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PRIMER ON GAS INTEGRATED RESOURCE PLANNING

Prepared by
Charles Goldman, G. Alan Comnes, John Busch, and Stephen Wiel

Energy & Environment Division
Lawrence Berkeley Laboratory
University of California
Berkeley, CA 94720

for

National Association of Regulatory Utility Commissioners
Room 1102, ICC Building, P.O. Box 684
Washington, DC 20044

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The views and opinions expressed herein are strictly those of the authors and may not necessarily agree with opinions and positions of NARUC or those of the U.S. Department of Energy.

Contents

Tables

Figures

Exhibits

Foreword

This primer is the culmination of a project sponsored by the Energy Conservation Committee of the National Association of Regulatory Utility Commissioners (NARUC). In 1990, the Energy Conservation Committee formed a Subcommittee on Gas Integrated Resource Planning to examine technical and policy issues relevant to integrated resource planning (IRP) for gas utilities. The purpose of this effort is to provide the same useful discussion of issues for regulators as had been achieved through two previous handbooks related to IRP for electric utilities. We gratefully acknowledge the outstanding work which has been accomplished by Chuck Goldman, Alan Comnes, John Busch and Stephen Wiel of the Lawrence Berkeley Laboratory and express our appreciation for the project funding provided by the Department of Energy (DOE) through the Assistant Secretary for Energy Efficiency and Renewable Energy.

This primer addresses utility and regulatory considerations which are relevant to the strategic planning process in the provision of natural gas utility service. Such strategic planning is key to the prudent operations of gas utilities, just as it is for electric utilities. An optimum resource selection process should not be viewed as new to either industry, but rather is already or should have been an integral part of a given company's operations. This primer is not intended to serve as a handbook, but rather as a treatise exploring considerations which are worthy of review by those willing to give the subject of IRP for natural gas fair and objective consideration. One of the very purposes of this project is to compare key similarities and differences between strategic planning processes for electric and gas utilities. While IRP for electric utilities has received more attention, that does not make it more important, particularly to the customers of gas utilities.

As background research was in progress, the Energy Policy Act of 1992 (EPACT) was passed which requires state regulatory commissions to consider whether it is appropriate to implement IRP for gas utilities. The EPACT requirements positively affect the timeliness and relevancy of this primer because it provides state commissions and their staffs with information on technical and policy issues they will face in their consideration of gas IRP.

We believe an unprecedented and successful effort has been made in the development of the primer to obtain input and comments from industry groups, consumer representatives and technical experts through the formation and active involvement of a Technical Advisory Group (see "Acknowledgements"). This document has also been reviewed extensively by individuals from the NARUC Energy Conservation and Gas Committees and their respective Staff Subcommittees. Over 40 individuals contributed their ideas during this project, and helped assure that this primer provides a fair and balanced treatment of gas IRP policy and technical issues. We sincerely thank those individuals who together have contributed hundreds of hours improving the quality and usefulness of the report.

As this primer goes to press in the fall of 1993, many Local Distribution Companies (LDCs) and their customers are experiencing significant price increases as the result of implementation of FERC Order 636 and increased demand for natural gas. Pricing trends and multiple choices for supply make state-of-the-art resource planning for natural gas critical.

We trust that you, the reader, will find this primer to be a resource of great value.

Commissioner Steve Ellenbecker
Gas IRP Subcommittee Chair

Commissioner Jo Ann Kelly
Gas Committee Liaison

Paul Newman
Lead Staffmember, Gas IRP Subcommittee

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ANR Pipeline

Paul Buckley
Office of the Maryland People's Counsel

Mark Caudill
Ed Overstreet
Atlanta Gas Light Company

Adrian Chapman
Washington Gas Light

Theresa Flaim
Bill Hamilton
Niagara Mohawk Power Corporation

William Harding
Bethlehem Steel

Bruce Henning
Eric Wise
American Gas Association

Rick Hornby
Tellus Institute

Patrick Hughes
Oak Ridge National Laboratory

Val Jensen
ICF Incorporated

Ken Kazmer
Gas Research Institute

Steven Kline
PG&E

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Natural Gas Supply Association

Craig McDonald
Dean White
Synergic Resources Corporation

Luc Piessens
Wisconsin Gas Company

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Executive Summary

State public utility commissions (PUCs) have taken increased interest in integrated resource planning (IRP) for gas local distribution companies (LDCs). IRP involves a process used by utilities to assess a comprehensive set of supply- and demand-side options based upon consistent planning assumptions to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost. Consideration of gas IRP by state PUCs is driven by several factors:

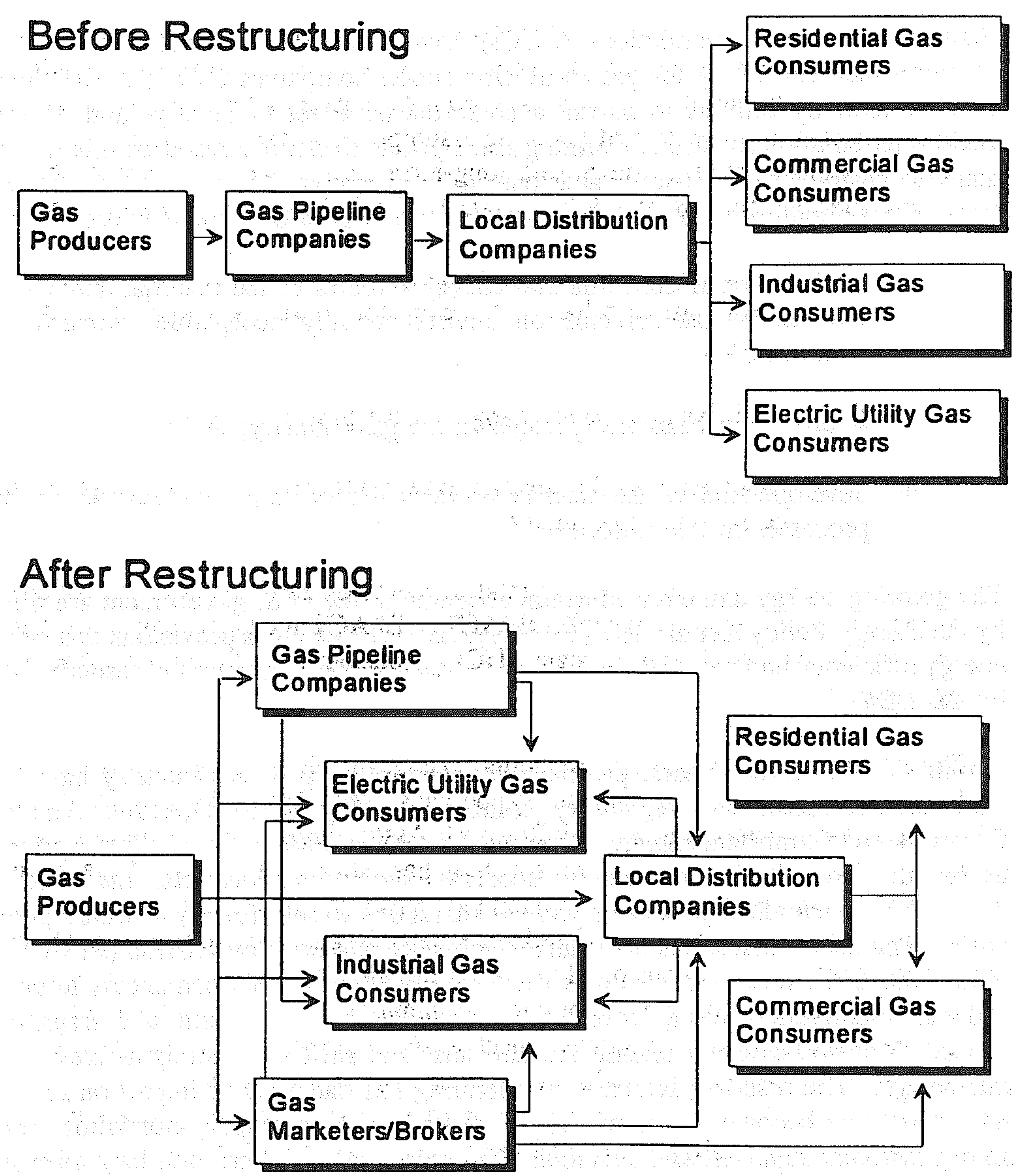
- environmental concerns and energy policies at the national and state levels that emphasize reliance on environmentally acceptable, domestic energy resources;
- internal dynamics and changes in the gas industry; and
- developments in the electric power industry (e.g., widespread use of IRP processes in that industry).

The growing energy and environmental concerns of the U.S. government are illustrated by the Energy Policy Act of 1992 (EPACT). EPACT includes provisions that encourage energy efficiency and requires state PUCs to consider use of integrated resource planning by gas LDCs.

During the past fifteen years, profound changes in the U.S. gas industry have resulted from market forces and regulatory policies (see Figure ES-1)(Arthur Andersen & Company and Cambridge Energy Research Associates 1988). Gas wellhead prices were deregulated and vibrant markets for spot gas, short-term contracts, and futures have developed, which allow producers and gas marketers to sell directly to LDCs and large-volume end users. In a series of Federal Energy Regulatory Commission (FERC) Orders (436, 500, 636), interstate pipelines were required to provide open access to end users and gas marketers/brokers, completely unbundle their merchant and transportation services, develop capacity release mechanisms, and shift to a "straight-fixed variable" rate design. The resulting industry restructuring has had a major impact on gas utilities who must now become active managers of their own gas supply portfolios, choosing among different suppliers and developing the proper mix of short- and long-term supply. LDCs are faced with deciding whether to develop their own gas supply portfolios or contract out portfolio aggregation and rebundling functions to other parties (e.g., producers, pipeline affiliates, marketers).

State regulators face the challenge of managing and responding to the competitive forces that have been unleashed by gas industry restructuring. PUCs will have to decide to what

Figure ES-1. Evolution of Gas Marketing



Source: Arthur Andersen & Company, and Cambridge Energy Research Associates 1988 extent they want to extend and replicate FERC policies and goals for pipelines in their regulation of gas LDCs. State PUCs and gas LDCs are likely to continue recent trends in which they distinguish between captive core and large volume noncore customers in terms of the services offered, the extent of regulation, and their obligation to serve. Current procedures for monitoring gas supply costs and reliability may also have to be adapted in the period after FERC Order 636. State PUCs must also consider differences between electric and gas utility industries when developing appropriate regulatory policies and expectations for gas LDCs.

Some states have adopted formal gas IRP regulations <u>with mixed success</u>; regulators of adopting states were influenced by the electricity industry's IRP paradigm and tried to transfer that approach to the gas industry. In some cases, PUCs were also attempting to be consistent in their treatment of regulated energy industries or wanted to facilitate statewide integrated electric and gas planning.

Table ES-1 highlights differences between the U.S. gas and electric industries in five major areas: industry structure and organization, planning practices, end-use market characteristics, avoided supply costs, and access to retail utility service. Distinctive features of gas LDCs compared to electric utilities include a lack of vertical integration, shorter planning horizons, a focus on supply procurement and distribution system expansion rather than generation capacity expansion, more intense competition in end-use markets, and lower avoided supply costs. Low avoided gas supply costs mean that it is more difficult for gas conservation programs conducted by gas utilities to pass cost-effectiveness tests.

Integrated resource planning for gas LDCs <u>is one approach</u> for state PUCs to consider in addressing the challenges of gas industry restructuring. An IRP regulatory process may typically involve:

- a formal integrated resource plan presented by a gas LDC in a regulatory forum that is separate from rate cases;
- explicit consideration of a wide variety of supply- and demand-side options;
- public participation in the development and/or review of the resource plan;
- review, and possibly approval, of the utility's plan by a regulatory commission.

Table ES-1. Differences Between Gas and Electric Utilities

	Electric	Gas
Industry Structure and Operation	• Vertically-integrated, except for new generation	• Separate firms handle production, Transmission & Distribution (T&D) • Prominence of storage
Planning Practices	• 10-30 yrs	• 1-10 yrs
End-Use Market Characteristics	• Electricity is an essential service • More difficult to fuel switch	• Gas service is optional • Core and noncore markets
Avoided Supply Costs	• Higher than gas when adjusted for equivalent energy services provided • Methods reasonably well developed	• Methods still evolving
Access to Retail Utility Service	• Virtually universal	• Not as widely available as electric

Potential benefits of gas IRP cited by proponents include:

- IRP provides documentation and support for the strategic planning activities of gas LDCs;
- IRP may provide for implicit or explicit risk-sharing on major supply and capacity decisions between utilities and regulators;

- IRP helps overcome market barriers and imperfections that inhibit penetration of high-efficiency end-use options, and by encouraging gas DSM, may provide new opportunities for high-efficiency gas technologies where societal benefits can be demonstrated;

- IRP facilitates public participation and input in resource planning;

- IRP helps facilitate coordinated energy and environmental planning.

Others involved in the gas industry believe that there are significant drawbacks to gas IRP regulatory processes. They conclude that significant differences between electric and gas utilities mean that the benefits captured by a formal IRP proceeding are likely to be small and will not justify the additional transaction costs of such a process. They are generally supportive of some IRP objectives (e.g., fair consideration of supply- and demand-side options, development of appropriate evaluation criteria for DSM programs), but conclude that the regulatory process associated with addressing IRP objectives should be far less complex and costly than approaches typically used for electric IRP. In critiquing the value of gas IRP regulatory processes, they raise the following issues:

- The direct and indirect costs of an additional gas IRP regulatory process can be substantial, and the benefits are uncertain and likely to be small. Critics note that gas IRP processes often involve significant amounts of utility, regulatory, and third party staff time, which could be better spent, given limited resources, on other activities. Concerns over the costs of the process are important because the potential benefits of gas IRP are inherently less than those that can be realized by an electric IRP process. Supply-side decisions for gas LDCs do not imply large, long-term irreversible cost commitments and competitive gas markets limit opportunities for a public process to further reduce gas costs.

- A gas IRP regulatory process, particularly one that implies regulatory preapproval, is incompatible with the development of a competitive gas industry.

- The gas conservation potential that can be acquired cost-effectively by an LDC is relatively small because much of the economic potential will be captured through government appliance and building standards and codes. Moreover, the potential scope for developing cost-effective energy efficiency programs is less for gas utilities than for electric utilities because gas avoided costs are lower.

Both proponents and critics of gas IRP regulatory processes agree that strategic planning is critically important for gas LDCs. To some degree, the incremental benefits of a formal IRP process will depend on the extent to which a LDC's existing strategic planning process already includes and adequately addresses IRP goals and objectives. Alternative regulatory approaches can achieve many of the goals of IRP for gas LDCs; a variety of regulatory strategies are currently being considered and tested by state PUCs.

The primary focus of this primer is on technical and analytical issues that gas LDCs and state regulators are likely to confront in attempting to achieve IRP objectives and goals. A 1991 survey conducted by the National Association of Regulatory Utility Commissioners (NARUC) found that a lack of information on various IRP-related technical and analytical issues limited consensus. This primer, prepared at the request of NARUC's Energy Conservation Committee, is intended to fill the informational gap. Because gas IRP is a relatively new phenomenon and there is less consensus on accepted practices, many topics in the primer cannot be treated in a definitive manner; instead they are treated through a discussion of alternative approaches and their implications.

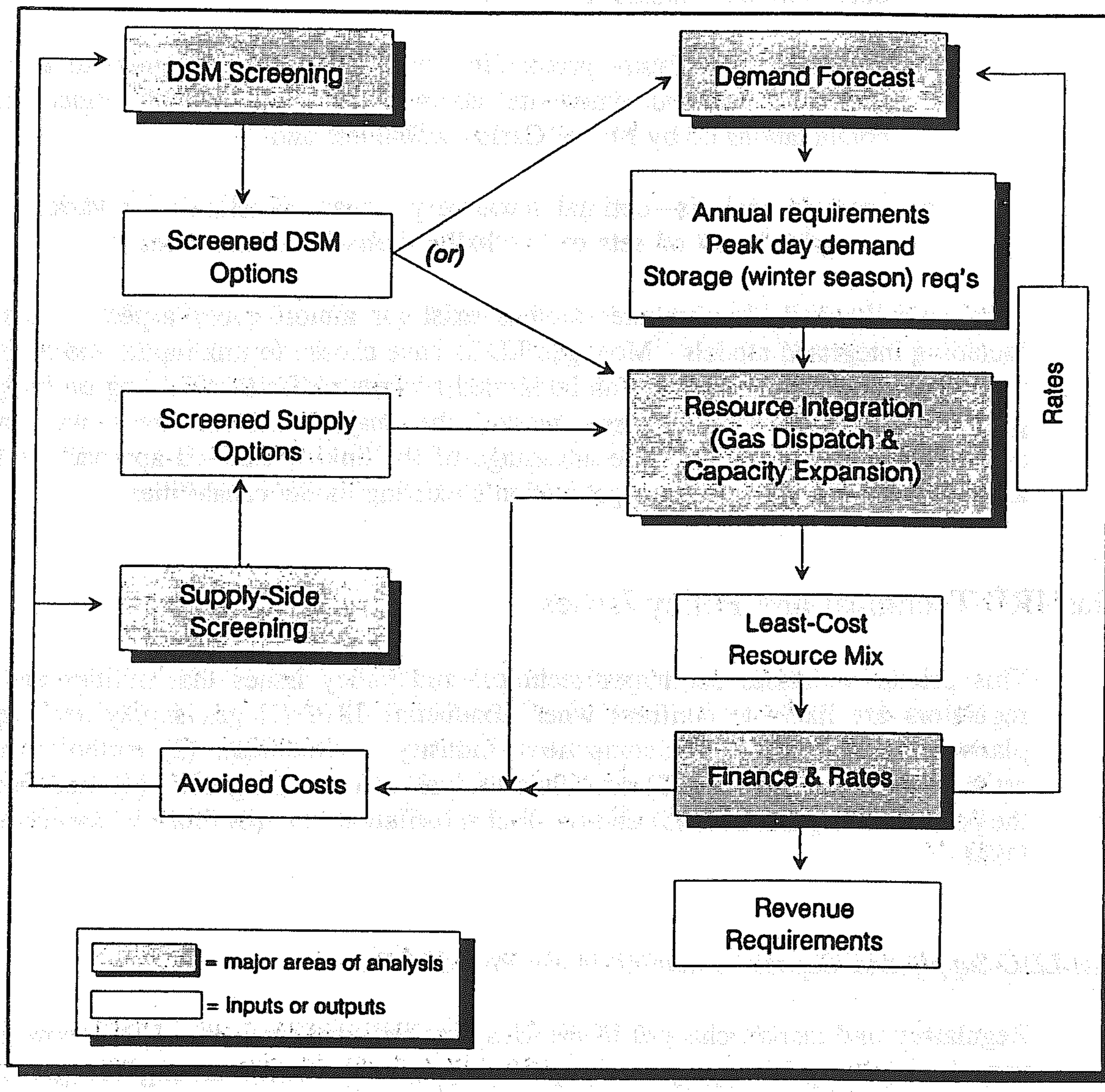
Gas IRP Methods and Models

Regardless of whether gas IRP is pursued through a formal regulatory process or set of methods that are overlaid upon existing business and regulatory practices, IRP requires the coordination of several major areas of utility resource planning: demand forecasting, supply-side resource selection, demand-side resource selection, resource integration, and financial and rate forecasting. This coordination should begin with a clear set of objectives that define the mission of the gas local distribution company. IRP objectives usually include the minimization of private or social costs as well as other objectives that address rate impacts, equity impacts, and utility financial health. A simplified representation of the analysis framework and the relationships among various areas is shown in Figure ES-2.

Demand forecasting may be conducted using econometric or end-use models, or models that combine both. Most gas utilities currently use econometric methods to forecast residential and commercial sector demand. End-use models have advantages in an IRP context because the impacts of utility DSM programs can be reflected in the load forecast more easily and because underlying assumptions and key appliance stocks and efficiencies are more understandable to nonutility parties. The complexity of demand forecasting will increase for LDCs in the post-636 era because of increases in the size and variety of customers that purchase transport-only services from gas LDCs.

During resource integration, the utility analyzes in detail supply- and demand-side options that have emerged from screening processes and selects a mix of resource options that

Figure ES-2. Analysis Framework for Gas IRP



best meets its IRP goals and objectives. An important resource integration issue is where to incorporate the effects of gas DSM programs: as a modification of customer demands or as a resource option that is selected, along with supply-side resources, in the gas dispatch and capacity expansion models (see Figure ES-2).

Uncertainty is a critical factor in gas utility resource planning. One of the major contributions of IRP has been its emphasis on analytic techniques that explicitly assess risks associated with uncertainties in key variables. These techniques include:

- sensitivity analysis—key input variables are varied over a plausible range to determine their impact on results;

- probabilistic analysis—probability distributions are assigned to key input variables, and outcomes are computed for all possible input variable combinations or by Monte Carlo techniques; and

- scenario analysis—optimal resource plans are developed for various future scenarios based on sets of internally consistent assumptions.

Commercially-available computer models exist for almost every aspect of gas IRP, including integrated models. Most gas LDCs have chosen to link inputs and outputs of individual, detailed models into an integrated process rather than relying on integrated planning models where linkages among the major analysis areas are handled automatically by the model. The advantage of the linked, detailed approach is that it allows gas LDCs to use their organization's existing model capabilities.

Gas IRP Technical and Policy Issues

This primer addresses six major technical and policy issues that utilities and state regulators are likely to confront when conducting IRP: (1) gas supply and capacity planning in an increasingly competitive industry environment, (2) methods used to estimate gas avoided costs, (3) economic analysis of DSM programs, (4) assessment of the potential for gas DSM, (5) end-use fuel substitution, and (6) financial aspects of gas DSM.

Gas LDC Supply and Capacity Planning in the Post-636 Era

Regulatory and market changes in the U.S. gas industry mean that LDCs now have a very broad array of supply and capacity options to choose among for gas supply planning; they can no longer rely on gas pipelines for supply management. The primer focuses on four general topics: (1) existing and emerging supply and capacity resource options, (2) major supply and capacity planning methods and issues, (3) approaches to PUC oversight of gas LDC procurement decisions, and (4) gas system reliability and contingency planning.

Major strategies used by LDCs to achieve gas supply planning goals include:

- relying on a portfolio of gas supplies that is diversified with respect to gas supply owner, contract term, and, if possible, supply basin and transport facility;
- managing price risks in a post-636 world by complimenting physical gas supply contracts with financial contracts (i.e., futures, options, swaps, and other types of forward contracts); and
- managing the load shape of gas purchased from the producer either by diversifying demand amongst different groups of customers, using storage or peak-shaving facilities to manage load shape, or by developing buyback provisions for certain sales customers.

The primer highlights a number of issues that arise in capacity planning, including:

- methods of screening resource options and limitations of such analysis;
- detailed capacity expansion planning methods including iterative simulations and optimization models;
- storage resources as an alternative to pipeline supply: functions of storage (i.e., daily balancing, seasonal balancing, peak-day protection, and price benefits) and maximizing efficient use of different types of storage resources;
- the build vs. buy problem for an LDC; that is, a consideration of increased reliance on third parties for various types of capacity (e.g., joint ventures for storage resources, firm capacity sold by brokers or marketers as part of bundled product); and
- incorporation of potential for retail bypass into the capacity planning process.

In addition to cost considerations, gas LDCs review the reliability implications of gas supply and capacity options. Gas LDCs develop reliability goals over the planning horizon and attempt to balance the need for reliable service and reasonable cost. Historically, gas system reliability planners have depended heavily on prescriptive rules. Gas system reliability planning will most likely evolve under IRP and in response to ongoing industry restructuring. Increased competition will be a double-edged sword for many LDCs. LDCs will determine the appropriate reliability standard for all LDC customers and, to retain load, LDCs will have to focus more on the reliability provided to all customers, including customers formerly satisfied with interruptible service. However, the possibility of building additional facilities to provide reliability will be limited by price competition from alternative fuels and bypass alternatives.

IRP processes could lead to greater use of benefit-cost studies to determine LDC-specific reliability standards as well as inclusion of the potential reserve margin benefits of DSM options. In addition to reliability planning, gas LDCs can maximize the reliability of an existing system by developing contingency plans. Contingency plans include steps a utility can quickly take to acquire supply during periods of critical demand and detailed curtailment plans to minimize the negative consequences of any curtailment.

Methods for Estimating Gas Avoided Costs

In IRP, it is crucial for the utility to develop estimates of the gas system's avoidable costs associated with supply-side resources in order to evaluate the economic benefits of DSM resources. Avoided supply costs are also useful in initial screening of incremental gas supply capacity contracts or capacity projects as well as cost allocation and rate design. This primer presents four methods for calculating avoided gas costs: system marginal cost, generic proxy approach, targeted marginal approach, and average cost methods. Each method starts from a common point, which is a base case supply plan that meets the projected gas demand forecast.

- System marginal cost—avoided costs are estimated by taking the difference between the total change in system costs between the base case supply plan and a supply plan that is developed for a new demand forecast that includes the effect of the DSM program, which is divided by the size of the decrement on a volumetric basis.

- Generic proxy approach—an avoidable resource (or resources) is selected from the base case supply plan, and the costs of this resource are used as the basis for avoided costs.

- Targeted marginal approach—supply resources are segmented by the type of demands that they principally serve (e.g., base, temperature-sensitive, peaking loads), and the highest cost supply in each category is identified and its costs allocated to the corresponding demand impact.

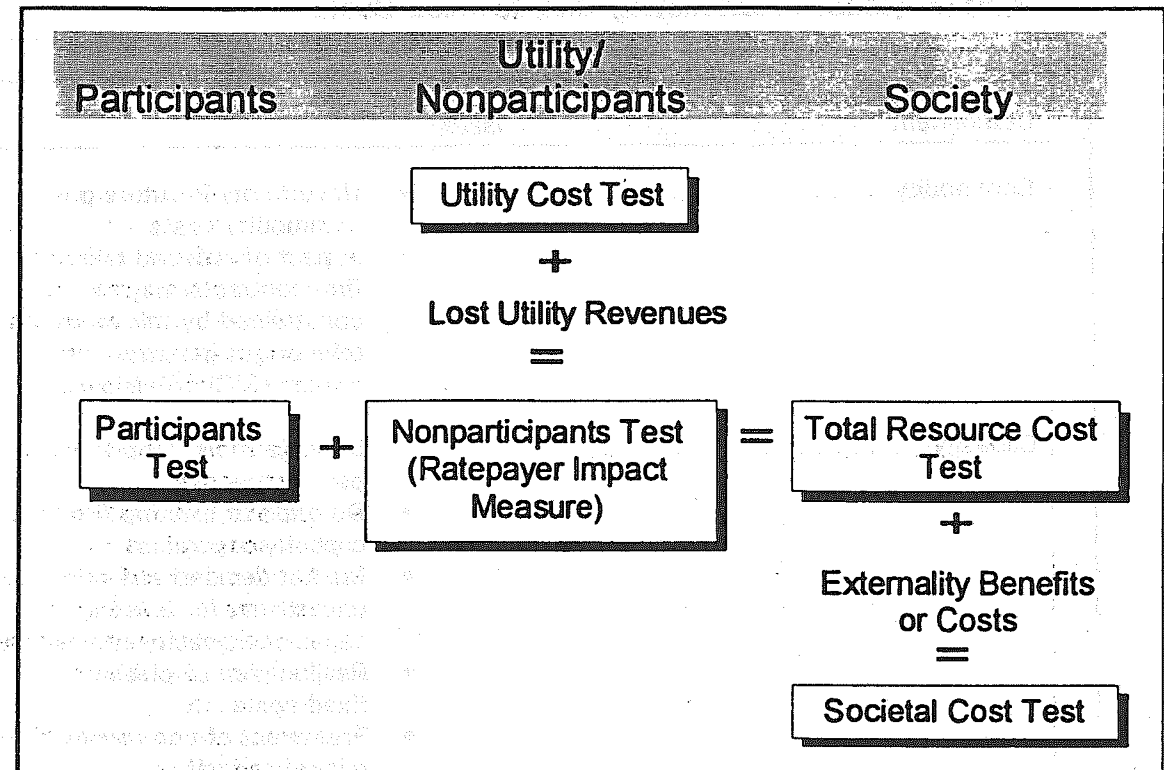
- Average cost methods—the unit cost of all supply resources is estimated based on a weighted average of their respective volumetric contribution to the total gas sendout.

Table ES-2. Issues in Estimating Gas Avoided Costs

Component	Issue
Commodity	• Uncertainty in future gas commodity costs • Impact of reduced takes on firm contracts may be constrained by minimum take or gas inventory charge (GIC) provisions
Capacity	• Short-term vs. long-term perspective • Duration of existing firm capacity contracts • Market demand and price uncertainty for existing capacity (capacity release) • Reallocation of pipeline fixed costs • Treatment of commodity-related capacity investments • Cost allocation methods for long-lived facility investments
Local Transmission & Distribution (T&D) and Customer Costs	• Frequently not avoidable by most DSM programs

Two key issues that arise in estimating gas avoided costs are accounting for the uncertainty in future gas commodity costs explicitly through sensitivity analysis and accurately assessing capacity-related costs that are actually avoidable by a DSM program (see Table ES-2).

Figure ES-3. Interrelationship of Standard DSM Benefit-Cost Tests



Source: Adapted from Washington Natural Gas (1992)

Economic Analysis of DSM Programs

The economic analysis of DSM programs or measures relies heavily on results of multiple benefit-cost tests that attempt to capture program impacts from the perspective of different affected parties (e.g., participating customers, nonparticipating ratepayers, utility, and society). Figure ES-3 provides an overview of these tests and emphasizes the relationships among them.

This primer reviews various technical issues that arise in the application of the benefit-cost tests: appropriate discount rates, period of analysis, inclusion of effects of free riders, analysis of programs that affect multiple fuels, and additional considerations for interruptible and transport-only customers. Key policy issues are also discussed: appropriate use and limitations of the benefit-cost tests in the IRP framework, implications for PUCs of establishing a primary test and the debate over usage of the Total Resource Cost (TRC) test vs. the Ratepayer Impact Measure (RIM) test, underlying assumptions of TRC vs. RIM tests regarding markets for energy efficiency and the impact of market imperfections, and alternatives to the standard benefit-cost tests.

Assessing Gas DSM Potential

Assessing the magnitude and cost of DSM resources is an important activity, in part because it provides utilities with information on one of the underlying rationales for IRP: whether or not there are significant quantities of cost-effective DSM resources that can be captured by utility DSM programs. This primer reviews results of recent gas DSM potential studies and provides technical information on individual gas equipment efficiency measures and strategies that are applicable to the residential and commercial sectors. Opportunities to improve end-use efficiency often involve multiple measures and strategies for a broad range of end uses.

In the residential sector, the economic gas savings potential ranged from 5 to 47% of total sector sales among nine LDC case studies, with a median value of 24%. In the commercial sector, the economic gas savings potential ranged from 8 to 23% of total sector sales, with a median value of 15%. In interpreting the results, it is important to understand distinctions between technical, economic, and achievable potential:

- *Technical Potential* is an estimate of possible energy savings based on the assumption that existing appliances, equipment, building shell measures, and processes are replaced with the most efficient commercially available units, regardless of cost, without any significant change in lifestyle or output.

- *Economic Potential* is an estimate of the portion of technical potential that would occur assuming that all energy-efficient options will be adopted and all existing equipment will be replaced whenever it is cost effective to do so based on a prespecified economic criteria, without regard to constraints such as market acceptance and rate impacts.

- *Achievable Potential* is an estimate of the energy savings that would occur if all cost-effective, verifiable, energy-efficient options promoted through utility DSM programs were adopted. Achievable potential excludes efficiency gains that will be achieved through normal market forces and by existing or future standards or codes.

Differences in gas efficiency potential are attributable to differences in physical stock, initial efficiency levels, heating loads, and climate severity among utilities as well as differences in study methods (comprehensiveness as indicated by measures and end uses considered) and assumptions (e.g., criteria used to establish the cost-effectiveness threshold). These results suggest that gas DSM potential is more limited than U.S. electric utilities' DSM potential; similar studies of electric utilities' DSM potential give estimates of between 25-50% of the applicable sector's sales.

This primer reviews key issues involved in designing, implementing, and evaluating gas DSM programs. Themes that are discussed include:

- the match between end-use technologies, customer segments, and program delivery mechanisms in designing DSM programs;
- strategies to minimize rate impacts in the design of DSM programs;
- opportunities for joint electric-gas DSM programs in certain market segments;
- innovative DSM program strategies (e.g., market transformation); and
- the importance of program evaluation.

End-Use Fuel Substitution

High-efficiency gas and electrical equipment can potentially substitute for one another in many applications. Fuel substitution programs can be defined as programs that substitute for energy-using equipment with a competing energy source by promoting or providing an incentive for efficiency improvements associated with the fuel conversion. These programs have been quite controversial, in part because significant tensions exist between the natural gas and electricity sectors of the U.S. economy. The two industries compete for residential and commercial space conditioning, water heating, cooking, and drying equipment markets in many parts of the U.S. The competition between electric and gas utilities has been, and continues to be, profoundly influenced by federal and state regulation. With the advent of IRP, PUCs have encouraged more active interventions in end-use markets by utilities (primarily electric utilities).

For regulators, a central issue is whether the efficient selection of fuels in certain end-use markets by consumers can be improved upon through an IRP planning process that explicitly considers fuel substitution opportunities, or whether current utility marketing practices result in a better social outcome. At a minimum, controversies over fuel substitution policies should result in PUCs reviewing their policies on promotional practices and DSM program implementation (e.g., incentive levels to customers) to ensure that existing utility DSM programs are not introducing undesirable distortions into consumers' fuel choice decisions. The gas industry has raised concerns that electric DSM programs have the effect of encouraging customers to adopt electric technologies when gas options would be more economically efficient.

Proponents of utility-funded fuel substitution programs argue that DSM programs should not be restricted to higher efficiency products using the same fuel but that utilities should identify and promote (if necessary) cost-effective fuel substitution opportunities for their customers as part of their IRP process. Opponents argue that mandatory fuel substitution would, in effect, require one utility to subsidize sales by its competitors at the expense of its remaining customers.

This primer explores the various pros and cons to utility fuel substitution programs and identifies the various policy approaches that are available to state regulators. In addition, technical opportunities for fuel substitution in the residential and commercial sector are described, including electric-to-gas options and gas-to-electric options. In evaluating fuel-switching opportunities, utilities should consider the relative site- and source-energy efficiency of technologies using each fuel, the load shape impacts on each utility, relative gas and electric avoided costs, price volatility and uncertainty of the respective fuels, and environmental impacts and tradeoffs. Arguments that have been raised by proponents and opponents in the fuel substitution debate are reviewed, and case studies of the experiences of eight state PUCs are presented in order to describe alternative regulatory approaches (Vermont, California, Georgia, Wisconsin, Oregon, Maryland, Colorado, and New York). The primer also discusses several policy and programmatic issues that state regulators are likely to confront if they choose to address fuel substitution policies explicitly: economic and other evaluation criteria, cost allocation and responsibility, customer equity issues, and treatment of unregulated fuels.

Financial Aspects of Gas DSM

Significant disincentives may exist under traditional rate regulation that dampen utility enthusiasm for energy efficiency opportunities. These disincentives include failure to recover DSM program costs, negative financial impact on gas utility earnings because of reduced sales, and loss of financial opportunities because the utility may forego more profitable supply-side investments. The primer discusses various strategies that address the financial impacts of gas DSM on utility earnings:

- DSM program cost recovery including timing issues (e.g., general rate cases versus frequent proceedings or deferred accounts) and expensing versus ratebasing;
- net lost revenue adjustment mechanisms, which allow the utility to recover margin lost from customers due to specific DSM programs;
- revenue decoupling mechanisms, which make utilities financially indifferent to short-term changes in sales and essentially guarantee that utilities will recover their authorized nonfuel revenues regardless of sales fluctuations; and

- various types of positive financial incentives for utility shareholders: an incentive rate-of-return, a bounty paid based on specific accomplishments, or shared savings in which the utility keeps a fraction (5-30%) of the net resource value provided by the DSM program.

Various methods to allocate DSM program costs are also examined because many gas consumers are price-sensitive, and competitive impacts can affect LDC profitability.

Conclusion

Although this primer is not intended to resolve major regulatory policy issues, it should contribute to the discussion and development of planning methods that have broad acceptance among regulators and gas utilities.

Introduction

Consensus is growing among federal and state policymakers that natural gas will play a more prominent role in the U.S. energy future. Natural gas is an abundant domestic resource; it can be produced and delivered at prices that appear to be competitive with alternatives whose environmental impacts are often less favorable. Estimates of the recoverable gas resource base continue to increase as a result of technological innovations and production experience. A recent study by the National Petroleum Council (1992) estimated that about 600 trillion cubic feet (Tcf) of gas is recoverable at wellhead prices of $2.50/MMBtu ($1990) or less with advanced technology (see Table 1-1).[1] This represents about 30 years' worth of consumption at current levels. Moreover, the existing transmission and storage system (280,000 miles of gas transmission pipeline and about 8 Tcf of storage capacity) is more than adequate to meet existing firm requirements on an annual and peak-day basis and is sufficient to allow for growth in gas demand in certain regions (see Figure 1-1). The markets for gas are quite diverse: residential customers use gas equipment to provide energy services such as space and water heating, cooking, and drying with gas bills of $500-1000/year; large industrial users or gas-fired power plants consume gas worth tens of millions of dollars per year. The gas industry faces stiff competition in many of these markets from electricity and unregulated, alternative fuels. Thus, the potential for natural gas hinges in part on industry and federal and state regulators helping to ensure that gas is used *efficiently* and that barriers to its efficient use are removed (National Petroleum Council 1992).

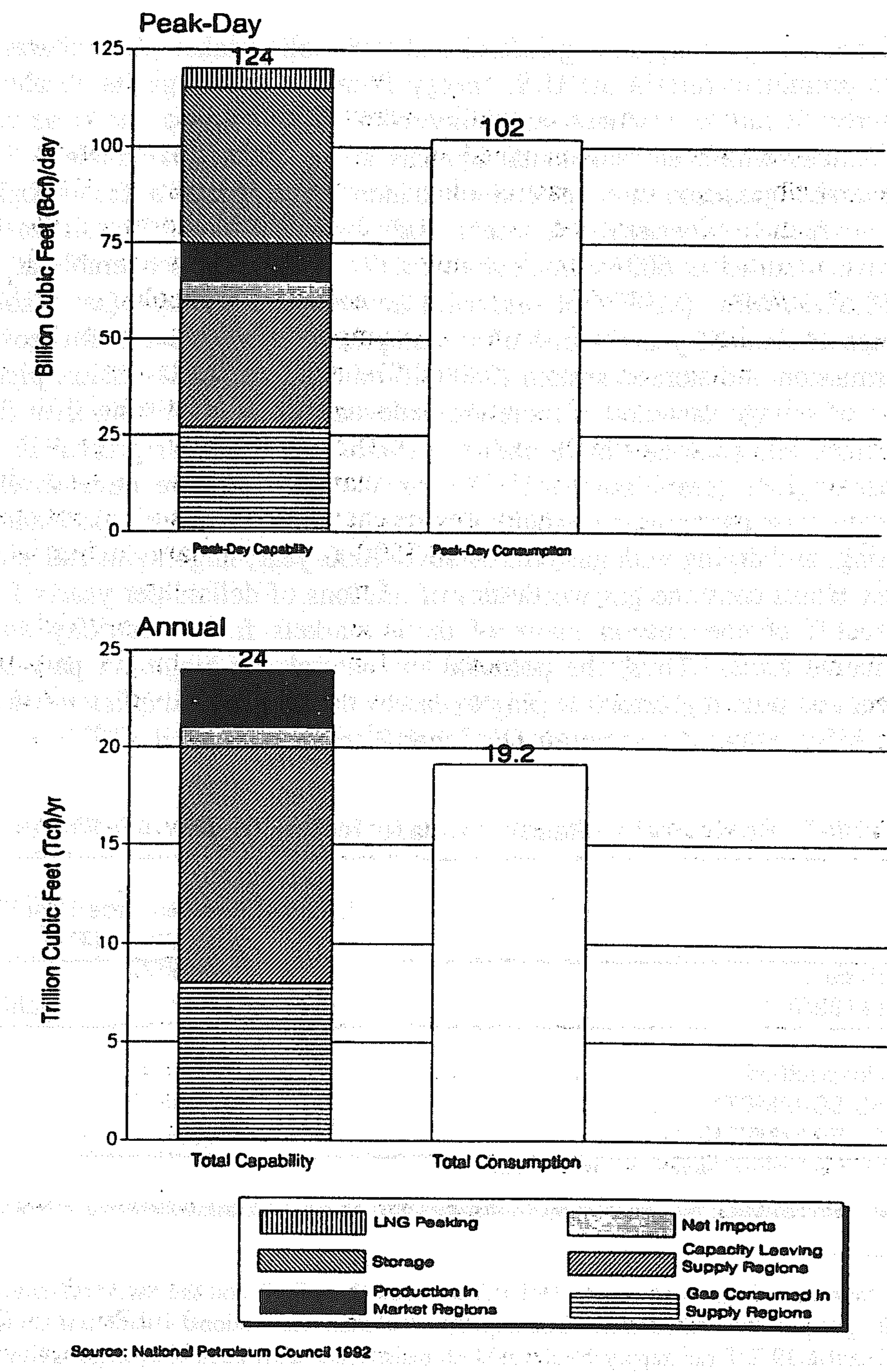
Table 1-1. Recoverable Resource Base for the Lower-48 States

	Recoverable Resource Base Trillion Cubic Feet (Tcf)	
Price ($1990)	1990 Technology	2010 Technology
Unspecified	1,065	1,295
$3.50/MMBTU	600	825
$2.50/MMBTU	400	600

Source: National Petroleum Council 1992

[1] In 1992, annual U.S. gas usage was 19.8 trillion cubic feet (Tcf) and the estimated average wellhead price was $1.84 per thousand cubic feet. One important caution: the National Petroleum Council (NPC) study also concluded that a 19 Tcf gas supply level could be maintained until 2010 if average wellhead prices were $2.50 per million Btu (MMBtu) ($1990), but would decrease to about 10-11 Tcf if wellhead prices only averaged $1.50/MMBtu ($1990). This implies that gas commodity prices would have to increase at 1.8%/year in real terms, compared to estimated 1992 wellhead prices.

