characterized by high peak consumption relative to their average consumption. High load factor customers, on the other hand, tend to have a flatter consumption pattern, with their peak consumption closer to their average consumption. Load factor is an important determinant of cost allocation. It generally costs more to deliver a unit of energy to a low load factor customer than to a high load factor customer. The reason is that the low load factor customer imposes a relatively high capacity cost on the system and this cost needs to be recovered from fewer units of energy.

Access to alternatives refers to the fact that some customers may have alternative fuel capability or access to nonutility providers for their gas services.

A rate class is generally defined by a combination of two or more of the above criteria. For example, a rate class may be defined as “firm capacity, industrial” or FCI. Another rate class may be defined as “space heating, residential” or SHR.

Once costs have been classified by cost causation criteria (e.g., demand, energy), and rate classes have been defined, the costs are *allocated* to each rate class. Certain costs can be allocated by direct assignment. For example, the cost of installing a meter on a customer’s premises can be assigned directly to the customer. For costs that are not directly assignable, costs are allocated on the basis of the contribution of each rate class to each cost causation category.

For example, the cost of procuring gas is classified as a commodity cost. To determine the contribution of the FCI rate class to the commodity cost, one can compute the ratio of the volume of gas consumed by the FCI class to the total system consumption. This ratio is then multiplied by the total cost of gas procurement to find the allocation of the commodity cost to the FCI class. This method of allocating costs is known as the fully distributed cost (FDC) method. Alternative cost allocation methods can also be used to allocate the commodity cost. Similar allocation of costs can be done for demand, customer, and revenue-related costs.

Certain types of costs are particularly difficult to allocate. They are common costs and joint costs. Common costs are those which are incurred in common while providing multiple services, and generally involve the use of a common facility. Common costs are characterized by a congestibility or capacity constraint feature. For example, a gas main is used to serve several classes of customers, and the amount of service that can be provided is constrained by size. Therefore, its operating and maintenance costs constitute common costs.

When provision of one service leads to the automatic provision of another as a by-product, the underlying cost is a joint cost. For example, when a utility serves its system peak demand, it also serves demands below peak.

Allocation of common and joint costs is difficult and often contentious. The most well-known method for allocating common and joint costs is the FDC. The FDC method assigns this cost on the basis of relative demand of each rate class. Using the noncoincident peak (NCP) method, for example, the capacity cost allocated to the FCI class would be the ratio of the FCI peak and the system peak multiplied by the capacity cost. The coincident peak (CP) method uses the ratio of FCI demand on the day of the system peak to allocate the same cost. Table 2.1 shows an example of a cost of service analysis with functionalization, classification, and allocation of costs.

The last step in the rate design process is the *design of end-user rates* or tariffs. The generic rate is a combination of a fixed charge per accounting period (e.g., month) and a volumetric charge per unit of service (e.g., Mcf). The fixed charge corresponds to the fixed costs allocated to the rate class and generally reflects capacity costs. The volumetric charge corresponds to the variable costs allocated to the rate class and generally reflects energy or commodity costs. Both the fixed charge and the volumetric charge may also incorporate customer and revenue-related costs. However, either the fixed charge or the volumetric charge may incorporate costs that are not truly reflective of the corresponding fixed and variable costs allocated to a rate class. For example, prior to the issuance of Order 636 by the Federal Energy Regulatory Commission (FERC), interstate pipelines charged customers according the modified fixed-variable (MFV) tariff, in which the variable part

Table 2.1: Cost of Service Analysis

	Classification with Allocation Methods				
Function	Demand	Commodity	Customer	Specific	Revenue
Production & Gas Supply					
1. Gas Supply	CP	Mcf or Therms			
2. Storage	CP	Seasonal Mcf or Th			
3. Liquefied Nat Gas	CP	Seasonal Mcf or Th			
4. Propane	CP	Seasonal Mcf or Th			
Transmission					
5. Compressor Stations	CP	Mcf or Th		Spec Assign	
6. Mains	CP	Mcf or Th		Spec Assign	
7. Regulatory Stations	CP	Mcf or Th	Spec Assign		
Distribution					
8. Compressor Stations	NCP				
9. Mains	NCP		No. of Cust	Spec Assign	
10. M&R Stations	NCP		No. of Cust.	Spec Assign	
11. Services	NCP		No. of Cust.		
12. Meter & Install			Wgt. Cust		
13. House Reg & Install			Wgt. Cust		
14. Imd M&R Stations				Spec Assign	
15. Cust. Install				Spec Assign	
Other					
16. Customer Accts			Wgt. Cust		
17. Sales Expense			Wgt. Cust		
Revenue					
18. Revenue from Sales					Revenue
19. Revenue Taxes					Revenue

Source: American Gas Association, *Gas Rate Fundamentals* (Arlington, Virginia: AGA, 1987), 142.

Key				
	CP:	Coincident Peak	Spec Assign:	Special Assignment
	Th:	Therms	No. of Cust:	Number of Customers
	NCP:	Noncoincident Peak	Wgt. Cust:	Weighted Number of Customers

of the tariff incorporated certain components of the fixed cost (rate of return and taxes). In theory, the rate design can vary anywhere between the extremes of a pure fixed charge (with no volumetric charge) and a pure volumetric charge (with no fixed charge), as long as the tariff for a rate class recovers costs allocated to that rate class.[6]

In most PUC jurisdictions, the fixed charge includes part of the demand costs and customer costs, and the variable charge includes the remainder of the demand and customer costs, plus commodity costs in full.

Besides tariffs with defined components, LDCs often offer special tariffs that depart from fully distributed costs. Such tariffs may be designed to meet social objectives such as low income assistance, local employment and energy conservation. For example, increasing block rates may be offered to low-income customers, although actual costs may decline with the volume of consumption. Further, industrial customers may be offered a flexible volumetric rate for interruptible service that varies between a rate floor (set at short-run incremental cost) and a rate ceiling (set at FDC). Such a tariff generally results in a lower bill for the relevant customers and presumably promotes local employment by preventing such customers from relocating to a different service jurisdiction.

Although end-user rates are designed to recover the costs (i.e., revenue requirements) allocated to a rate class, the revenues actually recovered may deviate from projected allocations. The resulting deficit or surplus may be subjected to a truing up process and adjusted in the rates for the next rate period.

[6] The merits and demerits of different tariff designs are discussed in Chapter 6.

Changes to the Rate Design Process Introduced by Unbundling

As mentioned above, the basic mechanics of rate design under unbundling are similar to those for a traditional rate design process. The major change introduced by unbundling is the incorporation of additional cost allocation and cost separations that correspond to the unbundling of services. Throughout the rate design process, it may be necessary to reallocate and separate costs of unbundled services from the previously bundled ones.

Two basic approaches may be used with respect to adjusting the rate design process to account for unbundling of gas services. The more comprehensive approach, or the top-down approach, calls for repeating a traditional cost of service analysis with adjustments to steps that are affected by unbundling. The alternative approach, or the bottom-up approach, starts the adjustments at the tariff design level and moves up as necessary and appropriate.

Figure 2.2 provides an overview of the rate unbundling process using the top-down approach. The bottom-up approach can be understood as one that starts the process at the bottom box of Figure 2.2 and may terminate at any of the boxes preceding it. To date, most of the state commissions have used the bottom-up or *ad hoc* approach, which is simpler to implement and more appropriate for pilot programs. As state commissions move toward full choice programs, or when they reach the next rate cycle, the use of the top-down approach is more likely.[7] The following sections explain the different steps of the rate unbundling process using the top-down approach.

---

[7] See, for example, the Georgia program; Atlanta Gas Light (AGL) filed for adjustments to revenue requirements, customer cost allocations, allocation of costs between AGL and its affiliate, and end-use tariffs.

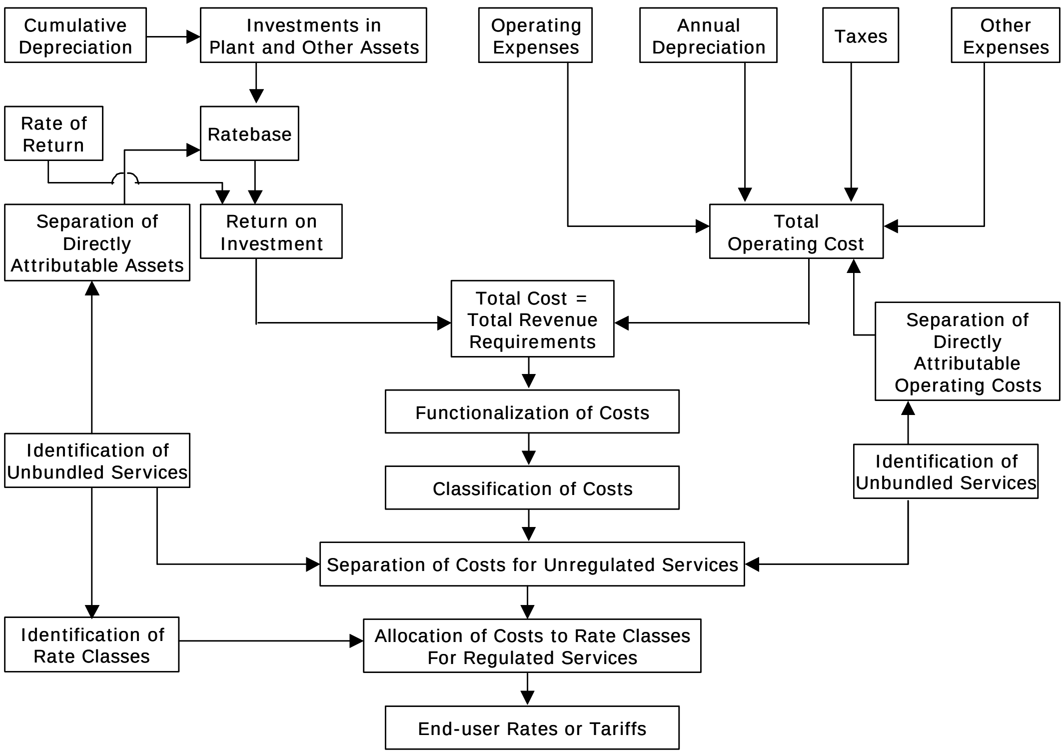

Fig. 2.2. Overview of rate design under unbundling.
Source: Author's Construct.

Identification of Services to be Unbundled

An important step in the rate unbundling process is the identification of services to be unbundled. Until recently, rate unbundling has meant the unbundling of gas commodity and gas transportation services. As of the writing of this report, unbundling of a wider scale with a greater differentiation of services has been introduced by a few jurisdictions.[8]

Determination of Total Costs and Revenue Requirements

As a certain service is unbundled, the gas utility either stops providing the service, or provides the service at a reduced volume. Therefore, there is a corresponding reduction in the total cost of service, and the total revenue requirements of the utility. If an asset is no longer used in providing a service, the corresponding capital costs can removed from rate base. If certain operations of the utility are discontinued or reduced, there needs to be a corresponding reduction in the operating cost component of the revenue requirements.

Some of the above cost separations may be straightforward. For example, if the utility sells a upstream storage facility because it is no longer needed to provide commodity gas, the corresponding capital costs are excluded from the utility's rate base,[9] and related operating costs are excluded from the utility's operating costs. Other cost separations may be more complex. For example, if the utility holds upstream capacity rights on an interstate pipeline on an unexpired contract, and there is a reduction in the use of the capacity because marketers choose to purchase capacity from another party, the treatment of this "stranded capacity" in the utility's revenue requirements poses difficult policy

[8] *Gas Utility Repor*t, December 31, 1999.

[9] A related issue would be whether the asset should be valued at market price or original cost for purposes of cost separations. If original cost valuation is chosen, the treatment of the difference between original cost and market price may be an issue.

and methodological questions. Such questions can only be addressed by a combination of regulatory judgment and careful cost allocation analysis.

One component of the revenue requirements that is likely to be significantly affected by the unbundling process is the rate of return. As some of the unbundled services are competitively provided, one expects an increase in the rate of return for the corresponding investments to reflect an increase in risk and the cost of capital. Also, there might be a reduction in the market risk of “backbone” monopoly services, as competition may stimulate increased consumption of gas services that use such services. The result may be a reduction in the cost of capital and rate of return for certain monopoly services. The overall rate-of-return for the utility would depend on the net effect of unbundling on the rates of return of individual services.

Functionalization of Costs

Generally, the functionalization of costs under an unbundling regime would be similar to that in a traditional rate design process. However, it might be possible to subdivide functional categories to facilitate separation of costs for unbundled services. For example, the functional category, interstate transmission capacity, may be divided into interstate capacity-marketers and interstate capacity-utility. Also, new functional categories may have to be introduced to reflect new operations that the local utility undertakes to deliver unbundled services. One such possible function might be standby storage to help the utility meet its obligation to serve or supplier of last resort requirements.

Identification of Rate Classes

Under unbundling, traditional rate classes would undergo three different kinds of modifications: (1) attrition, (2) subdivision and (3) regrouping.

Attrition would happen to those customer classes that experience a decline in the number of customers and volume of service received. For example, the number of customers receiving firm gas commodity service would decline as some of these customers opt to receive this service from alternative providers. *Subdivision* of a rate class may be necessary when the customer class in question rearranges itself by size and by consumption characteristics because of unbundling. For example, the traditional rate class of small distribution customers would be subdivided into utility customers and choice customers. Also, it may be possible to subdivide a traditional rate class by such usage characteristics as delivery pressure and seasonal consumption. Finally, traditional rate classes may need to be *regrouped* under unbundling. For example, traditional large customers of distribution services, such as industrial customers may be regrouped into the same group as the new large aggregators, particularly if they have comparable load factors. Each of the reclassifications of rate classes under unbundling may have significant cost allocation and rate design consequences. A major reason for defining new rate classes for unbundling is to allocate the fixed costs associated with competitively offered services between customers taking the service from the utility and those that are not.

Allocation of Costs

Allocation of costs to redefined rate classes can proceed as in a traditional cost allocation process. However, part of the cost allocation process will be used to separate costs for those services that are no longer provided by the utility, for example, gas procurement. Consequently, such costs will be excluded from the utility's total costs of service and total revenue requirements. The remaining services will continue to be subject to rate regulation. An issue arises with regard to fixed costs, particularly how they should be allocated and whether they become stranded costs.

Design of End-User Rates

The end-user rate design for an unbundled service may vary, based on which of the following categories it may fall under.

- Services that are currently and clearly competitive and are provided only by nonutility providers
- Services that are currently and clearly competitive, and are provided by both the utility and the nonutility providers
- Services that are potentially competitive and are provided by only the utility
- Services that are potentially competitive and are provided by both the utility and nonutility providers
- Services that are monopolistic and are provided by only the utility

Clearly, competitive services that are provided only by nonutility providers require no further examination. Such services will be deregulated and opened to market pricing.

Individual PUCs may allow some competitive services to be provided by both the utility and nonutility providers. The reasons may include concerns about reliability, insufficient development of the market for alternative providers, and a policy preference for letting the local utility compete with other providers. For such services, the regulatory policy options may vary between traditional cost plus rate-making to complete deregulation of rates. Regulators may opt for cost plus rate-making if they have reasons to believe that the market is insufficiently developed for the services in question, that the utility enjoys market power or incumbency advantages, and that total deregulation of prices may lead to an unregulated monopolistic pricing of such services. At the other extreme, if regulators believe that the market for such services is fully developed and that the local utility has no market power or incumbency advantages, then such services are likely to be completely deregulated. Other options may include price caps for core customers, price floors for noncore customers, and tying either the price cap or the price floor to a market index based on the unregulated prices charged by nonutility providers. All of the above options, except total deregulation, are likely to be temporary for a transition period until such time when the market becomes fully developed and the regulators have sufficient confidence to deregulate the prices of the services.

Potentially competitive services that are provided only by the utility will continue to be rate-regulated until an adequate number of alternative providers enters the market. As discussed later, such services will be regulated in the same manner as regulated monopoly services. One concern that will guide regulators in designing rates for such services is the minimization of entry barriers for nonutility providers and the encouragement of competition.

Potentially competitive services that are provided by both the utility and nonutility providers will also be rate-regulated in a manner similar to competitive services. In regulating such services, regulators will probably take into account any market power and incumbency advantages of the local utility. Regulators may lean toward designing cost separations and rates that offset some of the incumbency advantages of the local utility.

Finally, regulated monopoly services will continue to be rate regulated. Regulators have the option of choosing either traditional cost-plus regulation or some form of performance-based regulation to regulate such services.

CHAPTER 3

IDENTIFICATION OF SERVICES TO BE UNBUNDLED

Introduction

Traditionally, the LDC provided a package of bundled services consisting of two primary services, gas commodity and gas transportation, plus a host of ancillary and customer services. The ancillary services included storage, peaking, load balancing and related services. The customer services included meter reading, billing, customer service centers, customer premises services, and related services. The LDC acquired the resources for providing these services and packaged them as a single unbundled service to the ultimate customers.

Over the last decade and a half, gas commodity and gas transportation were offered as separate, unbundled services to large customers. The ancillary and customer services still remained bundled with the primary services, gas commodity and transportation. Unbundling of a wider scale with varying degrees of differentiation of services have been introduced in some states that are experimenting with unbundling pilot programs. In these pilot programs, primary services are unbundled further into ancillary and customer services and offered to a selected group of small customers. Some LDCs and their state commissions are now contemplating expanding the pilot programs into full-scale customer choice programs. Such programs will include both a full unbundling of services and a full offering of such services to all customers.