Figure 1-1. U.S. Gas Transmission and Storage System: Peak-Day and Annual Capability (1991)



Source: National Petroleum Council 1992

The Energy Policy Act of 1992 (EPACT) includes various provisions that encourage energy efficiency and also promote reliance on competitive forces. EPACT amends the Public Utility Regulatory Policies Act (PURPA) of 1978 by adding two new standards for consideration by state PUCs: (1) use of integrated resource planning by gas local distribution companies (LDCs) and (2) encouragement of investments in energy efficiency and load-shifting measures by ensuring that these investments are at least as profitable (taking into account the income lost from reduced sales under such programs) as prudent supply-side investments. Each state commission is required to provide public notice, conduct a hearing on the appropriateness of these new standards, and make a determination about whether or not to adopt each standard by October 23, 1994.[2]

Developments in gas wellhead markets and changes in regulatory policy at the Federal Energy Regulatory Commission (FERC) have also created new challenges and opportunities for gas LDCs and their state regulators. State regulators, who oversee a distribution segment that still has features of a natural monopoly, have to respond to and manage the competitive forces that have resulted from gas industry restructuring. Increased reliance on market forces does not necessarily mean that state regulation is outmoded but rather that flexibility and forward-looking planning processes become increasingly important as the number and type of utility supply choices increase.

A number of state public utility commissions (PUCs) have taken an interest in integrated resource planning (IRP) for gas utilities. IRP involves a process used by utilities to assess a comprehensive set of supply- and demand-side options based upon consistent planning assumptions in order to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost.[3] Gas IRP is in its formative stages, and a variety of regulatory approaches are being considered and tested by state PUCs. However, a survey of regulatory staff conducted for the National Association of Utility Commissioners (NARUC) revealed that limited information and lack of consensus on various IRP-related technical and policy issues has hindered progress (Goldman and Hopkins 1991). NARUC concluded that additional analysis of selected issues would be useful, particularly if it drew on the initial experiences of PUCs and gas utilities that have implemented gas IRP.

[2] A more detailed discussion of relevant EPACT provisions for state PUCs can be found in NRRI (1993).

[3] For those readers who want additional information on issues associated with developing IRP for electric utilities, refer to Krause and Eto (1988), Hirst et al. (1991), and Hirst (1992b).

1.1 Overview of the Gas IRP Primer

NARUC asked Lawrence Berkeley Laboratory (LBL) to develop a primer on gas integrated resource planning. Our primary focus is on technical and analytical issues that gas LDCs and state regulators are likely to confront in attempting to achieve IRP goals and objectives. The intent of this primer is to introduce commissioners and regulatory and gas LDC staff to the full scope of IRP-related topics by highlighting major issues, synthesizing available information, and identifying additional sources for those who want more information. Because gas IRP is a relatively new phenomenon and there is a range of ideas about practices and policies, many issues in this primer are presented through discussions of alternative approaches and their implications. Many issues such as fuel substitution and financial aspects of gas demand-side management (DSM) are quite controversial from a policy standpoint.

Chapters 2-9 of this primer discuss the following topics:

- Chapter 2 reviews recent developments in the gas industry and their implications for gas LDCs and state regulators. The chapter also examines similarities and differences between the electric and gas utility industries in order to provide a context for understanding the challenges involved in creatively adapting IRP to the conditions faced by gas utilities. Principal goals and objectives of IRP are identified and the benefits and potential drawbacks of gas IRP regulatory processes are discussed.

- Chapter 3 describes the major analytic steps in developing a gas integrated resource plan and provides an overview of current IRP models and modeling tools.

- Chapter 4 reviews gas supply and capacity planning and focuses on issues that assume increased importance for LDCs in an IRP context (e.g., reliability planning criteria) and/or increased prominence in the post-636 era.

- Chapter 5 describes various methods used by gas utilities to estimate gas avoided costs and analyzes the strengths and weaknesses of alternative approaches. The technical nuances and key uncertainties presented in this chapter related to estimating gas avoided costs are designed to help regulatory and utility staff in their assessments of the potential economic benefits of various types of gas DSM programs.

- Chapter 6 discusses the various economic perspectives from which gas DSM resources can be evaluated and examines issues that arise in the application of benefit-cost tests for gas LDCs.

- Chapter 7 examines the technical opportunities of selected gas efficiency and fuel substitution options and strategies and discusses how utilities can package these measures to acquire DSM resources. The goals of this chapter are to convey the relative magnitudes and economics of the technical opportunities for the efficient use of gas as well as insights gained from the experiences of leading gas and electric utilities on effective ways to market and implement DSM options.

- Chapter 8 reviews policy issues involved with end-use fuel substitution and discusses various regulatory approaches.

- Chapter 9 discusses financial aspects of gas DSM programs, including program cost recovery and allocation methods; mechanisms such as decoupling or lost revenue adjustments, which can be used to overcome disincentives to utility DSM investments; and various bonus or incentive mechanisms.

Gas Resource Planning: Need for IRP

2.1 Overview

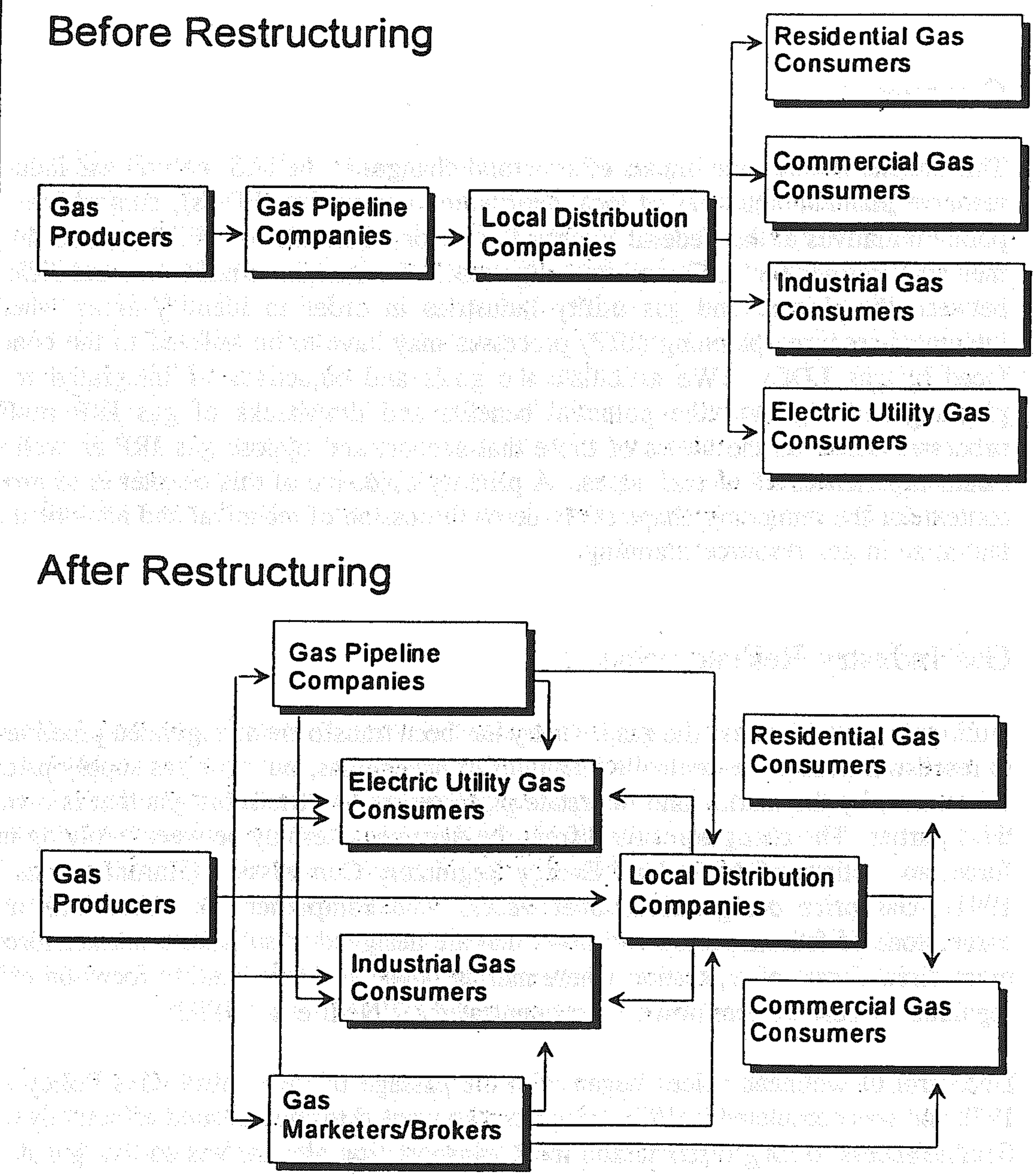
This chapter reviews the impact of structural changes in the U.S. natural gas industry on resource planning activities of local distribution companies (LDCs), summarizes recent policy initiatives at the Federal Energy Regulatory Commission (FERC), and discusses their implications for LDCs and state regulators. We examine similarities and differences between the electric and gas utility industries in order to identify areas where gas integrated resource planning (IRP) processes may have to be tailored to the conditions faced by gas LDCs. We articulate the goals and objectives of integrated resource planning and highlight the potential benefits and drawbacks of gas IRP regulatory processes based on the views of those that support and oppose gas IRP as well as the initial experiences of several states. A primary objective of this chapter is to provide a context for the remaining chapters' in-depth discussion of technical and analytical issues that arise in gas resource planning.

2.2 Gas Industry Restructuring

During the past 15 years, the gas industry has been transformed; regulated pipelines used to resell wellhead price-controlled supplies of natural gas, but now gas supply prices are determined by the market and interstate pipelines mainly transport gas that is owned by third parties. The changes resulted from the dynamic interplay between evolving market forces and actions of the Federal Energy Regulatory Commission (Harunuzzaman et al. 1991). Gas price deregulation, open access, and comprehensive unbundling are the cornerstone of federal policy initiatives that are designed to substitute market forces for more direct forms of regulation where market power is diffuse and to focus on efficient regulation where market power is concentrated (O'Neill et al. 1992).

Decontrol of wellhead prices began with the passage of the Natural Gas Policy Act of 1978 and was completed in 1993. Buyers who wanted to shop around effectively needed flexible access to long-distance and local transportation alternatives so that gas delivery could be arranged from decontrolled upstream supply options. This need led to the separation of transport service from commodity sales. The unbundling of pipeline transportation by FERC began in earnest with Special Marketing Programs and has evolved in successive FERC Orders (i.e., 436, 500, and 636) in response to legal decisions and concerns raised by various parties (see Appendix A for a summary of FERC Orders and related legal decisions). Although the transition to a more competitive

Figure 2-1. Evolution of Gas Marketing



Source: Arthur Andersen & Company, and Cambridge Energy Research Associates 1988 industry has been difficult and painful for industry participants (e.g., take-or-pay problems), these regulatory reforms have contributed significantly to lower gas costs and innovative and expanded gas service choices (Makholm 1993). Industry restructuring has resulted in significant changes in gas marketing with the entry of gas marketers/brokers and producers selling gas directly to end users via spot markets and various contractual arrangements (see Figure 2-1). By 1991, nearly 80% of all gas was sold under transportation arrangements rather than as bundled pipeline sales.

2.2.1 FERC Order 636

Order 636 is the latest gas industry restructuring effort by the FERC; it focused on several broad issues (see Table 2-1): pipeline gas merchant services; access to available transportation and storage capacity; transportation terms, conditions, and services; and ratemaking issues (see Gaske 1993 for an excellent summary of FERC 636 and its implications). Interstate gas pipelines have traditionally combined merchant and transportation functions in linking upstream gas producers with downstream markets. This bundling of services resulted in part from the conditions associated with licensing and financing pipeline construction.[1] However, various parties (e.g., producers and marketers) made convincing arguments that pipeline gas often received priority transportation service and that third parties could not, under the existing arrangements, compete on an equal basis with pipeline merchant services. Order 636 required pipelines to completely unbundle merchant and transportation services, which meant that a pipeline company's firm sales customers were converted into firm transportation customers and are now responsible for making their own gas purchases. In effect, the firm sales service agreement served as a contractual backstop for LDCs and other pipeline customers in the event of a shortfall in supplies. With the elimination of the traditional bundled sales service, all gas must be aggregated, managed, and transported separately. This is likely to lead to a situation in which the responsibility for assuring supply reliability will be dispersed among multiple entities (LDCs, interstate pipelines, and gas merchants) (CERA 1992).

Order 636 also includes a capacity release mechanism, which allows a holder of pipeline capacity to sell or assign unused capacity through a transaction controlled by the pipeline. Parties that place the highest value on firm capacity will have an opportunity to obtain that capacity through a bidding process. Pipelines are also required to offer a "no-

[1] Both regulators and lenders wanted assurances that pipelines would have sufficient supplies and demand so that gas throughput was adequate to assure that major capital investments were economic. Long-term gas contracts with suppliers and long-term sales contracts with LDCs were the means to provide these assurances.

Table 2-1. Major Provisions of Order 636

Element	Description
Unbundling of pipeline services	• Effectively mandates that interstate pipelines separate the buying and selling of gas from the transport of gas • Pipelines are also required to provide customers with open access to storage and offer these services separately from all other services
"Open access"	• Pipeline companies must provide "open access" transportation that is equal in quality for all gas supplies, whether purchased from the pipeline or not
"No-notice" service	• Pipelines currently offering bundled city-gate firm sales service must provide a quick response, backup transportation service for the benefit of competing shippers (i.e., advance notice by the shipper is not required)
Capacity release	• Authorizes a reallocation mechanism so that firm shippers can release unwanted capacity to those wanting it by holding an auction, with results turned over to the pipeline to be posted on an electronic bulletin board
Rate design	• Requires a "straight-fixed variable" rate design (see Figure 2-2), unless other agreements are negotiated with the customers • Pipelines are required to use various ratemaking techniques to mitigate "significant" changes in revenue responsibility to any customer class • Pipeline companies must phase in rate increases over a four-year period if revenue responsibility changes exceed 10% for any customer class
Transition costs	• Pipelines are given the opportunity to recover 100% of "transition costs" created by new rules (e.g., stranded investment costs)

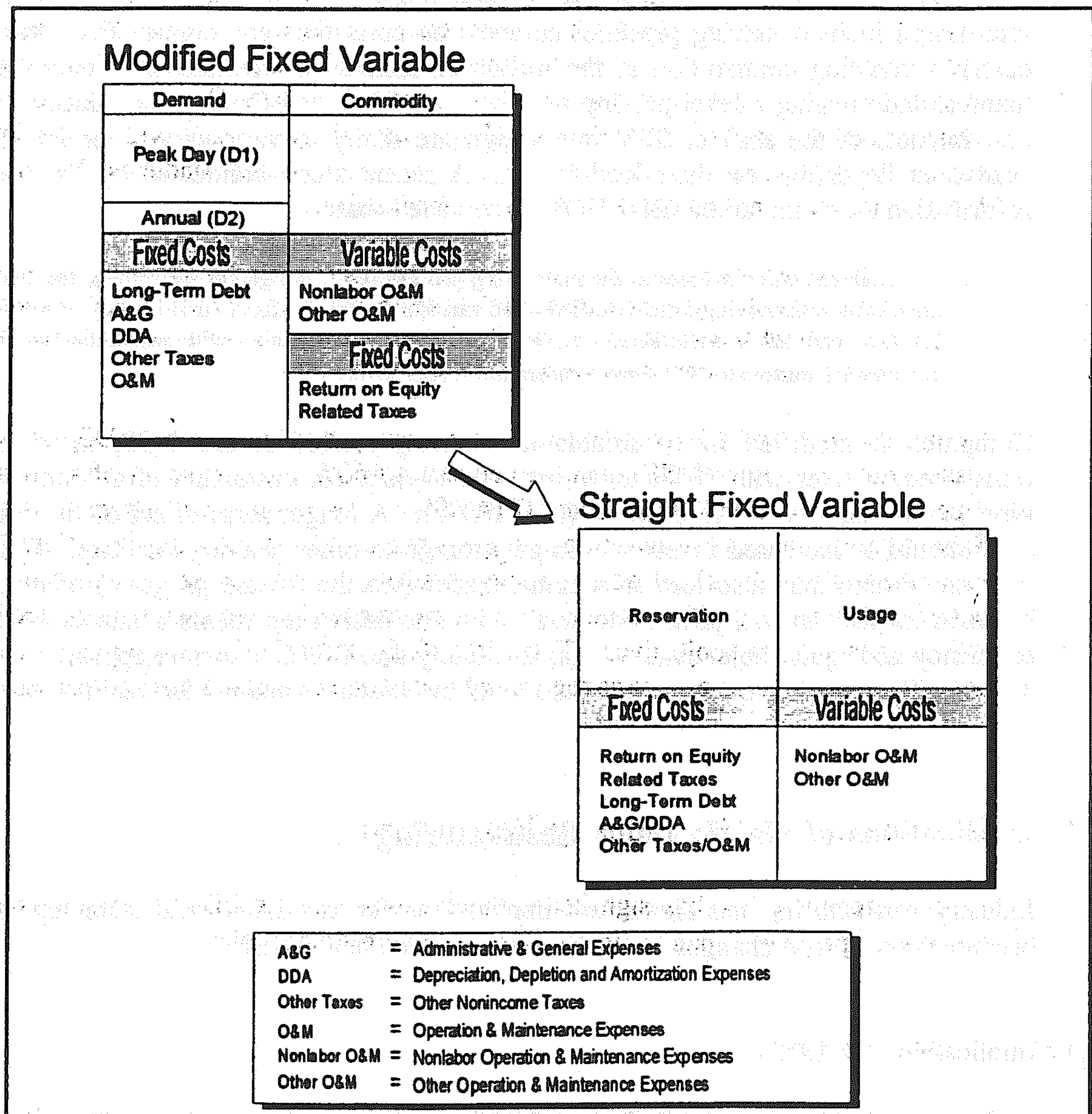
Sources: EIA 1993c, Cambridge Energy Research Associates 1992

notice" service, which is FERC's attempt to assure maximum reliability in a deregulated market.[2]

In terms of ratemaking issues, Order 636 also requires that all fixed costs associated with pipeline transportation service be recovered in a capacity reservation fee rather than the current modified fixed variable system, which allocates certain fixed costs to the

[2] "No-notice" service is technically categorized as firm transportation service but essentially includes a provision of gas supply under emergency circumstances to meet firm peak loads.

Figure 2-2. Pipeline Rate Design Changes



Source: Energy Information Administration (EIA) 1993

volumetric charge (see Figure 2-2).[3] Prior to Order 636, FERC maintained that it was important for pipelines to be "at risk" for recovery of a portion of their fixed costs in

[3] The reservation fee is charged to pipeline transportation customers on a monthly basis to reserve daily capacity, based on their requirements during peak periods.

order to provide a cost minimization incentive, which resulted in the Modified Fixed Variable rate design. FERC's reasons for switching to a "straight-fixed variable" (SFV) rate design include: having pipelines compete on costs they can control (i.e., variable costs), promoting competition at the wellhead, facilitating creation of a national gas market, and creating a level playing field between U.S. and Canadian producers. The cost impacts of the shift to SFV rate design are likely to vary widely for individual customers depending on their load factor. A recent study conducted by the Energy Information Administration (EIA 1993c) concluded that:

> ...absent other changes in the ratemaking process (e.g., mitigation strategies), the cost shift associated with moving from modified fixed variable to straight-fixed variable may be very large for low load factor customers, i.e., local distribution companies with residential and small commercial customers that have temperature-sensitive loads.[4]

Compared to modified fixed variable rates that prevailed before 1990, increases in transportation rates with SFV ranged between 40-60% for customers of a "composite" pipeline that had a 35% load factor (EIA 1993c). A longer term effect of the shift to SFV should be increased investment in gas storage or other peaking facilities. FERC's new rate design may also lead to seasonal trades (via the release program) of capacity between on-peak and off-peak customers. Any rate design represents a balance between efficiency and equity objectives. Thus, it is likely that FERC's current approach to rate design will continue to evolve as regulatory policy objectives and market realities change.

2.3 Implications of Gas Industry Restructuring

Industry restructuring has significant implications for gas LDCs and state regulators because of profound changes in the business environment of LDCs.

2.3.1 Implications for LDCs

In the past, pipelines and LDCs operated their systems together on the principle of city-gate service that bundled commodity with transportation services. An interstate pipelines' sales service insured adequate supply and capacity were available to deliver promised quantities of gas in a timely fashion, and distribution of gas was a main role of LDCs. In the post-636 era, these two industry segments must operate their systems

[4] EIA developed a composite pipeline based on six large interstate pipeline companies serving the East Coast.

together under different principles. Securing natural gas and the capacity to deliver it has become the principle mission of LDCs. With complete unbundling, LDCs have become active managers of their own gas supply portfolios, choosing among different suppliers and developing the proper mix of short- and long-term contracts. LDCs now face an expanded array of options for securing gas supplies and transportation as well as increased competition from alternative fuels and "bypass" of the LDC by its customers that can connect directly to an interstate pipeline.

In the post-636 era, the most basic strategic choice that an LDC must decide is whether to:

- develop its own gas supply portfolio, which will involve aggregating, seasonally shaping, and firming through direct purchases at upstream market centers; and bundle these supplies with firm transmission and storage rights, or

- contract out portfolio aggregation and rebundling functions to other parties (e.g., producers, pipeline affiliates, or independent marketers) that offer a firm, seasonally shaped supply at the utility's city gate (Tussing 1993).

These alternatives represent the extremes of possible approaches, and in practice many intermediate paths will most likely evolve. Regardless of the approach that LDCs take to managing their increased supply responsibilities in the post-636 era, they face an increased possibility that their actions will be reviewed by state regulators.[5] Thus, an LDC's strategic choices will be strongly influenced by state PUC preferences, especially the rules and guidelines adopted to monitor gas costs and service reliability.

The move to SFV rates and the resulting higher reservation fees for peak-day capacity will also encourage LDCs to closely examine and rationalize their capacity holdings and look for alternative and more inexpensive ways to obtain the same level of service. Various peak-shaving DSM alternatives are likely to be more attractive under SFV rate design.

[5] FERC does not plan to approve the price of commodity gas sold by pipelines restructured by Order 636. Thus, more responsibility is placed at the state level for oversight of reliability.

2.3.2 Implications for PUCs

Historically, in regulating gas LDCs, many state PUCs have focused on safety, reliability, and prices offered for natural gas services. However, the new supply management responsibilities of gas LDCs may create a need for broadened regulatory oversight of the way LDCs purchase gas supply. Current procedures typically used to monitor gas supply costs and reliability (e.g., purchased gas adjustments, prudence reviews, least-cost purchasing requirements, and occasional management audits) may have to be adapted to respond to the changes in industry structure and gas supply markets.

PUCs will also have to decide the extent to which they want to extend FERC policies and goals for pipelines to the regulation of gas LDCs. This will involve decisions about the degree to which LDCs and intrastate pipeline services should be unbundled, the benefits of and need for franchise protection for LDC services to certain market segments, and alternatives to traditional service obligations (National Petroleum Council 1992). At a minimum, state commissions and gas LDCs will continue trends which distinguish among services offered, extent of regulation, and implied obligation to serve among captive core customers vs. large-volume, noncore customers. PUCs have a continuing responsibility, however, to insure that core customers, with limited market power, are provided reliable service at reasonable rates and that deregulated activities are conducted at arm's length from a utility's regulated business in order to minimize opportunities for cross-subsidization and self-dealing. Regulation of the gas distribution sector will be required as long as uncontestable "natural monopoly" conditions exist.[6]

[6] "Natural monopoly" arises in an unregulated market when a single firm dominates the market by virtue of economies of large scale (size) or wide scope (across functions or products), which give that firm a cost advantage over any combination of multiple, smaller firms. For a gas LDC, "natural monopoly" conditions exist if its system is capable of carrying incremental volumes to or from a given point at a substantially lower expense than any "stand-alone" or "bypass" facility. Even where monopoly conditions exist, firms can exert market power only if the market is "uncontestable," which means that new entrants can't credibly threaten to enter on an efficient scale (Jaffe and Kalt 1993).

Table 2-2. Differences Between Gas and Electric Utility Industries

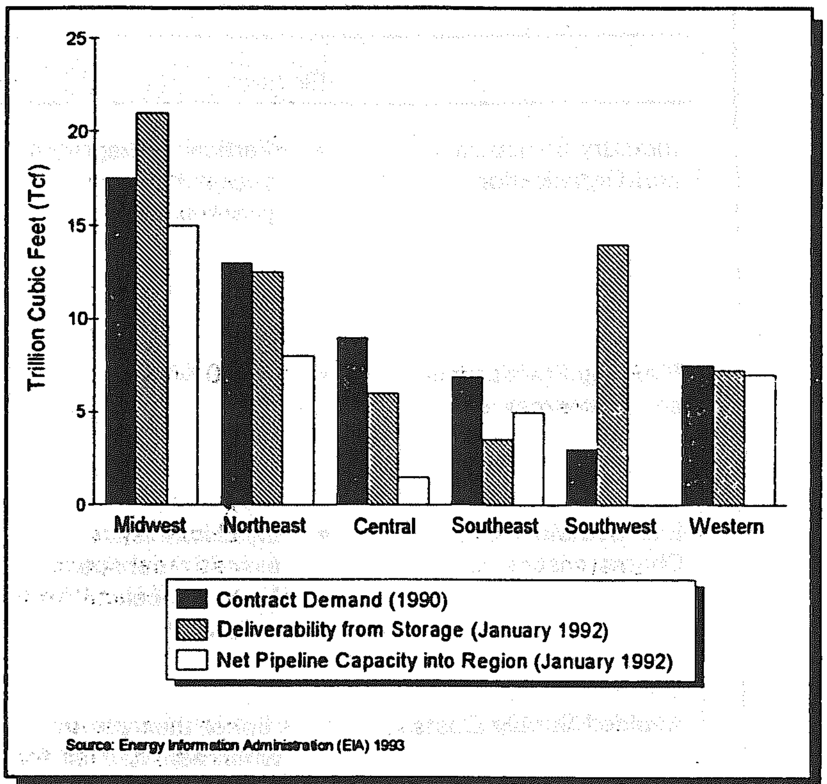
	Electric	Gas
Industry Structure and Organization	• Vertically-integrated, except for new generation	• Separate firms handle production, Transmission & Distribution (T&D) • Prominence of storage
Planning Practices and Resources	• 10-30 yrs	• 1-10 yrs • Less information on DSM savings and costs
End-Use Market Characteristics	• Electricity is an essential service • More difficult to fuel switch	• Gas service is optional • Core and noncore markets
Avoided Supply Costs	• Higher then gas when adjusted for equivalent energy services provided • Methods reasonably well developed	• Methods still evolving
Access to Retail Utility Service	• Virtually universal	• Need for review of line extension policies and tariffs

2.4 Similarities and Differences Between Gas and Electric Utility Industries

Similarities and differences between the gas and electric utility industries must also be considered by state PUCs in developing regulatory policies and expectations for gas utilities. Table 2-2 highlights differences in five major areas: industry structure and operation, planning practices and resources, end-use market characteristics, avoided supply costs, and access to retail utility service.

2.4.1 Industry Structure and Operational Characteristics

Figure 2-3. Contract Demand, Peak-Day Storage Deliverability and Pipeline Capacity by Region



The most pronounced structural difference between the two industries is that the electric industry is highly integrated vertically. Vertical integration allows electric utilities a greater opportunity to provide a bundled good and increased pricing flexibility compared to a local gas distribution company. Gas is typically produced, transported, and distributed by three unaffiliated companies while most electric power is still generated, transmitted, and distributed by a single entity (O'Neill et al. 1992). The emergence of independent power producers and the provisions of the Energy Policy Act (e.g., creation of Exempt Wholesale Generators, transmission access) will lessen this distinction between the two industries in the future. The electric industry is likely to remain integrated for the near-term, although market forces and federal legislation and regulation of the wholesale electricity market pose increasing challenges to the vertically integrated electric utility.

Each industry has three major segments: production/generation, transmission, and distribution. Transmission and distribution (T&D) systems in both industries are characterized by substantial economies of scale and of coordination. In the distribution segment, the economies are so great that it is almost always considered a natural monopoly. The availability and use of storage differ significantly between the two industries. Storage plays a much more prominent role in the natural gas industry, often providing an attractive alternative to pipeline capacity (see Figure 2-3). Gas can be stored rather easily in both gaseous and liquid states as line pack, in underground caverns, in depleted oil and gas reservoirs, and in liquified natural gas (LNG) plants. In the U.S., gas storage meets about 30% of U.S. peak-day demands while storage is too expensive for general use by an electric utility (EIA 1993c). For IRP, widespread availability of gas storage on a daily and seasonal basis has important impacts on the analysis of gas system marginal costs.

Differences in the degree of integration of the transmission and distribution networks of utilities in the two industries also affect reliability planning. Although gas systems are interconnected through pipeline systems, LDCs are often not extensively interconnected with other LDCs and thus each tends to plan for its own reliability. Electric utilities are interconnected with other systems through a grid and utilize this extensive transmission and distribution network to meet their loads in cases of emergencies. Reliability planning is typically done on a regional basis as individual electric utilities pool their requirements.

There is also a substantial mismatch between the time constants that govern operation of electric power systems and gas pipeline delivery system. These differences derive from the fundamental fact that electricity moves at almost the speed of light while gas is pumped through pipelines at about 15-20 miles per hour. The combination of shorter time to react to changing conditions, lack of storage, and constraints on system flow controls has meant that historically the electric grid was more automated and closely monitored (O'Neill et al. 1992). Because of the concern over public health, safety, and economic consequences of system gas service being interrupted during severe cold weather, gas operators have historically placed the highest priority on system reliability for residential and commercial customers who do not have short-term alternatives. Planned gas outages are possible in many gas systems for some individual large customers because these customers typically have ready access to substitute fuels, and gas utilities have a long tradition of using interruptible contracts to alleviate peak-period demands (Samsa and Hederman 1992).

Regional differences in resource endowments are important in both industries but are particularly striking in the gas industry as exemplified by distinctions between producing and consuming states. Most natural gas is produced in just five states and most gas transactions include long-haul interstate transmission.[7] In contrast, most electric generation is sited relatively closer to load centers, and most of the electric grid was originally built to connect major markets for better reliability and short-term coordination trades (O'Neill et al. 1992).

[7] The major producing states are Texas, Louisiana, Oklahoma, New Mexico, and Kansas.

2.4.2 Planning Practices and Resources

The focus of electric utility investment decisions and regulatory oversight has been on large capital projects to build new generation or transmission facilities. Historically, electric utility planners are accustomed to long-range planning for 10 to 30 year period because of the long lead times required to construct baseload power plants and the time horizon over which alternative resource options must be compared. In contrast, for most gas LDCs, fuel supply procurement and distribution system expansion rather than facility planning has been the major focus (Lerner and Piessens 1992; Samsa and Hederman 1992).

Gas supply planners must now evaluate an expanding array of supply options, and this trend is likely to accelerate in the post-636 era. However, the scale, capital requirements, and lead times for decisions on new gas facilities are often quite different than those involved in electric resource planning. For gas utilities whose major capital expenditures are related to local transmission and distribution investments, the share of bulk transmission and storage investments is small relative to investments in generation capacity and transmission in the electric industry. Lead times are short (one to three years) for these gas system investments. In today's gas supply market, three to five years is considered long term for a gas utility resource planner. Moreover, contracts of varying lengths expire at different times, so fuel supply procurement takes place almost continuously. Contracts and/or investments for capacity (e.g., acquisition of pipeline capacity, storage, and/or peaking service capacity) often entail longer time frames (e.g., 10 years). In contrast to the electric industry, among the resources being evaluated by a gas utility in an IRP plan, gas efficiency programs may require the longest lead and resource development time.[8]

At the present time, many gas LDCs have less detailed information than electric utilities do about the characteristics and performance of customers' equipment, appliance saturations, and end-use consumption. LDCs also have more limited information on the actual costs and savings of DSM resources in contrast to electric utilities. These issues affect the time frame in which gas LDCs can be expected to design and implement large-scale DSM programs.

[8] Some DSM options have economic lifetimes of 10 to 20 years (e.g., high efficiency furnaces). Planning horizons may be extended to match the life cycle of DSM applications with supply-side opportunities. Because of uncertainties in future gas commodity prices, sensitivity analysis using alternate gas price escalation rates should be conducted.

2.4.3 End-Use Market Structure and Characteristics

End-use retail markets in the natural gas and electricity industries are typically segmented along similar lines (i.e., residential, commercial, and industrial users). Product differentiation is increasing in both industries and currently involves distinctions based on reliability of service (firm vs. interruptible), usage during various seasons, and time of day (for electricity).[9] There is a general consensus that demand is relatively inelastic for most residential and commercial customers while industrial customers typically have elastic demands. Residential customers in both industries have limited options for substitution in response to short-term price hikes while large industrial customers have more choices.

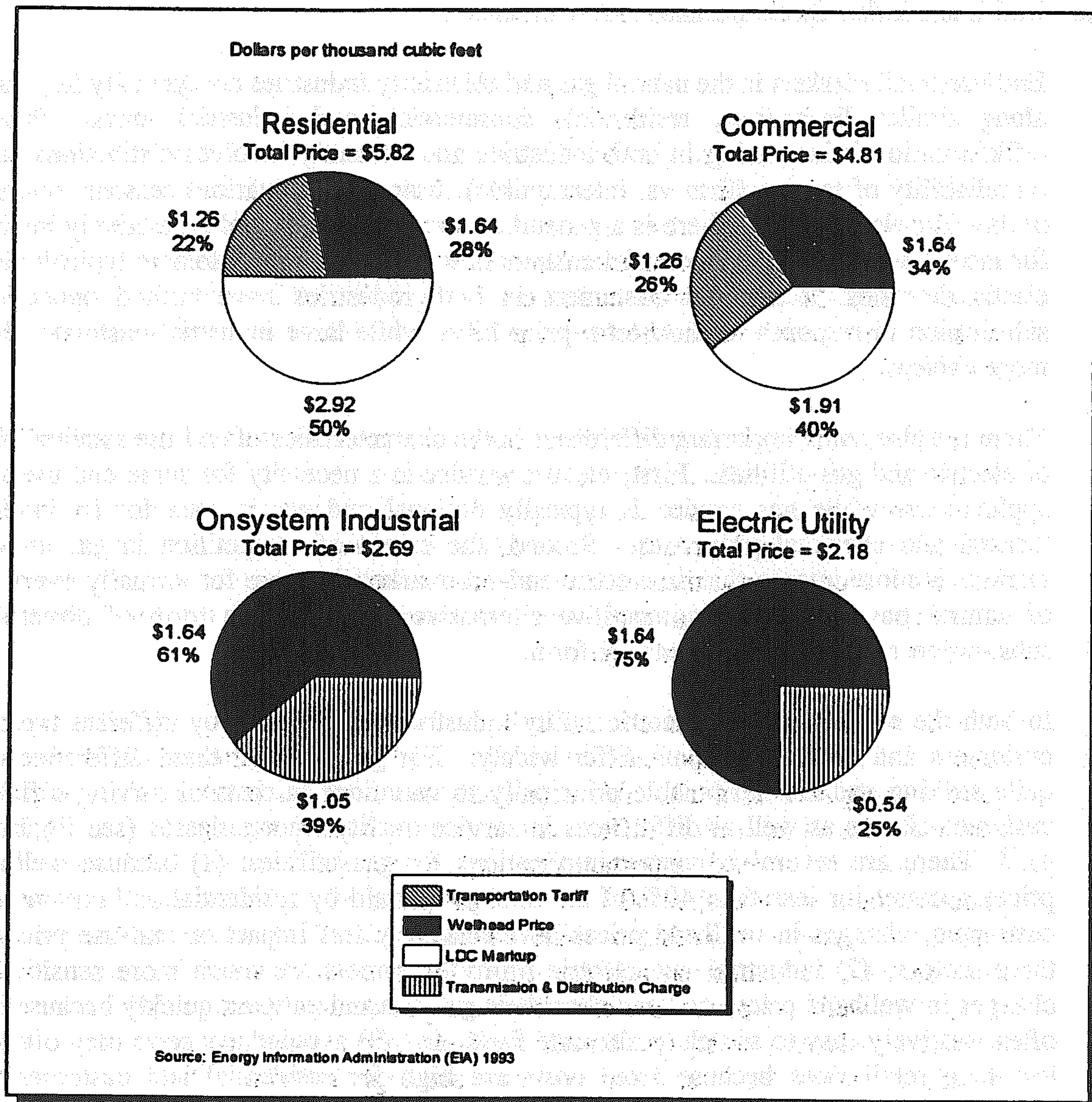
There are also some important differences in the characteristics of end-use retail markets of electric and gas utilities. First, electric service is a necessity for some end uses and applications, while gas service is typically optional and gas is used for its inherent thermal and chemical properties. Second, the extent of competition in gas end-use markets is more intense than in electric end-use markets because for virtually every use of natural gas, there is a competitive alternative, either in the form of direct fuel substitution or an alternative energy form.

In both the natural gas and electric utility industries, prices paid by different types of customers and cost components differ widely. For gas utilities, these differences are quite striking and are attributable principally to variations in costs of serving different customer classes as well as differences in service quality among classes (see Figure 2-4).[10] There are several important implications for gas utilities: (1) because wellhead prices account for less than 40% of the total price paid by residential and commercial customers, changes in wellhead prices have relatively less impact on end-use prices in these sectors, (2) industrial and electric utility customers are much more sensitive to changes in wellhead prices and can alter their gas demand patterns quickly because it is often relatively easy to switch to alternate fuels, and (3) avoided gas costs may often be less than retail rates because fixed costs are high for residential and customer gas customers and because local distribution and customer-related costs are typically not avoidable.

[9] Ultimately, utilities in both industries may end up providing bundled service to small customers and unbundled service for large customers with competitive alternatives.

[10] In Figure 2-4, "wellhead price" is the commodity cost of gas; "transportation tariffs" represent costs paid by the LDC to interstate pipelines from producing area to city gate; and "LDC markup" is the amount charged by the utility to cover distribution, storage, and other customer-related expenses which recover costs of providing end-user service. Note that onsystem industrial sales account for only about 33% of total gas throughput in the industrial sector; offsystem sales have become predominant (EIA 1993c).

Figure 2-4. Components of End-Use Prices by Sector (1991)



Source: Energy Information Administration (EIA) 1993

2.4.4 Avoided Costs

Avoided electricity costs often tend to be higher than gas avoided costs when adjusted for equivalent energy service provided. However, it is not that easy to directly compare avoided electric and gas costs because of differences in costing methods and conventions, end-use conversion efficiencies, and operational characteristics of electric and gas utilities (Samsa and Hederman 1992). Despite that caveat, avoided gas costs that are lower than avoided electric costs for DSM suggest that: (1) it will be relatively more difficult for gas energy efficiency programs to pass cost-effectiveness tests compared to electric DSM programs, and (2) all else being equal, net DSM program benefits might be smaller (Lerner and Piessens 1992).

2.4.5 Access to Retail Utility Service

Electric utility retail service is more widely available in the U.S. than gas service. The gas industry's access to some end-use markets is hampered somewhat because gas service is not universally available. In addition, some PUCs do not have uniform line extension policies for electric and gas retail service. Several PUCs are in the midst of reviewing their policies and tariffs for gas line extensions and are examining such questions as comparability of treatment among electric and gas utilities and the extent to which growth is in the interests of existing gas ratepayers.[11]

2.5 Alternative Regulatory Approaches

Many PUCs and gas LDCs are rethinking the role of state regulation in light of the massive structural changes occurring in the gas industry (see Public Service Commission of Wisconsin (PSCW), 1993). In this section, we describe briefly a range of generic approaches as background to a more detailed discussion of the potential benefits and drawbacks of integrated resource planning regulatory processes. Table 2-3 summarizes alternative regulatory approaches and highlights the regulatory forums and elements which would be involved in overseeing the various activities of gas LDCs (e.g., gas supply oversight, treatment of capacity and facility investments, and role of DSM).

Option A represents the status quo in the majority of states. Regulatory processes include periodic rate cases in which rates are set, purchased gas adjustment (PGA) proceedings for review and recovery of gas supply costs, and certificate of public convenience and necessity (CPCN) proceedings to approve any gas LDC's application for major facility investments. PUCs rely primarily on retrospective, after-the-fact prudence reviews of gas LDC purchase decisions although several state PUCs require utilities to file gas supply plans in advance of purchases.[12] DSM options, to the extent

[11] Some PUCs use a "net benefits to existing ratepayer" test to determine whether line extensions and other growth strategies should be allowed. This test demonstrates whether the gas utility could provide the same level of energy service to existing ratepayers at the same or lower cost while adopting the growth strategy.

[12] A 1991 NARUC survey (Goldman and Hokpins 1991) found that 39 states conduct prudence reviews of gas purchases, of which 15 states review purchases annually or on a contract by contract basis. Six PUCs (Alabama, California, Massachusetts, Nevada, Oregon, and Rhode Island) also require gas LDCs to file gas

Table 2-3. Alternative Regulatory Approaches

Approaches	Elements
Option A (Status Quo)	• Rate case • PGA proceedings or gas supply plan review • CPCN for large ratebased facilities
Option B (Long-Range DSM Planning)	• Rate case and PGA • CPCN • Long-range DSM plan
Option C (IRP Rules)	• Rate case • PGA (decisional prudence only) • Utility develops IRP plan; PUC review • Review of supply portfolio mix
Option D (IRP Rules/PUC Approval)	• Rate case • PGA (decisional prudence only) • PUC approves IRP plan • PUC approves supply portfolio mix
Option E (Incentive Regulation)	• Eliminate PGA, retain PGA partially with true-up, or use benchmark indices • Initial rate case, then long lag
Option F (Partial Deregulation)	• No mandate for LDC DSM • Retail gas merchant industry competes with or supplants the LDC's merchant function • Eliminate PGA and PUC review for noncore customers • Rate regulation of transportation rates for LDCs continues

they are considered at all, are typically evaluated as part of a gas LDC's rate case.

supply plans in advance of purchases.

There is significant disagreement about the degree to which the status quo regulatory approach is appropriate in light of gas industry restructuring. Critics argue that traditional regulatory review processes may be too cumbersome, tend to create regulatory risk without necessarily protecting ratepayer interests, and create incentives for utilities to minimize short-run costs rather than looking at long-run cost minimization, rate stability, and reliability (Heintz 1993; Jensen 1993).

In order to encourage LDCs to consider demand-side options more systematically as strategies, a number of PUCs have required their gas LDCs to file long-range DSM or conservation plans.[13] These plans typically include short-term DSM program implementation activities as well (Option B). One rationale for this approach is that PUCs want to encourage gas LDCs to adopt some basic objectives of integrated resource planning. These goals include consideration of both supply- and demand-side options, and establishing criteria for evaluating the economics of gas DSM options. This approach attempts to develop some of the "building blocks" of IRP without requiring gas LDCs to file formal integrated resource plans, which would involve detailed analysis of existing and proposed supply-side options. In several cases, PUCs that require long-range DSM plans are also considering major changes in regulatory oversight of LDC gas purchasing, but are using separate regulatory forums from those used for DSM.

Several PUCs have established rules requiring gas LDCs to file integrated resource plans in addition to meeting requirements of existing regulatory proceedings. IRP requirements and procedures vary significantly among states, and regulatory treatment of a utility's filed plan is a critical difference. Some PUCs review, but do not approve, a utility's IRP plan; we call this approach Option C. The review process typically involves hearings or workshops intended to solicit comments from interested parties and regulatory staff on key elements of the utility's plan (e.g., the utility's supply and capacity portfolio, the mix of supply- and demand-side resources). The PUC might then comment on the utility's plan, offering suggestions for modification, but would not approve the utility's IRP plan.

As an alternative procedure, a PUC could formally approve an integrated resource plan for a gas LDC after public hearings, which might result in modifications to the utility's original plan (Option D). Under Option D, the PUC's review of gas supply planning issues might include preapproval of an LDCs supply portfolio mix. For example, Jaffe and Kalt (1993) have suggested that gas utilities propose preferred portfolio strategies for gas procurement as part of an IRP process. Based on the evidence presented by the utility and the PUC's policy goals, the commission would determine and, in effect, preapprove the general composition of the utility's acquisition portfolio (i.e., the relative

[13] A gas DSM plan would include all load shape objectives while a conservation plan would be limited to strategic conservation and possibly peak clipping load shape objectives.

mix of long-term and short-term contracts). Utilities would then use competitive bidding processes to acquire resources in their portfolio categories. The effectiveness of these efforts would be subject to regulatory review, but purchasing practices consistent with the approved portfolio would be presumed reasonable (Jaffe and Kalt 1993). Like Option C, Option D would include audits of purchase practices and monitoring of results as well as approval of exceptions to plans. In both Options C and D, LDCs and regulators share varying degrees of responsibility for the consequences of major resource decisions. Compared to other approaches, a PUC-approved plan (Option D) minimizes the risks of cost recovery and the likelihood of a prudence review for the LDC but requires a high level of proactive regulatory involvement (see Section 4.2.4 for a more detailed discussion).

Various incentive regulation approaches (Option E) have also been proposed (see Harunuzzaman et al. 1991 for general overview). In many cases, incentive regulation can complement traditional regulation (Option A) and other regulatory strategies (e.g., long-range DSM planning and the IRP regulatory process). Most proposals focus on an LDC's variable gas costs and involve either elimination or partial retention of the purchased gas adjustment (PGA) or cost-indexing approaches (see Section 4.3.4 for a more detailed discussion). For example, Hatcher and Tussing (1992) argue that linkage to a prespecified market index, in conjunction with incentive regulation that shares any cost savings among ratepayers and shareholders, will provide an effective basis for monitoring and oversight of gas costs. To encourage long-term contracts, Fessler (1993) suggests that these contracts adopt pricing mechanisms that follow the market (rather than try to outguess it) and that utilities should have the burden of proving that cost premiums over and above spot indexing are justified by benefits to core ratepayers.

Another general approach includes various partial deregulation proposals that significantly relax regulatory oversight in favor of reliance on market forces (Option F) (Harunuzzaman et al. 1991). The underlying goal is that market forces would establish rates, services (including demand-side services), and the degree of reliability desired by customers. The scope and extent of deregulation could vary just as with incentive regulation. PUCs would be required to establish new policies and rules to facilitate deregulation of certain markets (e.g., unbundling of LDC services, performance standards) and reduce the degree of regulatory oversight. Proponents advocate comprehensive unbundling and open access to transportation on local systems, leading to the emergence of a retail gas merchant industry that would compete with or supplant the LDC's merchant function. This strategy would involve deregulation of gas supply for all noncore customers and certain core customers. For this strategy, gas LDCs and PUCs may have to reallocate transportation costs associated with serving various customer classes, particularly facilities used jointly by core and noncore customers. While most customers would still rely on the LDC for transportation services, most noncore customers would procure gas independently or from third parties. Ultimately, some proponents of this approach envision that core customers may choose supply service from competitors to the LDC (Lemon 1993).

2.6 Potential Benefits and Drawbacks of a Gas IRP Regulatory Process

As the previous section illustrates, integrated resource planning for gas LDCs is one approach that state PUCs can consider to address gas industry restructuring. For discussion purposes, it is helpful to separate the underlying objectives and goals of IRP from the question of what regulatory processes would be most appropriate for gas LDCs in order to achieve various objectives. This distinction is useful because many gas industry representatives and organizations maintain that an LDCs' strategic planning process can achieve many of the objectives of IRP (e.g., consideration of both supply- and demand-side options) without a commission-mandated IRP regulatory process.

The fundamental objective of IRP is to insure that utilities assess a comprehensive set of supply- and demand-side options based on consistent planning assumptions in order to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost. In defining total costs, the regulator often assumes a societal perspective, which means that utilities are asked to consider environmental and other social costs of providing energy services in some fashion. This notion of the role of gas utilities as providers of energy services, and not simply gas therms, is an integral part of the move towards IRP (Ontario Energy Board 1991). Uncertainties and risks associated with different external factors and resource portfolios should be considered by the gas LDC as part of this comprehensive assessment of resource options.

As previously described in regulatory Options C and D, an IRP regulatory process will typically involve:

- a formal IRP plan presented by the gas LDC in a separate regulatory forum (i.e., not a rate case);
- explicit consideration of a wide variety of supply- and demand-side options;
- public participation in the development and/or review of the resource plan;
- review, and possibly approval, of the utility's plan by a regulatory commission.

Key factors to consider in assessing the value of a formal IRP process are:

- the adequacy of the existing regulatory system, given gas industry restructuring and specified regulatory policy objectives;

- the extent to which an LDC's existing strategic planning process already includes and adequately addresses IRP goals and objectives;

- determination of the potential benefits and costs of an IRP process in comparison to current and other proposed regulatory approaches; and

- the extent to which the incremental transaction costs associated with an IRP process are either not necessary or that similar costs would not be incurred with other regulatory strategies.

A handful of states have adopted gas IRP regulations and 10 to 15 gas LDCs have filed their initial integrated resource plans under these rules. Anecdotal evidence suggests that results have been mixed. For example, in Washington, gas LDCs are preparing the second generation of IRP plans, and the gas IRP process seems to have produced significant benefits for ratepayers as well as utilities (see Exhibit 2-1) (WWP 1993). In contrast, after completion of one statewide gas integrated resource plan and commission approval of the first integrated resource plans filed by individual LDCs, the Illinois Commerce Commission (ICC) concluded that gas IRP was an unnecessary cost burden on ratepayers, without the potential to provide net benefits. The Illinois legislature has repealed its IRP regulations for gas LDCs (see Exhibit 2-2) (ICC 1993). The IRP regulatory requirements adopted in Illinois are atypical in that they required a two-stage planning process (i.e., statewide plan and individual utility plans). This approach may be more time-consuming and resource-intensive for all parties compared to electric and gas IRP requirements adopted by other PUCs. At a minimum, these experiences suggest that IRP processes have to be tailored carefully to the conditions and capabilities of gas LDCs.

2.6.1 Potential Benefits

Potential benefits of gas IRP cited by proponents include:

▸ *IRP provides documentation and support for the strategic planning activities of gas LDCs.* An integrated resource planning process can help facilitate a systematic approach for utility managers to evaluate diverse business activities and potential investments (see Figure 2-5). Gas utilities will increasingly have to offer innovative services to diverse customer groups with varying needs. A robust integrated resource plan satisfies multi-attribute evaluation criteria (e.g., cost, reliability, competitiveness, and environmental acceptability) by performing well

Exhibit 2-1. Impact of IRP and FERC Order 636 at Washington Water Power

Washington Water Power (WWP), a combined gas and electric utility, has filed two IRP plans under regulations issued by the Washington Utilities & Transportation Commission (WUTC). WWP has about 102,000 residential gas customers and more than 12,000 commercial sector accounts with firm sales of about 150 million therms annually.

WWP's IRP process has produced some tangible benefits: reduced costs to utility ratepayers, improved analytic methods to value resource options, and increased resources devoted to long-term resource planning, which has helped the utility respond quickly to post-636 implementation issues. WWP's experience also highlights the iterative and ongoing nature of IRP. Many of the benefits of the IRP process have become more apparent in WWP's second IRP plan as action plan items have been implemented. For example,

- In its 1991 IRP plan, WWP added a 5% reserve margin to the peak-day forecast to allow for forecasting error and possible physical losses of supply or pipeline capacity. WWP agreed to examine this issue in more detail in its second IRP plan based on comments received by various parties. In its 1993 IRP plan, WWP concluded that its use of design-day cold weather conditions was sufficiently conservative so that the 5% reserve margin was not necessary. This means that WWP could reduce its peak-day supply by about 100-150,000 therms/day in each year over a ten-year planning period. If WWP is able to take full advantage of the capacity release provisions of FERC Order 636 to market the excess firm transportation capacity, the company could save about $15 to 25 million from reduced peak-day requirements.
- WWP has implemented several DSM programs (residential weatherization, high-efficiency appliance rebates, low-flow showerheads, and commercial/industrial incentives), which appear to be cost-effective from the utility's perspective. In aggregate, these programs are expected to produce peak demand savings representing about 8% of incremental growth in peak demand over a ten-year planning period at levelized cost of about $0.50/therm.
- As part of its electric IRP plan, WWP is implementing fuel substitution programs that pay financial incentives to eligible customers who convert from electric to gas space and water heating. Based on a successful pilot program, the company believes that these programs are effective ways to reduce average utility bills of its ratepayers.
- WWP used a targeted marginal cost method to determine supply costs avoided by DSM measures in its 1993 IRP plan. WWP believes that this method is a more appropriate methodology compared to the simple weighted average cost of gas method used in its initial 1991 IRP plan.
- WWP utilized a commercially available gas planning optimization model to prepare its 1993 IRP plan. The model was particularly useful in helping the company determine how long it should pursue capacity releases of firm transportation.

Sources: WWP 1993; WWP 1991

Exhibit 2-2. Illinois' Experience with Gas Integrated Resource Planning

In Illinois, the Public Utility Act of 1987 mandated that the Department of Energy and Natural Resources (DENR) prepare a statewide gas least-cost plan and that the Illinois Commerce Commission (ICC) establish administrative rules that implemented these legislative requirements for individual gas utilities. After adopting one statewide gas plan and approving initial plans for individual gas utilities, the ICC concluded that gas least-cost planning (LCP) should be discontinued. In June 1993, the Illinois Legislature agreed with this recommendation and amended the Public Utility Act to discontinue its gas LCP regulations.

The Illinois Commerce Commission (ICC) concluded that gas least-cost planning is an unnecessary cost burden on ratepayers, without potential to provide net benefits because:

- Review of ongoing gas purchases can be accomplished more expeditiously through annual purchased gas cost reconciliation proceedings. The purchased gas adjustment reconciliation is a more direct way to influence the behavior of gas LDCs and encourage them to do forward-looking planning because they are at risk for long-term planning decisions.

- Review of capital projects and operations can best be accomplished through focused certificate or rate case proceedings.

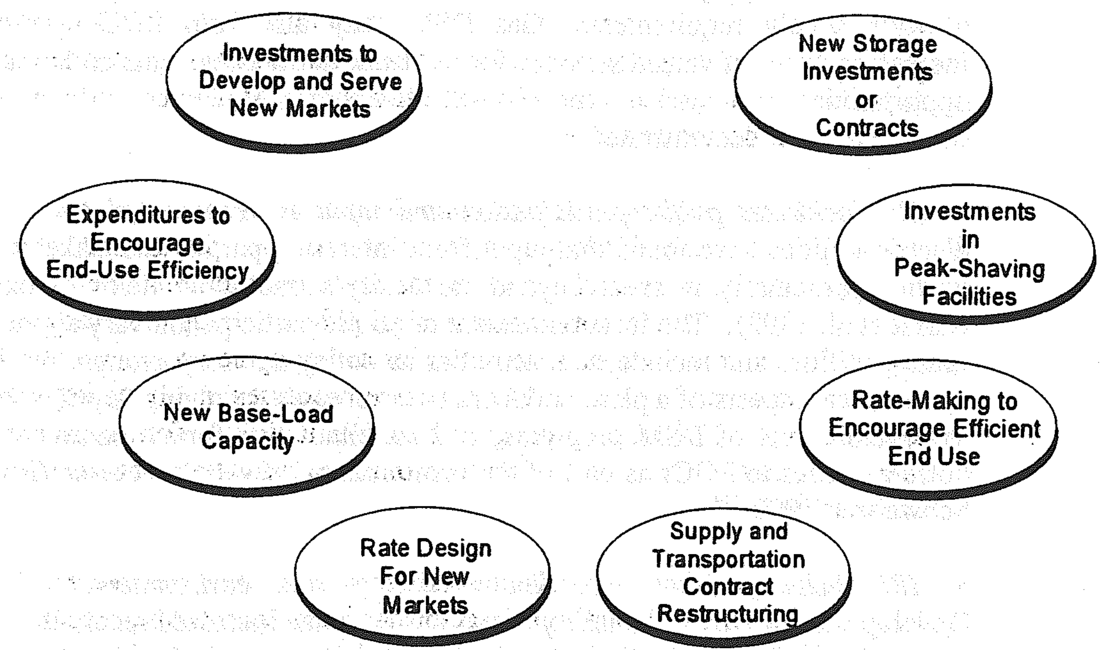
- Most of an LDCs' costs (i.e., gas commodity costs) are constrained by the existence of a highly competitive natural gas supply market. The Commission's scarce resources are better spent pursuing electric least cost planning given the greater potential for cost reductions for electric utilities.

Sources: ICC 1993, Jensen 1993

for most criteria for a range of alternative future scenarios (EMA 1992). After completing a strategic planning process, the utility is in a much better position to explain its decision-making and resource procurement process, whether or not it is required to do so by a regulatory commission. One indicator of success would be the extent to which IRP becomes the planning process for the company's core business rather than simply a response to regulatory requirements (Bauer and Eto 1992).

▸ *IRP provides for sharing of risks of major supply management and capacity decisions between utilities and regulators.* In return for increased input into the resource planning process, regulators, on behalf of ratepayers, and other participating stakeholders implicitly accept increased responsibility for resource

Figure 2-5. IRP Framework Helps Utilities Evaluate Business Activities and Potential Investments



Source: Energy Management Associates (EMA) 1992

planning decisions (Hirst 1988b). Decisions made as part of commission-reviewed and approved processes typically are given the presumption of prudence at a minimum (Bradford 1992).

Gas LDCs may face reduced regulatory risk if they obtain pre-approval on the composition of supply acquisition portfolios, agreement on the need for a major new capital investment (e.g., storage facility), or regulatory support to use various risk management strategies to manage uncertainties in supply costs. Hedging strategies are assuming increased importance in both electric and gas resource planning as flexibility and robustness of alternative resource portfolios are evaluated under various future scenarios (Bauer and Eto 1992).

▸ *IRP helps overcome market barriers and imperfections that inhibit penetration of high-efficiency end-use options.* Gas LDCs can play an important role in accelerating the acceptance of high-efficiency gas equipment and technologies, which must overcome a variety of barriers in various market segments, such as information gaps, higher initial costs, lack of capital, and the problem of "split incentives" (see section 6.4.3) (see Krause and Eto 1988). In an IRP context, high-efficiency gas conservation and load management options can be regarded as potential "supply substitutes" and evaluated for their ability to affect the utility's supply requirements. Gas DSM may also help LDCs provide an increasing array of valued services for different market segments and create new opportunities and markets for high-efficiency gas equipment where societal benefits can be demonstrated.

▸ *IRP facilitates public participation and input in resource planning.* Many electric utilities have found that input from interested parties and stakeholders is useful, particularly in areas beyond the utility's traditional fields of expertise (Hirst et al. 1992). The form and extent of public participation vary significantly among utilities and include such activities as policy advisory groups, workshops on technical aspects of a plan, collaborative processes involving key stakeholders to develop a set of DSM programs, and solicitation of formal comments from outside parties to PUCs as part of the commissions' review processes (Raab and Schweitzer 1992).[14]

▸ *IRP helps facilitate coordinated energy and environmental planning.* Development of IRP in the utility sector has led to an increased recognition of the potential benefits of coordinated energy and environmental planning among state agencies responsible for these functions. A number of states use IRP-type processes to develop long-range energy plans for all sectors (e.g., buildings, industry, and transportation). These efforts often include an overall resource assessment, articulation of state goals in energy-related planning areas, and policy direction on balancing economic and environmental goals.

State-level energy planning often provides policy direction or input on a key issue that affects a utility's integrated resource plan. Examples include state policies on environmental externalities, siting of new facilities, and development of alternate fuel vehicles in the transportation sector (Bradford 1992). As a relatively clean-burning fossil fuel, natural gas may play an enhanced role in meeting future energy service needs to the extent that the energy and environmental implications of resource alternatives become an integral feature of state-level and utility planning processes.

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[14] As competitive pressures increase, utilities are likely to request confidential status for ever-increasing portions of their IRP filings and supporting materials, which will complicate efforts to encourage public involvement and present regulators with difficult choices.

2.6.2 Potential Drawbacks

Critics of gas IRP regulatory processes emphasize the inherent limitations and regulatory costs of this approach (Kretschmer 1993). They argue that the significant differences between electric and gas utilities mean that the benefits to be captured by a formal IRP proceeding are likely to be small and will not justify the additional transaction costs of such a process. In critiquing the value of gas IRP regulatory processes, they raise the following issues:[15]

▸ *The direct and indirect costs of an additional gas IRP regulatory process can be substantial, and the benefits are uncertain and likely to be small.* Some policymakers argue that gas IRP processes involve significant amounts of utility, regulatory, and third party staff time, which could be better spent, given limited resources, on other activities (Kretschmer 1993).[16] Cost concerns are seen as critical because the potential benefits of gas IRP are inherently less than those that can be realized by an electric IRP process. Many gas industry groups maintain that supply-side decisions for gas LDCs do not imply large, long-term irreversible cost commitments and that competitive gas markets limit opportunities for a public process to further reduce gas costs.

▸ *A gas IRP regulatory process, particularly one that implies regulatory preapproval, is incompatible with the development of a competitive gas industry.* Given the realities of a rapidly evolving competitive supply environment, PUCs that review and approve utility integrated resource plans are very unlikely to be able to complete this process in a timely fashion. Moreover, if PUCs approve an LDC's integrated resource plan, the risks associated with long-range planning decisions are unnecessarily being shifted to ratepayers or regulators. This conflicts with policy goals intended to make utilities function as they would in competitive markets. Finally, in a competitive environment, the public nature of an IRP process is not necessarily a benefit because the gas LDCs bargaining power is reduced because potential suppliers have the opportunity to obtain information on the LDCs' supply plan and options.

▸ *The gas conservation potential that can be acquired cost-effectively by an LDC is relatively small because much of the economic potential will be captured through government appliance and building standards and codes.* The achievable DSM potential for a gas LDC is also more limited because gas avoided costs are

[15] See Jensen (1993) for a discussion of the pros and cons of gas IRP regulatory processes.

[16] One participant in the Illinois IRP process estimated that the direct costs of the gas LCP process was about $3 million for the seven gas LDCs (Jensen 1993).

lower than those for electricity. This means that, all else being equal, it is more difficult for gas utility programs to pass cost-effectiveness analysis from the economic perspective of the utility and society (Jensen 1993).

2.7 Summary

This chapter has highlighted the magnitude and nature of changes occurring in the U.S. gas industry and their potential implications for gas LDCs and state regulators. There is broad agreement among participants in the gas industry that strategic planning is critical for LDCs in the new business environment. For those regulators considering gas integrated resource planning, a major challenge is to adapt IRP processes to the conditions and circumstances of the gas industry. Flexible approaches are desirable for several reasons. First, the market forces unleashed by and uncertainties associated with gas industry restructuring mean that regulatory approaches must be compatible with emerging competitive realities. Second, the typical gas LDC may have fewer staff resources than the typical investor-owned electric utility, which also argues for more streamlined regulatory processes. Finally, in thinking about gas IRP, it is important to remember that fundamentally IRP is not an end in itself but a process designed to improve resource decisionmaking.

Gas Integrated Resource Planning: Methods and Models

3.1 Overview

Regardless of whether gas integrated resource planning (IRP) is pursued as a separate regulatory process or a set of methods that are overlaid upon existing business and regulatory practices, IRP requires the coordination of several areas of utility resource planning. This coordination should begin with a clear set of objectives that define the mission of the gas local distribution company (LDC) as an energy services company. The LDC sets out to meet these objectives by conducting business and resource planning in five major areas: demand forecasting, supply-side resource selection, demand-side resource selection, resource integration, and financial and rate forecasting. This chapter provides an overview of the major areas in IRP, discusses how the areas should be coordinated, and focuses on three topics that are not covered elsewhere in this primer: demand forecasting, resource integration, and the treatment of uncertainty. An overview of computer models that are used to facilitate IRP goals and objectives is also included.

3.2 The Gas IRP Analysis Framework

A schematic representation of the IRP analysis framework is shown in Figure 3-1. The framework is not intended to be all-inclusive; instead, it highlights some of the key planning areas and their relationships to each other. IRP processes usually begin with a demand forecast; based on this forecast, the utility develops an initial or base-case resource plan which usually includes only traditional supply-side resources and excludes demand-side options. The base-case plan and variations on it are used to develop initial estimates of avoided costs. These avoided costs are used to screen alternative demand- and supply-side resources. Based on the results of screening alternative resources, alternative plans are developed that best achieve a certain objective, like the minimization of total cost (i.e., the "least cost" objective). Exhibit 3-1 summarizes the particular approach taken by one LDC, The Peoples Gas Light and Coke Co., and provides a concrete example of the major steps taken to develop an integrated resource plan.

A gas integrated resource plan must specify a planning horizon. In the electric industry, planning horizons of 20 years are common. Because of shorter lead times necessary to construct natural gas supply facilities and the greater uncertainty associated with gas

Figure 3-1. Analysis Framework for Gas IRP

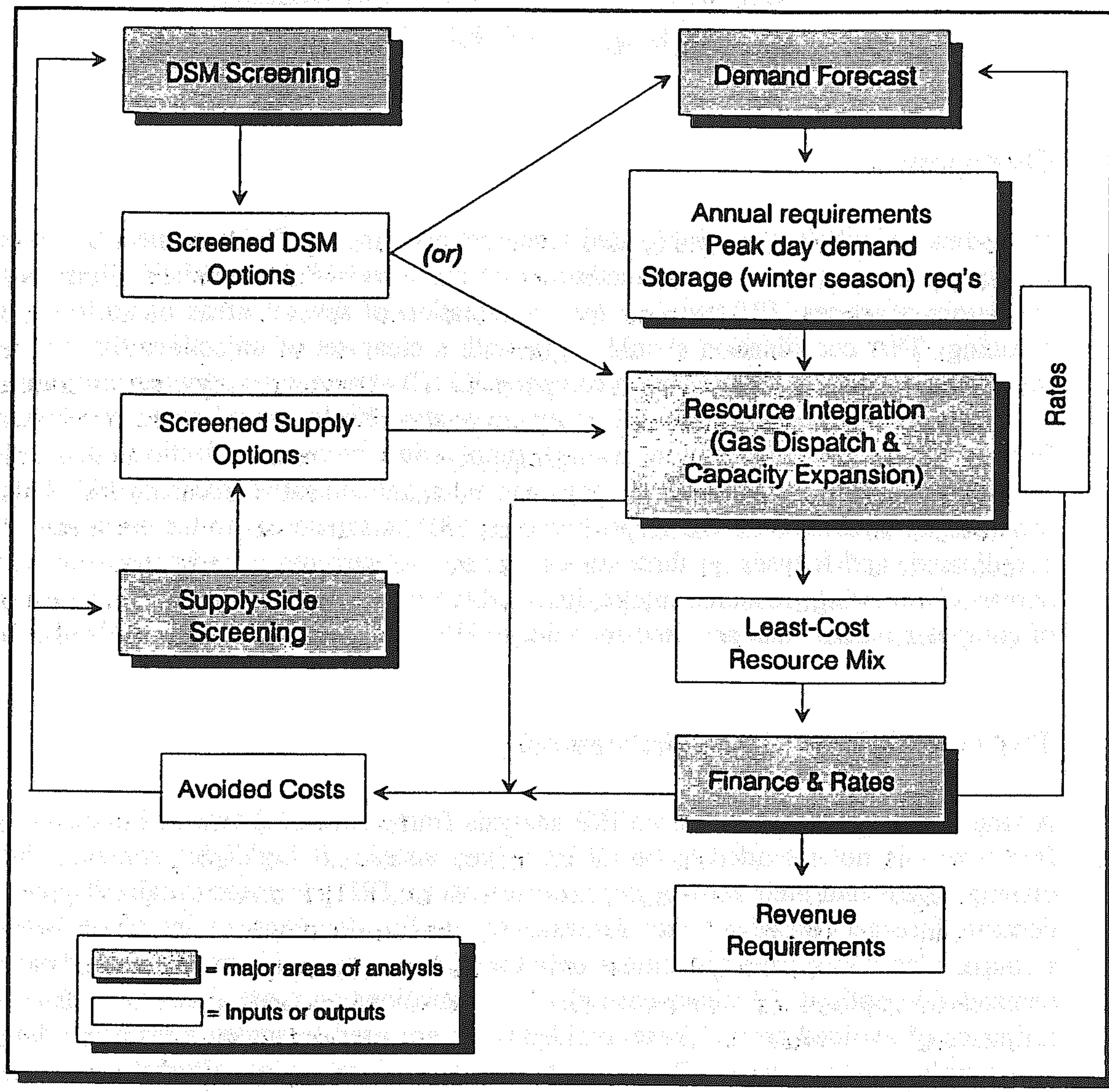


Exhibit 3-1. Major Steps in the Peoples Gas IRP Plan

The Peoples Gas Light and Coke Co. (Peoples Gas) prepared an integrated resource plan to comply with Illinois Commerce Commission rules (Peoples Gas 1991). The plan had four cornerstones: demand forecasting, supply-side management, demand-side management, and integration (see Figure 3-2). The plan was developed using a series of linked, detailed models rather than a single, integrated planning model.

Demand Forecasting

Peoples Gas forecasted demand of firm customers by combining the results of a short- and a long-term econometric model. The short-term model was designed to provide the best fit of recent historical data and could, therefore, be expected to produce more accurate forecasts in the short run. The two models were combined via weights: the short-term model was given greater weight in earlier years and the long-term model greater weight in later years. Peoples Gas forecasted the demand of larger, nonfirm customers on a customer-specific basis.

The peak-day demand forecast was estimated econometrically using recent daily sendout data and the assumption that the peak day would occur on a January weekday with ambient temperatures of -15 degrees Fahrenheit.

The company estimated demands consistent with five general scenarios: (1) a base case, (2) a high economic growth case, (3) a low economic growth case, (4) base-case economic growth combined with new demands from strong environmental regulations, and (5) a "price shock" scenario.

Demand-Side Management

Peoples Gas used a DSM screening program to assess many DSM measures and programs; measures and programs were identified that passed the Societal Cost test, Participant test, and Utility Cost test. Programs that passed the screening stage also had to be consistent with Peoples Gas's "overall DSM objectives."

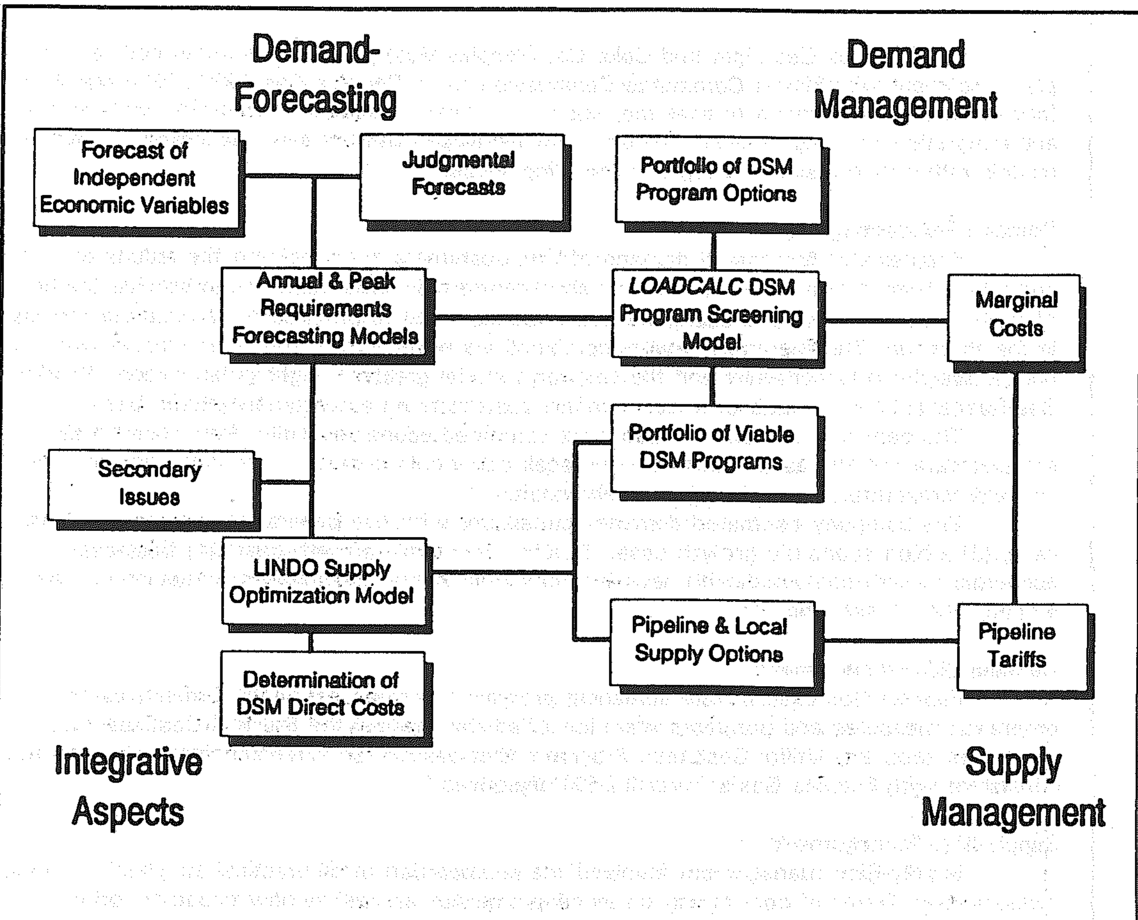
Supply-Side Management

Supply-Side management involved the enumeration of all practical supply-side options including new forms of contracting on existing pipelines as well as new capacity options.

Integrative Aspects

Peoples Gas's integrated resource plan was determined using its Daily and Monthly Optimization Models. These models are built upon LINDO, a commercial linear programming computer program. The models ensure that the system has sufficient gas supply and capacity available to meet the following design requirements: annual, January peak day, extreme Fall, and extreme Spring. The LINDO program picks the most economic supply- and demand-side options. Two types of least-cost plans were developed: a supply-only plan and a combined supply- and demand-side plan. The supply-only plan is used as a baseline for comparing energy and cost impacts and is used to develop the avoided costs for screening DSM programs. In addition to the least-cost criterion, some "secondary" attributes, such as rate impacts or the existence of possible implementation barriers, were considered in the final selection of DSM programs.

Figure 3-2. Peoples Gas IRP Process



Source: Peoples Gas Light and Coke Company 1991

demand forecasts, gas LDC planning horizons are typically shorter; three- to ten-years appears common.[1]

[1] To the extent that an IRP evaluates longer-lived resources, such as DSM measures, it may be necessary to extend the planning horizon to a point where the full costs and benefits of each resource option can be measured.

3.3 Defining IRP Objectives

It is essential that LDCs and PUCs define the mission of the LDC as an energy services company. This is done by adopting a set of IRP goals and objectives (Energy Management Associates (EMA) 1992). Achieving the proper balance between multiple objectives is a key challenge in IRP. For many PUCs, the overall goal of IRP is to develop a plan that reliably meets customer energy service needs at the lowest possible cost. Table 3-1 lists other major IRP objectives that are considered important by two major stakeholders: PUCs and gas LDCs. From these objectives, one can develop quantitative indicators for measuring how well a particular plan achieves its objectives. There is some overlap of the objectives that are important to PUCs and LDCs but not complete congruence. The degree of overlap between a PUC and an LDC strongly

Table 3-1. The Range of Objectives in Gas IRP

Major Stakeholder	Objectives	Key Indicators
PUC	Minimize source energy requirements	Total energy consumed
	Minimize total social costs	Societal Cost test, quantities of pollutants released
	Minimize total customer costs	Total Resource Cost test
	Share benefits equitably	Rate or bill impacts by customer class
	Minimize customer bills	Utility Cost test
	Minimize rates	Nonparticipants test
	Maintain reliability	Expected curtailments, reserve margins
	Maximize planning flexibility	Lead time of selected resources, dollar magnitude of long-term commitments
	Maintain market share	Market share, relative size of marketing budget
Utility	Maximize shareholder value	Stock price, return on equity

depends on the LDC's existing regulatory framework. For example, an LDC that has reasonable assurance of recovering prudently incurred DSM program costs and lost revenues is more likely to accept minimizing total costs as an objective than an LDC that does not have such an assurance.

3.4 Gas Demand Forecasting

The starting point of any gas integrated resource plan is the demand forecast, which estimates the future natural gas energy service needs of an LDC's customers. With the predicted demand, assessments of new supply- or demand-side resources can be made. For IRP purposes, the most common LDC demand forecasts are annual and design peak-day demands for each year of the planning horizon. If a gas utility has or is considering seasonal storage resources, then a forecast of peak season requirements is also needed. In addition to demand forecasts used in IRP proceedings, LDCs forecast demand for shorter-term purposes: day-to-day operations, supply portfolio planning, and revenue forecasting.

3.4.1 Econometric and End-Use Demand Forecasting Methods

There are two general types of forecasting methods: econometric and end-use. Econometric models typically rely on historical data sampled over time (*time series* data) or across customers (*cross sectional* data) to develop statistical relationships between demand and one or more explanatory variables. Econometric models may also be estimated using explanatory variables that are based on past values or moving averages of demand variable.[2] A statistical "best fit" of coefficients are found which relate demand to its explanatory variables (Pindyck and Rubenfeld 1981). The coefficients, along with additional data on the model's explanatory variables, may then be used to forecast demand. Table 3-2 shows a range of explanatory data that can be employed in econometric models for residential customers. A single econometric equation can be used to estimate total sales (Level 1), two equations can be used to estimate number of customers and use per customer (Level 2), or multiple equations can be used to estimate the number of customers in particular residential subclasses and use per customer in each of these subclasses (Level 3).

[2] Econometric models of this type are known as autoregressive (AR) and moving average (MA) models. These models may be combined to form ARMA or integrated ARMA (ARIMA) models (see Pindyck and Rubenfeld 1981). ARIMA models have proven to be very useful in forecasting peak-day demand.

Econometric models are attractive because of their power to correlate historical demand data with the historical explanatory data. Econometric models cannot, however, forecast relationships that are not somehow embodied in the historical data. The demand impacts of new, utility-funded DSM programs, which are undertaken to encourage customers to

Table 3-2. Levels of Load Forecast Disaggregation for Residential Customers

End Use-->

<--Econometric

Level 1	Level 2	Level 3	Level 4	Level 5
Residential sales	No. of customers	• No. of space heating single family (SF) homes • No. of nonspace heating SF homes • No. of multi-family building with gas space heat • No. of nonspace-heat multi-family homes	• No. of water heaters • No. of furnaces • No. of air conditioners • No. of boilers • No. of ranges • No. of dryers	Same as level 4, except appliance turnover is explicitly modeled *e.g.* • No. of existing water heaters • No. of new (high efficiency) water heaters . . .
	Use per customer	• Use per SF home, space heat • Use per SF home, nonspace-heat • Use per multi-family building, space heat • Use per multi-family building, nonspace-heat	• Use per water heater • Use per furnace • Use per air conditioner • Use per boiler • Use per range • Use per dryer	• Use per existing water heater • Use per new water heater . . .

Source: Adapted from presentation by Jim Lamb (WAPA 1993) adopt greater levels of energy efficiency than would be expected from customer responses to rates alone, represents an event that cannot be forecasted econometrically, at least not with data sampled from a utility's own service territory.

End-use models attempt to model explicitly, with varying degrees of sophistication, the stock and energy intensity of existing gas-consuming buildings and appliances (see Table 3-2). Level 3 can be considered a quasi-end-use model because an explicit representation of space heat and nonspace-heat loads is made. True end-use models begin at Level 4 where stocks of appliances are explicitly modeled. Level 5 illustrates a further expansion of the end-use framework: appliance stocks and turnover rates are forecasted to model the change in appliance efficiencies over time.

End-use models have advantages in an IRP context because they allow the impacts of utility DSM programs to be readily reflected in the load forecast and because they make underlying assumptions about the usage and efficiency of building and appliance stocks transparent and understandable. End-use models also have disadvantages. First, end-use models require extensive data that is not readily available to most LDCs. Utilities must either conduct surveys to collect the data or borrow it from similar utilities that have conducted such surveys. Second, the lack of time series data on all explanatory variables makes end-use models difficult to verify although this should be less of an issue with continued end-use data collection.

While the collection of end-use data may be seen as a significant model development cost, end-use surveys have value beyond demand forecasting applications. For example, Washington Gas Light used the results of end-use surveys it initially conducted for the development of demand forecasting models for other purposes including the estimation of price elasticities of demand, DSM program design, and DSM program evaluation (see Table 3-3). To collect these data, the utility has spent roughly $500,000 since 1987 (Washington Gas Light Co. 1992).

In some states, end-use models are already being used for natural gas resource planning. For example, in California, the California Energy Commission and investor-owned gas LDCs rely on end-use models for long-term demand forecasts. Also, several combination utilities have transferred their end-use modeling capabilities from their electric departments to their gas departments. Econometric models are likely to remain common, however, because of the short planning horizons in the natural gas industry and the extensive data requirements of end-use models. Even if econometric models remain common, however, some end-use modeling will be necessary in IRP processes to estimate the impacts of utility-sponsored DSM.

Table 3-3. Selected End-Use Data Collection Activities of Washington Gas Light (District of Columbia Division)

Name of Survey or Study	Purpose/ Type of Data Collected	Approx Sample Size	Uses of Survey
Load Research Advisory Group (LRAG) Residential Survey (1987 and 1990 follow-up)	Gather data on household characteristics which could affect energy consumption, including appliance saturations and behavioral characteristics. Follow up survey allowed for tracking of sample households over time.	1,500	• demand forecasting (including elasticity study) • program design
LRAG Commercial Building Survey	Assess the level of energy efficiency in commercial buildings.	2,000	• demand forecasting (including elasticity study) • program design
1990 Boiler/Furnace Replacement Survey	Estimate the annual turnover of boilers and furnaces and the percentage of the total market that participated in the utility's DSM programs.	600	• program design (estimate market potential) • program evaluation
ENSCAN Metering Project	Collect daily load data. Subset of ENSCAN sample is a part of the LRAG sample, so inferences on appliance use are possible.	700	• program evaluation • demand forecasting (especially peak-day models)
Socio-Economic Survey	Collect race and income data on participants to determine whether programs are reaching a broad range of customers.	331	• program design • program evaluation
Hidden Savers Survey	Investigate why certain program participants increase rather than decrease consumption. Look for changes in participant characteristics that could explain the increase including number of appliances, building structure behavior, and household size.	303	• program design • program evaluation

Source: Washington Gas Light 1992

3.4.2 Weather Normalization Procedures

A significant fraction of residential and small commercial demand is typically weather sensitive. For historical data to be useful for short- or long-term demand forecasting, this weather sensitivity must be characterized and controlled for. Average or normal temperature conditions are usually chosen for forecasting revenues and average utilization of contracts and facilities. For planning total contract capacity and the size of facilities, LDCs also want estimates of extreme peak day, peak season, or cold-year demands.

The simplest way to conduct weather normalization is to create an index that is directly proportional to heating loads, such as the *heating degree day* (HDD) (American Gas Association 1987b). The HDD for a particular day is equal to a predefined base temperature minus the day's average temperature.[3] The base temperature is set at a point where there are no heating loads. Traditionally HDDs have been recorded using a base temperature of 65 degrees F. Lower base temperatures at 60 or 55 degrees F are, however, becoming more common as the housing stock in the U.S. is becoming more efficient and people are lowering thermostat settings. If econometric models are used, then historical data are used to find the relationship between HDD and demand per customer. If an end-use model is used, a simple linear relationship is assumed for all heating end uses. Forecasted demand is then computed using a forecast of HDDs. For average conditions, some historical average HDD is used. Extreme-day or extreme-annual HDDs are used to compute design peak-day and cold-year demands, respectively.

Additional sophistication can be added to the weather normalization process. Daily demand forecasting models require a recognition of the time lag caused by the thermal capacitance of building shells; such a lag may be incorporated into models using lagged demand or temperature data. Other weather data such as wind speed and solar insolation can also improve the accuracy of models.

3.4.3 Peak-Day Models

LDCs also develop models to forecast peak-day loads in average or extreme weather conditions, in part because many facilities, especially those located near load center, are sized to meet peak-day loads. Most peak-day models are determined econometrically. Historical winter season daily demands are used to determine a relationship between demand per customer and HDD or temperature. The estimated equation will often include

[3] Similar to the HDD's ability to predict heating loads, *cooling degree days* (CDDs) are a temperature index that can be used to predict cooling loads. CDDs may become important for gas demand forecasting if the penetration of gas-powered cooling systems increases in the future.

time-lagged temperature data patterns and wind speed. This estimated relationship is then used to determine daily demand for the situation of interest (e.g., the peak-day temperature that will satisfy the utility's reliability criteria).

There are several approaches used by LDCs to define the design peak day. Ideally, the design peak-day standard should be based on a benefit-cost study that sets marginal value of service equal to marginal cost (see Chapter 4). In practice, however, most LDCs determine their design peak-day requirements by choosing a reliability standard and estimating demand at that standard. Because of the strong temperature dependence of peak-day loads for most LDCs, reliability standards are characterized by a design temperature or HDD. Some LDCs base their design temperature on the coldest day or coldest cluster of days ever recorded in their service territories. For many utilities, weather records are available for periods longer than 60 years. Other LDCs use the 90th- or 95th-percentile cold temperature using all data recorded in their service territories. A more sophisticated approach to determining the design temperature for a service territory is to fit recorded cold-year temperatures to a mathematical distribution. The utility chooses a mathematical distribution that appears to best describe the true variation in temperature. The design day is set at the coldest temperature seen at the 90th, 95th, or 99th percentile of the *fitted* distribution. Using fitted distributions to compute the design peak day uses more information than just the data on the most extreme days; however, the results depend heavily on the type of distribution chosen by the forecaster.