One of the critical issues surrounding unbundling of gas services is the level of differentiation to be achieved in unbundling a gas service. To address this issue, certain technical and economic considerations apply.

Technical Considerations for Unbundling a Gas Service

For a service to be provided separately, it must be technically and operationally feasible to do so. Operational feasibility means that the service in question does not have safety and reliability implications through inter-dependencies to other operations and services of the utility system. In other words, the service in question should be capable of being provided independently of one or more of the other services. Further, providing the service separately should not impact the integrity, reliability and safety of the gas delivery system. Therefore, the utility may need to retain complete control over certain systems to maintain these system performance criteria, which may be jeopardized by allowing separate provision of the related services. Finally, there might be some services that could be provided separately but over which the LDC must retain overall control. For such services, either the alternative provider must operate through a reliable coordination mechanism with the LDC, or the LDC alone should be allowed to provide such services.

Economic Considerations for Unbundling a Gas Service

There are two possible economic benefits of unbundling a gas service. *The first benefit arises from letting each customer choose a menu of services, according to her needs*.[10] Not every gas customer needs every service included

[10] The menu of services may include price-risk management options.

in the bundled package currently provided by the LDC. By letting the customer choose those services that she needs, the LDC and other market providers can produce the optimal quantity of the desired services (e.g., risk management services), and efficiency losses related to production of unneeded services are minimized. *The second benefit arises from the fact that some of the unbundled services can be provided competitively*. The competitive provision of such services are expected to achieve efficiencies that were absent in traditional cost-plus regulation.[11]

Unbundling of gas services can introduce new costs. These costs consist of (1) an increase in transaction costs, and (2) lost economies of scope. A customer, for example, may incur search costs in learning about marketers who never before served that customer or any customer of the local utility. In addition, a customer purchasing unbundled gas services from different providers may prevent cost savings from one entity providing all of the services.

A related issue, is the level of demand for an unbundled service. The volume demanded for an unbundled service may be so small that the increased transaction costs and lost economies of scope of unbundled service largely exceed any anticipated efficiency gains. *In other words, the actual or anticipated demand may be below the "critical mass" to justify unbundling a service.*[12] This is one reason why almost all the unbundling and customer choice programs introduced so far have a minimum number of customers or minimum volume requirement for unbundling the gas commodity service. The same requirements would also apply for unbundling other services. Table 3.1

[11] Competition induces two different kinds of efficiency: "allocative efficiency" that causes resources to be allocated to their best uses, and "X-efficiency" that minimizes wasteful use of resources.

[12] Jack Zekoll, New York Public Service Commission, private communication, 1999.

summarizes the characteristics of an unbundled service in terms of costs and benefits.

To be economically justifiable, the efficiency benefits of unbundling must be able to more than offset the increased transactions costs and lost economies of scope. Meeting this criterion, in turn, hinges critically on whether the deregulation of certain unbundled services results in true competition. Otherwise, one could have a scenario in which unbundling and deregulation would increase costs in three ways: increased transactions costs, lost economies of scope, and the efficiency and consumer-welfare costs of *unregulated monopolistic markets*. It is hoped that with careful shepherding of the gas market from a regulated regime to a mostly deregulated one by state commissions and the FERC, this scenario will not occur.

Table 3.1: Criteria for Unbundling a Gas Service

Characteristic	Correlation
Transactions costs	–
Economies of scope with other services	–
Actual or anticipated demand	+
Competitiveness	+
Regulatory costs	–

Source: Author's construct.

Key: – Indicates costs of unbundling increase with increase in magnitude of this characteristic

\+ Indicates benefits of unbundling increase with increase in magnitude of this characteristic

A related question is whether a competitive market exists, or will develop, for a deregulated, unbundled service. The economics literature characterizes the competitiveness of a market by two broad categories of tests. The market tests include an examination of market concentration indices, barriers to entry and the cost of exit. The product tests include an examination of economies of scale and the presence of close substitutes.[13]

The market tests obviously can be applied only to an already existing market. For example, the U.S. Department of Justice investigates whether changes in market concentration, introduced by a merger or an acquisition, would result in the development of monopolistic conditions in an already existing competitive market. Barriers to entry, and costs of entry and exit are other market indices that can be used to judge the competitiveness of a service. Baumol and others have proposed that a market with free entry and costless exit is "contestable" and exhibits the same efficiency characteristics as a competitive market, regardless of whether it has a high market concentration or not.[14]

For markets that do not already exist, the product tests can be applied to assess the competitiveness of a potential market. For example, if a service exhibits economies of scale, it is well-known that it satisfies the so-called natural monopoly condition. Deregulating such a service would result in an unregulated

[13] For reviews of the economics literature on competitiveness of markets, see John Horning et al., *Evaluating Competitiveness of Markets: A Guide For Regulators* (Columbus, OH: The National Regulatory Research Institute, 1988) and David Chessler, *Determining When Competition is "Workable": A Handbook for State Commissions Making Assessments Required by the Telecommunications Act of 1996* (Columbus, OH: The National Regulatory Research Institute, 1996).

[14] William J. Baumol, John C. Panzar, and Robert D. Willig, "Contestable Markets and the Theory of Industrial Structure," (New York: Harcourt Brace Jovanovich, 1988). For an opposing view, see William G. Shepherd, "Contestability vs. Competition," *American Economic Review*, 74, 4 (September 1984).

monopoly market. Most economists would argue that such a service ought to be regulated. One example of such a service is local gas distribution. Table 3.2 summarizes some of the characteristics that are relevant in evaluating the competitiveness of an unbundled gas service.[15]

Applying the Economic Criterion to Identify an Unbundled Gas Service

The analysis needed to apply the economic criterion that the economic efficiency benefits of unbundling and deregulation exceed the sum of increased transaction costs and lost economies of scope, is beyond the scope of the current study, and has not been attempted. Such an analysis would require access to company-specific data. In fact, such an analysis can reasonably be done only by an LDC. This report does not propose that such an analysis should necessarily be required before making decisions about unbundling a service. However, the economic criterion is suggested as an analytical standard that be used by state commissions to examine the choice of services to be unbundled. The criterion also can probably be used to monitor the success of unbundling programs.

Although it may be difficult to apply the above economic criterion, to candidate unbundled services, as well as to any aggregate package of services, it may be possible, for example, to estimate the cost of each unbundled service individually (the stand-alone cost), and also to estimate the cost of their joint provision. The difference, if any, can provide an indication of the lost economies of scope to the LDC. Further, one can estimate the transaction

[15] The characteristics are based on the authors' judgment of factors affecting the competitiveness of services. These factors are in line with economic theory.

Table 3.2: Some Examples of Competitiveness of Unbundled Services

Characteristics	Correlation with Competitiveness	Examples
Numerous existing buyers and sellers	+	Commodity gas
Few existing buyers and sellers	!	Most services except commodity gas
High economies of scale	!	Local distribution
Low economies of scale	+	Commodity gas, meter reading, billing, peaking
High entry costs	!	Local distribution, interstate capacity
Low entry costs	+	Meter reading, billing
High sunk costs	!	Local distribution, most services that include building of facilities
Low sunk costs	+	Most services that involve reselling or using existing facilities
Brand loyalty	!	All services

Source: Author's construct based on a qualitative evaluation.

costs of bundled services and the sum of transactions costs of individual unbundled services. The difference would be an indicator of the increase in transactions costs due to unbundling. Furthermore, one can estimate the cost savings due to reduction of certain services in response to customer choice. However, this estimation, unlike the previous estimations, can only be done *ex* *post*. The service-use data from pilot customer choice programs can help develop this estimation. Finally, one needs to estimate the efficiency gains, because of competition, from a deregulating an unbundled service. This estimation, like the previous one, can also be done only ex post. The data on estimated savings for a service, from customer choice pilot programs, can be used to develop this estimate.

Deregulation of Unbundled Services

Services which are clearly and currently competitive (based on one or more of the service characteristics or market tests) can immediately be unbundled and deregulated. Services that are clearly monopolies, and likely to remain monopolies in the foreseeable future, will continue to be regulated. There may be a class of services for which a definitive judgment cannot be made about competitiveness (or lack thereof). Such services need to be regulated until such time when a definitive determination of competitiveness can be made. The proper regulatory dispensation with regard to these services is to continue their provision under regulated rates, allow alternative providers to offer these services, establish criteria by which the competitiveness of such services are to be judged, and monitor the potential emergence of a competitive market for these services. Once such a service meets the regulatory criteria for competitiveness, it can be deregulated and opened to full market competition.

Candidate Services to be Unbundled

The candidate services to be unbundled can be divided into two categories: (1) upstream (before the city gate) and (2) downstream (behind the city gate).

Upstream Services

Traditionally, the LDC owned, or had access to, wellhead gas, interstate capacity, storage, and a host of ancillary services required to deliver the bundled gas service to the end-use customer. Many of these services, which will not be needed as the gas commodity service is unbundled from the LDC's local distribution service, can be unbundled and competitively provided by an alternative provider. Some of these services are competitive (e.g. gas procurement) and others have monopoly characteristics (e.g., interstate transportation). However, *the LDC is not the monopoly provider of the upstream monopolistic services*, which are regulated by the FERC[16]. Therefore, both the competitive and the monopolistic upstream services can be unbundled and deregulated from the LDC's service jurisdiction. The upstream services that could be unbundled include:[17]

- gas procurement
- pipeline transportation – firm and interruptible
- interstate storage
- nominations and balancing on interstate pipeline
- peaking on the interstate pipeline

[16] The upstream regulated services also experience a certain degree of competition because of the presence of alternative providers and close substitutes. For example, interstate transportation faces competition from secondary transportation markets.

[17] Although the unbundling of upstream services as well as downstream services (see the following section) may be technically feasible, it may not be economically feasible. Further, many of these services may be repackaged or bundled together by marketers, aggregators, and other entities.

Downstream Services

The LDC generally owns and operates the facilities that are used to provide the downstream, or behind-the-city gate services. Under regulation, the LDC traditionally has been the monopoly provider of these services. Except for local transportation, the downstream services do not have any inherent monopolistic characteristics. However, a fully or workably competitive market may not exist for most of these services, but such markets may develop in the future. Most of these potentially competitive services would have to be regulated until a workably competitive market develops. Until then, the LDC could be allowed to provide these services under regulated tariffs while alternative providers are also allowed to provide the same services at unregulated prices. Some of these services may have system safety and reliability implications. For such services, either the LDC would need to retain control of the relevant operations or a good coordination mechanism would need to be developed and implemented, to ensure system safety and reliability. The downstream services that could be unbundled include:

< on-system balancing
< on-system storage
< on-system peaking
< local distribution
< metering
< billing
< customer turn-ons and turn-offs

Local distribution is the only downstream service that is clearly monopolistic. The remaining services may be competitive to various degrees and have markets that may vary between fully developed to nonexistent. The decision regarding deregulating any of these services will be contingent upon an empirical determination of a workably competitive market. Also, among these services, balancing, peaking, and customer turn-ons and turn-offs may have safety and reliability implications, which must be considered in deciding the appropriate level of control and coordination to be exercised by the LDC.

CHAPTER 4

ALLOCATION AND SEPARATION OF COSTS FOR UNBUNDLED SERVICES

In general, allocation of costs refers to an apportionment of costs among operations and activities of a business firm. Cost allocation is an important element in every business enterprise, and has a range of applications that include: (1) accounting for costs of inputs, (2) pricing of products and services, and (3) distribution of cost responsibility among affiliated business units.

The first two of the above applications of cost allocation have been, and will continue to be, an essential part of regulatory rate-making. The third application is likely to become increasingly relevant in the emerging market regime of unbundled and deregulated utility services, particularly if a regulated utility shares assets, facilities and operations with an unregulated business affiliate.

Cost Allocation: Basic Concepts and Applications

As discussed in Chapter 2, cost allocation is one of the steps in regulatory rate design, preceded by functionalization (by operations) and classification (by production and consumption) and followed by the design of end-user tariffs. In turn, the cost allocation process itself has three major steps: (1) the categorization of costs by the presence and the type of sharing among costs, (2) the categorization of costs by their variability and (3) the choice of a cost allocation technique and its application.

Categorization by the Presence of Shared Costs

Directly Assignable or Attributable Costs

Many of the costs of a utility is directly traceable to a service category. For example, the costs of a customer hookup and setup of facilities on a customer's premises are clearly traceable to a specific service. The allocation of costs to directly traceable services is relatively straightforward. Unfortunately, many of the costs of a utility do not belong to this category; they are either common costs or joint costs.

Common and Joint Costs

Common costs refer to those costs that are shared because the underlying operations share a common facility, and the provision of one service constrains the provision of another. Joint costs, on the other hand, involve operations in which provision of one service leads to provision of another service as a byproduct. As a result, the provision of one service does not constrain the production of the other service, and the two services are produced in a fixed proportion. So, the distinguishing feature of a common cost is congestibility, and the distinguishing feature of a joint cost is joint or proportionate variation.

A well-known example of a common cost is the total cost of storing furniture and clothing in a warehouse. Given the capacity constraint of total warehouse space, any increase in the volume of furniture stored will diminish the space available for storing clothing. Also, the storage of either furniture or clothing does not lead to the automatic storage of the other commodity.

A well-known example of a joint cost is the cost of producing wool and mutton from sheep. If mutton is produced, wool is produced as a byproduct and the production of one does not constrain the production of the other. Also, the two are produced in a fixed proportion.

In the gas utility context, an administrative overhead cost is an example of a common cost. An administrative overhead cost, such as the total cost of billing different classes of customers, shares common facilities (e.g., computers) and operations (e.g. printouts of bills). However, if the billing-related activities increase for one group of customers, they must necessarily decrease for other groups of customers, for a given set up of facilities. This cost, therefore, satisfies the congestibility condition of common costs.

A corresponding example of a joint cost is the cost of serving customers during the peak and off-peak periods. Even though new capacity may be built to meet the coincident peaks of all customers, its use occurs across all periods.

It is easy to see that increasing the capacity to serve customers during the peak does not constrain the capacity available to serve off-peak demands. Consequently, if more capacity is built to serve peak demands, proportionately more capacity becomes available to serve off-peak demands.

Categorization by Variability of Output

Costs can also be categorized by their variability in response to levels of output. Costs that do not vary when the output is varied are known as fixed costs. Costs that vary when the output is varied are known as variable costs. Well known examples of fixed costs are capital costs (including any applicable interest charges) of constructing pipeline facilities, contracts for firm capacity, fixed operating and maintenance costs, and property taxes. Well known examples of variable costs are fuel costs, variable operating and maintenance costs, and sales taxes.

There is a general correspondence between fixed costs and demand (or capacity) costs, and between variable costs and commodity (or energy) costs.

Most fixed costs are generally traceable to demands placed on the system by customers and most variable costs are generally traceable to volume of consumption of the gas commodity by customers.

Combining Categories

Using the above two categorizations (by the presence of sharing and by variability), one can arrive at six possible combinations of cost categories. Each combined category of cost presents a different degree of difficulty for the allocation of costs. Directly assignable costs, whether they are fixed or variable, are the easiest to allocate. Fixed costs are generally more difficult to allocate than variable costs. This is true because the level of consumption, which provides a convenient index to allocate variable costs, cannot be used to allocate fixed costs. Fixed common and joint costs are arguably the most difficult, and contentious, to allocate. The degree of difficulty in allocating a cost also depends on the choice of a cost allocation technique.

Choice of A Cost Allocation Technique

A cost allocation technique is derived from a cost allocation principle or approach. There are three general approaches to cost allocation. Under the fully distributed cost (FDC) approach, also known as the fully allocated cost (FAC) approach, costs are allocated according to some measure of consumption or benefit accruing to an individual or a group of customers. According to the marginal cost (MC) approach, the costs of the last unit of service are allocated to the relevant service category or customer. The stand alone cost (SAC) approach, which has been proposed as a standard to test for inter-service or inter-customer cross subsidies, is the total cost of a providing a service, when the service is provided exclusive of other services.

The cost allocation approach, in turn, is premised on chosen economic or accounting principles. In fact, the economic and the accounting approaches do not just differ on how costs are to be allocated, but also on what constitutes cost.

Definition of Cost: Cost Allocation Implications

In the accounting discipline, cost is viewed as the price actually paid to obtain a product or service, as and when it happens, that is the original cost. For example, the actual total amount of money paid to complete the construction of a pipeline, or alternatively, the price of purchasing one, is the accounting cost of the pipeline. This measure of original cost is what would be used as the amount (adjusted by some periodic depreciation factor over time) to be allocated to the various services or customer classes, or both. Neither the cost basis nor the depreciation factor depends on the changes in any measure of economic value over time. The cost basis would only change when another sale transaction occurs and, then, the new sale price would become the cost basis.

The economic definition of cost, on the other hand, is premised on the contemporaneous value of a commodity or service mediated by the market process between a buyer and seller. For example, the economic cost of a reserve of stored gas is not its original purchase price, but the price that the gas would command in the current market. The difference between the accounting and the economic definitions of cost appears most clearly in the definition of two well-known concepts. The first is profit.

In accounting parlance, profit is understood as the excess of accounting revenues over accounting costs. As such, a return earned on a firm's investments constitutes its profit. But the economic definition of profit includes only earnings that are over and above the normal return on investment. In other words, a normal return earned on investment is still part of the economic cost, and only earnings in excess of this economic cost constitute economic profit. The second cost concept that distinguishes the economic formulation from the accounting formulation is the notion of opportunity cost. Opportunity cost is defined as the cost or value of the best alternative to the use of a resource or facility for producing a good or service. For example, the opportunity cost of a manager's labor is not his current salary, but the value of his best alternative earning opportunity.

The two definitions of cost have important cost allocation implications. The accounting definition relies entirely on the supply-side cost of inputs to provide a service. The economic definition on the other hand, which is based on the market value of services, must take into account demand-side considerations. For example, the consumption of a service depends both on its price and the price elasticity of customers. In allocating costs according to the economic approach, price elasticity of demand needs to be taken into account.[18]

Cost Causation: The Central Principle of Cost Allocation

Cost causation is the central principle for all cost allocation. This principle means that a cost is allocated on the basis of factors that cause the cost to be incurred. For example, an LDC has to invest in building distribution capacity to meet customer peak demand. There is a causal relationship between customer peak demand and investments in capacity. The investments in capacity correspond to the peak demand and, therefore, causes the investment expenditures to be incurred. It follows that the investment expenditures would be allocated on the basis of some measure of peak responsibility of different

[18] The most well-known method that uses price elasticity of demand in cost allocations is Ramsey pricing. According to this method, costs are allocated and services are priced in proportion to the inverse price elasticity of each service class.

customer groups or service categories. As another example, an LDC may contract for a certain volume of gas to be transported over an interstate pipeline. The contract may specify a fixed reservation charge for capacity (for maximum take) as well as a charge per unit volume transported. There is a causal relationship between the fixed capacity charge and the LDC's peak load, and the volumetric charge and the LDC's total gas delivery. The corresponding costs may be allocated according to some measure of peak and volume responsibilities of different customer groups or service categories.

Accounting Principles of Cost Allocation

There are several accounting principles of cost allocation, namely, traceability, variability and beneficiality.

Traceability is an attribute of costs that permits the resources represented by the costs to be identified in their entirety with units (some form of usage characteristics) of the service or product being provided. Not all costs may be traceable to a unit. Cost that are not traceable, as well as those are, may vary in some fashion according to the variation of the volume of a service provided. Such costs have the attribute of *variability*. Another principle often used to allocate costs is *beneficiality.* If a service could not be provided without incurring a certain cost, the customer being served is responsible for the cost.

To illustrate the differences between the above accounting attributes, the example of costs associated with pipeline transportation services can be considered. A pipeline transportation contract generally has two components: a fixed capacity reservation charge and a volumetric charge. Both the volumetric charge and the capacity charge meet the traceability and beneficiality criteria. Costs associated with the fixed charge are traceable to demands placed on the pipeline system, and those associated with the volumetric charge are traceable to volume of gas transported. Also, if these costs were not incurred, the related pipeline services could not be provided to any customer, and therefore, meet the beneficiality criterion.

By contrast, the variability criterion is not satisfied by the capacity reservation charge, although it is satisfied by the volumetric charge. As long as the peak load of a service class remains below the system peak, the variation of load of this class does not change the cost of the corresponding service, namely the capacity reservation charge. On the other hand, the higher the volume consumed, the higher the volumetric charge.[19]

The Fully Distributed Cost Method

The fully distributed cost (FDC) method, *based on embedded costs*, has been the method of choice in regulation. As discussed, the approach is based on the accounting definition of cost, and on the accounting principles of traceability, variability and beneficiality. The FDC method uses several techniques, each tied to the classification of the service, to allocate costs.

Allocation of Embedded Demand or Capacity Costs

The basic methods of allocating demand costs are summarized below. There are other methods of allocating demand costs, which are variations of the basic methods.

[19] Most of the preceding and subsequent discussion of cost allocation principles and methods use customer, service or rate classes as targets of cost allocation. However, the principles and methods can be used with equal validity when no ultimate or end-use consumers are directly involved. For example, if the utility sells an asset to an affiliate, the pricing of the asset involves a cost allocation decision. Although, in this case the affiliate does not "consume" any services, the value of the asset could be determined using FDC or MC principles. In fact, a major part of cost allocation for unbundled services involves separating costs of assets no longer used or services no longer provided by the utility.

The *coincident peak* (CP) method allocates costs a service class in proportion to its share of system peak. For example, if the system peak is *T* Mcf, and the firm industrial service class has a peak of *x* Mcf on the day of the system peak, the share of demand costs for this service class is *x/T.*

According to the *noncoincident peak* (NCP) method, the peaks of individual service classes are added to arrive at the composite peak (that may not coincide with the system peak). For a system consisting three service classes, with peaks of x, y and z respectively, the costs allocated would be, x/(x+y+z), y/(x+y+z) and z/(x+y+z), respectively.

The *average and excess* (A & E) method has a two-part allocation factor. The first part is the average consumption of a service class as a percent of the sum of the average consumption of all classes, multiplied by the system load factor (i.e., average system consumption divided by system peak). The second part is the ratio of the excess demand of each service class and the system excess demand, multiplied by the complement of the system load factor (one minus the system load factor). The service class excess demand is the difference between the peak demand and the average consumption for the class. The system excess demand is the sum of all service class excess demands. For example, if the system consists of two service classes with peaks of p_1 and p_2 and average consumption of a_1 and a_2, and the system peak demand is p, then the excess demands for the two classes are p_1-a_1 and p_2-a_2, respectively. The system excess demand is $(p_1-a_1) + (p_2-a_2)$. The system load factor is $(a_1+a_2)/p$, and its complement is $1-(a_1+a_2)/p$. Therefore, the allocator of capacity costs for the first service class is $[(a_1+ a_2)/p]\ [a_1/(a_1+a_2)] + [1-((a_1+a_2)/p)]$ $[(p_1-a_1) / [p_1-a_1) + (p_2-a_2)]]$.

Each of the above three methods of allocating capacity costs can be applied to a chosen period, that may vary between a month and a year.

Allocation of Embedded Commodity or Energy Costs

Energy costs are generally allocated on the basis of the share of total energy consumed by a service class. Such costs may be differentiated by time to recognize the difference in costs between on-peak and off-peak hours.

Allocation of Embedded Customer Costs

Customer costs are generally allocated on the basis of some index of the volume of customer costs. Examples of allocators include the number of customers, the number of billing inquiries and the number of customer hookups.

Economic Principles of Cost Allocation

As previously discussed, the economic approach to cost allocation has two fundamental differences with the accounting approach. First, the definition of cost is based on the contemporaneous market price or value, or the opportunity cost. Second, the cost to be allocated to a service or asset is based on the marginal cost or value of that service or asset. The first criterion requires the inclusion of demand-side effects in any cost allocation exercise. Both criteria make the historical or embedded cost immaterial to the cost allocation process.

The Marginal Cost Method

The marginal cost method calculates the cost of each unit increment of service. In contrast to the FDC method, the MC method is indifferent to the total cost of providing a service. The relevant cost, at any level of service, is the cost of the last unit of service. For example, if the system capacity has to be increased to hook up a new customer, the MC method would assign the incremental cost of the added capacity to all customers. In contrast, the FDC method would allocate a portion of the total capacity cost (sum of the cost of existing and new capacity) according to some measure of its share of the system capacity, such as the coincident or noncoincident peak. As for the FDC method, the use of the MC method to allocate costs depends on the classification of costs.

Allocation of Marginal Capacity Costs

In the short run, capacity costs do not vary and short run marginal costs for capacity are essentially zero. Over the long run, however, capacity needs to be added to serve increases in demand. Allocation of marginal capacity costs involves two steps: calculation of marginal costs, and allocation of the costs.

By economic definition, marginal capacity costs correspond to optimal additions of capacity. Therefore, calculation of capacity costs involves optimizing the system for a given combination of existing and projected demand, and calculating the cost of additional capacity needed for the optimized system.

In theory, the cost of each additional block of capacity would be allocated to the customer whose demand would be met by the incremental capacity. In practice, however, such atomistic differentiation of capacity additions is not feasible, and capacity addition decisions are based on total capacity needs of the whole system, which consist of multiple classes of customers. Therefore, the cost allocation would be based on some measure of cost responsibility for the marginal capacity additions. Under MC pricing, customers are priced based on their total usage of the service.

Allocation of Marginal Energy Costs

The consumption of gas varies not only by customer class and service category but also by the hour. Also, the cost of acquiring, storing and delivering gas may also vary by the hour. Therefore, the allocation of marginal energy costs of gas should take into account the time variation of gas consumption. In theory, one could track the consumption of gas by each customer at each hour of the day and each day of the year and allocate the related costs to that customer. If we assume that each block of gas and its delivery operations cost the same at a given hour, the marginal cost to be allocated to each customer would be proportional to its share of total gas consumed during that hour. In practice, the consumption volumes of customers within a customer class may have to be averaged. Similarly, the hourly consumption data may have to be averaged across days during the work week and also days during the weekend. The final allocations would be on the basis of averaged consumption and cost data.

Allocation of Marginal Customer Costs

There are two kinds of customer costs: (1) costs that are directly traceable to a customer, such as the cost of a service drop to a customer's premises, and (2) common and joint costs, such as the cost of office space, equipment, software and personnel for customer billing, customer complaints and service calls. The first type of costs can be directly assigned to a specific customer, with MC measured in terms of current market value and FDC measured in terms of original cost. For the second type of costs, there are again two components: (1) costs that related to expansion of facilities and capabilities, and (2) costs that depend on the number of customers (or weighted number of customers), and the type and volume of customer transactions. The first type of costs is analogous to capacity costs and can be allocated using similar methods. The marginal cost is simply the cost of adding facilities and expanding capabilities. For example, if facilities need to be added to serve expanded volume of service calls, the related incremental cost is the marginal cost. This cost can be allocated in proportion to the contribution of each customer class to the system peak.

The second type of costs is analogous to energy costs and can be allocated using methods similar to those used to allocate energy costs. For example, the costs of service calls can be differentiated by the hour and each customer class can be allocated its proportionate share of these costs.

Avoided Costs

In the context of separations of costs of unbundled services, the relevant cost is the avoided cost. It is the cost that LDC does not have to incur because it is no longer providing a service (e.g., the gas commodity service if the LDC exits the merchant function) or reduces the level of a certain service (e.g. the gas commodity service if LDC continues to provide the service but at a reduced level because other providers also offer the service).

As in the case of marginal costs, avoided costs can also be divided into the short run and the long run. While avoided energy and customer costs occur both in the short run and the long run, avoided capacity costs are generally zero in the short run and occur mostly over the long run. As the LDC can avoid additions of capacity to its system because it does not provide certain services or provides them at reduced volume, it avoids related costs. One exception to this rule for time dependence of avoided capacity costs would occur if the LDC were to sell some of its assets that were used to provide a service. In this case, the LDC does not pay the carrying charges (interest, property taxes, etc.) on the related investments and, therefore, avoids short-term capacity costs.

The Stand-Alone Cost Method

Stand-alone cost, as the phrase indicates, refers to the cost of a service if the service were provided alone, exclusive of other services. When two or more services share costs jointly or in common, the removal of all services but one from the mix would still entail the service incurring these joint and common costs.[20] In other words, the stand alone cost of each of the services would include the entire common and joint costs of these services. The stand alone cost of a service is generally higher than the cost allocated to this service by any other cost allocation method.[21] An example of a stand-alone cost is the use of separate systems of mains to each customer class. The capacity of the main to serve peak-day load is related to the volume of the pipe (area multiplied by length), while the cost is related to the pipe's circumference times its length.

The stand-alone cost is not generally used as a cost allocation method in actual regulatory or business applications. However, it serves as a theoretical benchmark specifying an upper limit on the cost to be allocated to a given service.

Cost Allocation and Unbundling

The introduction of unbundling challenges LDCs and regulators with both a larger array of cost allocation issues and a sharper delineation of underlying

---

[20] The stand-alone cost is the sum of directly attributable costs of a service, and the common and joint costs the service shares with others.

[21] On exception involves the situation where there are diseconomies of scope.

technical and policy issues. As more and more services get unbundled, LDCs will be required to analyze the underlying asset values and operating expenditures, and PUCs will be expected to evaluate the methodological correctness and policy implications of LDC submissions. Under unbundling, the cost allocation process would span three separate steps: (1) separations of costs for unbundled services that utility would no longer provide or provide at a reduced level, (2) allocation of costs among rate classes for regulated services, and (3) the design of end-use tariffs. Step 2, namely, the allocation of costs among rate classes for regulated services, has been reviewed in the foregoing section and will not be discussed further. The following sections discuss step 1, namely the separations of costs for unbundled services. Step 3, namely design of end-use tariffs is discussed in Chapter 5. Among the above three steps, separations of costs of unbundled services are a relatively new regulatory challenge in the gas utility sector;[22] allocation of costs among rate classes and end-use tariff design is a relatively well-developed practice under traditional regulation.

Use of Cost Allocation in Cost Separations

The same principles, methods and techniques used to allocate costs to traditional bundled services can be used to separate the values of assets and costs of services. For example, a peak responsibility method, such as the NCP (noncoincident peak), used to allocate the costs of distribution capacity to regulated service classes, can also be used to separate the costs for marketers (or alternatively, “choice” customers) that purchase the distribution service.

---

[22] The separation of costs between inter-jurisdictional regulated services, and between regulated and unregulated services, is a relatively well-developed practice in the telecommunications sector. For a comprehensive overview, see William Pollard, *Cost-of-Service for Intrastate Jurisdictional Services* (Columbus, OH: National Regulatory Research Institute, April 1985).

Also, because some, or many, of the unbundled services will be provided in an unregulated market, *market-value may become an important determinant in cost separations and pricing of unbundled services.*

Under unbundling, it may be useful to classify the LDC's costs into (1) upstream (i.e., before the city gate) and (2) downstream (i.e., behind the city gate) costs. This classification is particularly convenient in examining separation of costs, as most of the upstream costs are incurred in supplying the gas commodity service, a service most likely to be unbundled and provided by alternative suppliers. Also, many of the upstream services are rate-regulated by the FERC. For these services, the separation of upstream costs can be based directly on FERC-determined tariffs. The downstream costs, on the other hand, are incurred to provide local distribution service and customer services.[23] Local distribution service will continue be provided by the LDC and regulated while some of the customer services may be unbundled, deregulated and provided by alternative suppliers.

Separation of Upstream Costs

As mentioned, upstream costs are incurred to provide the gas commodity service. The services that comprise the gas commodity service include gas purchasing and aggregation, interstate pipeline capacity, production and market area storage, parking, peaking, balancing, price risk management and title transfer. Each of the above may have up to three cost components: (1) financing costs or asset values if the LDC owns the underlying physical asset (2) contract service costs or contract values if the LDC receives the

[23] The state PUC does not have to make policy decisions regarding those upstream costs that can be based on FERC-determined tariffs. The treatment of downstream costs, on the other hand, is open to the policy choices to be made by the PUC.

service through a contract and (3) operating expenditures if the LDC operates any facilities to provide a service.

Separation of Financing Costs or Asset Values

An LDC may own an asset, such as a storage facility, a part of an interstate pipeline or a peaking facility. Under traditional regulation, the appropriate rate base (original cost minus cumulative depreciation) would be multiplied by the allowed rate of return to find the cost basis or revenue requirement for the facility. If a single asset were used to provide multiple services or customer groups, the appropriate FDC method (e.g., CP, NCP, A&E) for allocating capacity-related costs would be used.

Under unbundling, several possible dispensations of the asset would have to be considered before an appropriate cost allocation method can be chosen. They are:

1. The asset would be divested in its entirety because the LDC would no longer be providing the services that use the asset.
2. Part of the asset would be divested because the LDC would reduce either the volume or the number of services that use the asset.
3. The asset would be retained in its entirety because the LDC would continue to provide the services that use the asset.

Full Divestiture

In the first case, the asset could be costed at either at its market value (to be determined by competitive bidding, bilateral or negotiated sale, or some other market mechanism) or its book value. If the market value is chosen as the proper cost basis, the LDC could either make a profit (if the market value exceeds the book value) or incur a stranded cost (if the market value is below the book value).

The market value option has the merit that it is consistent with economic efficiency. The demerit is that if the market value is smaller than the undepreciated book value, then the utility could face stranded costs, and regulators would have to address the proper dispensation of stranded costs. Depending on the magnitude of the costs and its impact on rates, stranded costs may or may not be a significant regulatory issue.

The book value option, for all practical purposes, is the equivalent of the market value option, in combination with stranded cost recovery. Therefore, it has all the merits and demerits of allowing regulatory recovery of uneconomic assets.

A particular case for the separation of upstream assets, in which the utility sells its assets to an affiliate, merits special attention. In this case, use of the book value option would be the most straightforward and the least controversial option. The market value option, on the other hand, provides the utility an incentive to undervalue the asset and then ask for regulatory recovery of the resulting stranded cost. By doing so, the utility minimizes the cost to the affiliate of acquiring an asset, and then passing on the residual cost (i.e., the difference between the sale price and the book value of the asset) to its monopoly customers. One way to prevent this possibility of abuse is to deny any stranded cost recovery if the utility sells an asset to one of its affiliates. Another is to value the asset at the higher of either the book value or the market value. Either of these options eliminates the possibility of the utility manipulating the value of the asset to its or its affiliate's advantage and to the detriment of the utility's customers and the affiliate's competitors. Critics of the higher-of-book-or-market-value method contend that it is economically inefficient and does not necessarily protect customers.[24]

---

[24] Kenneth W. Costello, "A Pricing Rule for Affiliate Transactions: Room for Consensus,“ *Electricity Journal* (December 1998), 59-66..