Several utilities are beginning to combine econometric and end-use techniques in their peak-day forecast models. For IRP processes, the impact of appliance efficiencies on peak-day loads must be considered if the capacity-related benefits of DSM are to be realized. Analysts have attempted to incorporate appliance efficiencies into peak-day models which is an important step in making demand forecasting more consistent with IRP (Atlanta Gas Light Company 1992; Carillo 1992).

3.4.4 Demand Forecasting in an Unbundled World

Interruptible Demand

Interruptible demand is often an important component of an LDC's demand mix. While estimates of firm demand are needed to estimate the LDC's need for capacity, estimates of interruptible demand are needed for estimating revenues, rates, and profitability. Previously, interruptible demand was categorized by a system of priorities that closely matched customer class definitions. For example, it was commonplace for all electric generation boiler load to receive equal priority and that priority was usually lower than the priority given to industrial process load. In recent years, ample natural gas supplies at the wellhead combined with more stringent air quality regulations in certain parts of the country have made gas more desirable for interruptible customers; this change has resulted in demand for firm or quasi-firm service from all customer classes. Thus, it is likely that all classes except for residential and small commercial will have firm and interruptible subclasses in the future. The implication for demand forecasting is that distinctions between firm and interruptible loads must be made for additional customer classes and that such distinctions can add to the complexity of the demand forecasting process.

Transport-Only Demand

When customer-owned transport began to appear in the 1980s, it was often considered to be a subset of industrial interruptible demand because of the price sensitive nature of transportation customers and the unavailability of truly firm transport-only service from pipelines. Despite the quality limitations of retail transportation, the service has been a huge success and now transport-only customers account for much of the total throughput of many LDCs. In a post-636 world, the size and variety of customers that purchase transport-only services from gas LDCs will increase. The result of growing demand for transport-only service is that yet another dimension must be added to the demand forecasting process. Many LDCs will now need to forecast sales separately from throughput for every customer class in which transportation is offered. LDCs will develop commodity portfolios only for their sales customers and will still need to plan to acquire on-system capacity for their total firm throughput, which includes firm sales and firm transport-only loads.[4] Upstream of the LDC, it is an open question whether LDCs will be responsible for acquiring capacity for their transport-only customers. The LDC or PUC may require transport-only customers to acquire their own capacity.

3.5 Development of Alternative Integrated Resource Plans and Resource Integration

3.5.1 Developing a Base-Case Supply Plan and Initial Avoided Cost Estimates

Once the relevant demand forecasts are prepared, the next step of an IRP process is to develop a base-case plan. The base-case plan usually relies on traditional supply-side resources and typically excludes proposed DSM programs and new or emerging supply-side resource options. Avoided cost estimates, crucial for screening new resources evaluated in alternative plans, are first calculated using the base case. To estimate these costs, base-case demands are perturbed by some increment and the difference between

[4] Utility sales are equal to total throughput minus transport-only throughput.

the base case and the perturbed base case is used to calculate an initial estimate of avoided costs. Avoided costs are an important intermediate product of IRP processes because they link the various planning models used in IRP. If IRP could be conducted using only one model to evaluate all possible demand- and supply-side resources simultaneously, avoided cost estimates would not be necessary. Such a level of integration is usually impossible, so avoided costs become important for screening alternative resources. Avoided costs are a function of a plan's resource mix, so re-estimation of avoided costs may be necessary as alternative plans begin to differ considerably from the base-case plan. Methods for estimating avoided costs are discussed in detail in Chapter 5.

Once a base-case plan is prepared and initial estimates of avoided costs are available, alternative plans are developed that test one or more proposed utility actions. Possible alternative plans could include a DSM program, a new rate design, or an alternative supply-side plan. Although some PUCs may be reluctant to consider LDC marketing (non-DSM) programs, LDCs can certainly use IRP processes internally to evaluate such programs.

3.5.2 DSM Program Options

Utility-sponsored DSM programs are undertaken to modify customer demands and achieve an IRP objective. The modification of demands may be characterized in terms of load-shape objectives and include: conservation (a reduction of demand in all hours), load building, seasonal load reductions, "valley" filling, peak clipping, and peak-load shifting (see Chapter 7). Proposals for innovative pricing and improved rate designs can also be considered DSM in an IRP context because they are also undertaken to modify customer demands (Stutz et al. 1993). For example, PUCs and LDCs could consider alternative plans that promote marginal-cost-based rates that price natural gas services in proportion to current or future costs. Service characteristics that significantly affect marginal costs and which should be considered when adopting marginal-cost-based rates include: the time of year in which service is taken, the reliability provided, and the pressure level/volume capability at which service is provided.

3.5.3 Alternative Supply-Side Options

Because of the ongoing industry restructuring, new supply-side resource options are becoming feasible and, yet, may not be a part of the base-case plan. LDCs are increasingly responsible for developing their gas supply portfolios. In response to changes in pipeline transportation rate design as well as the advent of capacity release programs, LDCs will reconsider their pipeline holdings and pay increased attention to storage and other capacity options. The IRP process is well suited for the evaluation of alternative supply plans. LDC supply and capacity options and planning methods are discussed in detail in Chapter 4.

3.5.4 Resource Screening

Because detailed evaluation of any resource can be complex, LDCs typically employ screening analyses for both potential demand- and supply-side resources. As already discussed, avoided costs are a key variable in these analyses. DSM screening is often facilitated by use of dedicated computer models (see Section 3.8). Supply-side screening usually involves looking at information on system load shapes and the fixed and variable costs of supply-side options (see Section 4.3.3 for additional discussion). During the screening phase, it is a good idea to retain resources that are marginally cost-effective to allow further consideration in the more detailed resource integration stage.

3.5.5 Resource Integration

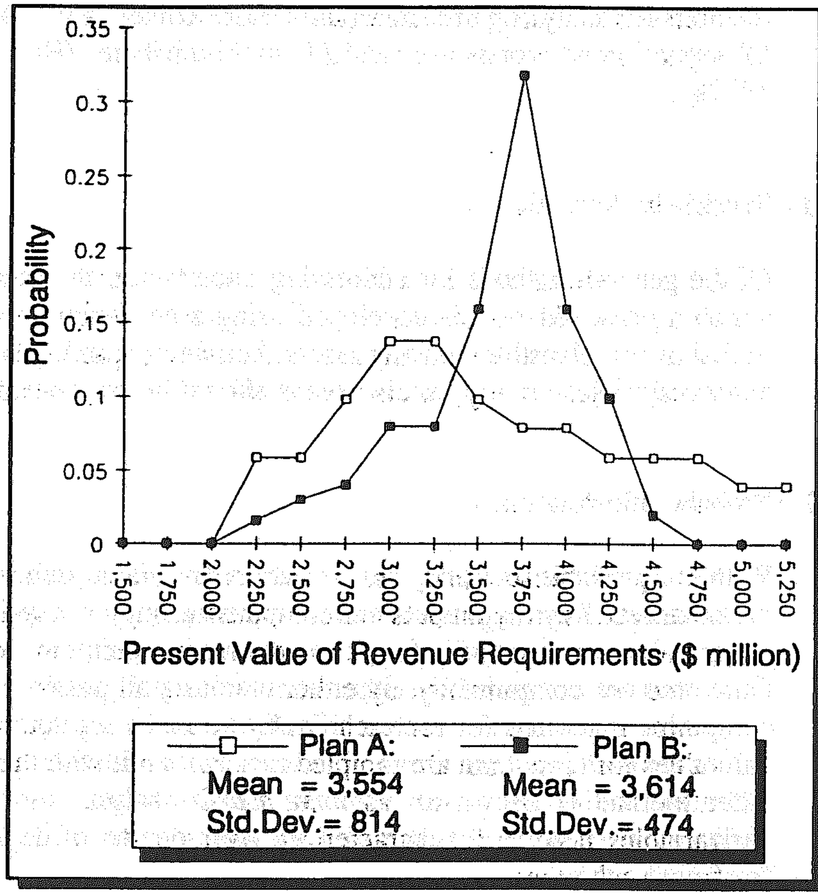
The goal of resource integration is to find the mix of resource options that best meets IRP objectives. Resource integration is facilitated by the use of gas dispatch and capacity expansion models. These models compute total system cost and help insure that energy service needs have been met adequately.

An important resource integration issue is where to incorporate the effects of a DSM program: as a modification of customer demands or as a resource option that is selected, along with supply-side resources, in the gas dispatch and capacity expansion models. It is common to incorporate DSM programs as a modification of demand. The reasons appears to be simplicity and the fact that many supply-side models are not well equipped to incorporate DSM programs as a resource. Studies that have looked at this issue in electric IRP have found representing DSM programs as a demand modifier can introduce inaccuracies that bias the IRP plan (Stone & Webster 1989; Hill 1991). Bias can be introduced because DSM programs that are treated as demand modifiers are usually selected using preliminary estimates of avoided cost that may not be equal to the final estimates. Treating DSM as a resource means that it can be evaluated in a manner consistent with supply-side options and modeled more flexibly (e.g., program size and implementation dates may be varied). Treating DSM programs as a modification of demand is acceptable, however, so long as careful attention is paid to changes in avoided costs, and alternative program sizes and implementation dates are considered.

3.6 Treatment of Uncertainty

Uncertainty is a critical factor in gas utility resource planning. Whenever a plan considers resource options that require irreversible decisions, are capital intensive, or require long-term financial commitments, the potential benefit of such options is clouded by uncertainty. The importance of considering uncertainty is illustrated in Figure 3-3. The figure shows distributions of total cost for two alternative resource plans, A and B. Plan A has a lower expected value than B, but Plan A has a larger standard deviation. As a result, there is a greater risk that plan A will, in fact, be more costly than Plan B. An LDC or PUC considering these two plans should give serious consideration to Plan B because it reduces risk. Key variables that contribute to uncertainty in resource planning include: demand fluctuations, gas commodity prices, prices of alternative fuels, level of economic activity, environmental and economic laws and regulations, weather, decisions of competing firms, the cost and availability of resources, and DSM program market penetration rates.

Figure 3-3. The Importance of Accounting for Uncertainty in Resource Plan Selection



Uncertainty can be characterized in several ways. If a particular variable is uncertain but has been measured over time, one can characterize uncertainty by estimating its *mean* and *variance*.[5] A plan's ability to respond to uncertainty may be characterized both qualitatively and quantitatively. Qualitatively, plans are often described in terms of their *flexibility* or *robustness*. A flexible plan allows for changes to be made in midcourse. Robust plans are optimal over a wide range of possible outcomes. It is also possible to use quantitative methods to assess a plan's ability to respond to uncertainty. Four general methods for analyzing uncertainty in an IRP context are: (1) sensitivity, (2) probabilistic, (3) scenario and worst-case, and (4) multi-attribute. (Hirst and Schweitzer 1988; Hirst 1992a)

3.6.1 Sensitivity Analysis

Of the general methods for addressing uncertainty, the easiest is sensitivity analysis, in which a preferred plan is developed using a deterministic set of inputs; key inputs are varied over a plausible range to assess their impact on key output variables. If key results change significantly, alternative plans should be considered.

3.6.2 Probabilistic Analysis

With probabilistic analysis, key variables are given probability distributions as well as mean values. Key outputs are computed using not just expected values of input variables but also combinations of inputs taken from other points on their probability distributions. Outcomes are computed by either enumerating all possible configurations of inputs and computing outcomes for each configuration or by setting a fixed number of runs where values for each input are sampled in accordance with their probability of occurrence. The latter method is known as a *Monte Carlo* analysis. For either method, all random variables need to be characterized by their degree of dependence on or independence from each other.

Probabilistic analysis is illustrated in the reliability plan developed at San Diego Gas & Electric Co.; it is highlighted in Exhibit 4-1.

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[5] A mean is the simple average of a sample or population. Variance is a measure of how a variable will move around its mean and is equal to the average of the square of each data point minus the mean of the data. A *standard deviation*, which is equal to the square root of the variance is another common measure of uncertainty. A bandwidth that is set at a variable's mean plus or minus its standard deviation will encompass 68% of a sample or population's variation. Two standard deviations will encompass 95% of the variation. A related term is *risk*: the probability or chance that a certain positive or negative outcome will occur.

3.6.3 Scenario and Worst-Case Analysis

In scenario analysis, sets of internally-consistent input assumptions are developed before a plan is constructed. Scenarios could describe such futures as "most likely," "high commodity price, low economic activity" or "high demand caused by environmental regulations." Plans are developed separately for each scenario. This method of addressing uncertainty is useful because it may find a course of action that is not least cost under the "most likely" scenario but is the most appropriate course of action in a large number of scenarios.

Scenario analysis may be considered an intuitive form of probabilistic analysis. Although probabilistic analysis is theoretically attractive, it may be too difficult to articulate the nature of each random variable and the variables' relationships to each other. For example, weather is uncertain but, because of historical records, can have its uncertainty characterized precisely. On the other hand, the demand for natural gas powered vehicles is also uncertain but has no historical precedent, so any distribution assigned to a demand variable would require considerable judgement. Rather than force numeric distributions on each source of uncertainty, scenario analysis only requires a handful of internally consistent scenarios. Optimal plans are then developed for each scenario. The challenge in scenario analysis is to maximize the use of available data and intuition to develop a representative set of scenarios.

A variation on scenario analysis is something called "worst-case" analysis. In this analysis, the utility plans for one extreme scenario but ends up facing a totally different scenario. Such an analysis gives an estimate of the cost of being "wrong" and shows the benefits of flexible plans.

3.6.4 Multi-Attribute Analysis

Rather than develop input scenarios, it is also possible to develop sets of attributes, objectives, or criteria. A set of plans are then rated according to their ability to meet major objectives (such as those listed in Table 3-1) or specific plans are developed that best meet specific objectives. For each objective, the plan may be subject to sensitivity analysis or probabilistic analysis. Plans that are best for a wide range of objectives are given favor in this type of approach. For example, Washington Gas Light rated several plans against eight attributes and each plan was given a total score based on its ranking for each attribute (see Table 3-4) (Washington Gas Light Co. 1992).

A multi-attribute analysis often addresses uncertainty implicitly because the attributes selected can be indicators of a plan's riskiness. For example, an attribute that measures the share of long-term contracts in the gas supply portfolio indicates a concern over the

Table 3-4. Ranking Alternative Plans Against Attributes: Washington Gas Light Co.

Attribute	10% of DCPSC's DSM Goal	100% of DCPSC's DSM Goal	125% of DCPSC's DSM Goal	DSM Pilot Programs Only
Meet Design Day & Sales Req.	9	2	1	8
DSM Programs	9	2	1	8
Commission Goals	2	9	10	3
Least Cost	6	1	2	9
Free Riders	9	2	1	8
Rate Impact	9	2	1	7
Environmental Impact	2	9	10	3
Good Will	1	5	2	8
TOTAL	47	32	28	54

Note: DCPSC = District of Columbia PSC
Source: Adapted from Washington Gas Light (1992)

price volatility or reliability of short-term supplies. The more risk-related attributes are included in the analysis and are given weight, the more likely it is that the ultimate plan selected will be able to respond to uncertainty.

3.7 Public Participation and Action Plans

Development of an integrated resource plan involves more than just technical analyses. As described by Hirst (1992b), a comprehensive IRP regulatory process should include meaningful public participation and action plans. These components are described further below.

3.7.1 Public Participation

Most PUCs have well developed rules for allowing public participation in commission proceedings. In an IRP proceeding, public participation can be enhanced through the creation of a technical advisory group. For participation to be meaningful, several things must occur. First, participation in the plan should begin at an early, preapplication stage so that any contributions of the participants have a chance of being incorporated into the filed plan. Second, the advisory group should include members from a wide range of interests. Relevant parties include consumer representatives, PUC staff, environmental groups, gas pipelines and suppliers, and representatives of the DSM and building trades. Third, although expertise on gas issues should not be a prerequisite, the utility should strive to include members who are either knowledgeable about some of the subject areas or who can commit the time to make a meaningful contribution. Fourth, advisory group members should be given a real opportunity to make a contribution to the plan. This is not to say that the utility has to agree to everything that the members of the advisory group want, but the utility should, where there is consensus, strive to incorporate into the plan contributions made by advisory group members and, in areas where there is disagreement, respond to questions or criticisms raised about the plan.

Some PUCs have taken the advisory group concept a step further and promote *collaborative processes* that represent an intense form of public participation on one or more aspects of an integrated resource plan (e.g., DSM program development). Collaborative processes usually involve frequent meetings and detailed review of issues with the goal of trying to build a consensus on as many issues as possible. In some cases, consensus processes are better able than traditional, litigated proceedings to reach agreement on certain challenging issues or focus areas of disagreement for later resolution by the PUC (Raab and Schweitzer 1992).

A major challenge for PUCs that wish to see successful public participation in gas IRP proceedings will be how to respond to LDC requests for confidentiality on the price and availability of certain resource options. Gas LDCs are likely to either resist submitting or request confidentiality on certain information because they believe such information could harm them competitively. It is possible to establish a procedure for reviewing requests for confidentiality and, if necessary, make certain aspects of the IRP filing subject to protective orders. Unfortunately, such procedures and orders may have the effect of limiting or increasing the cost of public participation.

3.7.2 Action Plans

"Least cost planning" transforms into "least cost doing" by means of the action plan, which describes a set of near-term activities designed to achieve integrated resource plan goals. Action plans usually describe the near-term goals and activities for the utility's DSM programs (including measurement and evaluation), supply acquisition activities, utility projects to improve the quality of the next plan (model development, data collection), and continued public participation.

3.8 Overview of IRP Models

Computer models facilitate several of the major areas of IRP: demand forecasting, DSM screening, the estimation of gas system supply and capacity costs, and financial and rate modeling. Table 3-5 characterizes the major types of computer models available. Models used in electric utility planning have a long history and have had extensive technical review, including scrutiny during the course of litigated PUC proceedings. In contrast, planning models for gas LDCs are relatively new and have not been scrutinized to the same degree.

Models can be important tools in IRP and provide valuable insights; however, if data are poor or assumptions questionable, model results will not be very useful. In reviewing IRP plans, PUC staff should pay particular attention to underlying assumptions and quality of input data.

3.8.1 Demand Forecasting Models

Demand forecasting models may be categorized as either econometric or end-use (see Section 3.4). Many generic econometric computer packages are available. End-use demand forecasting models are more specific to the energy utility industry than econometric models are. End-use modeling for gas LDCs is still in a developmental stage and some LDCs have adapted end-use models originally developed for electric utilities.

Table 3-5. Classification of Gas IRP Methods and Models

Type of Model or Method		Primary Purpose & Results	Examples of Commercially-Available Models (& Vendors)
I.A.	Demand Forecasting: Econometric	•Forecast: -firm & interruptible annual gas demand -firm peak-day demand -other peak periods, such as cold-year winter	• Utilities usually build upon one of the many standard econometric packages
I.A.	Demand Forecasting: End Use	•Are most useful for estimating annual requirements of firm customers •Can explicitly model the impacts of DSM programs	•COMMEND (EPRI) has been adapted to the natural gas industry by Wa. Gas Light
II.	DSM Screening	•Track end-use data •Estimate DSM program savings •Compute benefit-cost tests •Model market diffusion processes	•LOADCALC (Applied Energy Group) •COMPASS (SRC) •DSM Planner (BCI, Inc.) •ECO (Tellus Institute)
III.A.	System Supply and Capacity Costs: Gas System Simulation	•Produce pressures & flows at various points in the LDC's system •Assess the feasibility & cost of alternative expansion plans in detail	•GASSS & GASUS (Stoner Assoc.)
III.B.	System Supply and Capacity Costs: Gas Dispatch	•Determine the optimal use of existing gas supply facilities & contracts •Compute average costs, marginal costs •Estimate curtailments	•GDC (Planmetrics) •Sendout (Energy Management Associates) •GasPlan (Tellus Institute) •ROGM (Raab Economic Consulting)
III.C.	System Supply and Capacity Costs: Capacity Expansion	•Compute optimal choice of supply- (& possibly demand-) side resources over a multi-year time frame •Produce least-cost supply plan & long-run avoided costs	•Contract Analyzer (Planmetrics) •Sendout (Energy Management Associates) •GasPlan (Tellus Institute) •ROGM (Raab Economic Consulting)
IV.	Financial and Rates	•Compute: -revenue requirements, rates -financial statements -key financial indicators	•PROSCREEN II (Energy Management Associates)
V.	Integrated	•Provide modules that cover the following areas: -dispatch -capacity expansion -DSM program screening -demand forecasting -marginal costs -financial and rates	•UPlan-G (Lotus Consulting Group) •Sendout (Energy Management Associates) •Energy 2020 (Illinois Dept. of Energy and Natural Resources)

Source: LBL and GRI data

3.8.2 DSM Screening Models

DSM screening models are useful for developing a portfolio of DSM programs. For evaluating DSM programs, data are needed on end-use characteristics, stocks of appliances, and the cost and performance of DSM measures. Commercially-available DSM screening models often include default values for some of these inputs and typically calculate the standard economic tests for DSM programs (see Chapter 6). Some DSM screening models include market diffusion models, which can be useful for estimating the market penetration of DSM technologies.

3.8.3 System Supply and Capacity Cost Models

Gas System Simulation

Gas system simulation programs (Table 3-5, item III.A) actually model the flows and pressures of a gas transmission and distribution network based on detailed representations of the gas system's pipes, compressors, storage reservoirs, and valves. These models take a detailed description of a gas pipeline, storage, and distribution facilities and solve for pressures and flows using algorithms that model the behavior of natural gas in a network system. To simplify the complex problem these models are designed to solve, the models typically simulate the gas utility system using only daily or hourly demands for limited periods of time at design conditions. Network simulation models have not been introduced into IRP proceedings, but they are essential in determining the cost of supply-side capacity expansion options. For an accurate estimate of the capacity of a pipeline or storage resource option, the option must first be modeled using a gas system simulation model.

Gas Dispatch or Sequencing Models

Gas dispatching or sequencing is the process of scheduling and taking gas on a short-term basis. Dispatching is done on an hourly and daily basis by the gas control group of every gas LDC. Complex data acquisition and control systems as well as transaction data bases are used by many LDCs to track gas flows and dispatch resources in real time and to make short-term forecasts. Such systems and models are not discussed further here. IRP processes will, however, use simplified models of the gas dispatching process for medium- and long-term planning purposes. Dispatch models may be used to make detailed forecasts of an LDC's contract mix and purchased gas budget one month to two years into the future. For longer-term planning, dispatch models are used to estimate the impacts of facility additions on purchased gas costs. The gas dispatching problem can be solved in a variety of ways including spreadsheets, utility simulation, and linear programming techniques (Hornby 1991; Washington Gas Light Co. 1992). The general goal of the model is to find a least-cost dispatch of gas supply resources subject to firm demand constraints, interruptible demand price constraints, capacity constraints, storage limitations, and contractual constraints (particularly minimum take obligations). While many LDCs rely on models developed in-house, a sample of commercially-available models is shown in Table 3-5.

Gas dispatch models used for planning purposes must model the highly variable loads that are common to LDCs. One simple way to do this is to "splice" loads for the design peak-day onto an annual load profile. With this hybrid demand profile, the model can compute a least-cost dispatch for the expected year and make sure that adequate supply and capacity are available on the peak day. Demand variability is also addressed by performing multiple dispatch model runs for each year under different weather scenarios.

Capacity Expansion Models

As the time horizon grows to periods greater than one year, the LDC faces the problem of optimizing the mix of contracts and facilities as well as the problem of economic dispatch. Capacity expansion models are designed to address this problem. Two general approaches to solving the capacity expansion problem are iterative simulation and full optimization. In the iterative approach, a utility articulates a set of facilities and then computes total costs over a multi-year period. In conjunction with this method, gas dispatch models may be used to compute purchased gas costs. Alternative plans are developed and simulated until an optimal one is found according to the LDC's planning objectives. Some trial and error is involved in selecting plans for simulation. LDCs commonly use the iterative approach and implement the approach using in-house models. In the full optimization approach, the planning model automatically selects and sizes facilities and computes total cost. The models find the optimal expansion plan using automated iterative simulations, linear programming, or other optimization algorithms. Most commercially-available capacity expansion models can run as optimization models. Capacity expansion planning methods are discussed in more detail in Section 4.3.

3.8.4 Financial and Rate Models

Financial models typically compute income statements, balance sheets, and cash flow statements for each year of the plan. This information is useful for estimating impacts on an LDC's cost of capital and shareholder impacts. Many LDCs have financial models already developed in-house. Although financial models are needed for short-term operational purposes, financial models used for medium- or long-term planning are usually simpler than those used for operations.

Rate models take the cost data estimated by gas dispatch and capacity expansion models and use these data to compute class average rates and, possibly, specific tariffs for each year of an IRP plan. This information is useful for determining an integrated resource plan's economic impact on a particular customer class. If an LDC's gas demand forecasting model responds to changes in rates, rate models are also necessary to update the demand forecast. Most rate models are developed by utilities in-house.

3.8.5 Integrated Models

LDCs and PUCs must make an important decision before embarking on an IRP analysis: whether to use linked, detailed models or to use an integrated model. Electric utilities faced the same choice when developing IRP models for their industry (Eto 1990). With the first approach, utilities link into an integrated process the inputs and outputs of individual, detailed models for each step of the integrated resource plan. In the second approach, utilities use integrated planning models that incorporate elements necessary for a comprehensive analysis of DSM and supply-side options, and major linkages among the major areas of analysis are handled automatically by the program. Commercially-available integrated models for gas utilities have been developed by Lotus Consulting Group and Energy Management Associates. Despite the availability of integrated planning models, most gas utilities have used linked, detailed models. The advantage of the linked, detailed approach is that utilities can maximize use of their existing model capabilities already developed and maintained in various company departments. Linking models from different departments in an IRP proceeding can also provide an incentive for departments to increase communications among themselves. Further, the linked, detailed approach can lead to maximum consistency between IRP modeling results and the results of modeling efforts conducted by the LDC internally or in other regulatory proceedings. The advantage of integrated models is that, once set up and calibrated, they are simpler to use, especially when many alternative plans are to be tested. Integrated models may also be better suited for use in contested IRP proceedings where parties other than the LDC want to independently prepare LDC resource plans.

3.9 Summary

Gas IRP takes a set of multiple objectives for meeting customer energy service needs of a gas utility and creates a plan to best meet those objectives. The major areas of analysis in IRP are demand forecasting, DSM resource selection, supply-side resource selection, resource integration, and financial and rate forecasting. The planning horizons of gas integrated resource plans are typically shorter than those for electric integrated resource plans. Ten years is a common time horizon for gas integrated resource plans. Overall, the informational and coordination requirements of gas IRP are large, but IRP provides a way to improve the quality of resource planning decisions.

Demand forecasting may be done using econometric or end-use methods. Econometric methods are more common, but end-use methods are gaining acceptance by gas utilities. Even if econometric models are used, some sort of end-use modeling is necessary to incorporate the impacts of utility-funded DSM in the demand forecast. Demand forecasting will grow more complicated as the range of services offered by gas utilities increases.

Gas IRP includes enhanced public participation and action plans to insure successful implementation. Some utilities and PUCs have found collaborative processes to be useful in improving the design of DSM programs, and, in some cases, these processes can result in reduced transaction costs compared to more traditional regulatory processes that involve litigation. Action plans provide a concrete set of actions for the near term that are consistent with the long-term plan.

Commercially-available computer models exist for almost every aspect of gas IRP, including integrated models. Most utilities have chosen to rely on linked, detailed models because this approach maximizes the use of an LDC's existing modeling resources.

Ideally, DSM should be treated as a resource option in the supply planning process rather than as a modification to the demand forecasts. DSM resources may also be modeled as demand modifiers if careful attention is given to changes in avoided costs caused by changes in the IRP plan and if alternative program sizes and implementation dates are considered.

A good way to address uncertainty is to carefully select a set of internally consistent scenarios for which alternate IRP plans are developed or to evaluate alternative IRP plans against a set of key attributes. The best plan may not be the lowest cost plan for any single scenario or attribute. Instead, the most robust plan is likely to perform well over a wide range of scenarios or to meet multiple engineering, economic, customer service, and public policy objectives.

Supply and Capacity Planning for Gas Utilities

4.1 Overview

This chapter discusses resource planning methods of gas local distribution companies (LDCs) with an emphasis on supply-side alternatives. The supply-side planning environment for LDCs is rapidly changing as more resource options are available, and LDCs can no longer rely on gas pipelines for supply management. The ramifications of gas industry restructuring are not yet fully understood and more changes are likely. Analysts and industry participants have issued reports and papers that focus on supply and capacity planning problems for LDCs, but none are comprehensive in light of the rapid change in the industry (NARUC Staff Gas Subcommittee 1990; Hatcher and Tussing 1992; U.S. Department of Energy (DOE) and the National Association of Regulatory Utility Commissioners (NARUC) 1993). This chapter discusses gas supply and capacity planning with an emphasis on four topics: (1) existing and emerging supply and capacity resource options, (2) major supply and capacity planning methods and issues, (3) public utility commission (PUC) oversight of gas LDC procurement decisions, and (4) reliability and contingency planning.

4.2 Planning for Gas Supply Portfolios

4.2.1 Overview

With the ongoing gas industry restructuring, the scope of gas LDC procurement activities has been reduced now that large end users have taken increased responsibility for procuring their own gas supplies. Gas LDCs still procure supplies for firm, usually "core," sales customers and many interruptible sales customers. Gas LDCs also procure gas as a standby or balancing service for transport-only customers who intermittently fail to deliver their own gas. LDCs can procure gas from an expanding set of supply options. In this section, the major types of gas supply contracts are discussed and terms and concepts are introduced for regulatory staff who are involved in reviewing and evaluating an LDC's supply plan. Alternative regulatory frameworks to review LDC procurement decisions are also discussed because a PUC's review process can significantly influence a gas LDC's procurement practices.

4.2.2 Gas Supply Options

A diverse set of gas supply options has existed for several years at the wellhead, and, in a post-636 environment, LDCs will be expected to look beyond interstate pipelines for sources of firm supply. Because of concern about the future price and availability of spot gas supplies, LDCs will also be re-evaluating the "short" side of their gas portfolios. Table 4-1 briefly describes the major types of gas supplies by contract type. Gas supply contracts are either physical gas contracts or financial gas contracts. Physical contracts include pipeline sales service, long-term firm contracts, gas reserve purchases, monthly or multi-month firm contracts, spot contracts, and customer buybacks. Financial gas contracts are relatively new in the gas industry and include contracts that are primarily designed to mitigate price risks rather than provide physical gas supplies. Financial gas contracts include forward, futures, options, and swap contracts. The remainder of this section examines key issues that arise for LDCs when assessing these supply options.

Basic Contract Terms: Spot Contracts

Any gas supply contract needs to specify the quantity of gas sold, term of the sale, point of delivery, and price. Because of the short, nonfirm nature of spot contracts, their terms may be considered the lowest common denominator of all gas contracts. Spot contracts specify an average daily quantity of gas as well as a maximum daily quantity (MDQ) of gas. MDQs are usually higher than the anticipated average demand to allow for daily variations in demand. Usually one party will act as a shipper and be responsible for scheduling gas delivery on the interstate pipeline and paying any transportation charges. Spot contracts allow either party to terminate the contract without penalty. Sometimes prices are renegotiated midmonth to prevent either the buyer or seller from terminating the contract.

Characterizing Long-Term Contracts

Long-term contracts are not synonymous with firm contracts, but reliability provisions are commonly included in longer-term gas contracts. Longer-term contracts are entered into for at least four reasons: (1) to improve supply reliability, (2) to improve price stability, (3) to improve revenue stability, and (4) to reduce transaction costs. In addition to the basic provisions included in spot contracts, longer-term contracts include provisions regarding supplier reliability, volume or take flexibility, and price determination. Supplier reliability is very important to buyers and buyers often attempt to eliminate unreliable suppliers by requiring potential suppliers to go through a prequalification process. Buyers ask the following basic questions when assessing supplier reliability: (1) does the supplier control the physical resource? (2) does the supplier

Table 4-1. Overview of Gas Supply Options

Option	Description/Features
Spot	Contracts to sell gas that allow either party to terminate without penalty. Term is usually on a calendar month basis. Spot markets are now evolving into daily markets where significant trading (and price variation) occurs all month long.
Long-term Firm	Gas supply contracts with terms longer than one year. A long-term firm contract usually provides greater reliability than a similar sized spot contract and includes procedures for dispute resolution. In return for accepting performance-penalty terms, the supplier usually requires the buyer to make volume commitments in the form of gas inventory charges, take-or-pay charges, reservation charges, or other minimum-take provisions. Prices may be fixed, indexed to inflation, indexed to spot gas prices, or indexed to alternative fuel prices.
Monthly or Multi-Month Firm	Contracts for firm supply on a short-term (less than one year) basis. They are usually entered into to supply swing- and heating-season loads. They are considered more reliable than spot supply and can provide a higher degree of price certainty than spot.
Pipeline Sales Service	As a result of FERC Order 636 pipeline sales gas (merchant function) are deregulated and unbundled from associated pipeline transportation and storage services. Merchant services provided by a pipeline or its affiliates may not be bundled with any regulated pipeline services and must compete with unaffiliated marketers that also sell gas through the pipeline.
Purchase of Reserves	A contract that purchases a quantity of proven or developed gas reserves. The reserves may require additional development before they can be delivered to the customers. The reserve purchase contract may be in the form of a joint venture among a set of parties.
Forward Contracts, Futures, Options, and Swaps	A forward contract is a contract to buy a quantity of natural gas at a specific location on a prespecified future date. Futures contracts are a type of forward contract that is publicly traded on the New York Mercantile Exchange (NYMEX). An options contract is the purchase of the right (but not the obligation) to buy a quantity of gas supply for a prespecified period at a prespecified future price. Swap contracts allow the exchange of gas contract terms between two parties without necessarily a trade of physical assets.
Customer Buyback	Utilities can make advance arrangements via contracts or tariffs to buy gas supply or gas capacity from certain firm customers to meet the needs of other firm customers during periods of high demand. A variation of customer buyback is known as a "BTU" contract where an alternative-fuel-capable customer agrees to be curtailed at the utility's discretion. The customer is reimbursed for the difference between the delivered price of gas and alternative fuel available to the customer.

control necessary transportation rights? (3) does the supplier have adequate "back office" resources (personnel and information and control systems) to respond to changing conditions such as last-minute nomination changes? and (4) what is the financial strength and reputation of the supplier? These reliability concerns are reflected in long-term supply contracts via penalty provisions, warranties, or early termination provisions if the seller fails to deliver. Although most firm contracts will have some sort of *force majeure* clause that will excuse the seller from performing because of unexpected events that are beyond the seller's control, the firmest contracts will have very narrow *force majeure* terms. With penalty or early termination provisions, buyers are financially compensated in the event a supplier does not perform. Under warranty provisions in firm contracts, suppliers warrant performance under the contract with their entire resource base—essentially waiving supplier *force majeure* terms.

Most firm contracts provide for revenue stability, which is valuable from the seller's perspective, by placing incentives in the contract to keep load factors high via a fixed payment obligation, a minimum-take provision, or a *gas inventory charge* (GIC).[1] Although these specific clauses vary in their mechanics, all discourage the buyer from deviating from the nominal volume terms of the contract. Because load factors are low for many LDCs, volume flexibility is an essential element of firm contracts but is likely to come at a price because of the seller's desire for revenue stability.

Some firm contracts, especially those of less than one year's duration, simply specify a fixed price. Longer-term firm contracts are likely to have more complex pricing formulae. Many firm contracts are indexed to spot prices but with significant embellishments. First, the contract may specify a premium or a discount from spot prices. Second, spot prices may be part of a formula that dampens fluctuations in the contract price relative to spot prices or combines a spot index price with other indices, such as alternative fuel prices or inflation indices. Besides initial price determination rules, long-term contracts often include conditions under which price can be renegotiated and any indices readjusted.

The Future Role of Pipeline Supply Services

Pipelines were the traditional source of gas supply for many LDCs. With the Federal Energy Regulatory Commission's (FERC's) Order 380, LDCs were no longer required to meet pipeline minimum bill obligations and began to take advantage of low-cost supplies that became available in the spot market. This trend accelerated with the passage of FERC Orders 436 and 500 et al., which encouraged the availability of nondiscriminatory transportation services. Despite the availability of transport-only services, many LDCs still relied on pipeline supplies to meet their firm customers' needs

[1] Take or pay charges are another way to insure volume/revenue stability although this term is no longer commonly used in new gas supply contracts. GICs were originally FERC-regulated supply inventory rates for gas held by interstate pipelines. It appears that the term GIC is being carried over into deregulated gas supply contracts at least in some instances.

during peak seasons. FERC Order 636 deregulated the gas sales operations of the regulated pipeline companies. As a result, pipelines have (1) negotiated gas supply contracts with their customers on a deregulated and unbundled basis, (2) sold or assigned gas supplies to an affiliated LDC or marketing company, (3) bought out or otherwise terminated gas supply contracts with producers, or (4) sold or assigned gas supply contracts to independent marketers. Any gas sales subsequently made to customers via options (1) and (2) are subject to the FERC's existing rules regarding standards and conduct and reporting requirements between pipeline operating divisions and their gas marketing division or affiliate under FERC Order 497 (Federal Energy Regulatory Commission (FERC) 1988). To facilitate the transition to an unbundled pipeline industry, the FERC will allow four different kinds of prudently incurred costs to be considered *transition costs* and to be recovered by the pipeline through its transportation rates: (1) unrecovered PGA balances, (2) gas supply "realignment" costs, (3) stranded investments, and (4) new facility costs necessary for implementing the rule.[2] In the post-636 environment, supplies from the affiliated marketing arms of pipelines will not be very different from supplies available in the competitive marketplace. Pipelines are required to offer supply service at deregulated rates before selling gas supplies to other parties. Some LDCs are choosing to buy gas from the pipeline while other LDCs have ceased sales transactions with their pipelines and are now negotiating with producers or marketers for firm gas supplies.

Although the pipeline merchant function is deregulated and diminishing, pipelines will still offer a limited supply service in the form of *balancing* services. First, pipelines are required to provide no-notice transportation service to customers who took bundled city-gate services as of May 18, 1992. This service is technically a transportation service, but because it allows a pipeline customer to transport gas from the pipeline without advance notice, pipelines providing the service will have to have gas supplies on hand until the customer replaces the taken gas with its own. Second, some pipelines will offer balancing tariffs, which allow customers to pay for the right to be out of balance by a certain amount every month. Third, pipelines have imbalance tariffs and scheduling penalties to charge customers a premium price for gas consumed on an unscheduled basis and reimburse customers (usually at a discount) for gas supplied on an unscheduled basis.

[2] It is FERC policy to allow pipelines to recover 90% of prudently incurred transition costs via firm transportation reservation rate surcharges and 10% via interruptible rates. Gas supply realignment costs were an important issue addressed in FERC Orders 500 and 528 (FERC 1987 and 1990). The FERC's allocation of these realignment costs, mostly take-or-pay buy-out or buy-down costs, required pipeline shareholders to absorb a portion of the transition costs. According to the FERC, the Order 500/528 allocation rules will remain in effect until pipelines are in full compliance with Order 636.

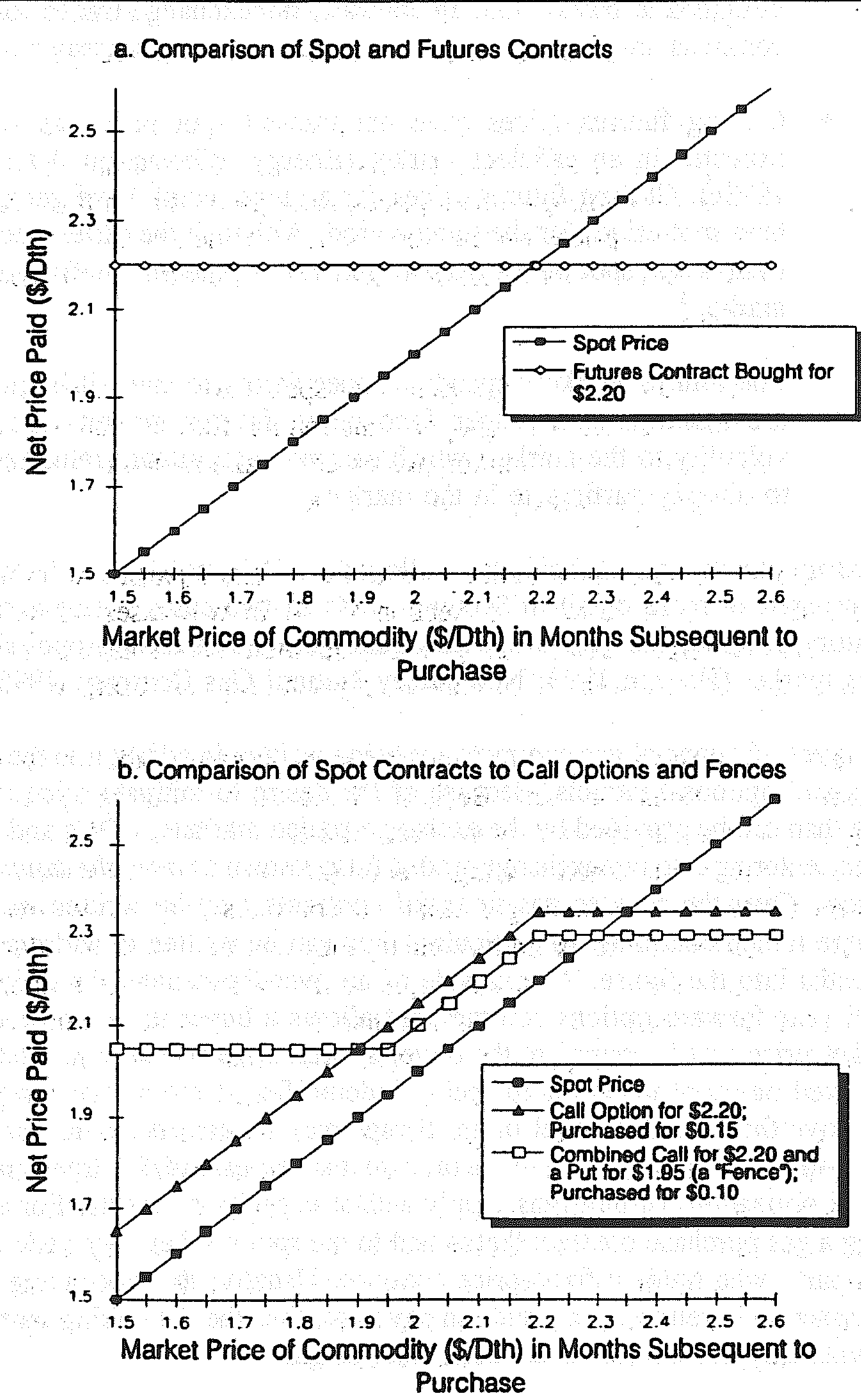
Futures and Other Types of Financial Gas Contracts

Financial gas contracts are an increasingly popular resource option to gas buyers. Most financial gas contracts are considered to be *derivative contracts*; i.e., the value of the contract is derived from prices in one or more primary commodity or financial markets. Futures and options contracts have emerged as the most well-known forms of financial gas contracting. A futures contract is a standardized type of forward contract that is publicly traded. A natural gas futures market has been open on the New York Mercantile Exchange (NYMEX) since April 1990. The market allows a party to buy or sell multiple contracts of 10,000 MMBtu each of natural gas for delivery at the Henry Hub of the Sabine Pipeline Company in Louisiana up to 18 months into the future. "Open interest," the number of outstanding contracts at a given point in time, has grown steadily since the market's inception and averaged more than 2,000 in 1992 (Energy Information Administration (EIA) 1993c; Mitchell 1993). The seller of a futures contract is obligated to provide the gas at Henry Hub at the future date but, as in other commodity futures markets, many of the contracts are sold before the future date so only a fraction of the outstanding contracts ultimately result in a physical delivery. The futures market provides two valuable functions from the perspective of gas utilities and consumers: (1) it provides a price discovery function (i.e., futures prices represent current expectations of where prices are heading) and (2) futures contracts and related options contracts allow buyers and sellers of gas to protect themselves from unfavorable price changes. By buying or selling in the futures market, one can lock in a particular price up to 18 months before delivery begins. Figure 4-1a compares unhedged prices to contracts purchased on the futures market. The futures contract at $2.20/MMBtu is represented as the horizontal line. The "45 degree" line shows the price that would be paid if a buyer bought gas in the spot market rather than buying a futures contract for delivery up to 18 months into the future. With a futures contract, the buyer would take the gas at the $2.20/MMBtu contract price regardless of subsequent spot market prices. Options contracts allow flexibility in price hedging. For example, a buyer of gas worried about price run-ups, could buy call options for purchasing gas at a prespecified "strike" price for a prespecified time period in case future prices eventually exceed the strike price. Similarly, a seller of gas, worried about price drops can buy put options contracts, which guarantee a floor price. Put and call options contracts can be combined into "fences" or "collars" that provide a price ceiling and a floor (see Figure 4-1b).