Partial Divestiture

The second case can be addressed in two ways: (1) direct valuation of the partial asset or (2) valuation of the full asset and allocation of the value to the partial asset. The first option can be exercised if the partial asset is operationally and functionally separable from the full asset and can be independently put on the market. However, for a lot of utility assets, this may not be feasible and the second option would have to be exercised. From the above discussion, the second case requires a two-stage cost allocation process: the valuation of the full asset and the separation of the partial asset from the utility's rate base. Take the case of a storage facility. Under the two-stage approach, after calculating the total cost of the facility, these costs are then allocated between (say) the regulated utility and a nonregulated subsidiary.

The valuation options would be the same as for full divestiture. A market value would be established for the entire asset and a value would be assigned to the partial asset by using an appropriate cost allocation method. One problem with the market value option is that if the whole asset is not being divested, it may be difficult or impossible to establish its market value. The alternative is to use the book value as the basis for allocating and separating costs for partial assets.

The allocation of costs between partial assets could based on one of the FDC, MC or SAC methods. The following discussion assumes that FDC > MC and SAC > FDC. While these relationships arguably hold in most situations, there are exceptions. For example, with diseconomies of scope, SAC may be lower than FDC.

If the FDC method is used, one can use either direct assignment if the partial asset or any of its part is directly assignable, or one of the peak responsibility methods if the partial asset shares common or joint operations with the remainder of the asset. The latter would be true if the utility sells part-ownership of the asset to an affiliate. As a concrete example, the LDC could sell part-ownership of an upstream storage facility to an affiliate and jointly operate the facility with the affiliate. This would entail two cost separations problems. The first would be to determine the sale price and the second is the separation of costs of operation. Obviously, a regulatory commission would not approve any sale price negotiated between the utility and the affiliate; doing so would provide the utility the incentive to price the partial asset below either the normal market price or the FDC-based value of the asset. If the commission were to approve a sales value of the asset based on FDC, it could use one of the peak-responsibility methods for allocating capacity costs to apportion the value. For example, it could use the estimated percentage share of the utility's original system peak to be served by the utility as the allocation factor for the utility's part of the asset. The separation of costs for joint operations is discussed in the next section.

Alternatively, the commission could approve an MC-based method to separate the value of the partial asset co-owned by the affiliate. The appropriate cost measure in this case would be the marginal capacity cost. Depending on the relative share of high load factor or low load factor customers between the utility and the affiliate, the marginal capacity cost could be lower or higher than the FDC-based capacity cost for the partial asset. If the regulatory commission allows the MC-based method to separate the value of the asset, the utility would have an incentive to let the affiliate acquire the relatively high load factor customers.

Finally, the value of the divested partial asset could be based on SAC. For an asset that is functionally inseparable, the SAC would be measured by creating a hypothetical asset that could provide the same services as the partial asset. Given the common or the joint nature of the costs shared between the partial and the full asset, it is likely that the stand alone cost of the divested partial asset would be larger than any cost estimate based on either FDC or MC.

Each of the methods, namely FDC, MC and SAC have merits and demerits. The FDC method has the advantage of being the traditional practice, and less difficult to measure than either MC or SAC. A disadvantage is that cost allocation according to the FDC method is inconsistent with economic efficiency, in the sense that it sends incorrect price signals to the consumer. In the particular case under discussion, the regulated services will be priced below their marginal costs, and may cause an over-consumption of these services by both marketers and end-use customers.

The use of the MC method for separation of costs of partially divested assets has the advantage that it is generally consistent with economic efficiency. Also, use of this method minimizes the possibility of stranded costs. However, use of this method could impose a barrier to entry on firms competing with a utility or its affiliates. For example, the utility's competitors would encounter set up and initial capital costs that are equivalent to a stand-alone facility that the utility or its affiliates would not face. As mentioned, choice of an MC-based method would allow the utility to game the process to minimize the cost assigned to the divested partial asset, by allowing or assisting the affiliate to acquire a relative higher share of high load factor customers. The MC-based measure, however, can be used as a floor below which the asset could not be valued, to prevent the possibility of cross subsidization of the utility's affiliates with revenues earned by the utility from its regulated customers.

The chief merit of an SAC-based estimate of the value of the divested partial asset is that it would be comparable to what an unregulated competitor of the utility or its affiliates face to purchase or construct a functionally equivalent facility. Choice of this method would favor utility competitors even more than any estimate based on FDC methods. However, there are several disadvantages to the use of a SAC-based measure. First, estimating the SAC of a partial facility may be as difficult, if not more difficult than an MC-based method. Second, utility competitors may be able to purchase or lease the related capacity services at a cost less than the SAC from the utility or others. Costing the partial asset at SAC would offer an unduly high competitive advantage to the competitors and may encourage entry by inefficient providers. An SAC-based measure, however, can serve as a ceiling above which the partial asset would not be valued, to prevent unregulated customers from subsidizing the regulated customers and the utility competitors from earning above-normal profits, and discourage the entry of inefficient competitors.

No Divestiture

The third case essentially represents a continuation of the traditional regulated service scenario. In this case, the utility's competitors and affiliates would either lease the facility or purchase the services provided by the asset, and resell or rebundle them with other services for the end-use customers. The relevant cost allocation issue is the pricing of the lease or the services. This issue is discussed in chapter 5. It should be noted here that regardless of the method chosen, the price chosen for the lease or the service should be nondiscriminatory between the utility's affiliates and alternative providers.

The Rate of Return

There is another issue that needs to be addressed if any of the upstream assets are to be retained, either fully or partially, by the LDC to provide services. It is the reevaluation of the rate-of-return. The ultimate service provided by upstream assets is mostly gas commodity, which is expected to face competition. As the gas commodity service makes the transition from a regulated monopoly service to an unregulated competitive service, the market risk on the associated investments is expected to rise. As such, the investors may demand a higher return on their investments. This translates into a higher rate-of-return on investment in the upstream assets that the LDC may choose to retain. Consequently, this particular component of the total or composite rate-of-return may go up, and thereby may raise the overall rate-of-return. However, there may be other services, particularly downstream regulated services, whose market risk may decrease, warranting a downward adjustment on the rate-of-return on the investment in related assets. This effect may cause an overall decrease in the composite rate-of-return. The overall impact on the rate-of-return will be determined by which of the effects is dominant.

Separation of Contract Service Costs or Contract Values

The LDC may have contracts for services with various upstream service providers including interstate pipelines, storage service companies and marketers. The LDC may choose to abandon these contracts as it either reduces the volume or the number of the services provided by the contracts. The LDC may buy out or resell the unused portion of the contract term or contracted services. The proper dispensation as well as valuation of these contracts is an issue that increasingly confronts LDCs and regulators.

There are two different options for an LDC to reassign upstream service contracts to alternative providers.

1. Mandatory assignment to alternative providers prorated by market share of customers.
2. Release of contracts to the secondary market. Alternative providers are allowed to purchase their own contracts from either the LDC, from the interstate pipeline or from the market.

If the first option is chosen, the cost of the contract, at the FERC-tariffed price, is allocated to alternative providers according to their market share of customers and there is no contested cost allocation issue. If the second option is chosen, the LDC can resell their contracts either at FERC-tariffed price or below, because of the rate-cap currently operational under FERC Order 636. If the LDC is not able to resell all of their unneeded contracts or some of the contracts are resold below FERC-tariffed prices, the LDC may be faced with stranded costs. One option to mitigate stranded costs for the LDC would be to rebundle the capacity with other gas services and sell them in the "gray" market, which is not regulated by the FERC. To the extent an LDC is faced with stranded costs, a PUC may allow its recovery if the purchase of the related capacity contracts are deemed prudent. This may offset some of the expected savings from unbundling and deregulating some of the gas services.

The choice between mandatory assignment and market-based allocation of upstream capacity costs confronts the regulator with a difficult choice. The mandatory assignment option may foreclose potential savings to customers that could be achieved if gas marketers are allowed to purchase their own capacity from the market at prices below the FERC tariff. At the same time, this option avoids the problem of stranded costs.

On the other hand, the market-based allocation would presumably capture potential savings of using competitive or semi-competitive markets for capacity. Yet, this option could result in stranded costs to the LDC. To the extent these stranded costs could not be mitigated through market-based options such as resale in the gray market, regulatory recovery of these costs would offset the potential savings from markets for capacity. The net of costs and savings that would result from the two competing options is ultimately an empirical question.

From a purely economic efficiency point view, the preferred option would be to allow the market-based allocation of upstream capacity costs and encourage the LDC to mitigate stranded costs through resale of capacity in the gray market by providing appropriate incentives, such as allowing the LDC to retain a share of the potential profits. Any remaining stranded costs could be recovered from customers. An additional incentive could be provided to the LDC to minimize stranded costs by allowing only partial recovery of stranded costs.

Separation of Upstream Operating Expenditures

There are two kinds of expenditures to be considered. First, the LDC purchases upstream services from interstate pipelines and marketers to serve its customers. Second, the LDC owns and operates upstream facilities to serve its customers.

For the first type of services, there is essentially no need to use a cost separations process. The LDC resells these services to alternative providers and charges them the purchase prices, which are based on FERC-determined tariffs. The purchase costs of these services are part of the LDC's revenue requirements. The sales revenue from providing these services are a credit to the revenue requirements. To the extent both the purchase and sale prices are based on FERC-determined tariffs, there is no net change in revenue requirements of the utility due to upstream operating expenditures.

For the second type of services, the state regulatory commission currently has jurisdiction over their rates as long as these facilities are being operated to serve the state's jurisdictional customers. In this case, the allocation of costs would be similar to those for downstream services discussed in subsequent sections. However, if the utility chooses to sell these services to customers outside of the state's jurisdiction, it is possible that FERC will assert and gain jurisdiction over the rates charged for the services. In that case, the allocation of costs is identical to the first type of costs.[25]

---

[25] In the unlikely event that the state commission asserts and gains jurisdiction over these services, the allocation of costs would be similar to those for downstream services, this issue will be discussed in detail in a subsequent section.

Separation of Downstream Costs

A number of the LDC's downstream services are potential candidates for unbundling and eventual deregulation. They include such services as metering and billing. The separation of costs of these services can be subject to analysis similar to that done for upstream costs. The separation of costs for purposes of unbundling can be divided into two categories: (1) separation of costs for downstream assets and (2) separation of costs for downstream operations.

Separation of Costs for Downstream Assets

The analysis of options for separating costs for downstream assets are essentially the same as that for upstream assets, and therefore, will not be repeated here. The options are briefly summarized below.

Fully divested assets could be costed at either market value or book value. Use of the market value option could result in either stranded costs or profits. If stranded costs were to occur, the state commission would have to make a choice of whether to allow full, partial or no recovery of these assets.

Partially divested assets could either be directly costed, or be subject to a two-step process in cost separations: valuation of the full asset and allocation of cost to the partial asset. The direct costing option would be feasible if it is functionally separable from the fully assets. For most assets, the partial asset is not separable and cannot be costed directly. Alternatively, the full asset could be valued at book or market value and the value of the partial asset could be based on FDC, MC or SAC. Use of FDC or SAC in estimating the cost of the partial asset would offer competitive advantages to the utility's competitors, provided the utility is not allowed to fully recover the resulting stranded costs. Use of MC-based methods would offer competitive advantages to the utility or its affiliates. An estimate based on SAC and MC can act as a ceiling and a floor, respectively, for the cost of the partial asset.

Separation of Costs for Downstream Operations

For the separation of downstream operating costs, three possible cases need to be considered: (1) the utility discontinues providing certain services, (2) the utility provides certain services at a reduced volume, and (3) the utility continues to provide a service at the same level. An example, such as metering service, to illustrate the above three possibilities might be helpful. In the first case, the utility would discontinue providing metering service and sell its existing meters to an unregulated metering company. In the second case, the utility continues to provide the metering service but its sales volumes decreases because alternative providers also provide metering service. The third case is a continuation of the current scenario in which a market for metering service has not yet developed. The third case does not obviously need any cost separations and will not be further discussed.

Utility Discontinues Providing A Certain Service

In this case, the separation of costs is fairly straightforward. No cost separations need to be done for operating costs because the utility neither incurs related costs nor earns related revenues. Therefore, there is no net effect on the revenue requirements that the utility needs to earn. There may be minor adjustments to costs and revenues due to the transaction costs involved in discontinuing a service. Examples of these costs include increased customer costs due to increase in customer queries and requests, related to switching to an alternative provider, and costs involved in coordinating the transition with alternative providers. These additional costs can be treated as items separate from the costs related to the provision of the discontinued service. But for the most part, nothing needs to be done in the current rate period to separate costs, change revenue requirements or adjust rates for the discontinued service. In the next rate period, the costs of these services would be excluded from revenue requirements.

Utility Continues to Provide A Certain Service At A Reduced Volume

The separation of costs in this case is not as straightforward as the previous two cases. There are several possible methods to separate downstream operating costs. Besides the methods already discussed, namely FDC, MC and SAC, there are two other possible methods. These latter methods do not require any cost-of-service analysis. They are: no cost separations with adjustment to rates to maintain revenue requirements, and no cost separations with no adjustment to rates. All of the above methods are examined in subsequent parts of this section.

No Cost Separations: Rates Adjusted to Maintain Revenue Requirements

In this case, the utility does not incur short run variable costs associated with the reduced volume of service. The utility also does not earn the revenues associated with the reduced volume of service. Therefore, as for the preceding case, a regulatory commission may choose not to require any cost separations. Unlike the preceding case, however, there is a possibility of revenue shortfall because the utility is not able to recover the capacity costs and some of the fixed operating and maintenance costs associated with the reduced volume of services. These costs will continue to be incurred even if the corresponding volume of services are no longer provided. Therefore, the utility would probably propose some mechanism for recovery of the revenue shortfall, or stranded cost.

There are several possible mechanisms to achieve the cost recovery. The utility could (1) adjust the rates to remaining customers of the “choice” service,

(2) adjust the rates of all services, (3) adjust the rates of remaining services, and (4) adjust the rates to only the backbone monopoly services, such as the distribution service, to make the rate increase nonbypassable. Options 1 through 4 allocate a progressively decreasing share of stranded costs to the remaining customers . One can hypothesize that the above order of options also represent the degree of commission acceptability. Given the fact that almost all customer choice programs include a rate freeze on services that the customer is allowed to choose a provider, options 1 and 2 are likely to be unacceptable to a commission. Option 1 is likely to be even less acceptable than option 2 because it imposes the entire stranded cost of the given service on the remaining customers, while option 2 spreads it out among all customers of all services. Also, option 1 may be practically untenable: as the rate is increased on a service that is available from alternative providers, more and more customers are likely to switch. This may require further increases of rates to remaining customers to offset the remaining customers and lead to a "death spiral." The same effect, perhaps of a weaker magnitude, may follow from implementing options 2 and 3 as some of the services chosen for rate adjustments may also be available from alternative providers. Therefore, option 4 may not only be the most acceptable among options to a regulatory commission, it may also be the only feasible one among rate adjustment options.

No Cost Separations: No Adjustment to Rates

Of course, there are other options that do not require rate adjustments. As noted previously, most customer choice programs are predicated on a rate freeze or rate reduction. So, if there are no adjustments to be made to rates to meet potential revenue shortfalls to be faced by the utility, other mechanisms can be explored to compensate the utility. One possibility that has a good rationale is to allow the utility to profit from its off system transactions and keep part or all of such profits to offset its losses resulting from the reduction of volume of certain unbundled services. For example, the utility commission may want to consider allowing the utility to keep part of its profits from capacity release or “gray market” transactions.[26] Besides compensating the utility for its potential revenue losses, such a mechanism also provides an incentive to the utility manage its upstream capacity efficiently, and release any excess or unneeded capacity to those who value it more highly than the utility.

The previous two methods are based on no adjustments to the revenue requirements, and would be most practical for a short transition period following the unbundling of a service. The costs of service, however, should be ultimately separated for the unbundled services that the utility no longer provides, or provides at reduced volumes, most likely at the first rate hearing following the unbundling and partial or full deregulation of a service. To separate these costs, several methods are available, each of which are discussed below.

Separation of Costs Based on FDC

The operating costs of unbundled services from the utility’s revenue requirement could be based on FDC. The variable component of these costs can be separated on the basis of relative share of volume of sales between switched and remaining customers. The fixed and overhead costs, such as fixed operating and maintenance costs could be separated according to one of the peak responsibility methods.

This method is unlikely to be favored by the utility as it removes a relatively large magnitude of costs from the utility’s revenue requirements. For the same reason, this method of separating costs is likely to be favored by the utility’s - or its affiliate’s, competitors. From an economic efficiency perspective, this is not a sound method because it distorts price signals and may encourage entry by

[26] “Gray market transactions” are resales of bundled interstate capacity and other services in the secondary capacity market.

inefficient competitors. On the other hand, it does encourage competition and arguably offsets some of the incumbency advantages of the utility.

Separation of Costs Based on Short-Run Avoided Costs

The operating costs of unbundled services could be based on short-run avoided costs. The variable component of these costs for switched customers can separated by using the difference between the total cost for serving all customers and the cost of serving customers that choose to remain with the utility. The fixed operating costs of switched customers could be separated by using the difference between the demand cost of all customers and the demand cost of customers that choose to remain with the utility.

This method is likely to be favored by the utility as it removes a relatively small magnitude of costs from its revenue requirements. For the same reason, this method is likely to be opposed by the utility's competitors. From an economic efficiency perspective, it is a superior method as it correctly conveys price signals based on avoided costs. However, one can argue that use of this method reinforces incumbency advantages of the utility and may discourage competition.

Separation of Costs Based on Long-Run Avoided Costs

The operating costs of unbundled services could be based on long-run avoided costs. The methods to separate these costs are similar to those for short run avoided costs, except that long-run avoided costs includes costs associated with avoided future additions of capacity, and future operations. The long-run avoided costs can be found by performing a simulation of costs for a planning horizon with all customers and with a reduced number of customers and finding the difference. In the two simulations, optimal additions of capacity and optimal management of operations would have to be assumed.

This method has the same merits and demerits of the short-run avoided cost method. Further, it captures forward-looking costs of providing a service and is arguably superior to the preceding method. Whether or not this method would be acceptable to the utility or its competitors would depend on the magnitude of costs involved in the cost separations process and is ultimately an empirical question.

Separation of Costs Based on A Market-based Index

Finally, downstream operating costs could be separated using a market-based index. The avoided cost is the market price of the unbundled service times the avoided volume of service. If the prices offered by alternative providers are available to the utility or the commission, the volume-weighted average price for all providers can be used as an index of the market price. One problem with implementing this method is that either the price offered or the volume of sales of each provider, or both, may not be available to the utility or to the commission.

This method has sound economic efficiency properties in the sense that the cost separations are based on the market value of the underlying services. If the market for the services can be assumed to be workably competitive, use of this method would convey correct price signals to the utility's customers and provide them with a rational standard to judge whether to remain with the utility or switch. Use of this method, however, may disadvantage the utility's competitors because it tends to equalize the unit avoided cost of the utility and the cost of a competitor for providing the service. Given the fact that the utility has well-recognized incumbency advantages, use of this method may discourage competition.

Examination of Some General Issues With Regard to Cost Separations

Throughout the above discussion, there appeared a number of general regulatory policy issues that have common bearing in all the different approaches and methods for cost allocations and cost separations. These issues are examined in the following sections.

Economic Efficiency vs. Competition

In the context of unbundling, policy choices that tend to be economically efficient sometimes inhibit competition for a number of reasons. Economic efficiency requires that goods and services are produced at quantities and prices that maximize the social surplus. It is well recognized that the above criterion applies only to a perfectly competitive market that is rarely realizable in practice, and that the goal of regulation is to strive for the second best. Given the above fact and the fact that the utility has incumbency advantages that allow it to impede competitors and appropriate a part of the consumer surplus, policies that meet the economic efficiency standard under a regulatory regime may harm competition, and therefore work against economic efficiency. In the previous discussions, for example, we observed that cost separations based on marginal or avoided costs are economically more efficient than those based on fully distributed costs; and yet use of marginal cost to separate costs may offer competitive advantages to the utility, or its affiliates.

One can characterize this conflict between the two strands of economic efficiency as a conflict between static, and short run, economic efficiency and

dynamic, and long run, economic efficiency.[27] There appears to a good argument for tilting the scales in favor of a utility's competitors, at least in the beginning and transition periods of deregulating a market to "get the market up and running." If one accepts the above premise, that long-run economic efficiency is to be preferred over short-run efficiency, the level and form of leverage to be given to a utility's competitors to offset the utility's incumbency advantages becomes another challenging issue. No regulator would want to tilt the scales in favor of the utility's competitors so much that an inordinately large number of inefficient providers enter the market, and the prices offered to consumers are significantly higher than the economically efficient level, either in the short run or the long run.
This is particularly true for those states in which customers already enjoy relatively low rates for gas services.

The regulatory challenge is to find the right balance between short-term and long-term economic efficiency and frame policies that produce the optimal pace and level of competition.

Recovery of Stranded Costs

The issue of stranded cost has appeared in much of the previous discussions on cost allocations and cost separations. The stranded cost issue is involved in all instances in which the utility faces the potential problem of being unable to recover its embedded costs because of either a reduction of its revenue requirements caused by the use of a cost separations mechanism or because the market value of an asset is lower than its undepreciated book value.

---

[27] For a discussion of static and dynamic efficiencies, see Kenneth Rose, *An Economic and Legal Perspective on Electric Utility Transition Costs* (Columbus, OH: National Regulatory Research Institute, July 1996), 30-38.

An important regulatory challenge before a regulatory commission is whether, how and how much of, the stranded cost is to be allowed to be recovered from regulated rates. A commission may decide not to allow any regulatory recovery of stranded costs on the argument that the utility is entitled to an opportunity to recover its prudently incurred costs but not to a guarantee of such recovery.[28] The fact that the regulated gas utility has been operating under monopoly franchise agreement indicates that the utility has been allowed ample opportunities to recover all its costs.

On the other hand, it can be argued that restructuring of the regulated market and the unbundling and deregulation of services are events precipitated by the process of regulation, events that were beyond the control of the utility and events that jeopardized the ability and opportunities of the utility to recover its costs.

If a regulatory commission agrees to the recovery of stranded costs by a utility, an important issue is whether these costs are to be recovered from all customers or just the customers who have opted to leave the LDC. If the first option is chosen, the stranded cost can be uniformly distributed among all customers by imposing a surcharge on all customers. If the second option is chosen, the LDC could impose an exit fee on customers that leave the system. The exit fee could be designed to recover the LDC's stranded costs. The exit fee, however, can be at such a high level that the departing customer is either indifferent between staying and leaving the system or finds it more advantageous to a stay in the system. Such an exit fee defeats the intended goal of facilitating competition and creating a more efficient market place through unbundling and deregulating some gas services.

[28] Ibid., 39-72.

Between the two stranded cost recovery options, imposing an exit fee on departing customers has a better regulatory rationale. One can argue that the capacity in question was contracted to serve all customers based on prudently developed forecasts of demand. Therefore, if a customer chooses to leave the system, she should be responsible to pay for her share of the contracted capacity, which is precisely the capacity that would become stranded. It makes very little sense to reallocate these costs to remaining customers, in effect making them pay more than their share of the capacity.

The exit fee option could be combined with options to minimize stranded costs. As discussed, the LDC could be provided incentives to mitigate stranded costs by allowing profit-sharing on resales of capacity or by allowing partial recovery of stranded costs. If stranded costs have been minimized by using the above options, the resulting exit fees imposed on departing customers would also be minimized such that a customer would not feel constrained to stay on the system.

Unbundling and Cross Subsidization

Any policy deliberation involving cost allocation and rate design invariably entails the issues of cross subsidies and price discrimination. Both of these issues are also likely to confront regulators engaged in crafting rate-making policies for unbundled gas services.

Cross subsidization is generally understood as *an allocation of costs in such a manner that one customer, one service category, one segment of an industry or one market, bears more than, while another bears less than, its "true" share of costs*.[29] *Price discrimination* is generally understood as *the*

[29] For example, there can be cross subsidization among the customers of a regulated utility, and between the regulated and unregulated businesses of a parent company.

charging of different prices to different customers for a product when it costs the same to provide each customer with the product. Although the concepts of cross subsidization and price discrimination are closely related, they are also independent. Cross subsidization refers to sharing of the *total cost burden* for a service among parties. Price discrimination refers to *the per unit price* charged to different customers. Although many instances of cross subsidization may translate into price discrimination and vice versa, the two practices are not always, and not necessarily, related. An example of *cross subsidization with price discrimination* is a utility company's charging of a price to a customer group below its marginal cost.[30] An example of *cross subsidization without price discrimination* is a utility company's purchasing of one of its inputs from an affiliated company at above-market prices. In this case, *all the customers of the utility are subsidizing the affiliate*, and *there is no related price discrimination among the customer groups.* Finally, an example of *price discrimination without cross subsidization* is a utility company's charging different prices to different customer groups for the same service such that the price charged to each customer group is above its marginal cost.

Subsequent sections contain elaborations of the concepts of cross subsidization and price discrimination from the perspectives of different disciplines and a review of the relevant economics literature. These are followed by some general observations, and an examination of opportunities and remedies for cross subsidization and undue price discrimination, in the context of unbundled gas services.

---

[30] Marginal cost is a standard that neoclassical economics uses to test for the presence of cross subsidies. This and other tests of cross subsidization and price discrimination are examined in detail in subsequent sections of this chapter.

Cross Subsidization: An Examination of the Concept

A universally acceptable definition of cross subsidization does not exist. However, an examination of real-world examples of cross subsidization and review of relevant literature may be helpful in elucidating the concept.

In common parlance, subsidization refers to an “unearned benefit” conferred to a person or party. Forms of subsidization range from those inspired by social equity concerns (e.g., low income assistance programs) and protectionist policies (e.g.,subsidies to farmers) to business practices that allow disproportionate share of costs to be borne by different divisions of a company.

Cross subsidization is a term used to denote one form of subsidization; it is internal to an institution or firm. Therefore, cross subsidization may also be called internal subsidization. Heald[31] lists the following possibilities for cross subsidization.

- Between outputs which are bundled together in a vertically integrated industry structure.
- Between outputs which are bundled together in a horizontally integrated structure.
- Between a monopolist and its affiliated supplier of inputs
- Between different consumers of a single product
- Resources committed by the firm to activities unrelated to its business to meet government requirements
- Between the regulated and unregulated sectors of an enterprise

Central to the concept of cross subsidization is the notion of the cost burden accruing to the production of a commodity or service and how the burden is shared. The perceived cost burden, in turn, depends on how the

[31] David Heald, *Cost Allocations and Cross Subsidies*, European Commission, 28-30.

relevant cost is defined. From the discussions in previous chapters, it is known that the relevant cost differs from the accounting and economic perspectives. Once the relevant cost is defined, one needs to define the appropriate sharing rule for the cost, which can be used to test the presence of inappropriate sharing of costs.

Cross Subsidization: The Accounting Approach and the Equity Standard

According to the accounting approach, the relevant cost is the average accounting cost. The appropriate sharing rule is the FDC costing methodology. Using these standards, one can say a cross subsidy exists if the average accounting cost of a product is shared among parties in a manner that deviates from that which would be derived from a valid FDC cost of service analysis. In the gas utility context, cross subsidies are costs (i.e., average costs) that are attributable to (according to the FDC costing methodology), but not borne by, a service category. Such a service category is the recipient of cross subsidies. Alternatively, cross subsidies are costs that are borne by, but not attributable to, a service category. Such a service category is the source of cross subsidies.

For example, the capacity costs of a distribution network, according to the FDC methodology, should be allocated to a service category in proportion to its share of peak capacity (determined by the CP or NCP method, or their variations). Any departure from this allocation, from an accounting perspective, would constitute a cross subsidy.

The accounting approach to cross subsidization also comports well with the notion of distributional equity. If a service class receives a benefit, the common sense notion of equity would require that the class be charged a price that is commensurate with the benefit, regardless of what the marginal cost of serving the class is. This argument is exactly what would follow from a fully distributed cost perspective, based on the beneficiality criterion.

Cross Subsidization: The Economic Approach and the Efficiency Standard

As alluded to earlier, the economic approach to cost allocation rejects the formulation based on average accounting costs and the FDC costing methodology. According to this approach, the relevant costs are economic costs, and the sharing rule is governed by marginal costs. The costs to be allocated to a service are the economic, and marginal, costs of providing that service. Using this principle, it is clear that any service that is charged a cost less than its marginal cost is the recipient of a cross subsidy. It follows that a service that is charged a cost equal to or greater than its marginal cost is not the recipient of a cross subsidy.

It is not as straightforward to establish a test by which one can judge whether a service is a source of cross subsidy. One can, however, hypothesize an upper limit on the cost that can be charged to a service such that any higher charge would clearly constitute a cross subsidy. One such limit, proposed by Faulhaber,[32] is the stand-alone cost, or the cost to provide a service exclusive of all other services. According to Faulhaber, if a service is charged higher than its stand alone cost, it is a source of cross subsidy.

The above discussion is based entirely on costs, which are presumed to be known with certainty, and their allocation. The discussion does not take into account demand conditions, or uncertainties of either costs or demand. To examine the phenomenon of cross subsidization under various conditions of costs, demand and uncertainty, it may be helpful to review the economics literature and trace the evolution of economic thought on cross subsidization.

---

[32] Gerald R. Faulhaber, "Cross Subsidization: Pricing in Public Enterprises," *American Economic Review*, Vol. 65 (1975), 966-77.

Review of Economic Literature on Cross Subsidies

Cross Subsidization as Predation: The earliest reference to cross subsidies appears in Edwards,[33] who considered cross subsidization as a form of predatory pricing. A firm, engaging in this form of cross subsidization, would price its products below the competitive price in one market and raise its price in another market where it has a competitive advantage. According to Areeda and Turner, one such form of predatory pricing would be for a firm to price its product below the marginal cost.[34] In view of the fact that marginal cost is generally difficult to estimate, Areeda and Turner proposed that average variable cost would be a good index to test for predatory pricing. Most economists, however, dismiss predatory pricing intermarket cross-subsidization as untenable.[35]

Overcapitalization for Intermarket Cross Subsidization: The next well-known reference to cross subsidies was made by Averch and Johnson, who contended that a regulated firm earning an above-market return on its capital (i.e. the famous "overcapitalization" or "A-J" bias of a regulated firm) has "an incentive to expand into other regulated markets, even if it operates at a (long-run loss) in these markets."[36] While the A-J model is well-known for its

---

[33] Corwin Edwards, *Maintaining Competition* (New York, NY: McGraw Hill, 1949).

[34] Phillip P. Areeda and Donald F. Turner, "Predatory Pricing and Related Practices Under Section 2 of the Sherman Act," *Harvard Law Review*, Vol. 88 (1975), 697-733.

[35] Robert C. Brooks, "Injury to Competition Under the Robinson-Patman Act," *University of Pennsylvania Law Review* (1961), 797.

[36] Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, vol. 52 (5) (1962), 1052-1069.

overcapitalization hypothesis, it is less known for its intermarket cross subsidization hypothesis.

Bailey analyzed a two-market model to examine the A-J proposition and concluded that a regulated firm does not have an incentive to enter a second regulated market.[37] The same conclusion was reached by Brock[38], who used a rigorous model of a regulated firm that explicitly accounts for fixed and common costs.

The Faulhaber Tests for Cross Subsidization: Kahn[39] and Posner[40] used the experience in regulated industries, rather than formal theoretical models, to indirectly introduce the notions of stand alone costs and incremental costs as tests for cross subsidization.

Faulhaber was the first to develop rigorous tests of cross subsidization. Faulhaber's model consists of a cooperative game between an efficient multi-product firm facing a zero economic profit constraint and its consumers.[41] He concluded that a firm is not the recipient of a cross subsidy if the revenue from producing a subset of services is greater than or equal to the change in total cost by not producing the subset of services. This constitutes the marginal cost

---

[37] Elizabeth E. Bailey, *Economic Theory of Regulatory Constraint* (Lexington, MA: Lexington Books, 1973).

[38] William A. Brock, "Pricing, Predation and Entry Barriers in Regulated Industries," in *Breaking Up Bell: Essays on Industrial Organization and Regulation*, edited by David S. Evans (*city, state*: North-Holland, 1983), 91-229.

[39] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* (New York, NY: John Wiley and Sons, 1970).

[40] Richard A. Posner, "Taxation by Regulation," *Bell Journal of Economics and Management Science*, Vol. 2 (1) (1971), 22-50.

[41] Faulhaber, "Cross Subsidization: Pricing in Public Enterprises."

test for cross subsidies. Faulhaber also concludes that a firm is not the source of a cross subsidy if the revenue from a subset of services is less than or equal to the cost of producing that subset of services independent of other services. This constitutes the stand-alone cost test for cross subsidies. The two tests introduced by Faulhaber, the incremental cost test and the stand-alone cost test, have become the standard in examining the economics of cross subsidization.

A Consumer-Focus Test for Cross Subsidization: Other economists have extended Faulhaber's work by relaxing his assumptions and coming up with more stringent tests of cross subsidization. Sharkey and Telser introduce a "consumer focus" in contrast to Faulhaber's "product focus" in defining criteria to test for cross subsidization.[42] They define "consumer subsidy-free prices" as those for which no coalition of consumers could provide services to themselves at a lower price. This is the so called "burden test." This test is more stringent than the Faulhaber test.

Later Developments: Other economists have extended the analysis further to include the effect of service quantities, demand functions and complementarity of services on cross subsidies.[43]

The Difficulty of Applying Economic Tests of Cross Subsidization: While some of the economic tests, particularly the Faulhaber test, may be easy to follow as theoretical constructs, and the underlying test parameters (e.g., incremental costs and stand-alone costs) may be easy to define, they are

---

[42] William W. Sharkey and Lester A. Telsen, "Supportable Cost Functions for the Multiproduct Firm," *Journal of Economic Theory*, Vol 18 (1978), 23-37.