Although the futures market is a useful tool for managing gas price risks, the market has several limitations:

- Contracts are available only 18 months into the future so the NYMEX futures market does not provide a way to manage longer-term price risks.

Figure 4-1. Examples of Contracts Available on the Futures Market



Source: Adapted from Mitchell (1993)

- The market does not explicitly address risk associated with demand variability. Parties that hold futures contracts on the contracts closing date are obligated to buy or sell. In contrast, nonexchange-traded long-term firm gas contracts may have provisions that allow the buyer greater volume flexibility.

- Closing futures prices have not tracked spot prices as well as would be expected in an efficient market (Energy Information Administration (EIA) 1993c). Closing futures prices for a given month have generally been higher than spot prices for the same period. Although the difference between closing futures and spot prices may shrink, it is a potential inefficiency in the current market.[3]

- The futures market depends on speculators to make it liquid. Although they are essential to a proper functioning futures market, speculators can add volatility to the market, which can make regulators reluctant to allow LDCs to directly participate in the market.

Regulatory structures that facilitate or allow for LDC participation in the futures market are discussed in more detail in Section 4.2.4. In two cases where a specific incentive regulatory program has been proposed or adopted, LDCs have proposed to enter the gas futures market (Henken 1993; New Jersey Natural Gas Company 1993).

Other types of financial gas contracts are being written in addition to the exchange-traded futures and options contracts. Because of the desire to mitigate price risks to a greater degree than can be provided by the exchange-traded markets, LDCs and other gas buyers consider entering into nonexchange-traded (also known as *over-the-counter*) financial gas contracts. Over-the-counter gas financial contracts may be written more flexibly than exchange-traded contracts; in particular, they can be written to address risks more than 18 months into the future. An example of an over-the-counter financial gas contract is a multi-year forward options contract that allows a buyer to purchase of natural gas at a market price that is capped at the buyer's alternative fuel prices. The buyer may pay some fixed payment in return for being indemnified if the market price of natural gas rises above the alternative fuel price. Swaps may be considered as another example of an over-the-counter contract; in them, two parties essentially trade part or all of the financial obligations of their gas supply and/or capacity contracts. For example, a party holding a gas purchase contract that is tied to the spot market may trade its pricing terms with a party who holds a fixed-price contract. Usually, the risk-taking party will enter the transaction in return for a premium payment; thus the risk-taking party accepts higher price volatility but lowers its expected cost of gas.

[3] This potential bias is not reflected in the examples presented in Figure 4-1.

4.2.3 Portfolio Construction and Risk Management

There is general consensus among industry participants on the overall goals of LDC gas supply planning. An LDC chooses a mix of gas supply resources to best meet the needs of its sales customers. For firm customers, supply reliability is a paramount goal. Meeting that criterion at the lowest possible cost is important, as is cost or price stability. For nonfirm sales customers, reliability is important but secondary to price. Nonfirm customers tend to have more heterogeneous needs, so specific supply contracts that vary with respect to reliability and pricing terms are useful in meeting their needs. LDCs are responsible for acquiring gas supplies to meet all these goals.

While it is possible to articulate these goals, it is not possible to provide prescriptive rules or methods for building a supply portfolio because each LDC has a unique set of available resources and a unique set of customers with preferences regarding reliability, price, and price stability. Further, uncertainty makes trading off different supply attributes difficult; it is only possible to identify major strategies used to plan gas supply portfolios. The first major strategy employed by LDCs is to rely on a portfolio of gas supplies that is diversified with respect to gas supply owner, term of contract, and, if possible, supply basin and transport facility. The second major strategy is for the LDC to manage the load shape of its customers by aggregating customers, setting up voluntary or mandatory curtailment provisions, acquiring storage, and acquiring peak-shaving facilities. These key themes of portfolio construction and load shape management are discussed further below.

Gas Supply Diversity

For reasons already noted, contract diversity means that a gas utility's supply portfolio includes more than just pipeline sales gas and spot gas contracts. Some LDCs have articulated guidelines for determining the mix of short- and long-term contracts in their portfolio. For example, these LDCs strive to enter into enough firm gas contracts to meet peak-day conditions plus a possible reserve margin (Peoples Gas Light and Coke Company 1991; Washington Water Power Company (WWP) 1993). Although use of storage or peak-shaving equipment is used to lower the peak-day requirements, ultimately some upstream planning demand is set and contracted for. Firm contracts usually have terms long enough to cover the next winter, and many utilities consider long-term contracts because they believe these contracts improve reliability, provide price certainty, and/or reduce transaction costs. LDCs seem reluctant at this time to enter into contracts with durations longer than three to five years given uncertainty over cost recovery (see

Section 4.2.4).[4] Although LDCs are seeking a high percentage of firm contracts in their resource mix, they also strive for take flexibility to allow for periods of slack demand. Gas utilities usually strive for enough volume flexibility so that they do not incur GIC or minimum-take charges in an average- or warm-temperature year. LDCs look for additional volume flexibility so that they can take advantage of the spot market during periods of low prices. As already noted, volume flexibility usually comes at a price, so LDCs must balance cost premiums with the future potential benefits of take flexibility. For interruptible sales customers, LDCs will usually acquire shorter-term, nonfirm contracts. If an LDC had confidence that a certain block of interruptible demand would exist at all times except for times of curtailment, it may aggregate that demand with firm demands and contract for longer-term firm supplies.

Some participants in the industry have a very different philosophy than described above for determining contract mix. An emerging view is that shorter-term supplies without explicit reliability clauses, such as spot contracts, can be a part of the peak-day supply mix of the LDC, even for firm customers (Hatcher and Tussing 1992; Tussing 1993). In a competitive market, buyers should face no impediments when purchasing gas supplies, even in periods of high demand; that is, there is not a reliability risk in relying on spot contracts. There is only price risk. If the prevailing market requires premiums for the contracting of long-term firm supply relative to spot gas, some argue that those premiums may not be worth the cost (Sutherland 1993). As an example of this philosophy, the California PUC recently issued a policy statement essentially putting the burden of proof on the LDC to justify any long-term contracts that come at a price premium (California Public Utilities Commission (CPUC) 1992b).

Although there is considerable controversy over the role of long-term firm contracts in LDC supply portfolios, the controversy does not appear to be over whether long-term contracts have a place in a LDC's supply portfolio. Long-term contracts save on transaction costs, and as long-standing buyer-supplier relationships are common in other industries, it is reasonable to think such relationships will re-form in the natural gas industry. The one controversial issue appears to be whether long-term contracts will be sold at a premium or a discount over spot gas. It is commonly understood that long-term contracts provide reliability and price stability to the buyer. Long-term contracts also provide revenue stability to the seller, and such revenue stability can allow for greater leveraging of supply assets and higher equity profits to the producer. Thus, all other things being equal, gas producers may be willing to provide a discount for a long-term contract with high minimum-take or GIC provisions. The ultimate premium or discount

[4] Owners of nonutility electric generation projects appear to be the biggest buyers of long-term contracts. Contracts with durations of 15 years or more have been signed, often as a way to facilitate the project's financing.

for long-term contracts will be best determined in a competitive marketplace. From a policy perspective, it is more appropriate for PUCs to allow market forces to determine ultimate price relationships rather than to accept assertions that term premiums are positive, negative, or zero.

LDCs also consider diversifying with respect to factors other than contract term. Diversity with respect to geography is important because it tends to improve reliability. Well freeze-ups or hurricanes in one area may not affect another area. Geographical diversity also improves the LDC's competitive position: the LDC is not captive to suppliers from a particular region. Even if geographical diversity cannot be achieved because of unavailability or expense of facilities that connect to alternative supply basins, diversity in ownership is also valuable; it means the LDC is not captive to any one producer or pipeline and reduces the risks associated with a particular supplier having financial problems. Diversity can be sought both at the time of solicitation and from the time that delivery of gas is taken. One of the advantages of competitive bidding is that the LDC can consider offers from a large number of potential suppliers (see Section 4.2.4).

Managing the Producer Load Shape

Average load factors for gas LDCs are low. In 1991, residential load factors were 45%. The load factor for all sectors (residential, commercial, industrial, electric utilities) was 67% (Energy Information Administration (EIA) 1993b). In addition, temperature-sensitive loads of firm customers vary greatly from winter to winter, making load factors for planning purposes even lower. Contracting for a low-load-factor load in isolation requires acquisition of wellhead and pipeline capacity that will be poorly utilized. In general, a gas buyer can get better price terms by buying at a high load factor.

LDCs can do several things to improve their buying power with producers despite the fact that many of the end uses or customer classes served by LDCs have low load factors. First, LDCs can diversify demand among different groups of customers before seeking gas supplies: the loads of low-load-factor customers may be combined with interruptible customers or customers that have counter-cyclical loads. For example, firm heating loads can be combined with interruptible loads or with electric generation loads. LDCs can perform this aggregation function or groups of customers can band together before entering into supply contracts. Also, smaller LDCs can benefit by teaming up with other LDCs on the same pipeline to reduce transactions costs and, possibly, improve load factors. Of course, when two different types of customer groups are combined, cost and risk allocation issues need to be considered. For example, if an LDC combines residential and commercial loads with industrial loads, and subsequently must pay a GIC or minimum-take charge because of reduced industrial load due to bypass, there is an unforeseen cost that must be absorbed by either the remaining sales customers, LDC shareholders, or, possibly, the industrial customer who left the system.

Second, the LDC can use storage or peak-shaving facilities. Such facilities are discussed in more detail in Section 4.3.

Third, PUCs and LDCs can develop customer buyback arrangements. Many states already have mandatory curtailment provisions, and the terms *firm* and *interruptible* generally separate the highest priority customers from lower priority customers. In fact, however, customer value of service exists over a wide range and many PUCs are moving to voluntary curtailment provisions. Customers who are interruptible by default are given the option to buy firm or near-firm service if they wish. One way to improve the range of services offered and to improve LDC load shapes is to have LDCs enter into contracts with customers with firm or near-firm rights but be allowed to curtail them in certain periods of high demand. These contract may specify compensation to the customer in return for curtailment. The gas utility improves its load shape as a result, and no party is involuntarily curtailed.

4.2.4 Regulatory Oversight of LDC Supply Portfolios

As the range of gas supply options increases for gas utilities, PUCs may need to re-evaluate their regulatory framework for the review of gas supply portfolios. Because gas supply purchases account for such a large proportion of an LDC's average rate, PUCs have a particular interest in reviewing a utility's gas supply planning and purchase practices. Four general regulatory approaches for reviewing gas supply portfolios are discussed although none are mutually exclusive: (1) reasonableness reviews, (2) portfolio preapproval, (3) incentive mechanisms, and (4) deregulation. Table 4-2 also provides a description of the approaches with respect to key policy attributes.

Reasonableness or Prudence Reviews

Almost every PUC in the U.S. has allowed LDCs to set up a fuel offset or purchased gas adjustment (PGA) account to improve, compared to traditional rate cases, the LDC's ability to recover gas supply costs (Burns et al. 1991). PGAs allow for more frequent revisions of rates to adjust for changes in gas supply costs. Most PGAs allow for "truing up" of forecast and actual costs, which substantially reduces LDCs' risk for recovery of supply costs. In response to this risk shift, many PUCs conduct audits or hold hearings to review the reasonableness of utilities' purchases. If utilities are found to be unreasonable, some portion of the cost of the purchases may be disallowed recovery in rates. The reasonableness review approach has the advantage of allowing PUCs to review

Table 4-2. Approaches for Review of LDC Gas Supply Purchases

Regulatory Approach	Is PUC Oversight Proactive or Reactive?	Ability of Approach to Adapt to Changing Market Conditions:
Reasonableness Review	• Reactive	• Low, unless PUC commits to a high level of staff resources
Preapproval	• Proactive	• Medium (preapproval of specific contracts) • High (preapproval of contract mix only)
Incentive Regulation	• Proactive	• High, until conditions change so much that index is no longer fair
Deregulation	• Oversight is relinquished until PUC decides to re-regulate	• High

utility decisions before ratepayers pay the full bill. Reasonableness reviews reduce an important asymmetry of information that exists between a utility and its regulator. The regulator can never hope to have all the information that the utility has on an ongoing basis. In an *ex post* environment, however, the PUC has enough time to get all the facts it needs to review the reasonableness of a gas utility's supply portfolio. Reasonableness reviews, although generally unpopular, have been effective in catching or preventing large errors made by LDC managers. As PUCs have improved their audit and analysis capabilities, reasonableness reviews have become more comprehensive and have been cited as causing inappropriately risk-averse behavior on the part of LDCs. Some analysts have argued that LDCs, in an environment of intense prudence reviews, begin to purchase gas not to meet the overriding goals of reliability, cost, and cost stability, but rather purchase gas in ways defensible in a reasonableness review (Pocino 1993). Although PUCs can continue to use reasonableness reviews in a post-636 world, the job of reviewing reasonableness will become more complex as the range of utility options increases. LDCs and producer interests are likely to claim that reasonableness reviews in a post-636 world impede LDCs from making the best gas purchases. However, regulators will be reluctant to remove after-the-fact reasonableness reviews because their regulated utilities that have heretofore been protected and many will not have a proven record of operating in competitive gas markets.

An alternative to the reasonableness review approach that is somewhat more forward looking but does not require express preapproval by PUCs is the use of informal meetings between LDCs and regulators to discuss gas procurement decisions in advance. Such processes allow the LDC, the PUC, and PUC staff to exchange information and to understand each party's thoughts and considerations. In such a process, the PUC still retains its rights to conduct reasonableness reviews at a later date. PUCs in California, Illinois, Ohio, and New York have used this approach in the past and, for some states and in some cases, it has helped eliminate contentious reasonableness review proceedings.

Preapproval and Competitive Bidding

An alternative or supplement to reasonableness reviews is the use of regulatory preapproval. Any LDC can consider preapproval as a regulatory approach but PUCs that expect to adopt specific LDC integrated resource plans (see Section 2.5) must decide whether and how far the preapproval of the plan extends into the gas procurement area. In the preapproval approach, an LDC files a procurement plan and, possibly, a set of specific contracts for preapproval. The procurement plan, specific contracts, or both are subjected to hearings and are ultimately approved, approved with modifications, or denied by the PUC. With preapproval, utilities are not subject to the same degree of regulatory risk as is the case with the reasonableness review approach. If the PUC has a preapproval process, then the LDC is held responsible only for the way it executes the plan or the way it responds to new situations not foreseen in the plan. If the utility has preapproval for specific contracts, then it is at risk only for review of the management of those contracts. Utilities can also be at risk if they intentionally misrepresent their supply alternatives in the preapproval process.

Although competitive bidding is not an approach to regulatory review, it can be particularly helpful in facilitating a preapproval process. The use of competitive bidding by an LDC can reduce the PUC's regulatory review dilemma because bidding relies on competition, rather than utility management actions, to find the best possible price for each type of gas supply contract. Bidding, in conjunction with preapproved market shares for short- and long-term contracts, has been proposed by Jaffe and Kalt (1993) as a workable approach to preapproval. Public bidding for spot gas is common, but public bidding for long-term contracts (as envisioned by Jaffe and Kalt) is less common. Even if it were used more frequently by LDCs, bidding would not be simple because many of the desirable attributes of a long-term contract, such as bidder reputation or supply reliability, need to be evaluated along with the bidder's price. Moreover, LDCs may request confidentiality for many of the contract terms, including price terms, which further complicates the process of regulatory preapproval.

Incentive Regulation

Incentive regulation attempts to harmonize the least-cost goals of the ratepayer and the profit motives of the LDC. Incentive regulation often does this by increasing the financial incentive for the utility to reduce its costs, usually by decoupling prices from costs via an external cost index. Because of the financial incentives it offers the utility, incentive regulation usually eliminates the need for retrospective reviews of utility gas purchasing decisions. Sustained or increased oversight of the LDC's service reliability is usually necessary by the PUC to make sure an LDC does not improve financial performance by degrading quality.

There are several ways that incentives can be used as a substitute for traditional regulation of gas LDC procurement decisions. First, PGAs could be eliminated and the gas commodity portion of rates would be set in rate cases. This form of intentional regulatory lag would give utilities an incentive to minimize gas purchase costs between rate cases. Second, PGA mechanisms could be retained, but "true-ups" would occur only for a fixed portion of the utility's purchased gas costs. Thus, the utility would have a financial interest in any changes in purchased gas costs relative to those set in rates. Such a mechanism, in which the utility was at risk for 20% of deviations in the PGA account, has been used in Oregon (Burns et al. 1991). Third, incentives based on indices could be used as benchmarks for setting rates. If a utility's costs are lower than a chosen index, it can keep a portion of the savings. Conversely, if purchased gas costs are higher, ratepayers are at risk for only a portion of the shortfall (Harunuzzaman et al. 1991). Such a mechanism has been proposed by economists for some time and has recently been adopted by the California PUC for San Diego Gas and Electric Co. (California Public Utilities Commission (CPUC) 1993). The challenge with indexed-based incentive mechanisms is in developing the benchmark formula. The majority of publicly-available gas prices are for spot transactions and many LDCs would balk at being held to a spot-only price standard when they are trying to achieve a high degree of reliability. However, there are ways to address this problem. For example, it is possible to set the index as a *function* of spot prices rather than exactly equal to spot prices. It is also possible to use the gas costs of similarly situated utilities in the index formula.

Deregulation of Gas Procurement

Another approach to regulatory oversight of LDC procurement activities is to rely on competition via deregulation. Deregulation reduces the need for regulatory oversight of LDC's gas purchases as fewer customers rely on the LDC for procurement services. For customers who purchase gas from the LDC but have the *option* of transporting their own gas, it may make little sense to have a PGA or to review the LDC's procurement decisions. Instead, the gas utility could be given the option to quickly change prices with no PUC approval. The gas utility would have the discipline of the marketplace to keep its prices low and service reliability high.

It is generally acknowledged that there are limits to how far customer-owned transportation will extend. Thus, there are limits on how far deregulation of LDC procurement activities can go before the risk of LDC's abusing their monopoly power becomes large. Recent evidence indicates, however, that transport-only service may be feasible for more customers than was once believed. The term core customers was first coined to identify customers who want vertically integrated services from the LDC. The definition of core customers has required revisions in recent years as many smaller industrial and larger commercial customers have become transport-only customers via aggregation programs. Even smaller customers, such as schools, churches, and fast food restaurants have participated in self-procurement programs in California and in Toronto, Canada (Lemon 1993). If such aggregation programs become sustainable, PUCs may have reason to further diminish their regulatory oversight of LDC procurement practices.

4.3 Planning for the Expansion of Capacity

4.3.1 Overview

This section focuses on the capacity expansion process, which, in this discussion, is defined as the process of choosing facilities that deliver gas from the wellhead or pipeline intake to the LDC's local transmission and distribution (LT&D) system. LT&D planning, while an important part of an LDC's overall planning, is not discussed because of space constraints in this chapter. Most facilities considered in the capacity planning process are expensive and long-lived; thus, attention to resource planning is warranted. This section describes the major capacity options and discusses simple and complex planning methods. Issues that are highlighted include: methods of screening resource options, consideration of storage resources as an alternative to pipeline supply, treatment of bypass in capacity planning, and the "build-versus-buy" problem.

Table 4-3. Overview of Gas Capacity Options

Option	Description/Features
Pipeline Firm Transportation	Firm transportation service is now sold on an unbundled basis. Firm transportation may be acquired when a sales customer converts contract demand quantities to firm transportation capacity, through the reservation of existing or new capacity held by the pipeline, or through short- or long-term release contracts.
Pipeline "No Notice" Service	For pipeline customers who took bundled city-gate service as of May 18, 1992, pipelines will be required to provide "no-notice" service as part of tariffs in compliance with FERC Order 636. No-notice service is technically a transportation service—customers can take gas at their delivery point in excess of their scheduled quantity without advance notice up to the MDQ in their service agreement with the pipeline. Customers are ultimately responsible for arranging the gas supply.
Pipeline Interruptible Transportation	Interruptible transportation does not provide any firm capacity.
Storage	Storage is used to balance the system on a daily basis, provide peak-season capacity, and provide capacity on an extreme peak day. Because of volume constraints, storage is not appropriate as a year-round source of capacity. Availability of underground storage is limited to certain geographical areas.
Propane-Air	Propane-air systems are smaller systems built near load centers used primarily to meet peak loads. Propane air systems are primarily limited to areas where underground storage is unavailable.
Liquified Natural Gas (LNG)	LNG provides a similar function to storage in areas that do not have natural storage resources. LNG facilities built in conjunction with marine terminals can use imported LNG supplies.
Customer Buyback	LDCs can make or facilitate arrangements via prearranged contracts or tariffs to buy gas and/or gas capacity rights from certain firm customers to meet the needs of other firm customers during periods of critical demand.

4.3.2 Options for Providing Gas Deliverability

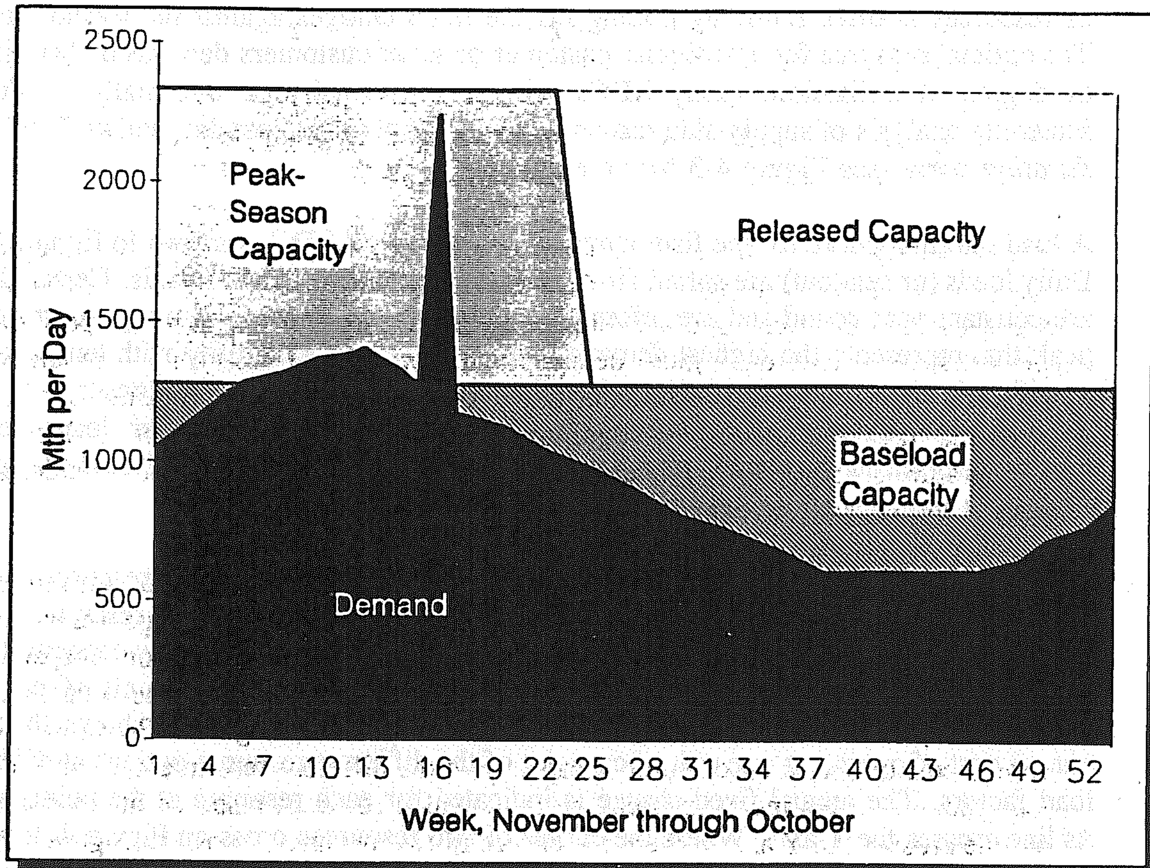
Gas LDCs can provide in several ways for capacity within their service territories (see Table 4-3). Interstate pipeline capacity and storage capacity are the two most common sources of capacity, and propane-air and liquified natural gas (LNG) systems have also provided capacity in certain areas. LDCs that have supply resources in their state also rely on intrastate pipeline capacity.

New Ways to Contract for Capacity: Capacity Release and Buyback Programs

Although the physical means of providing capacity has not changed much in recent years, the ways that LDCs can contract for the capacity have changed. A vivid example of a new way of contracting for capacity is the option of acquiring it on a secondary market through the capacity release program allowed for in FERC Order 636. All pipelines are required to set up a capacity release system so that firm customers (releasing shippers) may sell (release) their capacity rights in a secondary market. The program supersedes earlier attempts at creating secondary markets via brokering and buy-sell programs. Unlike these earlier programs, all secondary transactions are controlled by the interstate pipeline and are subject to FERC oversight. A firm capacity holder may release its capacity for any term up to the term of its service agreement with its pipeline. The releasing shipper may come to the pipeline with a prearranged deal or may publicly solicit bids via the pipeline's electronic bulletin board. There is considerable flexibility in how the release contract may be written so long as the terms of the release are nondiscriminatory; i.e., other prospective shippers have a fair opportunity to bid on the same release contract. Release contracts will go to the highest bidder subject to the FERC-approved maximum pipeline rate for firm service. Also, prospective shippers in prearranged contracts have the right of first refusal to match any competing, higher bids. The releasing shipper is still liable for the full reservation charge and any reservation surcharges associated with its release contract should the buying shipper fail to pay on its release contract. Thus, the creditworthiness of any prospective shipper is an important factor from the point of view of the releasing shipper. As a result, many pipelines are attempting to establish requirements for determining the creditworthiness of prospective shippers.

From the perspective of resource planning, the advent of a secondary market for firm transportation capacity allows for planning flexibility. LDC planners can now assign a value to an existing capacity resource rather than simply treat it as a sunk cost for the life of the service agreement associated with the resource. Planners can make forecasts of the market price of the release capacity and consider alternative capacity options, such as storage, that may be more economical than holding onto existing pipeline capacity. Given the move to straight-fixed variable (SFV) pipeline rate design, such options are being seriously considered by LDCs. Figure 4-2 provides an example of how one LDC, Washington Water Power Co., expects to release its firm capacity on a seasonal basis. The biggest difficulty in considering capacity release as a resource option is that it may be very difficult to forecast the price of released capacity. As long as it is likely that

Figure 4-2. Potential Releasable Capacity in a Year: Washington Water Power Co.



there is some value to the pipeline capacity in a release market, however, LDCs should evaluate the need for the capacity and consider whether there are options cheaper than pipeline capacity that provide the equivalent amount of capacity.

Another contractual option for the acquisition of capacity is customer buyback contracts. Under buyback programs, LDCs facilitate arrangements in which certain firm customers acquire the right to buy back capacity and supply from other firm customers during times of peak demand. Buyback programs have been developed in California where the investor-owned LDCs will, under extreme conditions, divert sales gas and transportation gas (and the capacity that goes along with it) from firm noncore customers to firm core customers (California Public Utilities Commission (CPUC) 1991; California Public Utilities Commission (CPUC) 1992c).

4.3.3 Methods for Screening Resource Options

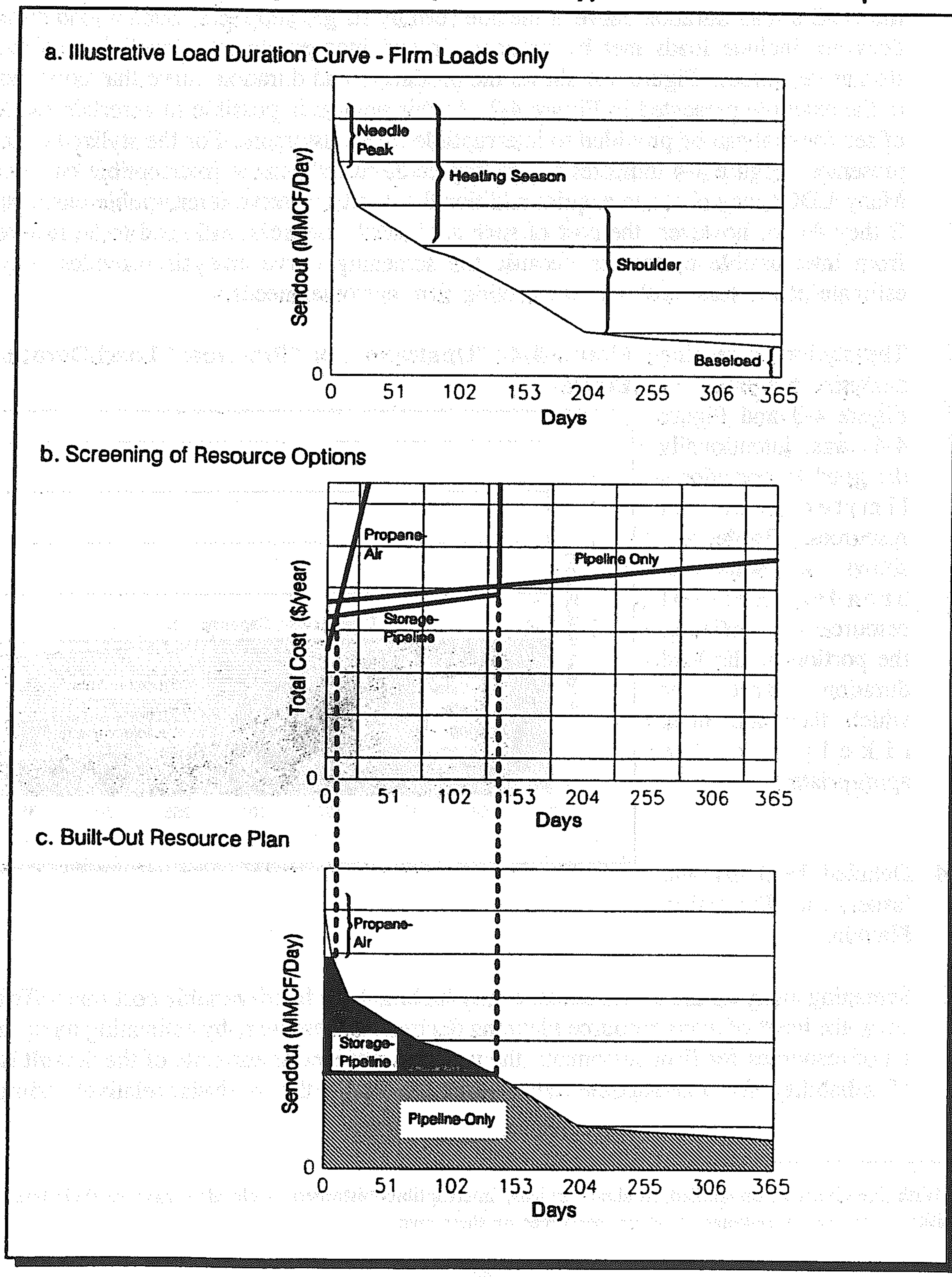
Gas utility supply resources have fixed- and variable-cost components. The optimal mix of resources is often found by trading off the fixed charges against the variable costs. The optimal resource for a particular customer or set of customers depends on load factor or degree of utilization. Many LDCs will either formally or informally conduct a screening analysis of supply-side resources using supply-side cost data and an LDC *load duration curve* (see Figure 4-3 for an example).

A load duration curve for the firm loads of a hypothetical LDC is shown in Figure 4-3a. Daily loads (or sendout) are sorted from highest to lowest along the X-axis. Certain loads are constant year-round and are referred to as base load. There is also a peak or needle peak that represents the highest demand conditions. For a gas utility with temperature-sensitive loads, the needle peak is based on design peak-day conditions rather than expected (average) peak-day conditions. Winter season and shoulder loads reflect temperature-sensitive loads; other variations in loads that appear in the shoulder area are caused by weekday-weekend demand fluctuations.

It is possible to make an initial assessment of the optimal mix of resources using screening curves for various resources such as propane-air; storage reservoirs with associated injection, withdrawal, and pipeline capacity; and pipeline-only capacity (Stoll et al. 1989) (see Figure 4-3b).[5] Using cost data normalized to one unit of capacity ($/MMcf) and estimates of associated commodity costs, Figure 4-3b shows the total annual cost of operating one unit of capacity of the different resource options at different load factors. The annual fixed charge is indicated for each resource at the point where its line crosses the Y axis. Where the curves of two resources cross on Figure 4-3b gives an indication of the optimal size and load factor for a particular resource. Because storage resources need to be filled, a particular storage-pipeline combination has a maximum load factor above which it cannot be used. Thus, the screening line for the storage-pipeline option has a cost "kink" at its maximum capacity factor. In this stylized example, the propane-air plant is not optimal to run more than nine days per year. The storage-pipeline resource is cheaper to run than a pipeline-only resource but only up to the point of its maximum capacity, approximately 85 days per year. For the remainder of the year, it is optimal to use pipeline-only resources. Figure 4-3c shows the dispatch of firm loads based on the screening curve analysis.

[5] Although not shown in the example, an existing resource may be screened against other alternatives by setting the Y-axis intercept at the resale value of the resource. For example, the resale value of existing pipeline capacity may be set at its estimated release price. Care must be taken to make sure the optimal size determined by the screening curve mix is feasible for the existing resource.

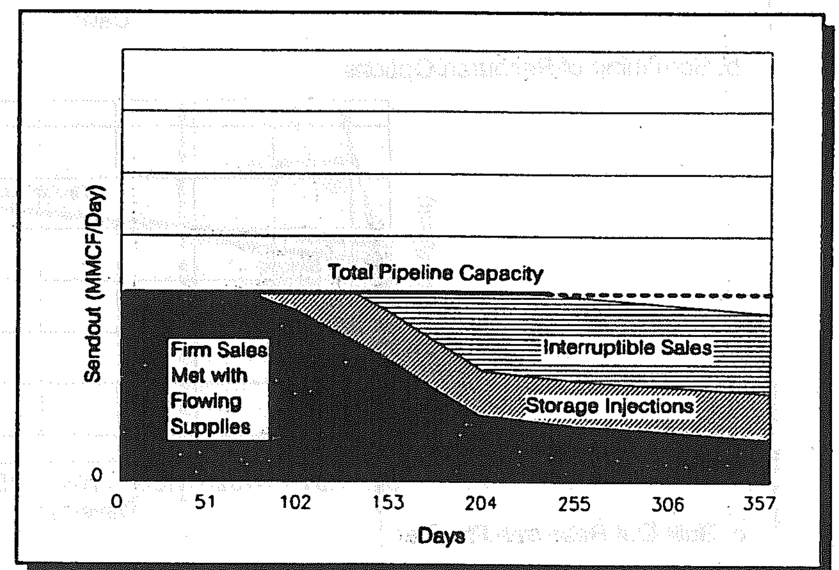
Figure 4-3. Screening Curve Analysis for 3 Hypothetical Resource Options



For an LDC, the built-out load duration curve shown in Figure 4-3c shows how demands of firm customers are supplied on the LDC's system. Another useful representation of the LDC's load duration curve is the one seen by its gas suppliers. Such a load duration does not include loads met by propane-air and incorporates the levelizing effects of storage resources. Figure 4-4 shows the producer load duration curve that corresponds to the example presented in Figure 4-3. At this point it is possible to ascertain the level of service that can be provided to interruptible sales customers. For the stylized example presented, Figure 4-4 indicates a high degree of curtailment to interruptible customers. Many LDCs may chose to acquire additional capacity to serve interruptible customers.[6] If they do so, however, the cost of such additional resources will need to be recovered from interruptible customers because the screening curve analysis provides only an estimate of the least-cost way of meeting firm customer needs.

The stylized screening analysis presented in Figure 4-3 and Figure 4-4 was intentionally designed to consider a limited set of resources. Table 4-4 shows a somewhat broader set of resources and indicates the portion of the load duration curve for which they are most likely to be appropriate.

Figure 4-4. "Upstream" or "Producer" Load Duration Curve



4.3.4 Detailed Methods and Issues in Expansion Planning

Screening analyses are useful because they highlight the fixed-variable cost tradeoffs that are at the heart of many resource planning decisions. Moreover, by estimating an optimal set of resources for firm customers, the analysis provides an estimate of the default level of reliability for interruptible customers. To make the analysis relatively simple,

[6] With the advent of unbundled pipeline services, interruptible customers could also improve their level of reliability by acquiring upstream capacity resources on their own.

Table 4-4. Typical Screening of Gas System Capacity Options

Option	Relative Fixed Costs	Appropriateness for the Following Load Types: Base	Shoulder	Heating	Peak
1. Pipeline Firm Transportation	H	Y	Y	Maybe	Maybe
2. Pipeline No-Notice Firm Transportation	L	N	N	N	Yes
3. Pipeline Interruptible	L	Maybe	Maybe	Maybe	No
4a. Pipeline Storage	M	N	N	Y	Maybe
4b. Building Storage	M	N	N	Maybe	Y
5. Propane-Air	L	N	N	N	Y
6. LNG Plant	M	N	N	N	Y
7. Customer Buyback	L	N	N	N	Y

Notes: L, M, & H represent low, medium, and high, respectively.
Source: Adapted from Newman and Kaul (1992)

however, certain complexities are suppressed in the screening curve methodology:

- Transport-only demand is an important component of many LDCs' throughput. Even though transport customers can be incorporated into a screening curve analysis, the LDC does not control the commodity supplies chosen by the transport-only customer and it may have little control over the upstream capacity that is contracted for by the transport-only customers. Thus, an LDC's planning for transport-only customers will be predominantly limited to forecasting transport-only customer choices and estimating the cost implications of these choices on the LDC's system.

- The load duration curve suppresses significant year-to-year variation in loads that are common on LDC systems. In any particular year, the capacity utilization of a particular resource may be much higher or lower than the levels shown in the screening curve method. Similarly, the level of service that can be provided to interruptible customers can show significant year-to-year variation.

- Load duration curves suppress the chronological variation in loads. Such variation may be important because the costs of some supplies vary by season and some resources can only change or sustain their output up to a limit. For example, storage resources may be able to run at peak capacity only for a matter of days before inventory levels fall, causing pressures and withdrawal capacity to drop.

- Optimal quantities of resources estimated by the screening analysis may be infeasible. Many resources come in fixed sizes and these constraints need to be considered.

- Differing reliability of resources needs to be considered.

- Screening analyses typically do not explicitly address uncertainties associated with cost and availability. A complete analysis would attempt to quantify risks and uncertainties in addition to quantifying expected costs.

More comprehensive and detailed methods are required to handle these additional complexities. LDCs typically perform more detailed analyses using one of two general modeling techniques: (1) iterative simulations and (2) optimization models.

Iterative Simulations

In the iterative simulation approach, the LDC uses rules of thumb or carefully chosen assumptions to decide which resource to acquire next. Using an initial set of assumptions an initial resource plan is simulated for a multi-year period. Although a computer simulation model for annual dispatch may be used, the planner rather than the model articulates the LDC's capacity configuration. For many LDCs, the initial plan is built out using existing capacity resources and incremental pipeline capacity. From the initial case, alternatives to the resource plan are tested. For example, a storage project may be tested and compared to incremental pipeline capacity. As another example, an LDC may consider releasing or relinquishing capacity and letting transport-only customers acquire capacity on their own. Alternative plans are simulated until a balance is achieved among particular indicators such as: total present value cost, curtailments, and the quantity of fixed-cost obligations entered into. Although this method may seem ad hoc or imprecise, it has advantages. For many LDCs, total growth in demand is not large, and many existing resources are effectively sunk costs. Thus, the number of resource option combinations for meeting demand in the future is relatively small and can be articulated without the aid of a detailed computer model. In addition, there may be considerable uncertainty associated with many of the cost estimates, so the possible benefit of fine tuning relative shares of the resource options may be small compared to the associated uncertainty of the resource plan's total cost.

Methods Using Optimization Models

Optimization models are detailed computer models that attempt to compute a least-cost resource plan considering the costs of resources, customer demand, reliability criteria, and other relevant constraints. The goal of the process is the same as for the iterative simulations method except that a computer model is used to estimate the LDC's capacity configuration rather than having the capacity configuration set iteratively by the planner. Optimization models may use simulation (internal to the model), linear programming, or other optimization techniques to find a resource plan (solution) that best meets the objective function. The objective function is usually specified as the total present value cost of a resource plan subject to a reliability constraint (see Section 3.8 for a list of commercially available optimization models).

4.3.5 Issues in Gas Capacity Planning

In this section, several of the most important resource planning issues for LDCs are discussed to provide insights into why more sophisticated LDC planning methods are often needed and why actual plans are often revised frequently.