[43] Karen Palmer, "Using An Upper Bound Stand-Alone Cost in Tests of Cross Subsidy," *Economics Letters*, Vol. 35 (4) (1991), 457-460.

difficult to apply in practical situations. For example, the two central assumptions of the Faulhaber model, efficient production and zero economic profit constraint, may not generally hold for a regulated firm. The traditional cost-plus, rate-of-return regulated utility may not choose the least cost or the most efficient input mix or production technologies. The zero economic profit constraint may not be satisfied under traditional regulation if the regulatory lag is long. The constraint is less likely to be satisfied under incentive or price cap regulation, whose very purpose is to allow an efficient firm to earn economic profits.

Cross elasticity of demand among various services also complicate the application of the Faulhaber tests. If services are substitutes, the incremental cost test becomes a necessary, but not a sufficient, condition for cross subsidization. On the other hand, if services are complements, the incremental cost test becomes a sufficient, but not necessary, condition for cross subsidization.[44]

The second of the Faulhaber tests, the stand-alone cost test, is even more difficult to apply, particularly in the presence of common and joint costs. The stand-alone cost is rarely estimated and has not been used as a test of cross subsidization. However, it may be possible to estimate an upper limit on the stand alone cost. Such an estimate is unlikely to be very useful given the fact that in most practical situations no service is likely to be allocated a cost above this limit.

Practical Alternatives to Economic Tests for Cross Subsidization: The Faulhaber tests, however, can be applied if certain conditions are met even if both of its major assumptions (i.e. efficient production and zero economic profit) are not completely satisfied. For example, the incremental cost can be taken as

[44] Ibid.

a lower bound that precludes *a single service* from being the recipient of a cross subsidy, even if the zero economic profit constraint is not met. For example, if the local distribution service of a gas utility is subject to a price cap plan, the zero economic profit constraint may not be satisfied, but the efficient production condition is likely to be satisfied. Under these circumstances, if any customer class is charged a price below its incremental cost, one can safely conclude that the customer class is the recipient of a cross subsidy.

Alternatively, the fully distributed cost can serve as a lower limit on the stand-alone cost. Therefore, in most practical situations, allocations of cost between the incremental cost and the fully distributed cost can be taken as a reasonable indicator for the absence of cross subsidies. This range, commonly used, can act as a "safe harbor" for the prevention of cross subsidies.

CHAPTER 5

PRICING AND DESIGN OF TARIFFS FOR END-USE SERVICES

The services that continue to be regulated will be subject to rate-making by PUCs. Such services will be provided under approved tariffs. As mentioned in Chapter 1, the generic local distribution company (LDC) tariff is a combination of a fixed charge per accounting period (e.g., month) and a volumetric charge per unit of service (e.g., Mcf).[45] The Federal Energy Regulatory Commission (FERC) and state public utility commissions have generally differed on how the costs of service are to distributed between the fixed and variable parts of the two-part tariff. FERC-approved interstate pipeline service tariffs generally consist of a demand charge that reflect capacity costs and a volumetric charge that reflect costs of throughput.[46] The PUC-approved local distribution company (LDC) tariffs, on the other hand, commonly has a monthly charge that reflects customer costs and a volumetric charge that reflects all upstream costs (gas commodity, interstate capacity, storage, etc.) and the cost of local

[45] In theory, one can design N-part tariffs such that each part incorporates one or more consumption factors..

[46] Prior to issuing Order 636, FERC used the MFV (the modified fixed variable) method in which the volumetric or commodity component of the interstate pipeline transportation tariff contained parts of the fixed capacity costs, such as the rate of return on investments and taxes. Under Order 636, FERC adopted the SFV (the straight fixed variable) method that incorporates fixed costs exclusively into the demand component of the tariff.

transportation. In other words, both capacity and energy costs are incorporated in the volumetric charge in the typical LDC tariff.[47]

With the generic rate as the template, there are a multitude of ways in which the tariff can be designed to reflect costs or values of the demand for capacity and the volume of use. The two most extreme forms are a flat fixed rate tariff and a pure volumetric tariff. There are numerous forms of tariff that fall in between these extreme forms. A tariff generally incorporates consumption factors in combination with chosen accounting, economic and public interest objectives. The consumption factors may include time-of-use, share of the system peak, price elasticity of demand and level of reliability (i.e. firmness or interruptibility) demanded. The chosen regulatory objectives may include accounting cost responsibility, economic efficiency or low income assistance.

End-Use Tariffs Under Unbundling

Presumably, there are some changes to conventional tariff designs that need to be considered under an unbundled and partially deregulated regime. Most of the changes are engendered by the following conditions.

- Some of the previously monopolistic services will be provided by unregulated providers.

[47] Depending on the objectives of the firm and the type of market, a two-part rate structure can be designed to distribute the fixed and variable costs in various ways between the fixed and variable part of the rate. For example, if the demand for access to phone service is fixed and if the usage is price sensitive, the optimal tariff would consist of a usage fee that equals the marginal cost of usage, and an access fee that is sufficiently high for the firm to break even. See Kenneth E. Train, *Optimal Regulation*, pp 196, MIT Press, Cambridge, Massachusetts, 1991.

- Some of the unbundled services will be provided by both the utility and unregulated providers.
- Some of the utility's services may continue to be price regulated although they are provided by alternative unregulated providers.
- The utility will provide regulated monopoly services (e.g., local transportation) to a new class of customers, namely marketers and aggregators of small customers.

The above conditions may merit a reexamination of traditional regulatory objectives, and identification of changes, warranted by the new realities, to those objectives.

Traditional Regulatory Objectives

The rationales for regulating public utilities were that they were natural monopolies and that they were enterprises "affected with the public interest." The natural monopoly argument contends that for a good or service with economies of scale, it is most efficacious for a single firm to serve the market. Such a firm, if unregulated, however, could restrict output and raise prices to inefficient levels to reap monopoly benefits. The public interest argument proposes that externalities and the possibilities of undue price discrimination and "cut-throat" competition also require public utilities to be operated as regulated monopolies. Based on the above rationales, public utility commissions have generally pursued the following goals:[48]

- Ensure just and reasonable rates.
- Prevent excessive (monopoly) profits.

---

[48] Adapted from Charles F. Phillips, Jr., *The Regulation of Public Utilities*, Public Utilities Reports, Arlington, Virginia, 1993.

- Prevent unreasonable (inequitable) price discrimination among customers and places.
- Assure adequate earnings to the regulated utility.
- Assure service to the maximum number of customers.
- Promote economic development and employment in a geographical area.

Evolution of Regulatory Objectives

Over the years, public utility regulation has increasingly adopted other objectives pursuant to its mandate of upholding the public interest.[49] These objectives include assistance to low income customers, promotion of energy conservation and energy efficiency, and management efficiency. The expansion of regulatory objectives has led to subsidization of rates to promote social goals, incentive-based rates to promote energy conservation and energy efficiency, and performance-based rate schemes to promote management efficiency.

In some sectors of the utility industry, particularly telecommunications and the interstate gas market, certain services were unbundled and deregulated. For such services, public utility regulators faced the issues of competitive entry, discriminatory access and pricing, and affiliate transactions. The traditional objectives of regulation were supplanted with other objectives that centered on the facilitation of market forces for deregulated services .

[49] For a comprehensive discourse on the evolution of regulatory objectives, see Sridarshan Koundinya, "Electricity Pricing Policy: A Neo-Institutional, Developmental and Cross-National Policy Design Map," Ph.D. Dissertation, The Ohio State University, 1998.

Regulatory Objectives Under Unbundling of Retail Gas Services

The current state of the retail gas market mirrors the situation sketched above. Besides continuing the traditional mandate for ensuring just and reasonable rates, nondiscriminatory prices, and supporting social goals, state regulators are increasingly faced with the issues of:

- Facilitating competitive entry
- Preventing cross subsidization of costs among the regulated and unregulated sectors of the industry.
- Developing codes of conduct for different players of the industry.
- Protecting consumers from potential abuses and risks associated with the transition to a restructured industry.

In the context of rate design, state regulators are confronted with choosing pricing policies for both regulated and unregulated services that generally advance the above goals.

Examination of Pricing Schemes and Tariffs for Unbundled Services

The following sections examine end-use tariff designs for each service type under defined regulatory and market conditions. For purposes of this examination, different end-use tariff designs are classified into nine broad categories as follows:

- One part tariffs
- Two part tariffs
- Block tariffs
- Price caps
- Other incentive rates

- Interruptible rates
- Value of service pricing
- Time-of-use rates
- Seasonal rates

It should be noted that the above are not parallel categories in the sense that they do not represent variations of the same pricing principle or concept. Two part tariffs, for example, distribute the price of service between its components (fixed and variable). Block tariffs, on the other hand, distribute the price among blocks of consumption. While each of the above tariff designs comprise a *price structure*, price caps represent a scheme to manage the *price level*, by establishing a formula to adjust the price from one rate period to another. Finally, seasonal rates and time of use rates attempt to incorporate the *time dependence of consumption*. Because the various tariff designs and pricing schemes are not parallel categories, they are not mutually exclusive and may be combined in various ways. For example, one can have a price cap with a two part tariff such that each part of the tariff is subject to a periodic adjustment.

One Part Tariffs

Under the one-part tariff, the customer is charged a single price per unit of consumption. The price needs to be set at a level that recovers all variable costs and makes a sufficient contribution to fixed costs such that the utility recovers all its costs including a rate of return on its investments. The appeal of the one-part tariff is its simplicity. However, the one part tariff is inconsistent with the fundamental cost-of-service principle that the price of a service should reflect its cost. In gas utility service, the cost of service is not linearly proportional to units of consumption. There is a set up or initial fixed cost resulting from the capital costs of building capacity. Further, there are fixed carrying charges (interest, taxes, etc.) on the related investments and fixed overhead costs related to the operation and maintenance of underlying facilities. These fixed costs are incurred regardless of units of consumption. By pricing successive units at a constant price, the distinction between the costs of capacity and the costs of output is not captured in the one-part tariff. The one-part tariff is not generally used in utility rate-making.

It may be instructive to observe that pricing of goods and services in most unregulated markets is akin to the one-part tariff. In such markets, there is a per unit price for an item purchased. The price generally includes the marginal cost of producing the unit and a contribution to the fixed overhead cost.[50] However, there are products in the unregulated market for which a reservation or access fee is charged in addition to the usage price. Markets for such products are generally observed to have one or more of the following characteristics. They are markets (1) for services rather than goods, (2) for input, intermediate or wholesale goods, (3) for firm delivery of goods under contract, and (4) in which customers separately value access to the good or service. The most relevant example in the gas utility context is the firm gas supply contract that requires a certain minimum take or a reservation fee.

To capture the nonlinear relationship between costs and the amount of services, some form of a multi-part tariff can be considered. Two most commonly used multi-part tariffs are the two-part tariff and the block rate.

[50] To the extent the market is imperfectly competitive (e.g., monopolistic competition) and the firm is able to separate customers by price elasticity or volume of consumption, the firm may also engage in price discrimination by offering discounts to certain groups of customers and for quantity consumed.

Two Part Tariffs

A two-part tariff consists of a fixed component and usage component. In designing a two-part tariff, the basic issue is how to allocate the costs of the service between the two components. Based on the traditional fully distributed cost (FDC) method, the most straightforward way of allocating these costs is to assign all fixed costs, including the fixed component of common costs, to the fixed part of the tariff and to allocate the variable component to the variable part. This is the method currently followed by FERC in the SFV pricing rule used for interstate transportation services. An alternative is to assign a part of fixed costs to the volumetric or usage component of the tariff. The latter was used by the FERC under the MFV rate in which a part of the fixed costs, namely, the rate of return and taxes, were allocated to the usage component. The latter method is also used by most PUCs for pricing an LDC's services. The typical LDC tariff for residential customers has a monthly charge that incorporates fixed customer costs and some of the other fixed costs, and the gas usage component that incorporates all other costs, including costs of gas commodity and upstream capacity and storage, and local distribution. [51]

As mentioned above, a reservation charge akin to the fixed charge is incorporated into a two-part tariff in some unregulated markets. In such markets, a firm may design two part tariffs such that low (high) demand users are charged a low (high) reservation fee and a high (low) usage fee to (1) maximize consumption, (2) penalize breach of contract and (3) prevent entry

[51] The usage charge is the sum of two components: the base rate that represents the local distribution costs and the purchased gas adjustment (PGA) component that represents costs of gas commodity and upstream capacity and storage.

of competitors. Such a two-part tariff can be designed to maximize economic welfare.[52]

Unlike two-part tariffs in regulated markets, two-part price schedules in unregulated markets have no correspondence to input cost structures. Such two-part price schedules are based more on the price elasticities and volumes of usage of the consumer. One could argue that allowing a regulated utility to design a self-selecting two-part tariff (i.e., to offer a menu of different combinations of fixed and variable charges to customers), subject to the revenue constraint, would be economically efficient. Such a tariff, however, would be in conflict with traditional cost of service principles (for example, the low volume user has a low load factor and a high contribution to capacity cost). It would also meet with opposition from the small-consumer advocate because the tariff for the small customer would have a relatively high usage charge compared to that of the large customer.

Block Rates

Block rates, or nonlinear tariffs, is commonly used by firms to maximize sales. The two common forms of block rates are the declining block rate and the inverted block rate. In the declining block rate, each succeeding block is charged a progressively lower rate and in the increasing block rate, the opposite holds true.

The basic rationale for the declining block is that under increasing returns to scale, successive blocks of production have a decreasing cost schedule. Also, under a downward sloping linear demand schedule, higher blocks of consumption have a higher price elasticity. As a result, a declining block tariff allows a firm to maximize the producer's surplus by charging a progressively

[52] Robert Graniere, The National Regulatory Research Institute, personal communication, 1999.

smaller price for successive blocks of output. The most common form of declining block tariffs is quantity discounts offered to the large customers of a utility. To the extent that a declining block tariff allows a utility sell larger volumes of service relative to a uniform schedule, it allows a greater recovery of fixed costs, maximizes utilization of capacity and reduces the revenue burden of the smaller customers. Therefore, a properly designed declining block tariff has a welfare-enhancing effect.

Inverted block tariffs have very little cost-of-service or economic welfare justification.[53] Inverted block rates were introduced primarily to provide a social subsidy to economically disadvantaged customers and are rarely used in utility pricing.

Price Caps

Regulators, particularly in the telecommunications sector, have been using the form of pricing known as price caps for a number years. Price caps have rarely been used in gas regulation in the U.S.[54] The basic price cap consists of a price ceiling for a single utility service, or a basket of utility services, that is based on the previous year's price cap, rather than the utility's actual cost. The price cap formula has three basic components: last year's price cap, an adjustment index for inflation and an adjustment index for productivity. The inflation index accounts for changes to the utility's cost of inputs based on an industry or economy index. The productivity index accounts for changes in industry-wide productivity as well as other factors. It is generally a negative index and adjusts the price cap downward. The utility is allowed to charge any

---

[53] An exception to this occurs when marginal cost increases with additional production.

[54] Price caps have been used for both gas and electric utilities in the U.K.

price equal to or less than the cap. If the utility's cost is less than the cap, the utility earns profits that it is allowed to keep. The regulator may review the price cap periodically and adjust the cap and its parameters based on the conditions of the firm and the market.

The basic rationale for the price cap is that it induces efficient behavior by the firm. As the cap is based on factors that are exogenous to the utility, with the utility rewarded for reducing its input costs below the cap, the utility has an strong incentive to choose a cost minimizing input mix, invest in cost-effective innovations, and adjust optimally to changes in cost.[55] There are, however, problems associated with implementing a price cap. The estimation of price cap parameters (such as the inflation and productivity indices) is often difficult and contentious. Further, if the utility makes windfall profits or suffer large losses, that most likely would trigger a rate review; the regulator is likely to adjust the cap to limit the profits to levels that are consistent with an "acceptable" range of rates of return. This reduces the effectiveness of the price cap to that of a traditional cost-plus rate-making arrangement. The possibility of a utility's profits being constrained reduces the incentive of the utility to minimize costs. Furthermore, a price cap may induce strategic behavior by the utility. For example, to preempt the possibility of a price cap reduction, a utility may choose to incur additional costs right before a rate review. After an evaluation of its strengths and weaknesses, price caps represent a promising rate-making mechanism that warrants strong consideration for setting rates for monopoly gas services.[56]

---

[55] Kenneth E. Train, *Optimal Regulation* (Cambridge, MA: The MIT Press, 1994), 318.

[56] Under fully competitive conditions, price caps are unnecessary. Under quasi-competitive conditions, price caps may impede the development of competition. For more discussion on these issues, see subsequent sections.

Interruptible Tariffs

Gas utility companies generally offer interruptible tariffs to customers that do not require firm service. These tariffs have lower rates than those for firm rates. In exchange for receiving a lower rate, the interruptible customer agrees to be curtailed during times of shortage and high demand. The interruptible rate generally does not include a capacity charge, and covers only the marginal cost of serving the interruptible customer.[57] Interruptible tariffs are generally beneficial to the gas utility's firm customers because they allow utilization of capacity during times, such as the summer, when the utility has a lot of idle capacity. An important issue is whether the interruptible customer should be required to make a contribution to the capacity cost and other fixed costs of the utility. One common argument often made is that interruptible customers are rarely interrupted, particularly under conditions of excess capacity. Under these circumstances, the interruptible customer is essentially receiving a firm service while paying much less than other firm customers; this constitutes a case of price discrimination. However, the interruptible customer generally has alternatives to the gas delivery service and increasing the rate may cause the customer to leave the system, with adverse effects on the system load factor and the utility's revenues.

Value of Service Pricing

Under value-of-service pricing, the price of a product is not based on its cost of production, but on the willingness of the customer to purchase the product at the specified price. In a perfectly competitive market, the marginal

[57] An interruptible customer may also be interrupted when the marginal cost of serving the customer exceeds the interruptible rate.

value of the product and the marginal cost tend to converge and is equal to the market price. For a regulated utility, however, the marginal value of a service is likely to be different from its marginal cost. Given the fact that marginal-cost-based prices for regulated utility service may lead to a revenue deficiency and FDC-based prices (although it collects the required revenues) have no economic rationale, mechanisms that incorporate value-of-service considerations to achieve the optimal combination of price and output under the revenue constraint have been proposed.

The most well-known mechanism that incorporates value-of-service factors or customer price elasticities is the Ramsey Pricing Rule. Under Ramsey pricing, the deviation of the price of a service from its marginal cost is inversely proportional to the price elasticity of the service. It follows that customers with high price elasticities would be charged lower prices relative to customers with high price elasticities. Because the prices differ from marginal cost, necessitated by the revenue constraint, there is a loss of social surplus and the outcome is not the "first best." However, Ramsey pricing seeks to achieve the "second best" prices that meet the revenue requirement while minimizing the loss of social surplus.

One of the problems with Ramsey pricing is that it has undesirable distributional equity consequences. Customers with lower incomes generally also have low price elasticities because they do not have access to alternatives to utility services. Therefore, under Ramsey pricing such customers would be charged a higher price relative to their marginal costs. Although Ramsey prices are optimal under the revenue constraint, they may consequently have unacceptable social equity consequences. Perhaps for this reason, Ramsey prices have not been used by gas utilities.

CHAPTER 6

EVALUATION OF ALTERNATIVE RATE DESIGN OPTIONS

Criteria for Evaluation

The state regulator's choice of a rate design option[58] for unbundled gas services would depend on regulatory objectives. While the public interest compulsions and attendant regulatory objectives may vary somewhat among state public utility commissions (PUCs), one can list the most important ones that are likely to dominate rate-making policies of most PUCs. As discussed in foregoing chapters, the regulatory objectives would include traditional ones that comported well with the regulated monopoly world and the more contemporaneous ones that are emerging in response to a mixed regulatory-competitive regime. The traditional regulatory objectives include: economic efficiency, equity among stakeholders, revenue sufficiency and ease of implementation. The emerging regulatory objectives include facilitation of competition for deregulated services and consumer protection.

In choosing a rate design option, the state regulator can perform a comparative evaluation of alternative options, with selected regulatory objectives as the evaluation criteria. Each state PUC may attach a different "public interest" or welfare weight to each criteria. The final choice of an option would depend on the relative weights assigned to each criteria. Each of the criteria is briefly examined in the following section.

[58] Unless otherwise specified, the term "rate design" refers to the combination of cost allocation, cost separation, and tariff design schemes.

Economic Efficiency

The text book economic definition of efficiency refers to a combination of price and output that maximizes total social surplus or welfare. In common regulatory parlance, economic efficiency refers to providing incentives to the regulated firm to plan and manage their operations in a least cost manner.[59] In the pre-unbundling world, regulators used a number of tools, which range from oversight and scrutiny to performance incentives, to encourage efficiency. Under the emerging mixed regulated-competitive regime, the promotion of economic efficiency may involve choosing a mix of options - or among them, that account for the incentive properties of both purely regulatory performance benchmarks and the presence of competitive or quasi-competitive market conditions.

Equity

Equity, a more controversial and elusive concept, has its root in the notion that each party to an arrangement has certain rights and entitlements. Such rights and entitlements are predicated, among other things, on "fair" or "just" sharing of costs and benefits that accrue from the arrangement. In regulatory parlance, equity has meant the protection of such rights for each group that has a stake in regulatory outcomes. Closely related to the notion of equity is the notion of symmetry. For example, if the utility exercises price discrimination among customer groups, one or more customer group may claim that it has been treated inequitably – i.e., the symmetry principle has been violated. On

---

[59] The setting of revenue requirements or rate levels with accompanying oversight was intended to promote efficient production. The allocation of costs among customer classes and pricing of services was intended to promote efficient consumption.

the other hand, the utility or other customer groups may be able to argue that differentiated prices alone do not constitute price discrimination, and therefore, do not constitute inequitable treatment, if there are cost differentials involved in serving different customer groups. Price discrimination itself can be welfare enhancing. For example, it can be shown that pricing of a product to a customer group according to the inverse elasticity rule maximizes economic welfare under the revenue constraint. Another situation that may engender claims of inequitable treatment is, if based on a marginal cost allocation methodology, a customer group is charged less than its accounting cost of service, while another group is charged more. The regulatory deliberations in such a situation would involve arguments on the economic and public interest rationales of the marginal cost versus embedded cost-based methodologies. Finally, a utility may make a claim of inequity if the distribution of benefits of an incentive program is asymmetric – the utility is severely penalized for unusually poor performance but not allowed to make high profits for exceptionally good performance.

Competition

The major goal of unbundling utility services has been to introduce and promote competition for those services that are believed to be competitive. In the gas utility sector, some of these competitive services already have an adequately developed market or are anticipated to develop a market. One such service is the gas commodity. There are other competitive services for which we do not yet have a developed market and for which a market may not develop rapidly. Billing and metering are such services. To facilitate competition for competitive or potentially competitive services, state regulators need to address issues such as access, barriers to entry, sharing of information between the utility and marketers, codes of conduct, brand name and incumbency advantages of the utility, and cost allocation and tariff design. In particular, choice of cost allocation and tariff design options affects relative advantages of the utility or its affiliates, and their competitors. For example, a service may be unbundled and opened to competition, while the utility is still allowed or required to offer the service. If the related costs are separated from the utility's revenue requirements on a marginal cost basis, marketers face initial set up costs that the utility does not. This may translate into a relatively high entry cost for the marketer and may therefore discourage competition.[60] As another example, if the utility sells a service to an affiliate at marginal cost that is lower than the market price, this confers a competitive advantage to the affiliate over unaffiliated marketers. In both of the above examples, marginal cost-based cost allocation can be supported on economic efficiency grounds, yet such an allocation would have an adverse impact on competition. One can argue that in the above cases, there is a possible conflict between short term static efficiency and long term dynamic efficiency.

Consumer Protection

One of the rationales for traditional monopoly regulation was to protect the customer from inefficiencies of a unregulated "natural monopoly." However, when some of the previously monopolistic services developed competitive characteristics, there was a movement to unbundle and deregulate these services. The argument has been that the customer would gain from the benefits of competition. However, the transition from regulation to competition also may take away certain protections traditionally available to the customer, such as guaranteed service at an acceptable quality, the lowest rates

[60] By assumption, a competitive service is likely to have low economies of scale and low entry costs. However, allocation of only marginal costs and guaranteed recovery of embedded costs would disadvantage the utility's competitors.

achievable through the regulatory process and certain publicly sanctioned social subsidies. The transition imposes certain risks on the customer, such as the possibility that prices of deregulated services may actually increase because of weak competition offsetting the economies of scale, scope or network, or lower transactions costs under the regulated monopoly regime, or because the utility or parties other than customers are able to appropriate the efficiency gains from competition. Loss of some of the protections of traditional regulation as well as some of the consumer risks of competition may have to be accepted as indispensable to the process transition to competition; regulatory policy may be able to preserve some of the traditional protections and minimize some of the risks. For example, politically driven social subsidies may be retained by imposing a non-bypassable surcharge on a backbone monopoly service, such as local distribution. As another example, regulators may choose an FDC-based method, as opposed to an MC-based method, to separate capacity costs for assets and facilities that are not used by the utility to provide an unbundled service. The reason for this is that this choice favors competitors and offsets some of the incumbency advantages of the utility. Customers may benefit if this regulatory choice promotes competition and results in lower prices for services.

Revenue Sufficiency

Revenue sufficiency has been one of the accepted objectives of traditional regulation. The regulatory compact has implied that the utility, under a monopoly franchise arrangement, would be allowed the opportunity to earn sufficient revenues to meet its costs. One of the reasons marginal cost (MC) based rate-making, as opposed to fully-distributed-costs (FDC) based rate-making, was not generally adopted was that it would fail to recover the total revenue requirements of the utility. Also, any revenue shortfall or surplus was to be compensated for in a truing up process.

Any time a utility service was opened to competition in the past, the likelihood of the utility earning insufficient revenues became a significant regulatory issue. Most recently, the “stranded cost” issue, arising from the unbundling and deregulation of the electric power generation sector, dominated the policy debate on electric utility regulation. In choosing options for cost allocation and end-user rates for gas services that will continue to be regulated, a state public utility commission will probably consider the impact on revenue sufficiency. If other things are equal, an option that offers a better assurance for revenue sufficiency is likely to be preferred over one that does not.

Ease of Implementation

Some cost allocation and pricing options that may appear to be methodologically sound may be hard to implement. It may be difficult or onerous to compile the relevant data, perform the needed measurements or do the underlying analysis.

Another important issue related to the ease of implementation is the related administrative costs. The administrative cost of regulation includes the direct costs of holding regulatory proceedings to the state PUC as well as the indirect costs incurred by the utility and other participants in the proceedings. Most of the above costs would ultimately be borne by the ratepayer; their magnitudes depend on the frequency of regulatory proceedings, and the underlying information processing and evidentiary requirements. In choosing a rate design option, the state PUC should be mindful of the trade off between the expected benefits of the option and the offsetting regulatory costs.

Comparison of Options

Tables 6-1 through 6-12 provide summary comparisons of different cost allocation and tariff design options. For each option, the tables contain the effects on economic efficiency, equity, competition, consumer protection, revenue sufficiency and ease of implementation. Certain general observations that follow from the tables are discussed in the subsequent sections.

It Is Easier to Separate Upstream Costs than Downstream Costs

As observed in earlier chapters, separation of costs for upstream assets and operations are easier to separate than downstream costs: the first costs are generally dictated by FERC-determined tariffs while the second costs depend on the regulatory policy choices of the state PUC. FERC-determined tariffs determine both the rate level (i.e., revenue requirements) and the rate structure (i.e., tariff design). Also, the costs of some of the upstream services to be unbundled (such as pipeline capacity) may already be separated based on a FERC-determined cost allocation scheme. Therefore, the state PUC has neither the obligation nor the difficulty of separating these costs for purposes of unbundling these services. This is particularly true for upstream *operations*. For separating the costs of upstream *assets*, however, the PUC may have to address the choice of a cost allocation method or scheme. For example, if the state PUC is trying to separate the cost of an upstream storage facility that the utility chooses to divest, the PUC needs to decide whether the facility would be valued at undepreciated book value, market value or the higher/lower of the book or the market value.

Cost Separations Are More Difficult If the Utility Continues to Provide an Unbundled Service

If the utility no longer provides an unbundled service (such as commodity gas), it may be relatively easy to separate the costs of such service from the utility's revenue requirements. There may still be some common and joint costs that the unbundled service shares with a regulated monopoly service. For example, commodity gas service may share labor and administrative costs with the local distribution service. The cost separations would become significantly more difficult if the unbundled service (such as commodity gas) was provided by the utility as well as alternative providers. There are methodological and technical difficulties in separating common and joint costs of a service. Issues of competitive impacts, inter-market and interclass cross subsidies, and the sharing of benefits may however exacerbate such difficulties if a service is provided by both a regulated monopolist and an unregulated provider.

Effect of Rate Design Options Depend on the Degree of Market Dominance of the Utility

One of the reasons an unbundled service would continue to be provided by the utility is that there is either an insufficient number of non-utility providers, or an insufficient volume of service produced by non-utility providers to supply the demand. In either case, the utility needs to continue to provide the service until such time as a sufficient supply market for the service develops. During the transition period, the state regulator would probably want to implement policies that expedite the development of a market. Likewise, once a market develops, the regulator would probably want to implement policies that foster and sustain competition in the market.

The above examination points to the critical role of the local utility company's market dominance in informing the policy choices of the regulator. Policies that were predicated on the regulated monopoly arrangement can no longer serve the new regulatory objective of expediting, fostering and sustaining a competitive market for certain unbundled gas services. The thrust of the regulatory policy must be to reduce the market dominance of the incumbent utility during the transition period, and to restrain market dominance of the utility or of any of its competitors once a market develops. This means that regulatory policies, including rate design policies, should address market dominance as a critical decision variable. For example, the same rate design option would have different effects on the behavior of the utility and alternative providers, and on the rates charged to ultimate customers, depending on whether any of the providers has market dominance. It follows that rate design options have to be evaluated on chosen regulatory objectives under two different scenarios: one in which the utility has market dominance and the other in which it does not (see Tables 6-9 and 6-10).

Conflicts Among Regulatory Objectives Are Exacerbated by Unbundling

While traditional regulation spawned conflicts among regulatory objectives, especially equity and economic efficiency, unbundling and deregulation of certain services tend to enlarge the scope of such conflicts and introduce new conflicts. Perhaps the most paradoxical one is the conflict between economic efficiency (within the regulatory framework) and competitiveness. For example, cost allocations based on marginal costs are believed to be economically efficient. Yet, cost separations for utility services based on marginal costs would put the incumbent utility at an advantage relative to its competitors. Further, providing the utility with an incentive intended to minimize costs and rates (such as in a PBR scheme) may have the perverse effect of allowing the utility to undercut potential competitors and deter entry, or drive out existing competitors. Finally, the economic efficiency criterion would support allowing the utility and its affiliate to conduct transactions that exploit underlying economies of scope (such as selling a service to its affiliate at a price that is lower than the price charged to others because it costs less to serve the affiliate). Yet such a discriminatory practice would deter entry by potential competitors or drive out existing competitors.

The above discussion underscores the conflict between short-term economic efficiency and long-term dynamic efficiency. There may be good arguments on both sides on whether short-term economic efficiency or competitiveness ought to be promoted in a mixed regulatory-competitive regime. The argument cannot be settled conclusively by appeals to economic theory alone. The ultimate regulatory choice might be determined by a combination of a priori policy preferences and empirical evidence (that would emerge in the future).

No Rate Design Option Meets All the Regulatory Objectives

As is evident from Tables 6-1 through 6-12, no single combination of cost allocation and tariff design options has all the desirable properties to meet the most important regulatory objectives, although some may meet more regulatory objectives than others. The reason is that there are inherent conflicts among regulatory objectives. Therefore, and as in the past, the regulator is forced to make educated trade offs among regulatory objectives.

A Strategic Framework for Evaluating Rate Design Options

It may be helpful to view the choice of rate design options in terms of regulatory strategies for unbundling. Table 6-13 lists possible regulatory

Table 6-13: Regulatory Strategies for Unbundling	
Strategy I:	**Gradualist** (utility and others provide unbundled services; cost separations are based either on FDC or MC; tariffs for utility services are based on traditional or PBR methods)
Strategy II:	**Market facilitation** (utility and others provide unbundled services; cost separations are based on FDC or SAC; tariffs for utility services are based on traditional methods)
Strategy III:	**Radical deregulation** (utility does not provide deregulated unbundled services; choice of cost separation and tariff design options do not have any noticeable effect on competition)

strategies and attendant choice of rate design options. *Strategy I* represents *a gradualist approach* in which none of the unbundled services is totally deregulated, and the utility continues to be a provider of these services, along with alternative providers. Also, the PUC does not take an activist role to expedite the development of a competitive market; instead, it limits itself to providing consumer protections. The PUC anticipates that a market will develop with time through the working of market forces. *Strategy II* represents *a market facilitation* approach, which is similar to the gradualist approach, with the additional feature that the PUC plays an activist role in expediting the development of a competitive market. In this strategy, the PUC chooses rate design and other (e.g, codes of conduct) policies that restrain and reduce the incumbency advantages of the utility. Strategy III represents *a radical deregulation approach* in which every service that is viewed as workably competitive is totally deregulated with the utility not required or allowed to provide the service.

Each regulatory strategy has its merits and demerits. Strategy I is predicated on caution, the belief that the benefits of full unbundling and deregulation are uncertain and an unduly activist posture toward developing a market may be harmful to the customers. This strategy has the demerit that it may prolong the transition to the development of a market, thereby depriving customers of the resulting benefits. Strategy II puts more faith on the feasibility and merits of competition, and attempts to facilitate its development. Given the fact that deregulation in several industries, including the wholesale gas industry, has produced significant benefits for consumers, and that the regulatory strategy employed by the relevant federal regulatory agency, including FERC, has been similar to strategy II, this strategy has a strong rationale. The only demerit is that the precedents cited above do not resemble the conditions of retail gas unbundling, and the expected benefits are arguably expected to be small relative to other instances of deregulation. Therefore, an unduly activist regulatory posture may not produce the desired competition and benefits, and may impose regulatory and other costs on society. Strategy III also relies strongly on the merits of competition. In addition, by eliminating the utility from the market for competitive services, it avoids the task of addressing its incumbency advantages. Also, the regulatory burden and cost related to allocation and separation of costs are significantly reduced. Therefore, provided a service is truly competitive, strategy III may be superior to strategy II. However, the determination of the true competitiveness of a service becomes the critical issue in pursuing this strategy. This problem, combined with the fact that the benefits of competition may be arguably small, makes this a relatively risky regulatory strategy.