Storage

LDCs that, in a pre-636 world, received storage as part of bundled pipeline sales service will now have to buy it on an unbundled basis along with pipeline capacity and gas supply.[7] Thus, LDCs and direct consumers of the gas pipeline system must now reconsider the purpose of existing storage and consider investments in new types of storage. Storage has four general functions for LDCs:

- Daily balancing: LDCs move gas in and out of storage on an hourly and daily basis to compensate for regular imbalances in supply and demand.

- Seasonal balancing: LDCs increase load factors and minimize upstream pipeline capacity requirements by acquiring storage to meet significant

[7] Pipelines will still retain some storage facilities to provide day-to-day balancing of pipeline transportation services.

portions of peak-season loads. Having storage is usually more economic than relying on pipeline capacity alone.

- Peak-day protection: During the months most likely to include an extreme peak day, storage withdrawal capability is kept at a maximum. Providing this capability usually requires a certain amount of extra inventory on hand to keep field pressures high. Once the possibility of a peak day has diminished, the gas inventory may be used for other purposes.

- Economic benefits: Storage resources can be used for economic benefits in supply markets. Inexpensive gas supplies generally available in off-peak periods can be stored and used in times of higher prices. Further, firm gas contracts can cost less if they can include high take provisions that are facilitated by storage facilities.

Different types of storage systems have different strengths and weaknesses in terms of being able to provide the four general functions described above (see Table 4-5) (Duann et al. 1990). Underground depleted reservoirs and storage from aquifers are generally the cheapest types of reservoirs to develop. Gas in and out of these reservoirs flows slowly, so if high deliverability is desired, many withdrawal wells must be developed or a large inventory of gas must be kept in the reservoir. Salt domes are more expensive to develop than these other two options but offer fast withdrawal capability, which makes them well suited for peaking, daily balancing and shorter-term cycling. Pipeline line pack is a byproduct of the pipeline system. Its inventory size is limited but is often an important resource for daily balancing. LNG systems provide another storage option; they are expensive but are not geographically limited like underground reservoirs. Thus, they may be a viable storage resource where other options are unavailable.

No definitive conclusions may be drawn when comparing the types of storage resources to storage functions because the cost and availability of storage varies by region, and every LDC's load shape is different. The concept of "layering" storage, where LDCs use more than one kind of storage resource to meet different storage functions, makes sense for many LDCs (Bickle 1993). For example, demand variations that require frequent storage cycling may be best levelized using storage provided in salt domes while steady winter season demand can be best supplied by depleted oil and gas reservoirs. An LDC also will need to consider the location of the storage resource. Storage close to an LDC's loads provides extra reliability benefits and decreases the cost of pipeline capacity. Storage located close to production fields or near major pipeline interconnections is more likely to exist already, or, if new, is likely to be developed by multiple sponsors. Therefore, storage in these locations is likely to be more flexible and/or come at a lower cost. Although not near LDC load centers, storage near production areas or market centers can provide many functions, including the economic optimization of supply

Table 4-5. Types of Storage Resources by Type of Reservoir Facility

Type of Storage	Features
Depleted Oil & Gas Reservoirs	Inexpensive to develop reservoir, limited to certain geographic areas. Reservoir of permeable rock requires many wells or a large inventory to provide deliverability
Underground Aquifers	Same as above; may be available in areas where depleted reservoirs are not. Viability of aquifers as gas reservoirs requires extensive testing.
Mined underground reservoirs (including salt domes)	Compared to alternatives above, more expensive to develop. Usually provides a high degree of cycling capability.
Pipeline line pack	Amount of available line pack generally limited; depends on pipeline configuration.
LNG	Can be built in a wide range of areas and, if built with a marine terminal, can take supplies from overseas. More costly to develop, higher running costs, safety considerations.

Source: Duann et al. (1990)

contracts, provided that sufficient downstream capacity is contracted for by the LDC.[8]

Scope of the Resource Plan

With the option of releasing or relinquishing capacity, LDCs have gained flexibility in the way they contract for pipeline capacity. Such flexibility, however, raises issues of scope for the planner. For many LDCs, the most likely buyers of released pipeline capacity will be large customers of the LDC. Even if large customers of the LDC do not bypass the LDC's system within its service territory, they may choose to contract for their upstream capacity rights independent of the LDC. Although LDCs, PUCs, and customers should certainly evaluate the potential benefits of such capacity transfers, these

[8] A market center is an area where many interstate pipelines meet that allows gas purchasers to choose among multiple suppliers.

transfers may have little impact on the total cost of gas facilities in an LDC service territory because these transfers represents a cost shift rather than a reduction in total facility costs.

Similarly, scope issues arise when an LDC considers terminating, or reducing the size of a service agreement with a pipeline. If there is no market for the unloaded capacity, it will end up as a stranded investment and may not represent a cost savings from a regional or societal perspective even though it may be pursued by the LDC to lower its costs. Further, under FERC cost-of-service ratemaking, LDCs that unload capacity that becomes stranded may face higher future rates when the pipeline attempts to recover its stranded costs from remaining customers (including the LDC) in a future rate case.

Ownership of Capacity: Buy versus Build

Most of the resources that provide deliverability are long lived. LDCs make long-term cost commitments when they (1) build long-lived facilities that have little resale value or (2) enter into a long-term agreement to purchase a resource from an independent provider. Resources provided by independent suppliers with few long-term commitments may not be "least-cost" in a static analysis but may be valuable from a risk management perspective because they do not obligate the LDC to purchase the resource if conditions change. For resources built near load center, there may be no alternatives to having the LDC construct the resource or commit to it on a long-term basis. Pipeline and storage resource options, however, will be more fungible. Existing pipeline capacity may be released or relinquished; new or existing pipeline capacity may be purchased as part of a bundled product from a producer or marketer; and storage resources constructed near production fields or market centers may be built as joint ventures and sold in small portions for limited terms. Prices for use of these facilities will be set more often by the marketplace than by the regulator. LDCs need to weigh the flexibility of going to rented resources against cost and reliability considerations.

Incorporating Potential Bypass into the Resource Planning Process

Sensitivity to potential bypass is an important consideration in utility resource planning. In the past, bypass was limited to large customers who could burn alternative fuels. This bypass option still exists but is becoming limited in certain parts of the country because of more stringent air quality regulations. Direct connections between customers and interstate pipelines are another form of bypass. FERC Order 636 and other FERC decisions have increased bypass pressures for many LDCs. FERC's adoption of SFV rate design, which effectively lowers rates to customers with high load factors, may make bypass attractive to these customers to the extent the changes to SFV are not reflected in the LDC's transportation rates.[9] FERC Order 636 also allows for the pass-through of transition costs to LDCs and their customers. Via bypass, industrial customers may be able to avoid paying some of the Order 636-related transition costs that they will pay if they stay on the LDC's system.[10] As customers bypass the LDC's system, there is the potential for stranded investment on the LDC system. Depending on how it is allocated, stranded investment can raise the rates of remaining customers and can induce further LDC bypass.

Bypass considerations do not fundamentally alter the planning process. However, bypass increases uncertainty with respect to sales, throughput, and cost recovery. LDCs should consider the impacts of higher-than-expected bypass before entering into any new, long-term resource commitments. Also, the rate impacts of any resource plan on rate-sensitive classes has to be carefully considered.

4.4 Reliability and Contingency Planning

4.4.1 Overview and Conceptual Framework

As is readily apparent in the preceding sections, the reliability of gas supply and capacity options is an important quality to the LDC or customer. The reliability that is ultimately provided to a customer depends on multiple supply- and demand-side considerations; because of this, IRP for gas LDCs should explicitly include a *reliability planning* component. A major purpose of reliability planning is to strike a balance between reliable service and reasonable cost. Because demand, supply cost, and supply availability are uncertain, it is difficult to balance reliability and cost objectives. For a typical gas system, it is relatively inexpensive to meet average gas demands. However, for firm customers who depend on supplies in cold weather when demand is high, such a system would be unsatisfactory. At the other extreme, it is possible to build gas systems to meet all foreseeable demands; such a system would be reliable but expensive. For example,

[9] Many LDCs will allow industrial customers to contract directly with the upstream pipeline for transportation services, thus allowing the benefits of SFV to flow to the customer.

[10] If a customer bypasses an LDC and reserves firm transportation service from the interstate pipeline that serves the LDC, it will be required to pay a transition cost surcharge on its reservation charge just like the LDC. Bypass customers may be able to pay lower transition costs, however, if (1) the LDC, through its cost allocation process, allocates more transition costs to the bypass customer than it would pay by directly contracting with the pipeline, (2) the bypass customer purchases only interruptible transportation service which receives a lower transition cost allocation under the FERC's rules, or (3) the bypass customer buys released capacity at a discount or transportation service with a different pipeline that has no, or lower, transition costs.

a 7% reserve margin on pipeline capacity can add 1% to the average rates of a typical LDC.[11]

Contingency planning is the process of setting up plans or rules that respond to events that can cause curtailments. Whereas reliability planning focuses on determining the appropriate quantities of long-term resources to provide adequate services, contingency plans focus on short-term actions that can mitigate a curtailment in response to an uncommon or unforeseen event. Contingency planning may be seen as a way to maximize the reliability of a system given a fixed set of supply and capacity resources, especially for firm customers.

Reliability is a relatively precise concept: it is the probability that demand will exceed supply in a given period (Kahn 1988). Probabilistic methods are necessary to compute reliability because both demand and supply exhibit random variation. The term Loss of Load Probability (LOLP) has been developed for measuring the reliability of electric systems and the term Loss of Load Risk (LOLR) has been used to quantify reliability of gas systems (Hiebert et al. 1992). Typically, reliability for gas systems is described in terms of actual or expected *curtailments*, which are the therms demanded but not served in a given period. Reliability can be measured historically or estimated for a future period. If it is measured historically, several years of data should be used because events in one year may not be representative of a system's true reliability.

An important component of reliability planning is establishing an appropriate reliability target or set of targets. All utility systems have a point at which adding additional facilities costs more than they are worth in providing reliability. In gas utility reliability planning, targets may be set based on standard industry practice or by performing a benefit-cost study that tries to find the optimal level of reliability.

A comparison of reliability planning in the gas and electric utility industries helps to illustrate the reliability problem faced by gas system planners. LOLP, or the associated criterion called expected unserved energy (EUE), is regularly computed by electric utility planners. Uncertainty in demand and supply can be characterized relatively precisely in that industry. There are reasonably good standards for identifying appropriate reliability targets and ongoing research on value of service is improving the accuracy of reliability targets. In comparison, the quantitative computation of reliability, especially forecasted reliability, for gas systems is difficult. Demand is much more random for gas systems than for electric systems. Gas supply resources also have random availabilities, but the distribution of those availabilities is not well understood. Actual physical failures of gas

[11] The example assumes an LDC with a 50% load factor, an average retail rate of $0.505/therm, and an avoidable pipeline reservation charge of $120 per year per Dth/day.

Table 4-6. Supply-Side Risks

I. Physical

- Wellhead or storage withdrawal:
  - -blowout
  - -freeze up
  - -damage caused by hurricane, tornado, or flood
  - -ground water intrusion
- LNG
  - -explosion
  - -condenser equipment failure
  - -electrical power failure
- Transmission, Distribution, or Storage Injection
  - -explosion
  - -accidental puncture of pipe
  - -vandalism

II. Contractual

- Producer/marketer nonperformance because of bankruptcy or other financial problems
- Buyer/seller price disputes that lead to nonperformance
- Gas supply and/or capacity diversion to another customer because of ill-defined interstate transportation rights
- Uncompensated diversion of storage gas by an adjacent well
- Gas supply diversion to another customer who is willing to pay more

production, transportation, storage, and distribution components appear small when compared to failure rates of thermal electric generation units. The lack of vertical integration, however, makes it difficult to characterize supply uncertainty precisely. Data on supply-side outages are not disseminated as widely in the gas industry as in the electric industry and, because gas LDCs do not directly control upstream gas supply and delivery facilities, there is an added contractual risk that resources will become unavailable even though the risk of physical failure is small (see Table 4-6). In addition, outage probabilities for electric utilities are usually computed assuming independence; in contrast, many of the risks faced by natural gas systems are correlated to weather and are, thus, dependent rather than independent. Finally, although both electric and gas customers value service over a wide range, gas systems are often faced with two groups of customers with very different reliability needs: residential and small commercial customers who cannot tolerate a loss of service, especially in cold climates, and large commercial, industrial, and electric generation customers who are often willing to accept curtailments of significant duration in return for competitive prices.

4.4.2 Reliability Planning in Practice

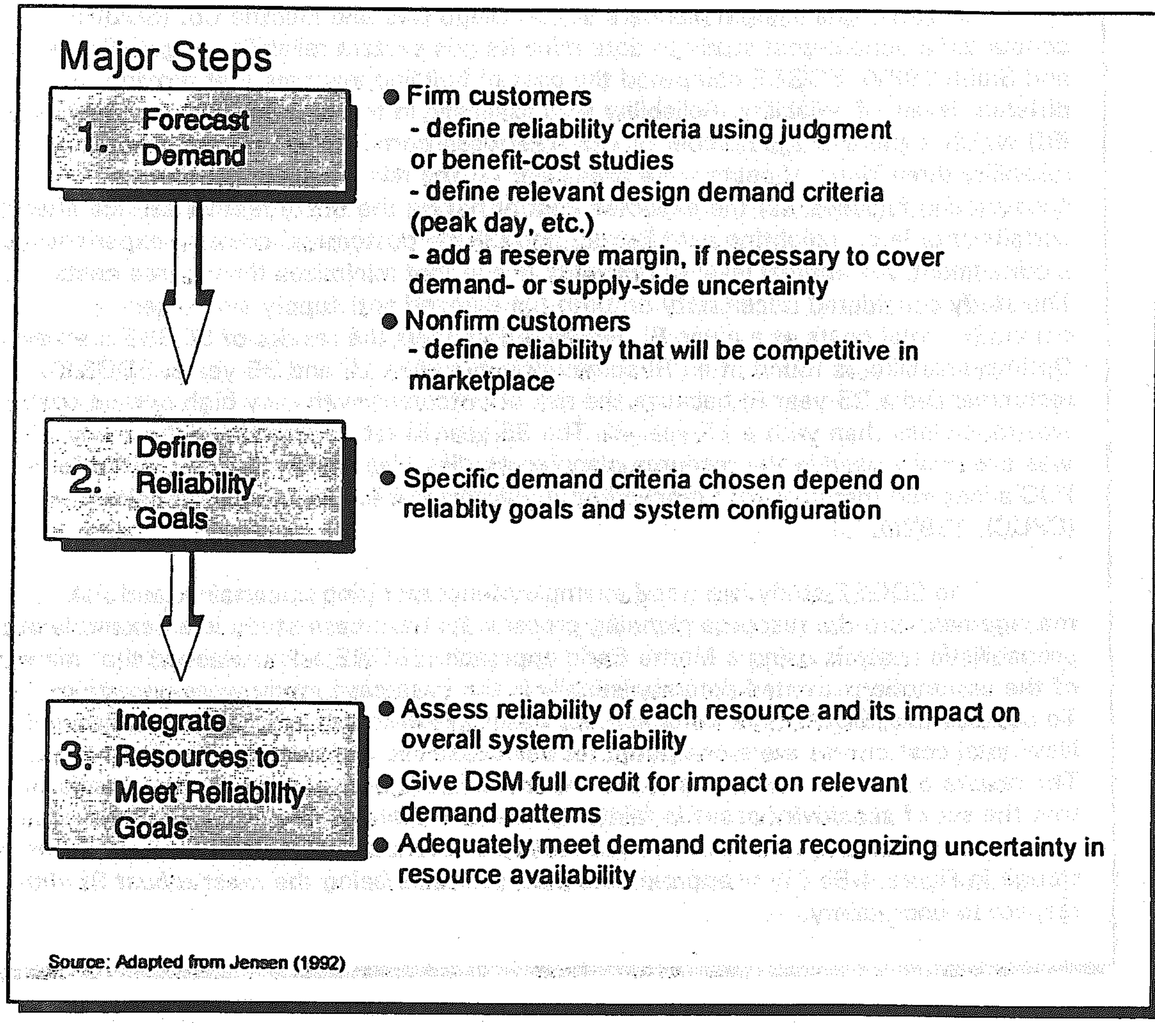
Although the conceptual framework for assessing reliability is similar in the electric and gas industries, gas system reliability planning has historically been based more on prescriptive rules than on detailed study. When gas LDCs define a peak day for firm demand, they typically incorporate extreme weather conditions for their service territories.[12] Sometimes an additional *reserve margin* is included to account for uncertainty in the peak-day demand estimate and uncertainty in supply. Reserve margins are often expressed as percentages of the design peak-day demand.[13] The design day criteria and any reserve margin are usually determined conservatively and typically involve judgment. In practice LDCs—especially LDCs in cold climates—set the design day high enough to meet the demands of essential-needs customers under *any* foreseeable weather conditions. With the peak-day target set for each year of the resource plan, LDCs assess the reliability of each supply and capacity resource. Often this assessment is qualitative rather than quantitative. The relative reliabilities of spot- and long-term supplies has become a major issue as a result of such reliability assessments (see Section 4.2). In the traditional reliability planning process, the reliability provided to interruptible customers is not explicitly determined. Instead, they are served at the "default" reliability that is available after firm loads have been planned for.

Gas system reliability planning will likely evolve under IRP and in response to ongoing gas industry restructuring. A three-step process for incorporating reliability into gas IRP processes is shown in Figure 4-5. Increased competition will require additional focus on the appropriate reliability standard for all LDC customers (see step one). Competition will be a double-edged sword for many LDCs. To retain load, they will need to focus more on the reliability provided to customers with competitive alternatives including customers previously considered interruptible. Building of expensive facilities to provide reliability will, however, be limited by price competition from alternative fuels and bypass alternatives. Greater use of benefit-cost studies to determine LDC-specific reliability standards is likely to become more common (see Exhibit 4-1). In the absence

[12] For many gas LDCs, reliability targets other than peak day are important. For example, systems with large storage resources may define reliability targets in terms of cold-year demands or cold-year, winter-season demands as well as peak-day demands.

[13] The term *reserve margin* is defined differently in the electric and gas industries. In the electric utility industry, reserve margin is a percentage of the expected annual peak-hour demand. In the natural gas industry, design-day peak demand is used in the denominator.

Figure 4-5. Incorporating Reliability into the Gas IRP Process



of detailed benefit-cost studies, LDC should use judgment to determine an appropriate reliability standard and attempt to meet it by evaluating the reliability of each resource option and its impact on overall LDC system reliability (see steps two and three). As can also be seen from the third step of Figure 4-5, demand-side management (DSM) resources can modify peak-day demands, and the avoided costs used to evaluate DSM resources should include the full value that DSM resources provide on a peak day, including any reserve margin benefit. Like supply-side resources, DSM resources have uncertain availabilities, and this uncertainty should be incorporated into the reliability planning process.

Although the advent of IRP and other changes in the industry indicates that LDCs need sophisticated reliability assessments, few deviations from standard utility practice can be

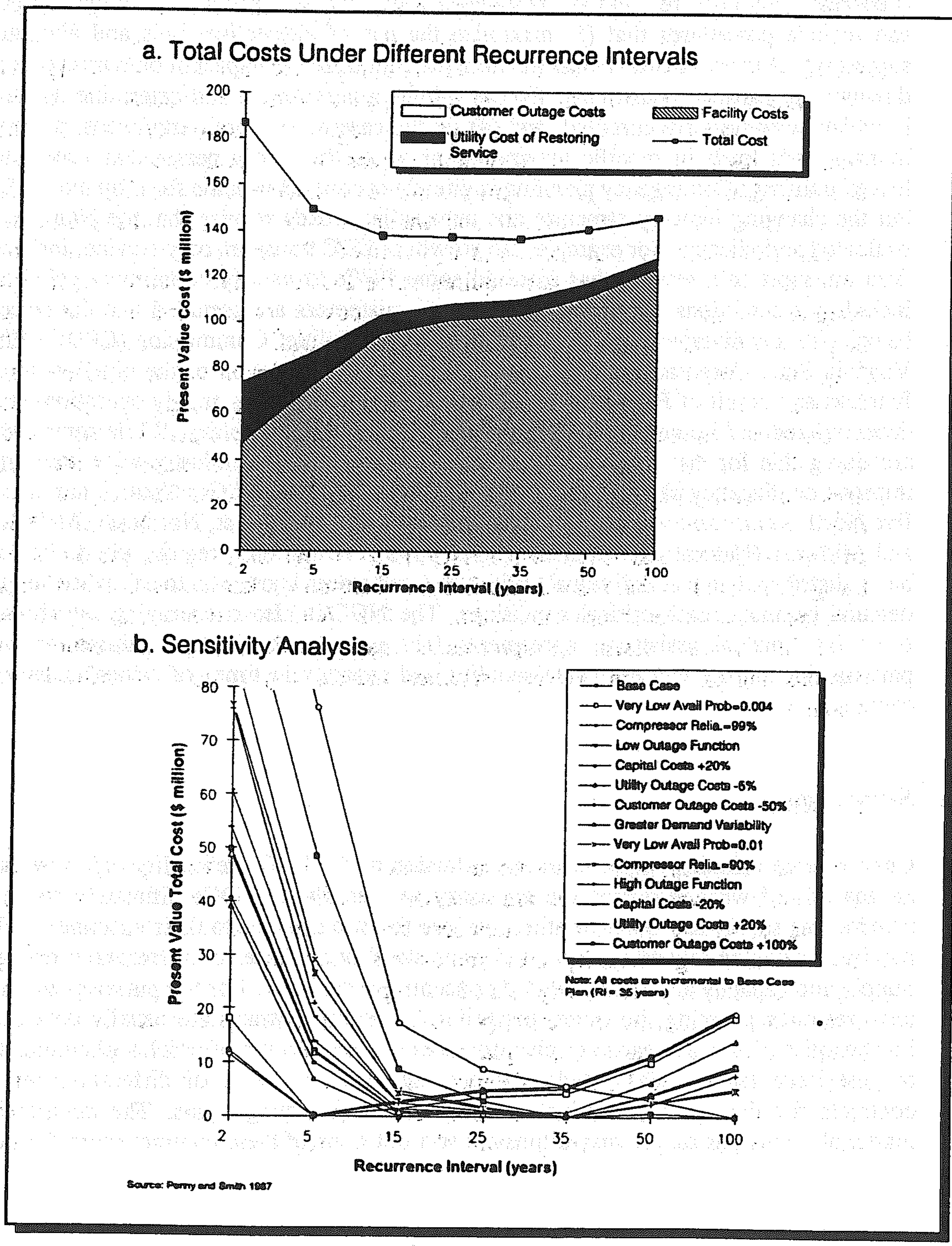
Exhibit 4-1. Use of Benefit-Cost Studies in Assessing Reliability Targets

In 1987, gas system planners at San Diego Gas and Electric Co. (SDG&E) conducted a benefit-cost study to determine its gas system reliability target (Penny and Smith 1987). SDG&E computed the cost of building systems that provide different levels of reliability. Reliability was assessed in terms of a *recurrence interval* (RI) which is the average number of years between curtailments. At each level of reliability three kinds of costs were assessed: (1) the relatively certain cost of constructing facilities, (2) the expected cost of having the utility restore service after curtailments (e.g., relighting pilot lights), and (3) the customers' costs of experiencing a curtailment. An optimal level of reliability is one that minimizes these three costs. The study considered uncertainty on both the demand and supply side when computing total costs at a given RI. Figure 4-6a shows the results of SDG&E's study. Optimal reliability is found at an RI somewhere between 15 and 35 years. SDG&E recommended a 35-year RI because the risk of outcomes with very high outage costs was much less than with a 15-year RI. The 35-year RI recommended in the study was eventually used in the resource planning studies filed as part of the California PUC's long-run marginal cost proceeding (California Public Utilities Commission (CPUC), 1992a).

The SDG&E study is a good example of incorporating uncertainty and risk management into the resource planning process. Its base-case study is an example of probabilistic analysis using a Monte Carlo approach. SDG&E acknowledged that many of the assumptions treated deterministically in the base-case study were uncertain. To address this, SDG&E ran 13 sensitivity cases in which key inputs were varied. New total cost curves were computed for each case and compared to the base case. The results of the sensitivity cases are shown in Figure 4-6b. Under the assumption that the set of sensitivity cases is fairly representative of all possible contingencies and that each case has a similar probability of occurrence, it is possible to look at the trough in Figure 4-6b (RI = approximately 35 years) as being the most *robust* RI with respect to uncertainty.

cited. The recurrence interval study conducted by SDG&E is a good example of a benefit-cost study (see Exhibit 4-1). A modest extension of the reserve margin concept, known as the Deliverability Assurance Ratio (DAR), was developed by the Illinois Department of Energy and Natural Resources for its review of gas IRP plans filed by Illinois LDCs (Hemphill 1989; Jensen 1992). Computations of LOLR have been made in the literature but have not been filed in any regulatory proceedings by an LDC (Hiebert et al. 1992). During 1993, the Indiana Utility Regulatory Commission directed Indiana Gas Co. to re-evaluate its method for setting reserve margins. This study may provide insights into improved reliability planning methods.

Figure 4-6. Using Benefit-Cost Studies to Determine Reliability Planning Targets: SDG&E



4.4.3 Contingency Planning

Gas LDCs can enhance reliability and the value of service provided to its customers by preparing to quickly respond to contingencies that threaten service. Contingency plans can include procedures that (1) maximize the use of alternative fuels and alternative suppliers, (2) improve operational flexibility to minimize the impact of both upstream and downstream capacity constraints, (3) can initiate a curtailment and determine the order in which customers are curtailed, and (4), in the case of a severe curtailment, prioritize human-needs loads in specific geographic areas so that every person has access to a heated building. Contingency planning is already conducted in some form by most LDCs but the changing industry structure and unbundling trends require that the plans be re-evaluated periodically. For example, the growth of LDC transport-only service, including firm transport-only service, has required some PUCs to modify curtailment policies to include the conditions in which transport-only customers are curtailed and the price to be paid for any diverted supplies (California Public Utilities Commission (CPUC) 1991; Virginia State Corporation Commission 1991). The elimination of the pipeline supply function as a result of FERC Order 636 is making interstate gas supply operations more decentralized and is another reason to re-evaluate contingency plans. While some LDCs are doing this for their service territories, there has been an industry-wide attempt to improve contingency planning at the regional level. The Natural Gas Council has created five North American reliability planning regions: West, Southeast, Northeast, Midsouth, and Midwest (Natural Gas Council (NGC) 1993). Within each region, phone lists are being distributed so that individual utilities and customers know who to call when supply-demand balances reach critical conditions. The NGC is also encouraging members to enter into mutual assistance agreements that provide explicit procedures on how participating parties can exchange supplies and capacity in times of critical supply or demand.

4.5 Summary

Gas resource planning begins with an evaluation of the LDCs reliability objectives and an analysis of what resources are necessary to meet them. LDCs ultimately strive to provide gas supply and transportation services that are of value to their customers. This requires balancing reliability, cost, and price stability attributes of all resource options. Supply and capacity are closely related concepts for the LDC. For the purposes of near-term resource planning, however, portfolios of supply contracts are usually developed independent of the gas capacity planning process. For supply portfolio planning, the biggest issue facing LDCs is determining the relative shares of different types of contracts for their portfolios, including contracts of varying terms. The competitive marketplace for gas supply may ultimately sort out some of these contract share debates.

LDC procurement activities are also likely to be significantly affected by the state PUC's regulatory approach to reviewing LDC procurement decisions.

With regard to capacity planning, LDCs will consider releasing existing capacity as well as acquiring new capacity to better meet reliability targets, to lower capacity costs, or to lower gas supply costs. For many LDCs, storage options will be increasingly attractive as an alternative to pipeline capacity. A simple screening analysis may be conducted to trade off the fixed and variable cost attributes of different resource options. More sophisticated resource planning is required to fully incorporate all the constraints that are relevant to an LDC and its customers.

Before embarking on a resource plan, PUCs and utilities should carefully consider their reliability objectives on both the demand and supply side. Current industry practice is to address reliability for firm customers by setting a conservative design peak-day target and, possibly, adding a reserve margin to that target. The reliability of individual resources to meet that target are assessed either qualitatively or quantitatively. Unless facilities are constructed specifically for interruptible customers, the reliability provided to interruptible customers is a byproduct of the firm customer reliability plan. In light of IRP and the ongoing gas industry restructuring, there will likely be an increased trend towards using benefit-cost analysis for determining appropriate reliability targets for both firm and interruptible customers. Once an LDC has acquired resources to meet its reliability targets, contingency planning can be used to maximize customer reliability. Contingency plans include procedures that maximize short-run resource availability and minimize the negative consequences of any necessary curtailments.

Chapter 5

Methods for Estimating Gas Avoided Costs

5.1 Overview

The concept of avoided cost grew out of federal legislation designed to encourage efficient production and the use of renewable fuels in the electric power industry; this legislation also sought to achieve these ends by stimulating investment of private, unregulated capital in the electric power sector. The concept has evolved to become the standard against which the benefits of electric utility demand-side management (DSM) programs are valued.

This chapter focuses on the estimation of avoided costs for gas as a means of valuing the benefits of gas-utility-sponsored DSM, including efficiency improvements, peak-shaving, and strategic load building. Given the vast differences in the characteristics of supply and demand resources and the state-of-the-art in gas planning tools, evaluating DSM on a program by program basis and optimizing both DSM and supply resources in an automated framework is currently impractical. Avoided cost methods have become the conventional means by which we approximate an overall supply-demand optimization. Avoided costs can and have been used in evaluating supply resources and in rate design, but those applications are not discussed in detail in this chapter.

Because the avoided-cost concept came from the electric power industry, it is useful to review features of the gas industry that are different from the electricity industry and of particular relevance to estimating avoided cost: (1) local distribution companies (LDCs) are not as vertically integrated as electric utility companies, so more of their costs are defined upstream through contractual agreements; (2) storage exists as a major gas resource option similar to pumped storage hydro for electric utilities except on a larger scale and for longer time intervals (i.e., seasonal instead of diurnal or weekly); (3) LDCs provide more diversity of services (e.g., end-user transportation, which would be analogous to retail wheeling in the electric power sector); (4) gas LDCs are not as capital intensive as electric utilities, so LDCs' cost structure tends to be dominated by variable costs; (5) the planning horizon for gas utilities is historically shorter than for electric utilities; and (6) there can be a higher degree of seasonality in gas costs than electricity costs. Given these differences, methods used to estimate avoided costs must be carefully adapted to the gas industry.

This chapter presents several methods that have been implemented or proposed for estimating gas avoided costs; a consensus does not yet exist within the gas industry or among regulators on appropriate methods. The next section describes the components of gas avoided costs. Various avoided-cost methods are then described in Section 5.3 with a discussion of their strengths and weaknesses. Major issues that should be considered in applying avoided costs to the valuation of gas DSM programs are also discussed.

5.2 Components of Gas Avoided Costs

Avoided costs for gas LDCs can be broken down into a number of components: commodity, deliverability from the wellhead to the city gate (capacity), local transmission and distribution (LT&D), and servicing customers. The relative shares of these components in the total avoided cost will vary by utility and over time. Generally, commodity and capacity costs will be the largest part of avoided cost for LDCs. The move to straight, fixed-variable rate design in FERC Order 636 will typically result in increased capacity costs for low-load factor LDCs than under the rate structure being replaced.

Two important timing-related issues need to be considered in developing gas avoided costs for analyzing the economics of DSM programs: (1) the cost structure of the LDC system, which is driven by demand patterns that are largely differentiated from one another by their time of occurrence, and (2) impact of a measure's lifetime on the time horizon of the analysis.

A range of demand patterns drives facility sizing and supply procurement (see Table 5-1) (Energy Management Associates (EMA) 1992). Although Table 5-1 indicates which demand patterns are associated with certain facilities, it does not say which demand pattern will be the binding one for facilities construction. The binding demand pattern depends on the specific supply and demand situation for each LDC. More than any other demand pattern, coincident design peak-day demand is usually the most important for designing facilities, such as system transmission, storage withdrawal, and peak-shaving capacity near load centers. Design winter season and average daily demand are other demand patterns commonly used by LDCs in supply planning. Establishing which demand patterns are binding for particular facilities is important because DSM-induced changes in the nonbinding demand patterns may have no impact on supply and hence no avoided cost implication. Ultimately, avoided costs need to be time-differentiated in a way that recognizes the demand patterns driving supply choices that in turn reflect the cost structure of the LDC. By the same token, assessing the economic merits of DSM programs using time differentiated avoided costs requires that the load shape impacts of DSM programs be decomposed into their impacts in the corresponding time periods (i.e., demand patterns). Otherwise, the wrong types and/or quantities of DSM resources will be deemed cost-effective and lead to suboptimal results in DSM resource acquisition.

Table 5-1.Typical Demand Patterns Associated with the Sizing of Facilities and Contracts

System Component	Non-coincident Design Peak Hour	Coincident Design Peak Hour	Coincident Design Peak Day	Design Winter Season	Late Season Cold Day	Avg. Summer	Avg. Daily Demand
Commodity-- Peak Deliverability			X	X		X	X
Commodity-- Energy							X
Peak Shaving		X	X				
Storage		X	X	X	X	X	
Pipeline Capacity		X	X	X		X	
LDC Transmission		X	X			X	
Distribution Main	X	X	X				
Services, Meters	X						

Source: Adapted from Energy Management Associates 1992

The second timing issue is the impact of a measure's lifetime on the time horizon of the analysis. Some DSM measures can produce savings for up to 20 years or more. In order to properly evaluate the benefits of DSM, estimates of avoided costs need to encompass the economic lifetime of DSM measures. This need means that many LDCs will have to develop estimates of avoided costs beyond their current supply planning horizon. The IRP process itself may extend LDC planning horizons beyond the typical three to five year timeframe, to 10 years or more. For planning horizons that are shorter than the lifetime of DSM measures, "end-effects" procedures can extend the last year's values to encompass the period of interest beyond.

The major issues associated with each of the following avoided cost components for gas are summarized in Table 5-2 and elaborated upon below.

Table 5-2. Issues in Estimating Gas Avoided Costs

Component	Issue
Commodity	• Uncertainty in future gas commodity costs • Impact of reduced takes on firm contracts may be constrained by minimum take or gas inventory charge (GIC) provisions
Capacity	• Short-term vs. long-term perspective • Duration of existing firm capacity contracts • Market demand and future price uncertainty for existing capacity (capacity release) • Reallocation of pipeline fixed costs • Treatment of commodity-related capacity investments • Cost allocation methods for long-lived facility investments
Local T&D and Customer Costs	• Not typically avoidable by most DSM programs

5.2.1 Commodity Costs

As characterized in Chapter 4 and summarized in Table 4-2, LDCs draw upon various types of gas supplies including long-term contracts, multi-month contracts, spot contracts, pipeline sales service (unbundled from pipeline transportation and storage service in the aftermath of FERC Order 636), purchases of reserves, futures and options contracts, and customer buybacks. LDCs dispatch supply resources in their portfolios to minimize cost, subject to operating constraints and reliability criteria. Avoided commodity costs are reflected in a change in the utilization of supply resources as a result of the DSM-induced change in demand.

A change in utilization of supply resources may allow for outright cancellation of prospective supply contracts or facilities and their associated costs. However, change in supply resource utilization may simply entail a reduction in gas takes from selected contracts. To the extent that firm supply contracts in the LDC's mix include take-or-pay clauses or gas inventory charges that penalize low load factor utilization, the avoidable commodity cost from reduced volumes of these contracts will be dampened. Gas dispatch models should handle such contract provisions and account for them in simulating least cost LDC system operation; for this reason dispatch models are useful tools to use in estimating avoided commodity costs.

The underlying uncertainty of future gas prices is an important concern in estimating avoided commodity costs. Uncertainty in future gas commodity costs is influenced by many factors: rate design policies, supply/demand balance, availability of supply, and competition with alternate fuels. Variations in future gas commodity costs could have a disproportionate influence on avoided costs because the commodity component often accounts for a significant fraction of an LDC's total cost of gas.[1] Uncertainty in future commodity costs assumes even greater prominence as time horizons under IRP are extended to ten years and beyond. Thus, in estimating gas avoided costs, it would be advisable to include a range of gas commodity escalation rates as part of the analysis. Approaches to treating uncertainties in commodity costs in avoided cost calculations are fundamentally no different than those described in Section 3.7 for other analytic areas of IRP.

LDCs typically offer a number of different categories of service to customers: firm sales, interruptible sales, transportation (firm, nonfirm), and standby sales. Which service categories should be included in the demand forecast upon which avoided costs are based? For the avoided commodity cost calculation, it has been suggested that in addition to the forecasted demands of firm sales, interruptible sales and transport customers on standby sales should be included because LDCs will sell gas to these customers if it is available and the customers are willing to pay the cost (Heaghney 1992). However, a significant uncertainty surrounds the possibility of customers switching the type of service they receive from the LDC. For instance, standby customers swinging between transportation and sales service can have a large impact on avoided commodity costs.

[1] The relative significance of avoided commodity cost in total avoided cost is a function of an LDC's load factor. For a low-load-factor LDC, fluctuations in commodity cost will have less of an impact on total avoided cost than they would for a high-load-factor LDC (all other things being equal).

5.2.2 Capacity Costs

DSM alters customer demand, which leads to changes in necessary facility investments and contractual agreements (without compromising reliability); avoided capacity costs derive from these changes. The types of supply resources providing delivery capacity within LDC service territories include pipeline capacity in the form of firm transportation, "no- notice" service, storage, liquified natural gas (LNG), or propane-air plants (see Table 4-3).[2] These capacity resources can be divided among committed and uncommitted resources. In the short run, most avoidable resources are uncommitted. In the long run, planned capacity facilities and/or firm capacity contract commitments could be avoided as well.

Options for Avoiding Capacity Costs

There is some controversy over how avoidable capacity costs in an LDC's portfolio really are, particularly in the short term. The answer is highly specific to the circumstances of each LDC. In general, "transition costs" that are approved under FERC Order 636 proceedings for individual pipelines are costs that cannot be avoided by subsequently implemented DSM programs (Armiak 1993). However, LDCs may have a number of other options for avoiding part of the costs associated with capacity that becomes excess as a result of DSM; these options include: (1) releasing capacity to the secondary market allowed for in FERC Order 636, (2) renegotiating capacity commitments in pipeline service agreements at the end of contract terms, (3) reducing or eliminating planned or committed stakes in new pipelines, and (4) making more interruptible sales from freed capacity.

The first option, avoiding capacity costs through releasing existing pipeline capacity held in firm transport contracts, depends to a great extent on market conditions. Previously, LDCs that reduced demand were unable to reap capacity cost savings until their existing pipeline contract expired and could be renegotiated. Now, for LDCs located near pipeline market hubs or near pipelines serving many customers, there may be an active market for released capacity. The great uncertainty in these cases is the price which will be determined in this secondary market. FERC Order 636 stipulates that releasing shippers remain liable for the full pipeline reservation charge and surcharges, so any difference between the market price of the released capacity and the pipeline charges will have to be made up by them. Thus, the avoided capacity cost through existing capacity

[2] Customer buyback programs listed in Table 4-3 under gas capacity options are not cited here because they occupy a minor position in the overall deliverability of gas within LDCs and because of the difficulty in assigning an avoided cost to them.

release may only be a fraction of the contractual obligation. For LDCs located far from market centers or LDCs that are the dominant pipeline customer in their area, the question of released capacity market price may be moot as there may be few potential buyers. A more subtle boundary issue is whether releasing capacity means transferring it to entities outside the LDC service territory or to customers served by the LDC. If the capacity goes to LDC customers, then there is no reduction in total fixed pipeline costs being passed on to the customers of the LDC (Armiak 1993). An added wrinkle is that, in circumstances where there is a strong market for released capacity, LDCs might decide to simply renew contracts with pipelines and retain all of their existing capacity; a byproduct of this could be a reduction in the effective cost of relying on a "reserve margin" to ensure system reliability (Gaske 1993).

A second option for avoiding capacity costs is reducing or terminating capacity rights at the end of an existing pipeline contract term, or relinquishing capacity as part of the industry restructuring process brought about through FERC Order 636. Since the mid-1980's, with the gas supply "bubble" and the uncertainties associated with gas industry restructuring, terms for pipeline capacity contracting have tended to be short (although long-term contracts still dominate). Moreover, many of the long-term contracts signed in the early 1980's will be expiring in the next several years. However, similar issues of market demand for released capacity apply to capacity let go by LDCs. In a situation where relinquished or terminated capacity finds ready buyers, the full costs of the relinquished contract will be avoided. In a situation where the pipeline cannot fully subscribe its available capacity, the pipeline may try to recover its fixed costs by raising rates in order to remain whole. Thus, the problem of stranded or underutilized pipeline investment could result in lower net avoided capacity costs for some LDCs than would otherwise be the case.

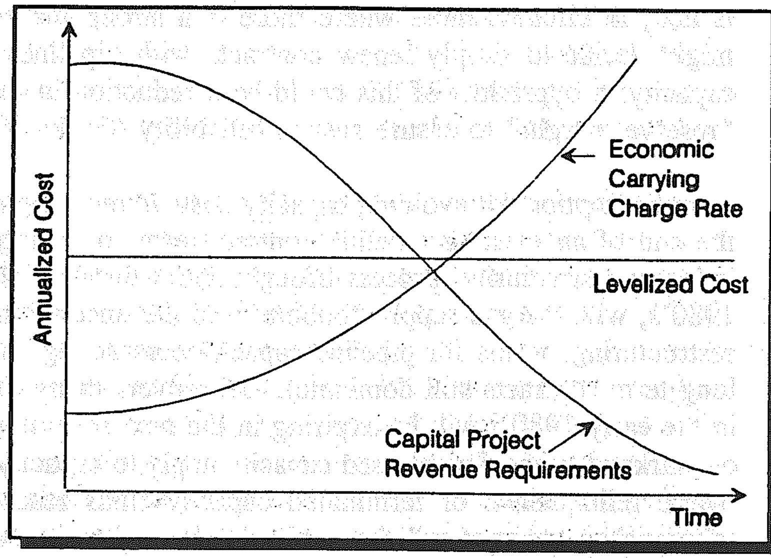
A third option for avoiding capacity costs is reducing or foregoing planned participation in pipeline "open seasons" or direct investment in new pipelines. Depending on the nature of the contract, investments in pipeline capacity rendered superfluous from one LDC's DSM program may in fact not be avoidable because of commitments to, and needs of, other parties in the project.

The last option for avoiding capacity costs is increasing interruptible sales; this is technically not a means of avoiding capacity commitments. Instead, it allows capacity costs to be redirected to taking advantage of incremental opportunities, which itself could have value to the LDC in added margins (Hornby 1991). Practically speaking, this "opportunity cost" concept may be difficult to apply because of the difficulty in ascribing a value to avoided capacity cost.

The uncertainties surrounding the market value of avoided capacity, particularly from the first two options described above, suggests that a range of avoided capacity costs should be prepared in a manner that is similar to the range of avoided commodity costs prepared from a range of gas price forecasts.

Allocation Issues

Figure 5-1. Three Methods for Allocating Capital Costs Over Time



Capacity cost is not always identical to pipeline reservation charges or fixed costs of a facility. Some resources with high fixed costs enable savings of variable costs. In the gas industry, this is commodity-related capital investment. Pipeline capacity that provides access to lower cost producer gas fields is an example of this phenomenon. One way of distinguishing between capacity and energy value in fixed costs is to assign to "capacity" the fixed costs of a resource that primarily serves capacity needs in the system to capacity and to ascribe the remaining portion to commodity. This approach is routinely employed in the electric power sector with the cost of gas combustion turbines serving as the proxy for pure capacity. The fixed costs of propane-air plants have been suggested as a proxy for capacity value for LDCs. Released pipeline capacity prices or other resources might also fill this role.

For long-lived facilities investments such as on-system storage, spreading the initial capital costs over the lifetime of the investment is necessary in order to allocate properly the capacity value of the facility over time. The economic carrying charge rate (ECCR) is useful in this regard (Kahn 1988). Figure 5-1 depicts three streams of capital costs of equivalent value in present value terms. The horizontal curve is the levelized annual cost, the falling curve is the revenue requirements stream employed in utility capital finance, and the rising curve is the ECCR increasing at the rate of inflation. Levelization, which is computationally equivalent to mortgage payments, gives equal payments over the period in nominal terms. In real terms, the value declines over time, so more of the total present value is in the early years. The revenue requirements stream represents the cost recovery process of utility investment in the regulatory arena with extreme front-loading. The ECCR method is intended to represent the behavior of capital in a competitive market operating under inflation with constant annual values in *real* terms (National Economic Research Associates Inc. (NERA) 1977). As such, the ECCR imposes no front-loading penalty and for this reason is the preferred method for allocating avoided capital costs over time.

Finally, LDCs may include only some customer service categories under their "obligation to serve," particularly from the standpoint of capacity investment decision-making. Only the demands of customer service categories that the utility chooses to serve from a capacity planning perspective would be included in any estimate of avoided capacity cost.

5.2.3 Local Transmission and Distribution Costs

Local transmission costs are associated with transporting gas from the "city gate" to the distribution main. Distribution costs are associated with transporting gas from the transmission system to customers. Together, LT&D investments are planned around local noncoincident demands rather than system coincident demands as is typical for system elements further upstream (see Table 5-1).

Scale economies are a large factor in the economics of LT&D because much of the cost of laying underground pipe is in the cost of trenching and not the pipe itself, so the incremental cost of increasing capacity (at the time of construction) can be relatively small.[3] These scale economies often dictate that LT&D expansions be designed to accommodate future growth. Costs of LT&D also have substantial geographic and density dependencies, making them less a function of demand level *per se*. Few DSM programs will result in avoided local transmission and distribution costs.

5.2.4 Customer Costs

Customer costs typically include service lines, meters, regulators, and some portion of main line extension cost. Avoided customer costs may only be relevant for DSM

[3] Additionally, piping comes in standard sizes and the impact of DSM is seldom large enough to warrant choosing pipe some standard size smaller.

programs that affect system expansion into new areas or additional customer hookups.[4] Fuel-substitution DSM programs are the most likely situation in which avoided customer costs would apply, and then only if the program resulted in new customers and not just expanded use for existing customers. These costs can be based either on engineering estimates or historical data analysis.

5.2.5 Externality Costs

The theory behind externality costs is that the market sometimes fails to incorporate all social costs in the observed prices of goods. For fuels, environmental externality costs are the most prominent. They include air and water pollutants and land impacts. These costs would ideally be based on estimates of the damage costs of the environmental impact, but reliable estimates are elusive especially for global or regional effects or effects that require putting a monetary value on human and other life forms or on aesthetic qualities. Various studies sponsored by states (e.g. New York and California) and the federal government are currently assessing damage costs of pollution. As a proxy for environmental externality costs, analysts use the costs of controlling pollutants or mitigating impacts of a project or activity as imposed by environmental regulations.[5] The choice of approach (damage cost or control cost) and the appropriate specific values to assign to each impact are areas of active and ongoing public policy debate (Consumer Energy Council of America Research Foundation (CECA/RF) 1993; ECO Northwest 1993).

A number of state PUCs have instituted or are considering rules regarding the use of environmental-externality-cost adders in integrated resource planning (Goldman and Hopkins 1991). Operationally, these adders appear as credits to more benign resources such as DSM or as additional costs to resources in the current mix or resources under consideration. These additional externality costs are reflected in estimates of avoided supply costs and are typically included in the Societal Cost test (see Chapter 6). Exhibit 5-1 describes current state regulatory activities with regard to environmental externality costs affecting gas utilities.

[4] An exception may be DSM programs targeting low-income groups where some customer-related costs are often avoidable such as uncollectible expenses and collection, termination, and reconnection costs.

[5] The control cost approach is predicated on the belief that the political process locates the intersection of the marginal benefit and cost curves when it imposes a particular standard for pollutant impact.

Exhibit 5-1 State Activities Incorporating Environmental-Externality Costs into Gas Utility Planning

Georgia

Atlanta Gas Light Co. used a composite externality cost (or value of damage or control) of $0.15/MMBtu for evaluating gas DSM programs. The calculated environmental-externality costs based on gas end-use technologies are:

residential space heater	–	$0.10/MMBtu
residential water heater	–	$0.11/MMBtu
residential clothes dryer	–	$0.05/MMBtu
residential range	–	$0.06/MMBtu
commercial boiler	–	$0.10/MMBtu
industrial boiler	–	$0.13/MMBtu

Iowa

The commission requires that natural gas least-cost planning include externalities in avoided-cost calculations. The Iowa Utilities Board proposes to add an "externality factor" to avoided cost calculations–10% for electric utilities and 7.5% for gas utilities.

Minnesota

Utilities are not required to consider externality costs when evaluating Conservation Improvement Programs (CIP). However, the commission adds an Environmental Damage Factor of $1.10/Mcf to avoided costs and lowers the discount rate from the 11.03% approved utility rate to a 5% societal rate when estimating of the cost-effectiveness of utility CIPs.

Nevada

Westpac Utilities (a subsidiary of Sierra Pacific Power Company) developed an Environmental/Societal test and used it with the four other tests described in the *California Standard Practice Manual* to evaluate each demand-side program. The test adds environmental values to other benefits and costs included in the Total Resource Cost test.

New Jersey

Gas utilities must include a commission-specified environmental externality cost in net benefits calculations, avoided costs calculations, standard offer pricing, competitive offer pricing, and the TRC test. This externality cost was estimated by Pace University to be $0.95/MMBtu (in 1991 dollars), based upon the pollution cost of gas-fired power generation. The commission stipulates that the value be adjusted annually at a rate equal to the GNP deflator index.

Vermont

The commission has adopted as *interim adjustments* a 5% adder to supply-side costs for negative externalities associated with supply sources and a 10% discount from demand-side costs for the risk-mitigating advantages of demand-side resources. This applies to both gas and electric utilities. The commission requires that the 5% adder also apply to fuel-switching programs, as it does for supply programs. However, any party is free to present evidence in compliance filings to substantiate a credit for reduction in the 5% penalty for alternative fuels.

Wisconsin

Externality regulations only apply to electric utilities. The commission requires that utilities multiply monetized greenhouse gas values by the amount of greenhouse gases a power plant will emit under a specific resource plan and apply the resulting cost to the energy-related costs of the plant for the period in which the energy is generated. The values are to be used when comparing resource options in planning, designing and implementing DSM programs. Additionally, the commission states that total technical costs plus quantified environmental externalities should be used to evaluate fuel alternatives–to determine which end uses are served at the lowest cost to society by fuels or energy sources other than electricity. The monetized values for greenhouse gases that the Commission thinks reasonable are:

carbon dioxide	–	$15/ton ($0.0075/lb)
methane	–	$150/ton ($0.075/lb)
nitrous oxide	–	$2,700/ton ($1.35/lb)

California

The commission requires that fuel-switching programs pass the three-prong test in which externality impacts are considered (see Chapter 8).

Source: Wang 1993

5.3 Methods for Calculating Gas Avoided Costs

Several methods for calculating gas avoided costs have been used by LDCs or proposed in the literature. The next section reviews approaches and discusses the pros and cons of each method.

The starting point for each method is a base case resource plan that satisfies a base case gas demand forecast.[6] The base case demand forecast typically includes the load impacts of committed or approved LDC DSM programs (and market- and standards-induced changes in average use) but does not include the effects of incremental DSM programs under consideration.

5.3.1 System Marginal Cost

The system marginal cost (SMC) approach calculates the change in system fixed and variable costs at the margin resulting from a change in demand. Because of the complexities of accurately determining supply-side resource responses at the margin, the use of detailed gas supply planning models is essential with SMC approaches. To the extent that gas supply planning models are being used by an LDC, a major benefit of SMC approaches is that they enable consistent treatment of avoided-cost estimation with supply planning assumptions and methods.

Three different ways of estimating avoided cost using an SMC approach are: instantaneous, increment/decrement, and differential revenue requirements methods.

[6] All avoided-cost methods are predicated on the assumption that the base case demand forecast is an accurate and reasonable representation of LDC expectations of future demand from its customers (in the absence of incremental LDC intervention) and that the base-case supply plan is the optimal plan to serve that demand based on current expectations and constraints. Any departure from this assumption will distort avoided-cost estimates.

Instantaneous Method

The instantaneous method for calculating marginal cost assumes a small perturbation to the system by DSM programs, compared to the overall size of the system. Because the load change is small—infinitesimal to be exact—no structural change to the mix of resources serving gas loads is warranted. In this approach, DSM programs facilitate a reduction in use of the most expensive resources at the margin. The instantaneous method produces what is essentially a short-run marginal cost and may only be valid for short-term valuation of gas DSM avoided cost. In principle, this method lends itself to easy time-differentiation but depends on the specific capabilities of the planning model being used. An instantaneous marginal cost is often given as a direct output of gas dispatch simulation models.

Increment/Decrement Method

The increment/decrement method (ID) is predicated on DSM program impacts being finite in size and possibly significant relative to overall demand. Load decrements apply to conservation, seasonal load reduction, or peak-clipping DSM programs whereas load increments apply to load building, valley filling, or peak load shifting DSM programs (see Figure 7-1). In the ID method, a finite, discrete block of load is added or subtracted from the demand forecast. With this new demand forecast, a second gas dispatch simulation is run and compared to the base case. Avoided costs are calculated by taking the difference in dispatch cost between the two runs (base case and ID) divided by the size of the increment or decrement on a volumetric basis.

Individual DSM programs are unlikely to produce any significant impact on a utility's costs or resource mix. Thus, for the purpose of estimating avoided costs, individual DSM programs should be aggregated into resource "blocks." The size of the increment or decrement block will have an effect on the resulting estimates of avoided cost.[7] The quantity of the DSM resource that is cost-effective is dependent on the level of avoided cost. Therefore, an equilibrium must be sought where the resource block used in estimating avoided cost is the same quantity of DSM that passes screening with that avoided cost. This equilibrium is found through iteration.[8] It is imperative that the

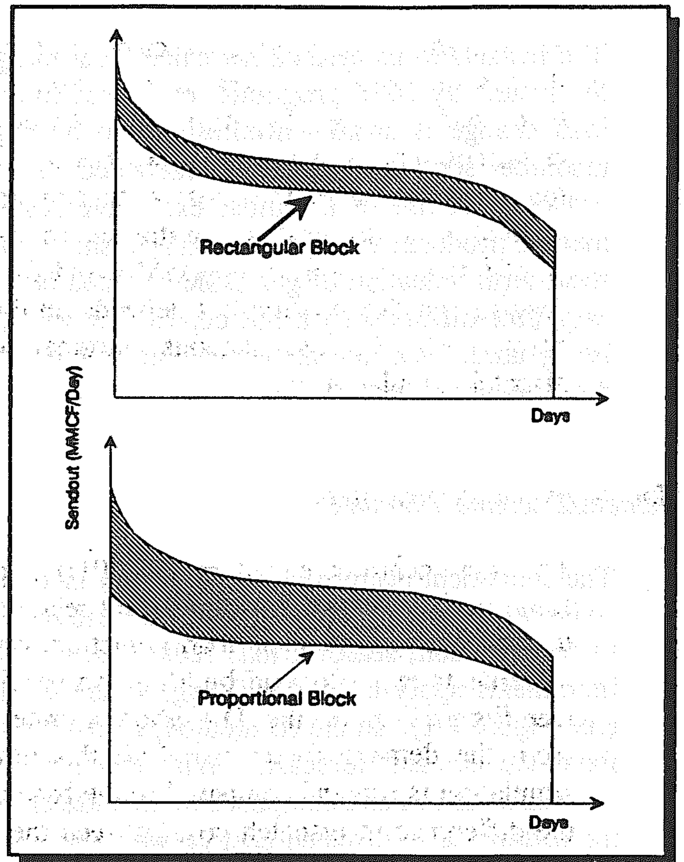
[7] The larger the size of the decrement block, the cheaper the average cost of the supply resources displaced by it, translating into lower avoided cost. By similar logic, a larger increment block will call upon yet more expensive resources that in turn produce higher avoided cost.

[8] An initial guess of resource block size is used to estimate avoided cost, which is then used to screen DSM programs, the passing quantity of which is compared to the original resource block size. If the quantity of cost-effective DSM is smaller than the resource block, then the resource block size is reduced (or vice versa) and the

initial size of the resource block used in the ID approach be verified in order to arrive at a plausible estimate of avoided cost.

The shape of an increment or decrement block will likewise influence the resulting avoided cost estimate. Although different programs exhibit their own characteristic load shape impacts, LDCs as a practical matter usually assume some characteristic shape (or set of shapes) in developing avoided costs. Figure 5-2 depicts two characteristic block shapes as decrements superimposed on a load duration curve. One is a "rectangular" block with the same load impact throughout the period, which would correspond to the impact one might expect from efficient hot water heating or efficient commercial cooking programs. The other is a proportional block that is a fixed percentage of the base case load shape, which would correspond to a temperature-sensitive load impact from efficient space heating programs.

Figure 5-2. Decrement Blocks in System Marginal Cost Methods



If a gas dispatch model is used in performing the ID avoided cost calculation, then only system operating cost changes will be reflected in the model output. Fixed cost implications have to be accounted for exogenously. Using large increment or decrement blocks in the simulations may necessitate making modifications to the supply resource mix (either adding or removing resources, respectively). A long-term optimization model in which fixed and variable costs are simultaneously accounted for is used in the differential revenue requirements method described below.

procedure is repeated until equilibrium is reached.

Differential Revenue Requirements Method

The differential revenue requirements approach is a variant of the increment/decrement approach in which fixed and variable costs are explicitly optimized in each simulation through the use of a capacity expansion model (see Chapter 3 for typology and discussion of gas planning models). In all respects, except its integral fixed cost treatment, the revenue requirements method is the same as the increment/decrement method. In principle, this method is the most rigorous, and so it can be an arduous undertaking, requiring multiple simulations with complex models.

5.3.2 Generic Proxy Approach

In this approach, the analyst selects an avoidable resource (or set of resources) from the supply plan and uses its costs as the basis for avoided costs. The underlying concept is that a resource in the supply mix could be entirely displaced by DSM resources theoretically serves as the proxy resource. The proxy resource could be the most expensive unit or the last resource dispatched in the supply portfolio, in which case the proxy method approximates a SMC method. However, in choosing a proxy resource, it is best to seek a reasonable match between the type of load shape impact from DSM and the supply resource in the portfolio that would otherwise serve that load. For example, in evaluating a nontemperature sensitive load impact (e.g., from efficient water heating programs), the appropriate proxy resource would be the combination of contracts and other facilities designed to serve a high load factor demand.

When load-reducing DSM is placed in the resource mix, proxy resources are either cancelled outright or deferred.[9] If the DSM resource block is large enough to permit canceling the proxy resource (this depends on each LDC's unique portfolio of contracts and facilities), we can directly assign its costs to avoided cost (converted to a unit-cost volumetric basis).[10] This method's appeal is that it is relatively simple to calculate, and it is transparent; the supply-side impact is determined without running multiple gas system simulations, and its costs are tangible. The date on which the proxy resource is introduced into the supply mix can also be delayed as a result of DSM instead of

[9] This description of the proxy methodology assumes load-reducing DSM but is applicable to load-building DSM with appropriate adaptations.

[10] Because the quantity of cost-effective DSM resource is dependent on avoided cost, the reasonableness of the assumption will have to be subsequently confirmed by screening the DSM programs with the avoided-cost estimate.

cancelled altogether. Determining how long to defer the proxy resource and the value of that delay is more complicated and requires the use of a gas planning model.[11]

Table 5-3. Model Simulations Used in Proxy Deferral Method

Simulation	Demand Forecast	Supply Plan
#1	Base Case	Base Case
#2	Base + DSM Case	Base Case
#3	Base + DSM Case	Proxy Deferral Case
#4	Base Case	Proxy Deferral Case

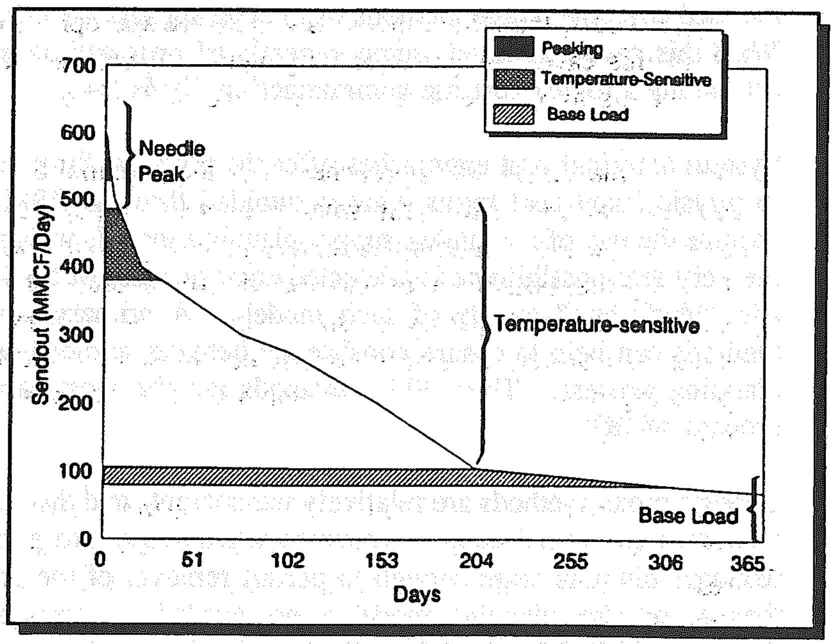
Table 5-3 shows the four gas planning model simulations usually performed in the proxy resource deferral method (Kahn 1989). As with all avoided cost methods, the proxy deferral method begins with a base-case supply plan and demand forecast (Simulation #1). The second step is to simulate the dispatch of the base-case supply plan with a decrement block of DSM in the load forecast. Simulation #2 should result in lower operating costs than in the base case because of the presence of DSM. The third step is to defer the introduction date of the proxy resource (or resources) for some period based on an initial estimate and then to run another simulation (#3) with the adjusted supply plan and the decrement load forecast. One then compares the present value (PV) of the stream of operating costs of Simulation #3 over the planning horizon with those of the Simulation #1 (i.e., the base case) with the goal of making them equivalent. If the deferral period in Simulation #3 is too short, then the PV operating costs will be lower than the base case (and vice versa). The analyst must repeat Simulation #3 with different proxy deferrals in order to arrive at this point. Once the optimal deferral is found, the last step is to simulate the dispatch of the adjusted supply plan with the base case load forecast (Simulation #4). The PV of operating costs of Simulation #4 will be higher than those for Simulation #1 because of proxy deferrals. The cost difference between Simulations #1 and #4 is the value of the deferral enabled by the DSM resource block; it is used as the basis for avoided cost. To summarize, avoided cost is the difference in PV of the stream of operating costs between the base case and proxy deferral cases (both employing the base-load forecast) divided by the load decrement (on a volumetric basis).

[11] Although this method can be applied with proxy gas resources that are physical plants, it may not be applicable for some types of contractual arrangements.

5.3.3 Targeted Marginal Cost

The targeted marginal cost (TMC) method is a composite of the proxy and system marginal cost approaches. Like the proxy method, it does not require the use of a gas dispatch simulation or long-term optimization model; instead the analyst selects the avoidable resources. Like the system marginal cost approach, TMC assigns avoided cost to the most expensive resources. The defining feature of this method is that the analyst partitions the supply resources into the types of demands they principally serve—typically base, temperature-sensitive, and peaking loads—then identifies the most costly supply in each category and allocates its costs to the corresponding demand impact (RCG/Hagler & Bailly Inc. 1991; Violette and Stern 1991). Figure 5-3 shows a hypothetical LDC load duration curve with the loads segmented into the three categories so the last resource dispatched in each category is highlighted (see shaded areas). The highlighted marginal resources targeted to specific demand patterns form the basis for avoided costs of DSM with the corresponding load-shape impacts. Costs of marginal resources are expressed on a unit cost volumetric basis in developing avoided-cost estimates.

Figure 5-3. Targeted Marginal Approach for Avoided Cost



Proponents claim that a major virtue of the TMC approach is that it explicitly accounts for cost causation (i.e., matching type of demand impact to resultant supply cost response)(RCG/Hagler & Bailly Inc. 1991; Violette and Stern 1991). Unfortunately, the causation is asserted by the analyst rather than demonstrated through the rigors of a supply planning process, so this benefit depends heavily on the skill of the analyst to accurately disaggregate and match up appropriate supply and demand elements.

5.3.4 Average Cost Methods

The principal virtue of average costing methods for estimating gas avoided costs is their simplicity. In this approach, the unit costs of all supply resources in the utility's portfolio are aggregated together, usually weighted by their respective volumetric contribution to the total sendout. This weighted average cost of gas (WACOG) customarily includes costs incurred at the city gate on an annual basis but could in theory be seasonally-differentiated and expanded to include other costs incurred by LDCs, such as LT&D costs.

These methods are based on embedded cost, which disregards many important LDC system operating characteristics. Further, use of average cost in avoided-cost estimation assumes that average cost of the current portfolio mix equals marginal cost, which will not be true for many LDCs.

5.3.5 Summary of Strengths and Weaknesses of Alternative Avoided-Cost Methods

Methods that rely on complex planning tools may offer the *potential* for greater precision, but if they are beyond what is needed for an LDC to adequately estimate avoided cost, then those methods will not be appropriate despite their general advantages. With this caveat in mind, some generalized pros and cons of the various methods for estimating avoided cost are summarized in Table 5-4.

System marginal-cost approaches offer the potential for greatest accuracy, showing both in physical and cost terms what is avoided through DSM programs. These methods require the use of a complex supply planning model, which can be costly and introduce the very real possibility of undetected error because of the formidable data requirements and "black box" quality of such models. A primary advantage is that use of SMC methods can help to ensure consistency between avoided-cost estimates and the overall planning process. Thus, SMC methods are the most harmonious with the goals and process of IRP.

Generic proxy methods are relatively transparent, and this is their main advantage; proxy resources are actual supply resources whose costs are generally known. If the DSM resource block is large enough to permit removal of the proxy resource from the mix, then a complex planning model is not needed to arrive at an avoided-cost estimate. However, if DSM only delays the introduction of the proxy resource, then a complex planning model is required to determine accurately the deferral period and the value of it. The potential weakness of both generic proxy approaches is that they rely heavily on the analyst's judgment to properly select the proxy resources. In addition, the proxy

Table 5-4. Strengths and Weaknesses of Alternative Avoided-Cost Methods

Method	Strengths	Weaknesses
System Marginal Cost	• Precise • Supply impact identified • Consistent with resource planning process	• Requires complex model
Generic Proxy	• Transparent • Model use optional • Supply impact determined (or asserted)	• Potential for proxy & DSM mismatch • Relies on judgment
Targeted Marginal	• Relatively easy • No model required	• Heavy reliance on judgment
Average Cost	• Very easy • No model required	• No relationship between DSM and supply impacts • Difficult to time-differentiate

deferral method includes the computational burden of complex planning models.

The key advantage of the targeted marginal cost approach is the relative ease of computation involved. No model is required in applying this approach; however, like all avoided-cost approaches, it requires a base-case supply plan that has been prepared presumably using a planning model. This method places heavy reliance on the analyst's judgment to break the supply mix into its constituent resource types—peaking, temperature sensitive, and base-load—and to properly choose the marginal resource within each.

Finally, the average-cost approach is the easiest method, and, like the targeted marginal approach, requires no significant modeling effort beyond developing a base-case supply plan. The disadvantage of this approach is that the computed cost based on the current portfolio of contracts may differ significantly from the costs actually avoided by DSM programs. WACOG used in avoided-cost applications tends to underestimate the value of savings during the temperature-sensitive and peak periods and to overestimate them in the off-peak period. At best, it should be considered a first-cut estimate of avoided cost.

Chapter 6

Economic Analysis of Gas Utility DSM Programs: Benefit-Cost Tests

6.1 Overview

Demand-side management (DSM) programs are typically analyzed using a benefit-cost framework. This chapter defines the most common benefit-cost tests used, discusses their uses, and explores technical and policy issues that arise in their application. The benefit-cost tests currently used by many PUCs have their roots in a report developed by the California Energy and Public Utilities Commissions: *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs* (California Public Utilities Commission (CPUC) and California Energy Commission (CEC) 1987).[1] PUCs have also derived their benefit-cost tests from the NARUC's publication *Least-Cost Utility Planning: A Handbook for Public Utility Commissioners Volume 2* (Krause and Eto 1988).

In principle, a benefit-cost test is the same whether it is applied to electric or gas DSM programs. Issues arise in applying the tests, primarily because of differences in industry structure. A total accounting of the benefits and costs of a gas utility DSM program will involve more entities because gas local distribution companies (LDCs) are not as vertically integrated as electric utilities. Methods and levels of avoided costs also differ between the two industries (see Chapters 2 and 5). Gas LDC services are unbundled for many customers, so the fuel cost savings of a DSM measure may not entirely flow through the LDC. Further, demand for natural gas services is generally more variable than demand for electricity and, from the perspective of the LDC, demand uncertainty is even greater due to competition from non-LDC gas suppliers and bypass pipelines.

Benefit-cost tests can be used for evaluating a variety of DSM activities, including conservation, load management, fuel substitution, and load building.[2] LDCs primarily use the benefit-cost tests as screening tools; that is, they are mostly used for winnowing large numbers of DSM program options. An LDC's ultimate decision to pursue a DSM program includes other factors in addition to the standard benefit-cost tests (see Chapter 3).

[1] One of the first papers to address the benefit-cost tests for conservation programs was a paper by White (1981).

[2] To keep the terminology as simple as possible, most of the examples will assume that the DSM program is a conservation program.

This chapter is structured as follows. Definitions and discussions of the most common benefit-cost tests are provided in Section 6.2.[3] Important technical complexities to the benefit-cost tests are addressed in Section 6.3. Examples of the tests are provided for both energy efficiency and fuel substitution programs. Section 6.4 discusses policy topics including: (1) the role of benefit-cost tests in the broader integrated resource planning (IRP) process, (2) the ongoing debate over the Total Resource Cost and Ratepayer Impact Measure tests, (3) frameworks for examining DSM markets and the existence of market imperfections and (4) alternatives to the standard benefit-cost tests.

6.2 The Benefit-Cost Tests

Benefit-cost tests provide useful economic figures of merit as seen from the perspective of different affected parties. Some of the most important perspectives are those of the (1) customers participating in the utility's DSM program (participants), (2) customers who did not participate in the utility's DSM program (nonparticipants), (3) the utility, (4) all utility customers, and (5) all people in a region or society.

For each perspective, benefit-cost tests show the net economic gain or loss that results from the pursuit of a DSM program. The gain or loss is measured by tallying up the program's costs and benefits and is expressed in terms of net benefits (NB) or as a benefit-cost ratio (BCR). Programs are cost-effective if the NB is greater than zero or if the BCR is greater than 1.0. In algebraic terms,

$$NB = B - C \tag{6-1}$$

or

$$BCR = \frac{B}{C} \tag{6-2}$$

The definitions of equation symbols used in all the equations presented in this chapter are provided in Table 6-1. In general, Equations 6-1 and 6-2 can be computed using benefits or costs stated on an annualized or present-value basis. For consistency, the following discussion and examples of the tests assume that the tests are computed on a present-value basis.

[3] To keep the discussion from being weighed down by technical equations, only simplified forms of the benefit-cost test equations are presented here. Readers interested in detailed equations are referred to Krause and Eto (1988), EPRI (1991a), and RCG/Hagler Bailly Inc. (1991).

Table 6-1. Definitions of Terms (in order of appearance)

NB	=	net benefit
BCR	=	benefit-cost ratio
B	=	program benefits
C	=	program costs
p	=	participants perspective
BR	=	bill reductions from DSM program
I	=	measures paid for by utility or incentives paid to participating customers
DC	=	direct cost of DSM measures (regardless of whether paid for by the utility or participant)
np	=	nonparticipants perspective
SCS	=	supply and/or capacity cost savings
RL	=	lost revenues
UC	=	utility program administration costs including shareholder incentives but excluding incentives paid to participating customers
u	=	utility perspective
tr	=	total resource perspective
s	=	societal perspective
NB_{ext}	=	net benefit of any externality impact of DSM program

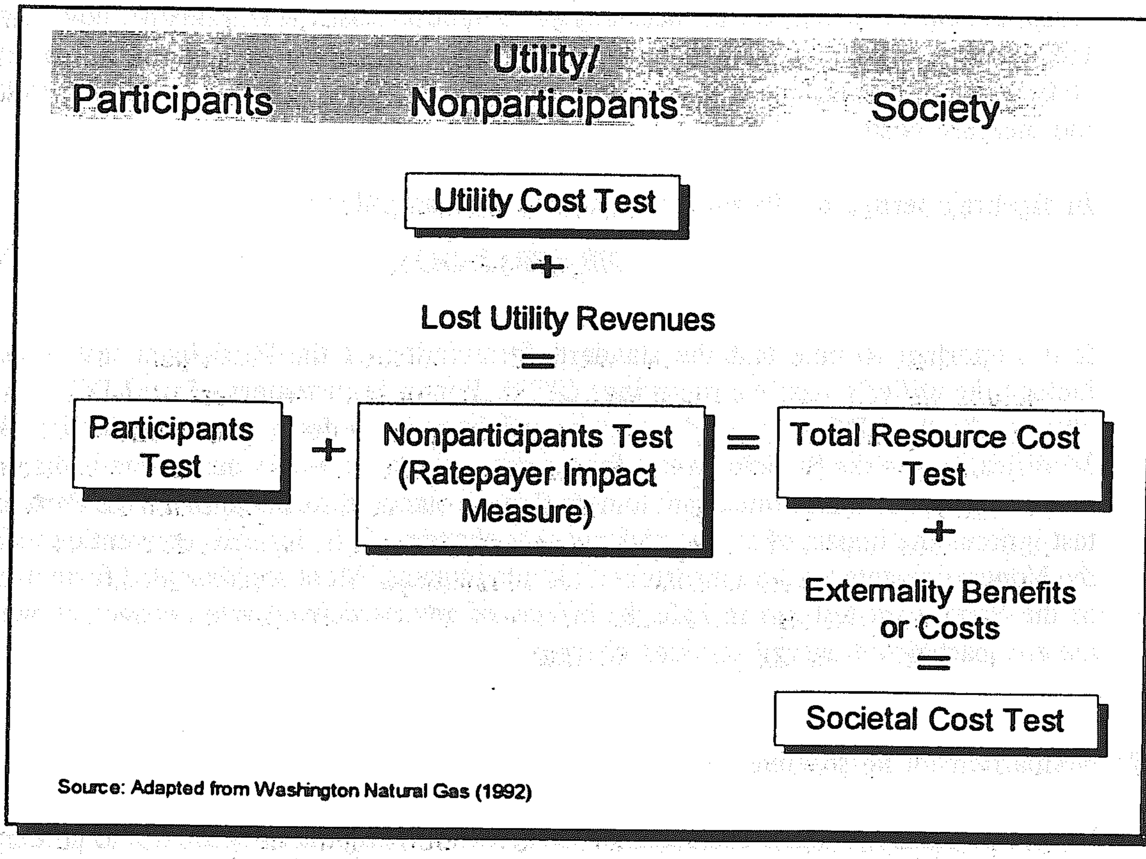
Table 6-2 summarizes relevant costs and benefits for each of the perspectives and provides an overview of the equations that will be described below. The net benefit from any one of these perspectives may be computed as the sum of all the relevant costs and benefits. Notice that two of these items—customer incentives and bill savings—are costs to nonparticipants but are benefits to participants. Figure 6-1 also provides an overview of the benefit-cost tests in a way that emphasizes the relationships among them. The figure shows that the Total Resource perspective is the sum of the Participant and Nonparticipant perspectives. The Utility perspective plus the addition of lost revenues equals the Nonparticipant perspective. Finally, the Societal perspective may be seen as the sum of the Total Resource perspective plus the net environmental benefits of the DSM program.

Table 6-2. Components of the Standard Benefit-Cost Tests

	Perspective				
Cost or Benefit Component	Participants	Non-participants	Utility	Total Resource	Society
1. Participant Commodity Cost Savings[1]	B			B	B
2. Utility Supply or Capacity Cost Savings[2]		B	B	B	B
3. Utility Program Administration Costs[*]		C	C	C	C
4. Incentives Paid to Customers	B	C	C		
5. Lost Revenues/ Utility Bill Savings	B	C			
6. Direct Cost of DSM Measures[3]	C			C	C
7. Externality Impacts					B or C

B = Benefit
C = Cost
[1] Participant Commodity Cost Savings applies only to transport-only customers; otherwise, reduced commodity costs are reflected in the utility bill savings.
[2] Includes both avoided gas commodity and gas capacity cost savings.
[*] Utility Program Administration Costs includes any incentive payments made to shareholders.
[3] Direct Cost of DSM measures includes all measure costs before any utility rebates.

Figure 6-1. Interrelationship of Standard DSM Benefit-Cost Tests



6.2.1 Participant Perspective

From the perspective of Participants, costs include the cost of the DSM measure, installation costs (including the cost of time lost by the participant during the installation), and the incremental operation and maintenance costs associated with the measure. From the participant's view, costs do *not* include the utility's program administration costs.

On the benefits side, the participant receives reduced utility bills from the DSM measure. The reduced bills are estimated using estimates of the consumption impacts of the DSM programs and the relevant LDC tariffs.[4] Bill savings may also come from the DSM measure's impact on other fuels. The customer may also receive an incentive from the

[4] As a simplification for screening purposes, bill savings are computed simply as the product of energy savings and the average or incremental rate for the customer.

utility in the form of a rebate or a subsidized loan. These payments to the participant are additional benefits. If a customer is *given* a DSM technology, such as a gas water heater wrap, the customer may never incur any out-of-pocket costs. It is standard, however, for the Participant test to include both the DSM measure cost and the utility incentive (rebate) payment and, in the case of utility "give always," the rebate simply cancels out the measure costs.

In algebraic terms, the Participant test is defined as follows:

$$NB_p = BR + I - DC \tag{6-3}$$

It is important to note that the standard formulation of the Participant test does not include the utility's supply cost savings (SCS). For sales customers of the LDC, the SCS obtained by the LDC are passed onto the participant in the form of a bill reduction (BR). Modifications to the Participant test for the case of transport-only customers is discussed in Section 6.3. It is also important to note that the standard formulation of the Participant test ignores the impact of any participant rate changes. It is, instead, convention to have the Nonparticipants test be a measure of all rate impacts. More sophisticated formulations of the Participant test can include the effects of any participant rate changes as well as the any participant energy services charges.[5]

6.2.2 Nonparticipant Perspective

Nonparticipants are utility customers who are either ineligible or chose not to participate in a utility DSM program. Their perspective is evaluated using the Nonparticipant test. Although called the Nonparticipant test, the test may be seen as measuring the rate impact on all ratepayers, even participants.[6] For this reason, the test is also known as the Ratepayer Impact Measure (RIM). The No-Losers test is yet another name for this test.

From the perspective of nonparticipants, the benefits of a DSM program consist of the supply costs savings obtained by the DSM program. Supply cost savings are computed as the product of the change in consumption and the LDC's avoided costs. Although ratemaking practices may not flow the supply cost savings immediately to the nonparticipating ratepayers, under the practice of cost of service regulation, it is reasonable to assume that utility cost reductions eventually accrue to the benefit of ratepayers.

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[5] Energy service charges for DSM are discussed in Chapter 6.

[6] Because it is convention for the Participant test to not consider rate impacts caused by DSM programs, there is no double counting of rate impacts when the Participant and Nonparticipant tests are summed.

On the cost side, nonparticipants are generally charged the utility's cost of the program, including incentives and program administrative costs. Further, nonparticipants can be expected to absorb revenue requirements that the participants were relieved of when the participants' bills went down. These revenues are called *lost revenues*.

In algebraic terms, the Nonparticipant test is defined as follows:

$$NB_{np} = SCS - RL - UC - I \tag{6-4}$$

The Nonparticipant test may be seen as an overall measure of the impact on *rates* resulting from the adoption of a DSM program. A rough estimate of the rate impact may be computed using the Nonparticipant test by taking the negative of the NB_{np}, levelizing it using an annuity factor computed using a discount rate and program life, and dividing it by after-program sales in each year. The resulting rate (in $ per therm) would be the average rate impact of the program. To compute the rate impact as a percentage rate increase, the annualized value should be divided by the total revenue requirement in each year of the program. In general, the Nonparticipant test will produce a negative net benefit, and a positive rate increase, whenever the utility's rates are above its avoided cost of serving the participating customer class.

A notable characteristic of the Nonparticipant test is that it is affected by the rates of the participant, not the nonparticipant. If rates for participating customers are above avoided costs, the Nonparticipant test will be negative. Another characteristic of the Nonparticipant test is its implicit assumption that *all* DSM program costs (program administration, incentives, and shareholder incentives) and lost revenues are passed through to ratepayers rather than shareholders. This is a reasonable assumption over a long period of time (a time greater than the LDC's typical rate case cycle). The test, however, may be an inaccurate measure of nonparticipant impacts in the short run because during that time revenue losses and, possibly, program costs may be shared between ratepayers and shareholders.[7] It is possible to develop a test that focuses specifically on the shareholder perspective but such a perspective is not a part of the standard array of benefit-cost tests.

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[7] Shareholders will not share in lost revenues if the utility is allowed to make up the lost margin before the next rate case via a net loss revenue adjustment mechanism or revenue decoupling mechanism. See Chapter 9.

6.2.3 Utility Perspective

A simple test for the impact of a DSM program on a utility's revenue requirement is included in the standard array of benefit-cost tests. The Utility Cost (UC) test is defined as follows:

$$NB_u = SCS - UC - I \qquad (6\text{-}5)$$

Although called the Utility Cost test, this test does not measure impacts on a utility's management or stockholders. Instead, the Utility Cost test compares a utility's supply cost savings to the utility's cost of delivering a DSM program. As such, the Utility Cost test makes the evaluation of a DSM program similar to methods that evaluate potential gas supply options. An LDC may face a range of technologies (on both the supply and demand side) available to meet its future demands and the Utility Cost test, which focuses on revenue requirements, requires that technologies with the lowest cost to the utility be chosen.

The Utility Cost test may also be seen as a measure of the change in the average energy *bills* for all customers. Assuming the number of customers in the with- and without-DSM cases are the same, the Utility Cost test measures the net change in utility costs and this change in costs will ultimately be allocated to ratepayers. A consideration of average bill impacts can be important in a situation where a utility's avoided costs are below incremental rates. In such a situation, a cost-effective DSM program is likely to result in a negative net benefit from the Nonparticipant perspective but produce a positive net benefit from the Utility Cost perspective. This means that although average rates will rise as a result of a DSM program, average bills to all ratepayers will go down.

The Utility Cost test is similar to the Nonparticipant test except that lost revenues are not considered a cost. Lost revenues, although a cost to nonparticipants, do not add to a utility's revenue requirement.

6.2.4 Total Resource/Total Technical Perspective

The Total Resource Cost (TRC) test takes the broadest perspective on private costs and benefits in evaluating the net benefits of a DSM program.[8] As may be seen from Figure 6-1, the TRC is roughly the sum of the Participant and Nonparticipant tests. Revenue losses and customer incentives that adversely affect nonparticipants are largely cancelled out by the bill savings and incentives received by the participants. All that is left is the

[8] Private costs and benefits exclude externalities.

direct costs of the DSM measures and the benefits from the utility's avoided costs.[9] Because the TRC represents the combination of the Nonparticipant and Participants tests, it is sometimes called the All-Ratepayers Test. The TRC is defined as:

$$NB_{tr} = SCS - UC - DC \tag{6-6}$$

With the TRC test, the utility-to-customer incentive is not considered a cost. Although this incentive is a cost to the utility, it is cancelled out by the benefit received by the participating customer.

It is generally accepted that shareholder incentives are a cost to be included in the UC term of the TRC test. Shareholder incentives may be considered a management fee paid to stockholders to assure the efficient delivery of a DSM program.[10]

Like the Participants test, the TRC test should measure the costs and benefits of a DSM program across all affected fuel types. This is an important consideration for many gas DSM programs. For example, a fuel substitution program that promotes gas-powered chillers over electric chillers will actually increase the gas supply costs. The electric supply cost savings may exceed the added gas supply costs, however.

A variant of the TRC test is the Total Technical Cost (TTC) test. The TTC test is like the TRC test but does not include any program administration costs. The TTC test may be computed by using Equation 6-6 and setting the UC term to zero. The TTC test is considered useful by some states as a screening tool for the development of a portfolio of DSM measures. When the TTC test is used, program administration costs are added to the portfolio of measures at a latter stage to insure the total portfolio is cost effective using the TRC test.

[9] There are a few reasons why the sum of the net benefits from the Participant and Nonparticipant perspectives will not always sum to the TRC. First, different discount rates may be used for different perspectives. Bill savings for the Participants test may be discounted at a different rate than the revenue loss of the Nonparticipant and they will not cancel each other. Second, it is standard to include the gross energy savings (including energy savings obtained by free riders) in the Participant test but only include net savings in the Nonparticipant test.

[10] Some analysts have argued that shareholder incentives based on shared savings are not a true cost to be counted in the TRC test but are, instead, simply a transfer of a portion of the net benefits from ratepayers to shareholders.