As discussed with regard to the choice of rate design options, the choice of a regulatory strategy would ultimately depend on the preferences of each state commission; these preferences in turn depend on the unique realities and public interest compulsions obtaining in each state. However, the delineation of rate design options and their properties, the composition of rate design options into a framework of regulatory strategies, with hope, will help the state regulator better evaluate regulatory policy options.

CHAPTER 7

CONCLUSIONS AND RECOMMENDATIONS

General Observations

This report attempts to delineate the relative merits of various rate design options for unbundled gas services. To accomplish this goal, the report examines and evaluates alternative options for allocating costs and designing tariffs against the yardstick of a set of chosen regulatory objectives. The regulatory objectives used as evaluation criteria include those inherited from the regulated monopoly era, such as economic efficiency and equity, and others spawned by the emerging hybrid regime of regulation and competition, such as facilitation of competition and consumer protection.

This report focuses on various cost allocation and tariff design options generally practiced by regulators or proposed by regulatory analysts. Each option has its origins in the accounting or economic disciplines and has its rationale in one or more of the following notions: cost causation, beneficiality, revenue sufficiency and welfare maximization. Also, each option is derived from one or more of the principal methodologies of cost allocation – fully distributed costs, marginal costs, stand alone costs and market value. The cost allocation and separation schemes that were examined include book and market valuation of assets, peak-based methods for capacity costs, short- and long-run marginal costs and market-based methods for operating expenditures. The tariff design options examined include traditional tariffs, performance-based rates (PBRs), interruptible, time-of-use and seasonal. rates. It should be reiterated that the cost allocation schemes and tariff designs are not mutually exclusive as there may be a significant degree of overlap among them. For example, one can use a fully distributed cost-based allocator to prorate the market value of an asset among its various uses.

Conclusions

This study finds that no single cost allocation or rate design option has all the desirable properties to meet the most important regulatory objectives, although some may better meet more regulatory objectives than others. One of the reasons no single option can perfectly satisfy all of the important regulatory objectives is because of the inherent conflicts among regulatory objectives. Arguably the most critical and somewhat paradoxical conflict is the one between short-run economic efficiency and competitiveness in a situation where the utility is the dominant provider of an unbundled service. Providing the utility with an incentive to minimize rates may allow it to undercut potential competitors and deter entry. One can argue that encouraging entry of potential competitors promotes long-term dynamic efficiency and that the public interest may be better served by such a policy even though it may entail the sacrifice of short-term economic efficiency. Another, and somewhat related, example would be to let the utility and its affiliate conduct a transaction that exploits the underlying economies of scope (such as selling a service to the affiliate at a price that is lower than charged to others because it costs less to serve the affiliate). Although it would be economically efficient to allow this discriminatory practice, it would deter entry by the affiliate's potential competitors and may even drive out the current competitors. There may be good arguments on both sides of whether economic efficiency or competitiveness ought to be promoted in a mixed regulatory-competitive regime. Ultimately, the state regulatory commissions will make a choice among conflicting regulatory objectives on the basis of their preferences.

Recommendations

Given the finding that no combination of cost allocation schemes and tariff designs is likely to meet all of the most important regulatory objectives, the study does not recommend any specific option. Also, the public interest compulsions and preferences of each state public utility commission may be different, and the desirable set of options for one PUC may be an inferior choice for another PUC. Finally, given the differing characteristics of each LDC even within the jurisdiction of a PUC, the same set of options may not be suitable for different LDCs.

This study identifies three possible regulatory strategies with regard to rate design options (see Table 6-13). The gradualist strategy is designed to move into a competitive regime at a relatively slow pace to allow for adjustments to traditional regulatory objectives and customer interests. The market facilitation strategy would facilitate market forces more aggressively and would attempt to achieve competitive conditions at a relatively rapid pace. The radical deregulation strategy would immediately unbundle and deregulate services that are deemed competitive.

The choice of the regulatory strategy would depend on the conditions prevailing in each state in addition to regulatory preferences. For example, a state in which gas utility service rates are relatively low may opt for the gradualist strategy. On the other hand, a state with relatively high gas utility service rates may opt for either the market facilitation or the radical deregulation strategy.

Table 6-1: Separation of Costs for Upstream Assets – Full Divestiture

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Book Value	Inconsistent with economic efficiency	Alternative providers may consider it inequitable	Disadvantages alternative providers	May harm consumers through anti-competitive effects	Recovers revenue requirements	No significant implementation issue. May be contested by alternative providers and customer groups
Market Value	Consistent with economic efficiency	Utility may consider it inequitable if it faces stranded costs	No disadvantage to competitors	Consumer at risk if asset is undervalued and stranded cost recovery is allowed	May not recover revenue requirements. May cause stranded costs	Market value may be difficult to estimate if the asset is sold to an affiliate or not sold
Higher of Book or Market Value*	Inconsistent with economic efficiency	Utility affiliates may consider it inequitable because of asymmetry	Favors competitors of utility and its affiliates	Consumer is protected against the risks of asset valuation	Recovers revenue requirements	Market value may be difficult and contentious to estimate

* May be used if the utility sells an asset to an affiliate.

Table 6-2: Separation of Costs for Upstream Assets – Partial Divestiture*

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC Methods for Capacity Costs	Inconsistent with economic efficiency	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	High informational and regulatory costs
Marginal Cost Methods for Capacity Costs	Consistent with economic efficiency	Competitors and consumers consider it inequitable	Favors utility	Anti-competitive effects may harm consumers	Minimizes revenue deficiency	Difficult to measure
Stand Alone Cost	A value between stand-alone cost and marginal cost meets the no-cross-subsidy test	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure
Pro-Rated Market Value	Consistent with economic efficiency	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure

* The asset is co-owned by the utility and its affiliate.

Table 6-3: Separation of Costs of Contracts for Upstream Services

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Mandatory Assignment	Inconsistent with economic efficiency	Alternative providers may consider it inequitable	Disadvantages competitors	Anti-competitive effects may harm consumers	Recovers revenue requirements	No significant implementation issues
Marketers Purchase Upstream Services	Consistent with economic efficiency	Utility may consider it inequitable	Helps competitors	Pro-competitive effects may help consumers	May cause stranded costs	No significant implementation issues

Table 6-4: Separation of Upstream Operating Expenditures

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC Methods	Inconsistent with economic efficiency	Utility may consider it inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause revenue deficiency	High informational costs
Avoided costs	Consistent with economic efficiency	No significant equity issue	Favors utility	Effect on consumers is neutral	Minimizes revenue deficiency	Low informational costs. Can be based on FERC tariffs

Table 6-5: Separation of Costs for Downstream Assets – Full Divestiture

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Book Value	Inconsistent with economic efficiency	Alternative providers may consider it inequitable	Disadvantages alternative providers	May harm customers through anti-competitive effects	Recovers revenue requirements	No significant implementation issue. May be contested by alternative providers and customer groups
Market Value	Consistent with economic efficiency	Utility may consider it inequitable if it faces stranded costs	No disadvantage to competitors	Consumer at risk if asset is undervalued and stranded cost recovery is allowed	May not recover revenue requirements. May cause stranded costs	Market value may be difficult to estimate if the asset is sold to an affiliate or not sold
Higher of Book or Market Value*	Inconsistent with economic efficiency	Utility affiliates may consider it inequitable because of asymmetry	Favors competitors of utility and its affiliates	Consumer is protected against the risks of asset valuation	Recovers revenue requirements	Market value may be difficult and contentious to estimate

* May be used if the utility sells an asset to an affiliate.

Table 6-6: Separation of Costs for Downstream Assets – Partial Divestiture*

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC Methods for Capacity Costs	Inconsistent with economic efficiency	Utility may consider inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	High informational and regulatory costs
Marginal Cost Methods for Capacity Costs	Consistent with economic efficiency	Competitors and consumers consider it inequitable	Favors utility	Anti-competitive effects may harm consumers	Minimizes revenue deficiency	Difficult to measure
Stand Alone Cost	A value between stand-alone cost and marginal cost meets the no-cross-subsidy test	Utility may consider inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure
Pro-Rated Market Value	Consistent with economic efficiency	Utility may consider inequitable	Favors competitors	Pro-competitive effects may help consumers	May cause stranded costs	Difficult to measure

* The asset is co-owned by the utility and its affiliate.

Table 6-7: Separation of Costs for Downstream Operations

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
No Cost Separations: Adjust Rates to Maintain RR	Inconsistent with economic efficiency	Inequitable for customers who remain with utility	Favors utility	Harms customers through increased rates and also anti-competitive effects	Recovers RR	High informational costs
No Cost Separations: No adjustment to rates	Consistent with economic efficiency	Utility may consider it inequitable	Disadvantages utility	Customers are protected from increased rates and anti-competitive effects	May cause revenue deficiency	Almost zero informational costs
FDC Methods	Inconsistent with economic efficiency	Utility may consider it inequitable	Disadvantages utility	May help customers with pro-competitive effects	May cause revenue deficiency	High informational costs

Table 6-7 – *continued*

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Short-Run Avoided Costs	Consistent with economic efficiency	Competitors may consider it inequitable	Favors utility	May harm customers through anti-competitive effects	Minimizes revenue deficiency	Applicable in excess capacity situation. Avoided costs are hard to measure
Long-run Avoided Costs	Consistent with economic efficiency	Equity implications unclear or neutral	Effect on competition depends on estimated costs of capacity additions	Helps current customers with credit for avoided capacity additions	Depends on magnitude of avoided capacity costs	Applicable in capacity shortage situation. Avoided costs are hard to measure
Market-Indexed Price Times Avoided Volume of Service	Consistent with economic efficiency	Equity implications unclear or neutral	May disadvantage competitors	May harm customers through anti-competitive effects	Revenue implications on the index and magnitude of avoided volume of service	Market index may be hard to measure. Not suitable if the market is not workably competitive

Table 6-8: End-Use Tariffs for Services Exclusively Provided by the Utility

Option	Economic Efficiency	Equity	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Traditional Rate Designs	Generally inconsistent with economic efficiency	Generally considered equitable	Not a significant issue	Recovers revenue requirements	High informational costs
Price Caps	Provides good cost minimization incentives. Allocates cost better than targeted PBR	Allows utility to price discriminate among customers	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Price cap parameters may be hard to measure and controversial
Value of Service Pricing	Generally promotes welfare maximization	Lets the utility appropriate consumer surplus. Allows utility to price discriminate	One group of customers may be disadvantaged relative to another	Utility is able to recover revenue requirements	May be politically unacceptable to certain customers

Table 6-8 – continued

Option	Economic Efficiency	Equity	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Interruptible Rates	Consistent with economic efficiency	May be considered inequitable if there is no capacity cost component	To protect captive or firm customers, price floor should be set at variable cost	Helps meet revenue requirements	No significant implementation issue
Time-of-Use Rates	Consistent with economic efficiency	Low load factor customers may consider it inequitable	Low load factor customers may be charged relatively high rates	Generally designed with revenue reconciliation	High metering and informational costs
Seasonal Rates	Provides correct price signals about seasonal fluctuations of demand and supply	Customers with relatively high demands during seasonal peak periods may consider it inequitable	No clear consumer protection implications	Generally designed with revenue reconciliation	No significant implementation issue. Currently practiced in the form of gas-cost recovery (GCR) charges

Table 6-9: End-Use Tariffs for Services Provided by the Utility and Others
Case 1: Utility Is the Dominant Provider

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Traditional Rate Designs	Generally inconsistent with economic efficiency	Generally considered equitable	May promote competition as utility prices are likely to be higher than others	Utility customers may face higher prices than other customers	Recovers revenues	High informational costs
Price Caps	Provides good cost minimization incentives.	Allows utility to price discriminate among customers	Utility may have an incentive to undercut competitors by minimizing prices for competitive services	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Price cap parameters may be hard to measure and controversial
Price Tied To Market Index	Provides good cost minimization incentives	Allows utility to price discriminate among customers	Utility may have an incentive to undercut competitors by minimizing prices for competitive services	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Generally allows revenue adjustment on a forward-looking basis

Table 6-9 – *continued*

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Value of Service Pricing	Generally promotes welfare maximization	Lets the utility appropriate consumer surplus	Utility may be able to price discriminate to deter competition	Anti-competitive effects may harm customers	Utility is able to recover RR	May be politically unacceptable to certain customer groups
Interruptible Rates	Consistent with economic efficiency	May be considered inequitable if there is no capacity cost component	No clear competitive implications	To protect captive or firm customers, price floor should be set at variable cost	Helps meet revenue requirements	No significant implementation issue
Time-of-Use Rates	Consistent with economic efficiency	May be considered inequitable by low load factor customers	Utility may be able to price discriminate to deter competition	Low load factor customers may be charged relatively high rates	Generally designed with revenue reconciliation	High metering and informational costs
Seasonal Rates	Provides correct price signals about seasonal fluctuations of demand and supply	Customers with relatively high demands during seasonal peak periods may consider it inequitable	No clear competitive implications	No clear consumer protection implications	Generally designed with revenue reconciliation	No significant implementation issue. Currently practiced in the form of GCR

Table 6-10: End-Use Tariffs for Services Provided by the Utility and Others
Case 2: Utility Is Not the Dominant Provider

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Traditional Rate Designs	Generally inconsistent with economic efficiency	Generally considered equitable	May promote competition as utility prices are likely to be higher than others	Utility customers may face higher prices than other customers	Recovers revenues	High informational costs
Price Caps	Provides good cost minimization incentives. Allocates cost better than targeted PBR	Allows utility to price discriminate among customers	Competitive implications are neutral	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Price cap parameters may be hard to measure and controversial
Price Tied To Market Index	Provides good cost minimization incentives	Allows utility to price discriminate among customers	Competitive implications are neutral	One group of customers may be disadvantaged relative to another	Generally allows revenue adjustment on a forward-looking basis	Market index parameters may be hard to measure and controversial

Table 6-10 – *continued*						
Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Value of Service Pricing	Generally promotes welfare maximization	Lets the utility appropriate consumer surplus	Competitive implications neutral	Consumer protection implications unclear	Utility may be able to recover revenues	May be politically unacceptable for certain customer groups
Interruptible Rates	Consistent with economic efficiency	May be considered inequitable if there is no capacity cost component	Competitive implications neutral	No clear consumer protection implications	Helps meet revenue requirements	No significant implementation issue
Time-of-Use Rates	Consistent with economic efficiency	May be considered inequitable by low load factor customers	Competitive implications neutral	No clear consumer protection implications	Generally designed with revenue reconciliation	High metering and informational costs
Seasonal Rates	Provides correct price signals about seasonal fluctuations of demand and supply	Customers with relatively high demands during seasonal peak periods may consider it inequitable	Competitive implications neutral	No clear consumer protection implications	Generally designed with revenue reconciliation	No significant implementation issue. Currently practiced in the form of GCR

Table 6-11: Pricing of Assets Sold/Purchased by Utility to/from Its Affiliate

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
Book Value of Assets Sold By Utility	Inconsistent with economic efficiency	Generally considered equitable	Favors the affiliate if book value is lower than market	May harm consumers through anti-competitive effects	Recovers RR	No significant implementation issue
Market Value of Assets Sold By Utility	Consistent with economic efficiency	No significant equity implication	Competitive implications are neutral	Protects consumers from anti-competitive outcomes	May cause stranded costs or prohibits recovery	Market value estimation may be difficult and contentious
Market Value of Assets Purchased By Utility	Consistent with economic efficiency	No significant equity implication	Competitive implications are neutral	Protects consumers from anti-competitive outcomes	No revenue recovery implications	Market value estimation may be difficult and contentious
Higher of Book/Market of Assets By Utility	Inconsistent with economic efficiency	May be considered inequitable by utility and its affiliate	Disadvantages utility and its affiliate. May help competition	Customers are protected from risks of asset valuation	May cause stranded costs	Market value estimation may be difficult and contentious

Table 6-12

Pricing of Services Sold/Purchased by Utility to/from Its Affiliate

Option	Economic Efficiency	Equity	Competition	Consumer Protection	Revenue Sufficiency	Ease of Implementation
FDC-Based Price for Services Sold by Utility	Inconsistent with economic efficiency	Generally considered equitable	Favors affiliate if FDC-based price is lower than market	May harm consumers through anti-competitive effects	Recovers RR	No significant implementation issue
Market Prices For Services Sold By Utility	Consistent with economic efficiency	No significant equity implications	Competitive implications neutral	Protects consumers from anti-competitive outcomes	May cause revenue deficiency and excess	Market price estimation may be hard or contentious
Market Prices For Services Purchased By Utility	Consistent with economic efficiency	No significant equity implications	No significant equity implications	Protects consumers from anti-competitive outcomes	May cause revenue deficiency and excess	Market price estimation may be hard or contentious
Higher of FDC/Market in Sale and Lower of FDC/Market in Purchase	Inconsistent with economic efficiency	Utility and its affiliate may consider it inequitable	Disadvantages utility and its affiliate	Protects consumers from price risk	May cause revenue deficiency and excess	Market price estimation may be hard or contentious