6.2.5 Societal Perspective

The Societal test has been developed to address concerns that there are unpriced impacts, known as externalities,[11] caused by energy consumption:[12]

$$NB_s = SCS + NB_{ext} - UC - DC \qquad (6\text{-}7)$$

Societal externalities are often identified as environmental externalities caused by natural gas production and consumption. The most common environmental externality considered is air pollution impacts including greenhouse gas pollutants. Whereas air quality impacts of electricity production occur primarily at the source of production, natural gas air quality impacts tend to occur at the point of consumption. Other environmental externalities, such as land or water use impacts could also be considered. Nonenvironmental externalities can also be considered and include the impact of changes natural in gas production and consumption on the local economy and on the Nation's trade deficit and reliance on foreign energy sources.

Unlike the other benefits and costs that have been identified so far, the estimation of externality values are controversial due to the inherent uncertainty of trying to assign monetary values to them. Several PUCs have included certain environmental externalities in their long-term electric resource planning process and at least 18 PUCs consider the use of externalities in their gas IRP or DSM planning processes (National Association of Regulatory Utility Commissioners (NARUC) 1992). Compared to electric resource planning, however, the development of externality values for natural gas consumption is unlikely to receive the same level of regulatory focus given that natural gas burns cleaner than other fossil fuels. One way gas combustion externalities will arise in a gas IRP context is in the examination of fuel substitution programs. Natural gas utilities in several states have developed externality values for gas combustion, along with externality values for electricity generation, to allow for a computation of the Societal test for fuel substitution programs. (See Chapter 5.)

Example calculations of the benefit-cost tests are presented in Exhibit 6-1, Table 6-3, and Figure 6-2 for a hypothetical DSM program wherein a gas LDC promotes the purchase of high efficiency residential gas furnaces.

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[11] An externality is a benefit or cost resulting from the production or consumption of goods in a market that accrues, unpriced, to a party outside that market. Inefficiencies result because, even if the market equates private costs and benefits on the margin, the externality goes unpriced and causes a level of consumption that is not optimal from a societal perspective.

[12] Some states have modified their TRC test to include the effects of externalities rather than create a new test. In this primer, the incorporation of externalities is reserved for the Societal Cost test.

Exhibit 6-1. Benefit-Cost Analysis for a Hypothetical High Efficiency Gas Furnace Program

To illustrate how benefit-cost tests are used to analyze gas DSM programs, a hypothetical program promoting high-efficiency furnaces is analyzed. The basic data and assumptions regarding the program are shown in Table 6-3. The program should be considered hypothetical, but numbers typical for gas utilities and the DSM technology were chosen. Avoided costs are estimated based on national average prices for natural gas delivered to LDCs and assumptions were made regarding the degree of seasonal variation in avoided costs and the amount of pipeline demand charges that are avoidable. Retail rates are based on national average data (American Gas Association 1992). Escalation rates are based on a recent GRI forecast (Holtberg 1993). With regard to discount rates, an 8% real discount rate is used for participants and a 6% real discount rate is used for all other perspectives. (See Section 6.3.1 for a discussion of discount rates.)

The program offers a $300 incentive to induce customers into buying a high efficiency condensing furnace. The example generally assumes that the participating customers would already be in the market for a furnace so the cost associated with the energy efficient technology is only its incremental cost over the standard technology. The analysis looks at the lifetime benefits and costs that come from one year of participating customers—400 in total. To implement the program, the utility will spend $40,000 in program administration costs, 25% of its total payout in incentives.

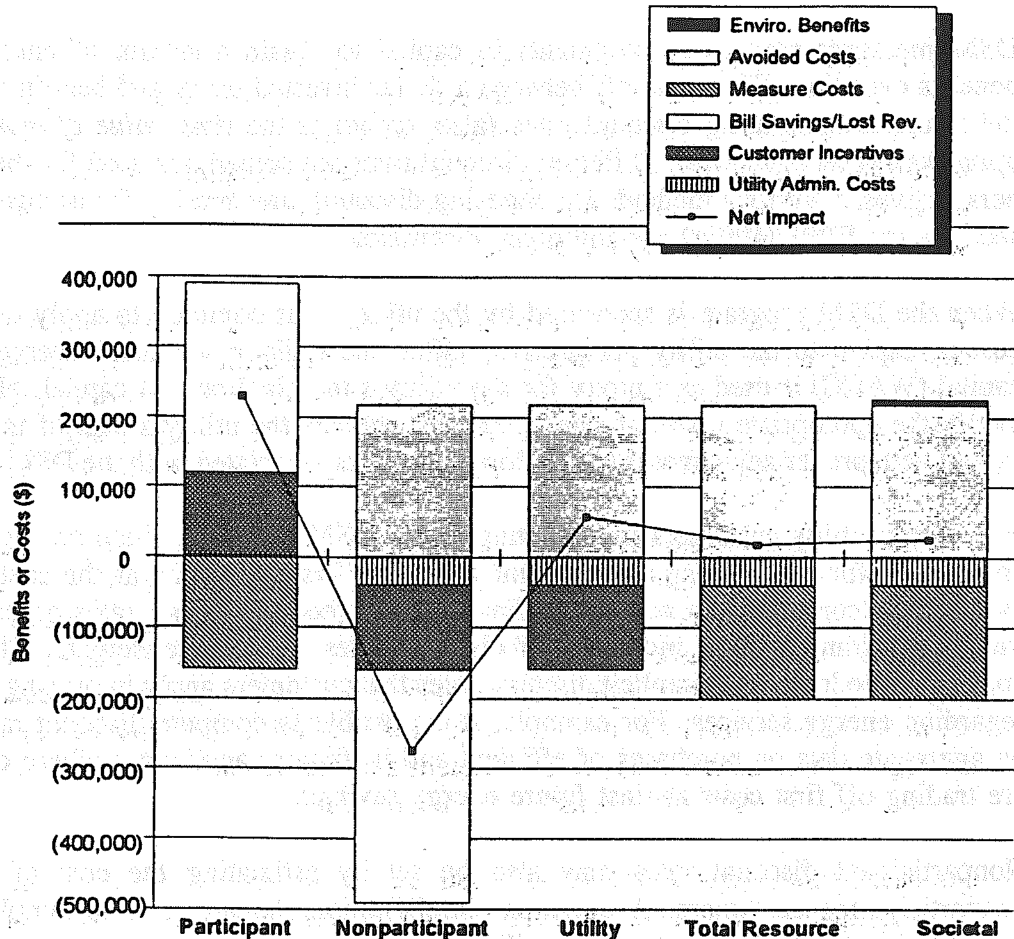
Results for the program are shown in Figure 6-2. The program is clearly a winner for participants with a net benefit of $230,000, a BCR of 1.43. For nonparticipants, the revenue loss, incentives, and program administrative costs exceed the supply cost savings and results in a loss of $274,000. The program shows positive net benefits for the Utility Cost and Total Resource Cost tests of $58,000 and $18,000, respectively. An important caveat to these net benefit figures is that it takes a considerable time, approximately 10 years, before the accrued avoided cost benefits outweigh the DSM measure costs. Thus, results would be very different if the gas avoided cost escalation rate was lower than the chosen rate of 2.5%/yr. Note also that the Participant and Nonparticipant tests do not sum to the TRC test because the bill savings seen from the Participant perspective is discounted at a different rate than the revenue loss seen from the Nonparticipant perspective.

If the reduced emissions from residential furnaces are considered, the net benefit increases by $7,000 to a total of $25,000. Reduced emissions in this example are valued at $0.015/therm, using estimates by Atlanta Gas Light in its recent IRP plan (Atlanta Gas Light Company 1992).

Table 6-3. Summary of Program Data for Residential High Efficiency Furnace Program

(1993 dollars unless otherwise noted)	
GENERAL ASSUMPTIONS	
Discount Rates (real)	
Participant	8%
All other perspectives	6%
No of participants	400
Effective life of measure (yrs)	30
PER CUSTOMER DSM PROGRAM DATA	
Gas load impacts, winter only (th/yr)	88
Incremental gas DSM measure costs	400
UTILITY COSTS	
Utility incentive, per customer	300
Utility costs, administration	40,000
AVOIDED COSTS (AC)	
Winter energy ($/th)	0.33
Real annual escalation in AC	2.50%
RATES	
Winter energy ($/th)	0.63
Real annual escalation in rates	0.70%

Figure 6-2. Benefit-Cost Tests for a Residential High Efficiency Gas Furnace Program



Costs and Benefits by Perspective (1993 Dollars)

Component	Participant	Nonparticipant	Utility	Total Resource	Societal
Customer Incentives	120,000	(120,000)	(120,000)		
Bill Savings/Lost Rev.	269,709	(332,483)			
Measure Costs	(160,000)			(160,000)	(160,000)
Avoided Costs		218,301	218,301	218,301	218,301
Utility Admin. Costs		(40,000)	(40,000)	(40,000)	(40,000)
Enviro. Benefits					7,268
Net Impact	229,709	(274,182)	58,301	18,301	25,569

Note: positive numbers are benefits, negative numbers are costs

6.3 Technical Issues in Application of Benefit-Cost Tests

6.3.1 Discount Rates

DSM measures represent investments in capital to obtain a stream of energy saving benefits over time. The trade-off between a dollar invested today and benefit realized in the future is done using discount rates (also known as the *time value of money* or the *opportunity cost of capital)*. Different discount rates are sometimes used for the different perspectives.[13] Various methods for choosing discount rates are briefly discussed in this section; see EPRI (1991a) for additional discussion.

When the DSM program is sponsored by the utility, it is common to apply the utility's cost of capital to the utility perspective. Often the utility's weighted average cost of capital (WACC) is used as a proxy for the utility's marginal cost of capital, although in theory the appropriate discount rate is one that reflects the utility's cost of incremental capital with proper adjustments (up or down) for risks associated with the DSM program.

For energy utility customers participating in the DSM program, there are two general approaches for determining the discount rate. The first is to look at the cost of funds available to consumers in real-world financial markets. Mortgage rates or credit card rates are commonly-used indicators of discount rates to small consumers. The second approach is to look at the implicit discount rates that customers apply in making decisions regarding energy services. For example, it is possible to compute discount rates based on aggregate data on purchases of efficient and inefficient appliances where customers are trading off first costs against future energy savings.

Nonparticipant discount rates may also be set by estimating the cost of funds to nonparticipating customers. A common simplification, however, is to simply set the nonparticipant's discount rate at the utility's discount rate.

For the TRC and Societal perspective, either the utility's cost of capital is used or there is an attempt made at computing a social discount rate. The utility's cost of capital is often used because it is the utility who is sponsoring the DSM program and will have to finance the DSM measures. Others advocate the use of lower discount rates for the Societal perspective. Social discount rates have been estimated by looking at discount rates on very-low-risk, long-term investments, such as 30-year Treasury Bills. Proponents of such methods argue that utility DSM programs affect a wide range of

[13] It is preferable to use the marginal opportunity cost of capital for all tests as opposed to a historical cost of capital or an average cost of capital.

people for a long period of time and that societal discount rates should be used as a matter of equity for future generations who will have to live with the effects of long-term energy resource decisions that they had no say in.

Finally, some analysts strongly reject the notion that discount rates should vary by perspective. Instead, one discount rate should be used that reflects the risk-adjusted discount rate appropriate for the DSM *program* (Alexis 1993). To estimate this discount rate, one would estimate the cost of capital if the DSM program operated as a venture separate from the utility. The variation in cash flows from the (hypothetical) stand-alone DSM program would be estimated. The cost of capital would be equal to the cost of capital of other investments available with similar variation in cash flows.

6.3.2 Free Riders and Drivers

In certain utility DSM programs, some participating customers would have installed the promoted DSM measure even if they were not provided an incentive. These types of customers are known as *free riders*. A particular participant may be free rider in one year but not in another. For example, a customer may have adopted an energy efficient technology five years out regardless of the existence of a utility program but adopted the technology immediately due to a utility program. This customer is a non-free rider for the first four years, but is a free rider from year five onwards. Similarly, a customer may be a free rider for only part of his or her savings. For example, a utility program that promotes buildings that are 30 percent more efficient than current building codes should not count the savings made by customers that would, even without a program, build in efficiency in excess of the building codes by 15 percent. In this case, a portion of the savings from free riders should be excluded.

With respect to the standard benefit-cost tests, the nonparticipant, utility, and total resource perspectives should be adjusted to incorporate savings after the effects of free riders are taken into account. This is typically done by applying a "net to gross" ratio (equal to the fraction of participants who are not free riders) to the energy savings. In the case of the Nonparticipant test, the net-to-gross ratio is also applied to the lost revenues and, for the TRC test, the net-to-gross ratio is applied to the measure costs. Utility program administration costs are usually unadjusted under the assumption of free riders. Because both the measure costs and supply cost savings of free riders are excluded, the net effect of free riders on the TRC test is typically much smaller compared to its effect on the Nonparticipant or Utility Cost tests (see Exhibit 6-2).

Free drivers are customers who modify their behavior as a result of a utility program but to a greater degree or at a lower cost than a standard participant. For example, a free driver might adopt the measure promoted by the utility but never bother to apply for the

Exhibit 6-2. The Effect of Free Riders

> Figure 6-3 provides an example of the effect of free riders on the high efficiency furnace program presented in Exhibit 6-1. The example assumes that 35% of the participating customers who receive the utility's $300 incentive would have bought a high efficiency furnace anyway.
>
> Free riders have no effect on the results for the Participants test, because it is standard to base the test on gross energy savings, which includes savings obtained by free riders. Results diverge, however, for the Nonparticipant, Utility Cost, and TRC tests. In the Nonparticipant test, only net lost revenues are included—a certain amount of revenues would have been lost anyway to the free rider participants. Similarly, the avoided costs are reduced because only the net participants really save the utility supply-side costs relative to the base case. Because avoided costs are lower than incremental rates in this example, the net benefit increases to -$234,000 from -$274,000. From the utility's perspective, costs do not change, but benefits decrease. In effect, the utility must make a business decision to pay customers for measures they would have installed anyway as a way of reaching all possible participants including those that generate real savings. The result of free riders in this example is a decrease in the Utility Cost test from $58,000 to -$18,000. For the TRC and Societal tests, supply cost savings, direct measure costs, and environmental benefits (if applicable) are both reduced and the program net benefits hover near zero.

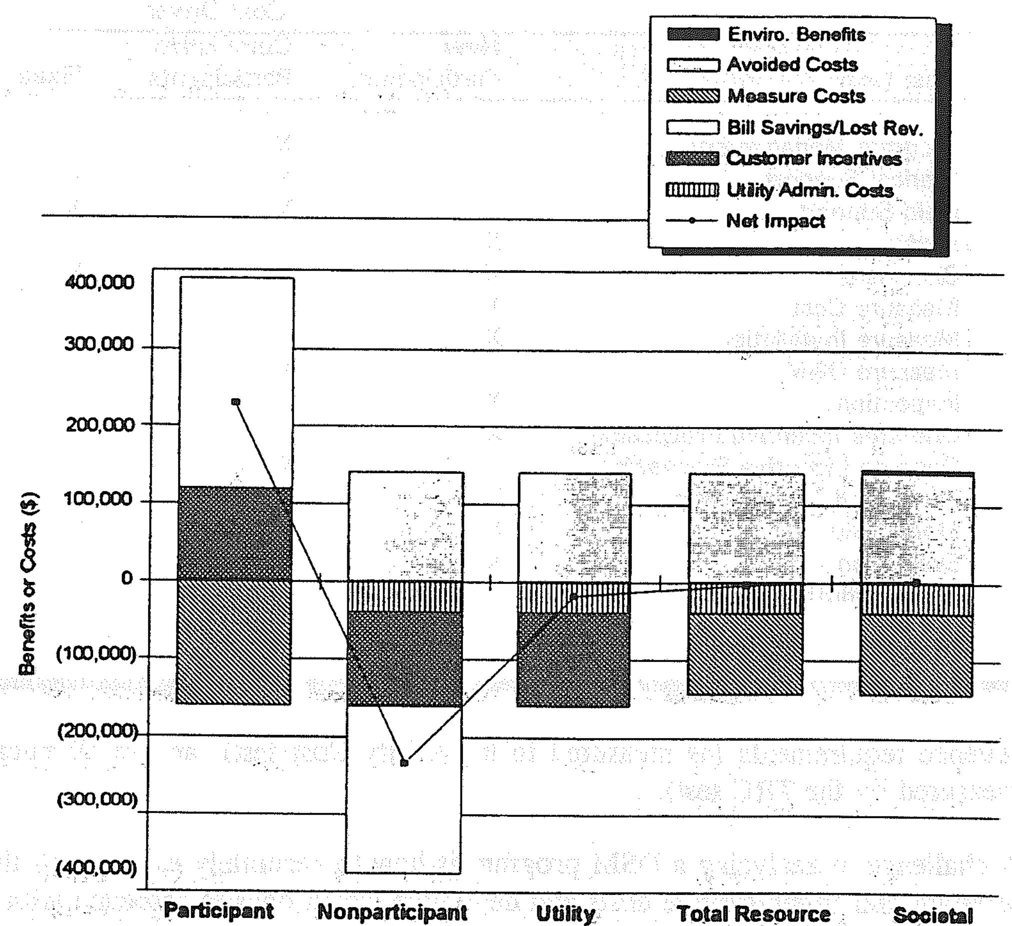
utility rebate. Another example of free drivership is when participating customers pay greater attention to energy efficiency in purchase decisions made subsequent to the conclusion of the utility's program. Free drivers can be incorporated into the benefit-cost tests by either increasing the energy savings attributable to the program and/or decreasing the program incentive payments per unit of energy saved.

6.3.3 Program and Administrative Costs

For purposes of analyzing a proposed DSM program, it is necessary to identify the cost of running a utility DSM program. Program and administrative costs can include several types of costs such as development, start-up, administrative, promotion/advertising, and monitoring and evaluation (M&E).[14] Shareholder incentives, if any, should generally be included in program and administrative costs. Although shareholder incentives are not a "cost" to the utility they are usually considered to be an added cost to nonparticipants,

[14] Utility program and administrative costs should not include the actual incentive paid to the participating ratepayer even if the utility buys or installs the measure itself. Such costs should be measured in the incentive payment (I) term

Figure 6-3. Benefit-Cost Tests for a Residential High Efficiency Gas Furnace Program with Free Riders



Costs and Benefits by Perspective (1993 Dollars)

Component	Participant	Nonparticipant	Utility	Total Resource	Societal
Customer Incentives	120,000	(120,000)	(120,000)		
Bill Savings/Lost Rev.	269,709	(216,114)			
Measure Costs	(160,000)			(104,000)	(104,000)
Avoided Costs		141,896	141,896	141,896	141,896
Utility Admin. Costs		(40,000)	(40,000)	(40,000)	(40,000)
Enviro. Benefits					4,724
Net Impact	229,709	(234,218)	(18,104)	(2,104)	2,620

Note: positive numbers are benefits, negative numbers are costs

Table 6-4. Participation Variables Used to Project Utility Program and Administrative Costs

	Cost Driver		
Cost Item	New Participants	Cumulative Participants	Fixed
Program Management		X	X
Clerical Support		X	X
Field Support		X	X
Audits	X		
Site Visits	X		X
Measure Cost	X		
Measure Installation	X		
Measure O&M		X	
Inspection	X		
One-time Incentive Processing	X		
Ongoing Incentive Processing		X	
Removal & Reinstallation	X	X	
Monitoring	X	X	X
Evaluation	X	X	X

Source: EPRI 1991a

revenue requirements (as measured in the Utility Cost test), and to all ratepayers (as measured by the TRC test).

A challenge in analyzing a DSM program is how to accurately estimate all the utility's program and administrative costs and determine which ones to associate with particular DSM programs. Table 6-4 identifies 14 types of distinct costs and indicates whether the cost is likely to be driven by new participants, cumulative (existing) participants, or is fixed regardless of the size of the DSM program.

Some program costs, such as measurement and evaluation (M&E) costs, are driven by more than one factor. The overall purpose of M&E is to see how the program performs over time and whether it performs as initially estimated. For every new participant, there are costs associated with including the participant in the M&E program. Once included, there are ongoing costs associated with the continuing monitoring of the participants and any control group. Finally, there are fixed costs associated with the overall corporate M&E capability and the analysis of DSM program effectiveness. It may make sense to associate the per participant and cumulative M&E costs with a particular program but assign the fixed M&E costs to the utility's entire DSM portfolio. If the M&E program is set up to reduce the uncertainty surrounding the delivered savings of a particular program or to provide information to make mid-course corrections, then it is clear that the M&E costs should be assigned to a particular program or set of programs. Whether to include these costs as a cost of a particular DSM program or a portfolio of programs can, however, depend on the purpose of the M&E effort. Given that a gas utility DSM programs are relatively novel, some of a utility's M&E function may be considered a type of research and development and should not be associated with any particular program currently proposed by the utility.[15]

If significant effort has been made to accurately estimate utility program and administrative costs one should, for the sake of accuracy, check that similar costs were included in proposed supply options as well.

6.3.4 Analysis of Programs that Affect Multiple Fuels

Many DSM measures can affect the consumption of more than one fuel. For example, in the case of improvements to building shell efficiency there is a reduction in the use of all fuels used to provide heating. Even if gas is the primary space heating fuel, there may be incidental impacts on wood use or electric use. Electricity consumption may be further reduced if the building has an electric air conditioner.

If the effects of a gas DSM measure on the consumption of other fuels is quite small, the impacts are typically excluded from the benefit-cost tests. For some DSM programs, however, a major goal is to impact multiple fuels (e.g., fuel substitution programs that promote a gas technology as a substitute to an electric technology). In such cases, the Participant, TRC, and Societal tests should include the impact of both fuels. This adds complexity to the analysis but is necessary to insure that positive net benefits accrue to participants and to all ratepayers or society as a whole. Although the Participant, TRC, and Societal Cost tests should be evaluated across all affected fuel types, the Nonparticipant test and the Utility Cost test should first be evaluated for the customers of each utility because customers of one affected fuel type may have little or no overlap of customers of another fuel type. Once such single-fuel tests have been computed, it may be useful to combine the Nonparticipant or Utility Cost test across all affected fuels. Combined tests show the average rate impact (Nonparticipant test) or revenue requirement impact (Utility Cost test) of the program within the combined set of utility service territories (see Exhibit 6-3).

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[15] Apparently because of the research function that M&E provides, California's *Standard Practice Manual* recommends excluding all M&E costs from the utility's program administration costs (California Public Utilities Commission (CPUC) and California Energy Commission (CEC) 1987).

Exhibit 6-3. Benefit-Cost Analysis for an Electric-to-Gas Fuel Substitution Program

A hypothetical program that promotes the use of air conditioning powered by gas-driven chillers over conventional electric chillers illustrates some issues that arise in the economic analysis of fuel substitution programs. Table 6-5 summarizes assumptions and relevant data on costs, savings, and utility rates. Target customers are operators of commercial buildings that are considering the purchase of an electric chiller either to replace an existing one or because their building is under construction. The incremental cost of a gas driven chiller is $25,000 per building and the utility is offering an incentive of $12,500. Under the utility's tariff, commercial customers pay $0.55/therm, which is a national-average rate. Incremental gas supply costs are lower than the avoided costs presented in Exhibit 6-1 because the increased gas use will occur in the summer. Electric avoided costs and rates are roughly based on an electric utility that has deferrable gas-fired resources in its resource plan. Forecasted escalation rates are from GRI (1993).

To fully analyze program impacts, both gas and electric customers should be considered. For the Participant and TRC tests, the impact of increased gas supply costs and decreased electric supply costs are incorporated. Separate Nonparticipant tests are developed for gas and electric customers, however. Participants have a net benefit of $8.7 million (see Figure 6-4). The benefits come primarily from the electricity bill savings. In comparison, the gas utility's incentive payment is small.

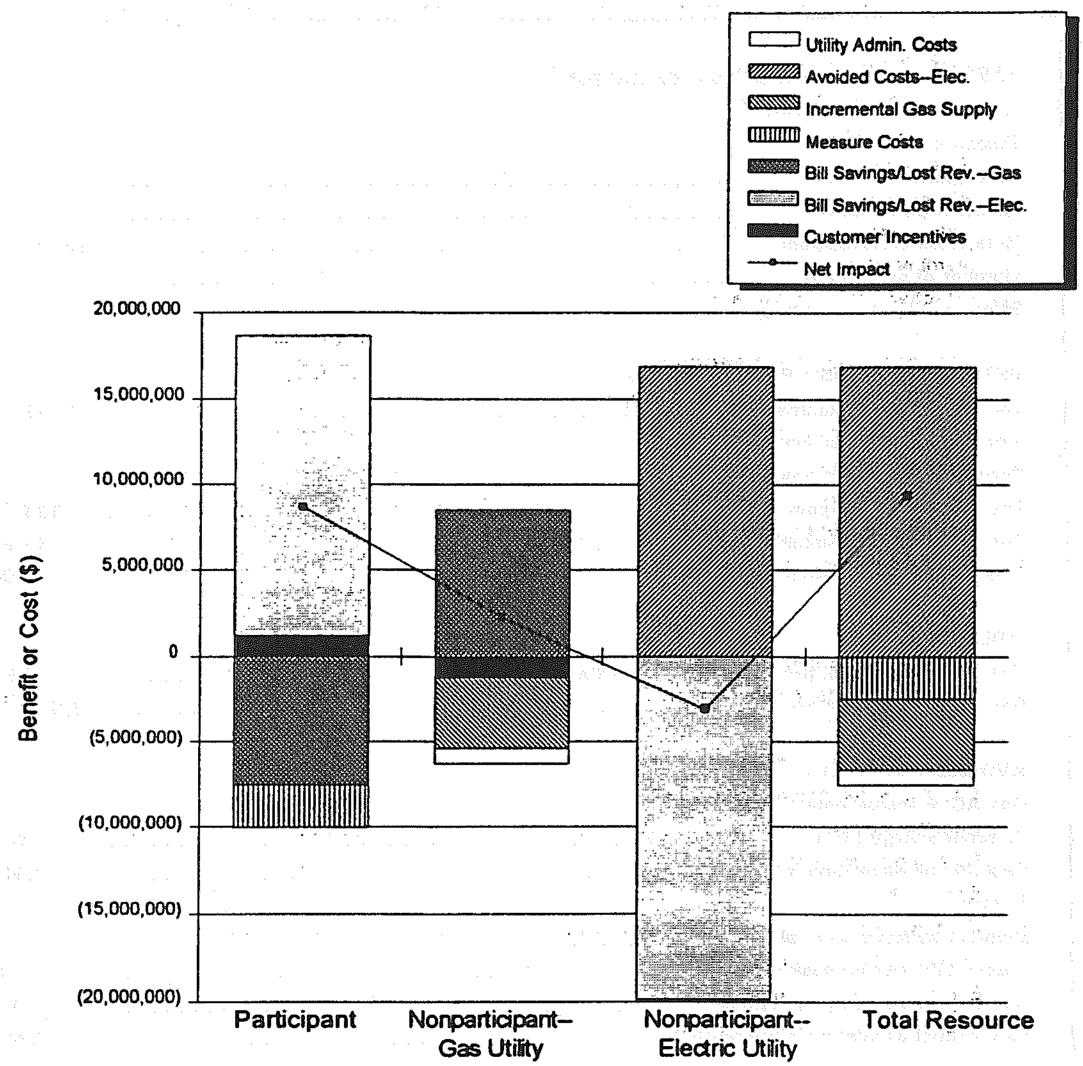
To nonparticipating customers of the gas utility, the program also provides benefits because the incremental revenues outweigh the extra gas supply costs, incentive payments, and program administration costs. The program provides negative benefits to nonparticipating customers of the electric utility, because the avoided cost benefits are exceeded by lost revenues.

From the Total Resource perspective, the benefits of the program are the electric avoided cost savings net of the incremental gas costs, measure costs, and program administrative costs. In this example, the net benefit of the program using the TRC test is $9.4 million.

Table 6-5. Summary of Program Data for an Electric-to-Gas Driven Chiller Program

(1993 dollars unless otherwise noted)	
GENERAL ASSUMPTIONS	
Discount Rates (real)	
Participant	8%
All other perspectives	6%
Rate class of participants	commercial
Number of participants	100
Effective life of measure (yrs)	15
PER CUSTOMER DSM PROGRAM DATA	
Gas load impact, summer only (th/yr)	-15,000
Annual Electric Load Impacts	
Demand summer on-peak (kW)	126
Energy summer on-peak (kWh)	131,888
Energy summer off-peak (kWh)	43,963
Gas-driven chiller incremental cost	25,000
UTILITY COSTS	
Gas utility incentive, per customer (@ $100/ton)	12,500
Gas utility costs, administration	2,500,000
AVOIDED COSTS (AC)	
Gas AC = Incremental Supply Costs	
Summer energy ($/th)	0.24
Real annual escalation in AC	2.50%
Electric AC	
Demand summer on-peak ($/kW/mo)	10.83
Energy summer on-peak ($/kWh)	0.04
Energy summer off-peak ($/kWh)	0.04
Real annual escalation in energy AC	2.40%
RATES	
Incremental summer gas rate ($/th)	0.55
Real annual escalation in rates	0.90%
Incremental Electric Rates	
Demand summer on-peak ($/kW/mo)	16.25
Energy summer on-peak ($/kWh)	0.06
Energy summer off-peak ($/kWh)	0.06
Real annual escalation in rates	1.60%

Figure 6-4. Benefit-Cost Tests for an Electric-to-Gas Fuel Substitution Program: Commercial Gas Cooling



Costs and Benefits by Perspective (1993 Dollars)

Component	Participants	Nonparticipant Gas Utility	Nonparticipant Electric Utility	Total Resource
Customer Incentives	1,250,000	(1,250,000)	0	0
Bill Savings/Lost Rev.-Gas	(7,523,917)	8,562,779	0	0
Bill Savings/Lost Rev.-Elec	17,467,841	0	(19,926,093)	0
Measure Costs	(2,500,000)	0	0	(2,500,000)
Incremental Gas Supply	0	(4,141,756)	0	(4,141,756)
Avoided Costs-Elec	0	0	16,878,331	16,878,331
Utility Admin. Costs	0	(875,000)	0	(875,000)
Net Impact	8,693,924	2,296,022	(3,047,762)	9,361,574

Note: positive numbers are benefits, negative numbers are costs

6.3.5 Interruptible and Transport-Only Customers

Interruptible customers and transport-only customers represent significant amounts of throughput for many gas LDCs. If a utility wishes to offer a DSM program to these customers, special attention should be given to the assumptions used in computing the benefit-cost tests.

Interruptible customers, by definition, are not provided the same degree of reliability as are firm customers. If the avoided costs include any components that are based on supply side projects that provide reliability, they should be excluded from the avoided costs used to evaluate DSM programs provided to interruptible customers. In other words, avoided cost should only include commodity components.

Transport-only customers do not buy gas commodity from the local utility. Further, with the advent of capacity release programs offered by interstate pipelines, the transport-only customer may not even rely on the local gas utility for upstream transportation rights. Thus, the costs avoided by a gas utility promoting a DSM program to transport-only customers may be very low.[16] One way to incorporate these lower avoided costs is to modify the Utility Cost and Nonparticipants tests to include only the utility's avoided costs. Not only should this modification be made for customers who transport their gas today; it should be made for customers who are forecasted to take transport-only service in the future. Unfortunately, such forecasts are hard to make with certainty. The combination of lower avoided costs and uncertainty over the forecasted service choices of customers makes it very difficult for DSM programs offered to current or potential transport-only customers to pass these two tests. In contrast, the Participant, Total Resource, or Societal Cost tests should look at both the utility's and the participant's avoided costs. When the avoided commodity costs of the transport-only customer are considered, a DSM measure may still provide considerable benefits. One of the few states that has authorized its investor-owned gas LDCs to offer DSM programs to industrial customers is California. One California combination utility, Pacific Gas and Electric Company, used the modified Utility Cost test as part of its review of bids under its pilot DSM bidding program.

[16] Because most gas utilities are effectively obligated to serve transport-only customers when they chose to return to the utility for commodity service, it may be appropriate to credit DSM for the avoided *standby cost* benefits that it provides.

6.3.6 Period of Analysis

Careful consideration should be given to the time frame chosen for the analysis of the DSM program. Usually, one of two time frames is chosen: the length of the expected life of the DSM measure or a fixed planning horizon (RCG/Hagler & Bailly Inc. 1991).

Choosing a time frame equal to the life of the DSM measure is attractive because it is an easy way to capture the full benefits that accrue from the near-term adoption of the DSM measure.[17] In selecting the life of the measure, it is important to take into consideration factors that may affect the useful life beyond its physical life. If the measure is installed in a building, its life may be cut short by remodels, demolitions, and, possibly, ownership changes. Further, as noted in the free rider discussion, above, certain measures may be eventually adopted in due course without a DSM program. Rather than decrease the net-to-gross ratio, it may be more straightforward to simply shorten the effective life of the measures.[18] An added complication occurs when the gas LDC DSM programs serves customers that may bypass the LDC before the end of the effective life of the DSM measure. From the perspective of the utility or nonparticipant, it may be necessary to effectively shorten the life of the DSM measure to account for the fact that the benefits of the measure will no longer accrue to the utility/nonparticipants after the customer leaves the LDC's system.

A fixed-period time frame may be useful when the modeling of DSM programs is more sophisticated or is done in comparison to a specific supply side plan. Time frames ranging from 5 to 20 years are all common. DSM measures may be installed over a period of years, not just in the first year. If the effective life of a measure is less than the planning horizon, a choice must be made regarding its replacement: either the device reverts to the base case efficiency level or the same efficient measure is reinstalled.[19]

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[17] Such an approach was taken in the preparation of the examples in this chapter.

[18] Shortening the effective life of DSM measures is an appropriate way to model free riders who, as a result of the utility DSM program, adopt the measure sooner. Free riders whose consumption was totally unaffected by the program should be modeled as a reduction in net program savings rather than by shortening the effective life of the DSM measure.

[19] It is possible that the base-case technology at the time of replacement may be similar to the efficient technology promoted by the utility in the first place. In this case, even though the efficient technology is reinstalled, it should not add to program-related savings.

6.3.7 Taxes

Taxes may affect the results of the benefit-cost tests in at least four different ways. First, utility incentive payments received by commercial and industrial customers are treated as taxable income and reduce the effectiveness of incentive payments. Rebates made to residential customers are not taxable under federal law so taxes are not a factor for residential programs.

Second, like any other business activity, utilities will pay sales taxes on goods and services purchased for the delivery of demand-side programs. The cost of these taxes should not be ignored when making cost estimates (RCG/Hagler & Bailly Inc. 1991).

Third, utility income is taxed, typically at an incremental rate of 35 percent or more and this rate can have a significant effect on the utility's avoided costs and discount rate. Although income taxes are a real cost to a utility, it may be fallacious to use it in a broad perspective such as the TRC or Societal Cost test. This is because the increase or decrease in DSM activity has probably little or no affect on the federal or state government's budget. One strategy is to remove corporate income taxes completely from the analysis. The easiest way to do this is to remove the effect of income tax on the cost of capital used in either the TRC or Societal Cost tests. If this is done, care must be taken to remove the impact of taxes from not only the discount rate, but any supply- or demand-side capital costs that have been annualized (such as the capacity component of avoided costs).

Fourth, many utilities are charged (and pass on to their customers) taxes that vary with revenues: sales taxes, franchise taxes, gross receipts taxes, and utility taxes. As a result, the bill savings seen by a customer may, in effect, be larger than the revenue reduction seen by the utility. As with the treatment of corporate income taxes, the best treatment of revenue-related taxes is not obvious because the reduction in tax revenues from a DSM program could possibly lead to an increase in the tax rate by the taxing agency or a reduction in the level of service by the agency.

6.4 Policy Issues in the Application of Benefit-Cost Tests

This section addresses some of the broader issues raised by the use of benefit-cost tests. First, the role of the benefit-cost tests in the larger IRP framework is discussed. Second, there is a discussion of the policy debate regarding which is a better primary test: the TRC or RIM test. The heart of this debate depends on estimates of the degree of market imperfections and a framework for assessing such imperfections is provided. Finally, emerging benefit-cost tests are described.

6.4.1 Role of the Benefit-Cost Tests in the IRP Framework

The benefit-cost tests are most useful for screening DSM programs, along with the screening of supply-side resources, in a resource integration phase and in an evaluation of multiple alternative plans (see Chapter 3). At this point in an IRP analysis, other objectives can be considered and items that may have been simplified or ignored in the computation of the standard benefit-cost tests can be incorporated. For example, a DSM program may affect avoided costs or have reliability impacts and both of these impacts should be considered in a full IRP analysis.[20] Further, a full IRP analysis may include an uncertainty analysis, which would test for *potential* benefits and costs not covered in the standard benefit-cost tests framework.

6.4.2 TRC versus RIM: Which Test is Best?

There is a long-standing policy debate over the appropriate tests to use for determining the level of cost-effective DSM that should be pursued by a utility. Most of the debate has been conducted with regard to electric utility participation in DSM programs, but PUCs have also grappled over which test to use for the evaluation of gas LDC DSM programs. The debate is often formulated in terms of which test should be considered primary in the economic analysis of DSM programs: the TRC test or the Nonparticipants test (also commonly known as the RIM test).

Arguments for the TRC Test

Proponents of the TRC test argue that it is a broad test that measures all the private costs and benefits applicable to energy consumers. The TRC test measures the total cost of energy services, including the portion of costs that customers contribute towards the purchase of a DSM measure. Further, if the related Societal Cost test is used, then externality costs and benefits can be added to the private costs and benefits included in the TRC test.

Results of a recent NARUC survey suggest that among those PUCs that responded: (1) the TRC test has broad support (18 of 23 PUCs) and (2) the TRC, Utility Cost, and Societal tests are specified as the primary test most frequently (see Table 6-6). The main reason that the TRC, Societal, and Utility Cost test dominate as primary tests is because

[20] For the interaction of DSM programs and avoided costs, see Energy Management Associates (1992) and Kahn (1992).

Table 6-6. Benefit-Cost Tests Used by 23 Public Utility Commissions for Evaluating Gas DSM Programs

	Perspective					
State	Participants	Non-participants	Utility	Total Resource	Total Technical	Societal
Alabama PSC	P					
California PUC	O	O	O	P		P
Connecticut DPUC	O	O	O	P	O	P
DC PSC				P		
Florida PSC	O	O	O	P		
Georgia PUC		O	O			O
Idaho PUC			P	P		
Illinois CC	O	O	P	P		P
Iowa UB	O	O	O			P
Maryland PSC				P		
Massachusetts DPU						P
Michigan PSC	O		P	O		O
Minnesota PUC	O		P	O		P
Missouri PSC			P	P		
New Jersey BRC				P		
New York PSC	O	O	O	P		P
Nevada PSC	P	P	P	P		
Oregon PUC				P		
Pennsylvania PUC	P	P	P	P		
Virginia SCC	O	O	O	O		
Vermont PSB						P
Washington UTC			P	P		
Wisconsin PSC	O	O	P	P	P	O
Total Primary	3	2	9	15	1	8
Total Other	10	9	7	3	1	3
Total Count	13	11	16	18	2	11

P = Primary Test(s) Used at PUC
O = Other or Nonprimary Test(s) Used at PUC

Source: NARUC (1992) and LBL and GRI date

PUCs want DSM to be treated like any other energy resource. When DSM is treated as a resource, its costs, whether it be to the utility (Utility Cost test) or the utility and the participants (TRC test), are simply compared to supply cost savings that are avoided. The primacy of the TRC/UC tests may also be attributable to the general IRP goal of using the benefit-cost tests primarily as a screening tool that precedes the more complex resource integration phase. In this context, it makes sense to consider only the resource costs of the DSM resource. Many PUCs consider rate impacts important too, but do not require that individual programs pass the RIM test. Instead, overall rate impacts of the *portfolio* of DSM programs is estimated. Under this framework, programs that pass the TRC but fail the RIM test may be pursued so long as the overall rate impacts are tolerable.

Arguments for the RIM Test

Proponents of the RIM test favor it for two reasons. First, the RIM test is a measure of distributional impacts of a DSM program. Proponents of the test claim it is unfair to nonparticipants to approve utility DSM programs that will on balance, bring no net benefits to the nonparticipant.[21] An integrated resource plan that includes DSM programs that pass the TRC test but fail the RIM test will be least-cost, but unfair. Customer classes that do not receive the bulk of the benefits of utility DSM programs, such as large commercial and industrial customers, have tended to support the RIM test as a result. Second, and more controversial, some energy industry participants have argued that the RIM test is a better measure of overall economic efficiency than the TRC test; that is, the RIM test does not just measure the net benefits of nonparticipants but is instead a measure of the overall net benefits of a DSM program (Joskow 1988; Kahn 1991a; Ruff 1992; Caves 1993). Proponents of the RIM test usually believe that markets for energy services work reasonably well and energy customers purchase optimal mixes of energy and energy-using equipment to minimize discounted life cycle costs. Under the assumption of competitive markets, it is unlikely that participants will accrue large benefits from participating in a utility-funded DSM program. Instead, they will be roughly indifferent and, at most, will have net benefits equal to the incentive payment paid to them by the utility (see next section). Thus, programs that pass the TRC test but fail the RIM test are simply "too good to be true" and should be viewed skeptically. By requiring DSM programs to pass the RIM test, utilities are essentially limited to pursuing load building programs and conservation programs where the conserved consumption is

[21] Some parties argue that DSM programs provide *potential* benefits to nonparticipants even if the program fails the RIM test. Environmental benefits, utility planning flexibility, and the development of new technologies have been cited (Centolella 1993). However, if an analyst expects these benefits to occur, they should be considered as a benefit in the Nonparticipant test. If they are considered to be *potential* benefits, then they should be considered in an uncertainty analysis.

priced below a utility's avoided cost. RIM test advocates believe that such limitations on utility involvement are prudent.

6.4.3 A Framework for Understanding Market Imperfections

At the heart of the RIM versus TRC debate is whether PUCs should presume that markets for energy services are competitive or presume that significant imperfections exists. To understand this debate, it is useful to have a framework for understanding markets for energy efficiency and what the impact of market imperfections, if any, are. Figure 6-5 presents supply and demand curves for a hypothetical market for a DSM measure in a particular service territory under two assumptions regarding market imperfections. The Y-axis measures the price or value of the DSM measure and the X-axis measures the quantity of DSM sold (shown in units of therms saved). Under the assumption of competitive markets, the demand for, and value of, the DSM measure are the same.[22] These values are shown as the V = D line. Before the DSM program, Q_o of DSM measures were sold and after the DSM program is implemented, Q_1 are sold. The effective price of the DSM measure to customers in the service territory is shown on the P_{DSM} line. Net value to participants is measured by subtracting the P_{DSM} line from the D = V line. Thus, the total value of the DSM measures purchased as a result of the program is equal to Areas A + B and the value, net of the participants' costs, is Area B.

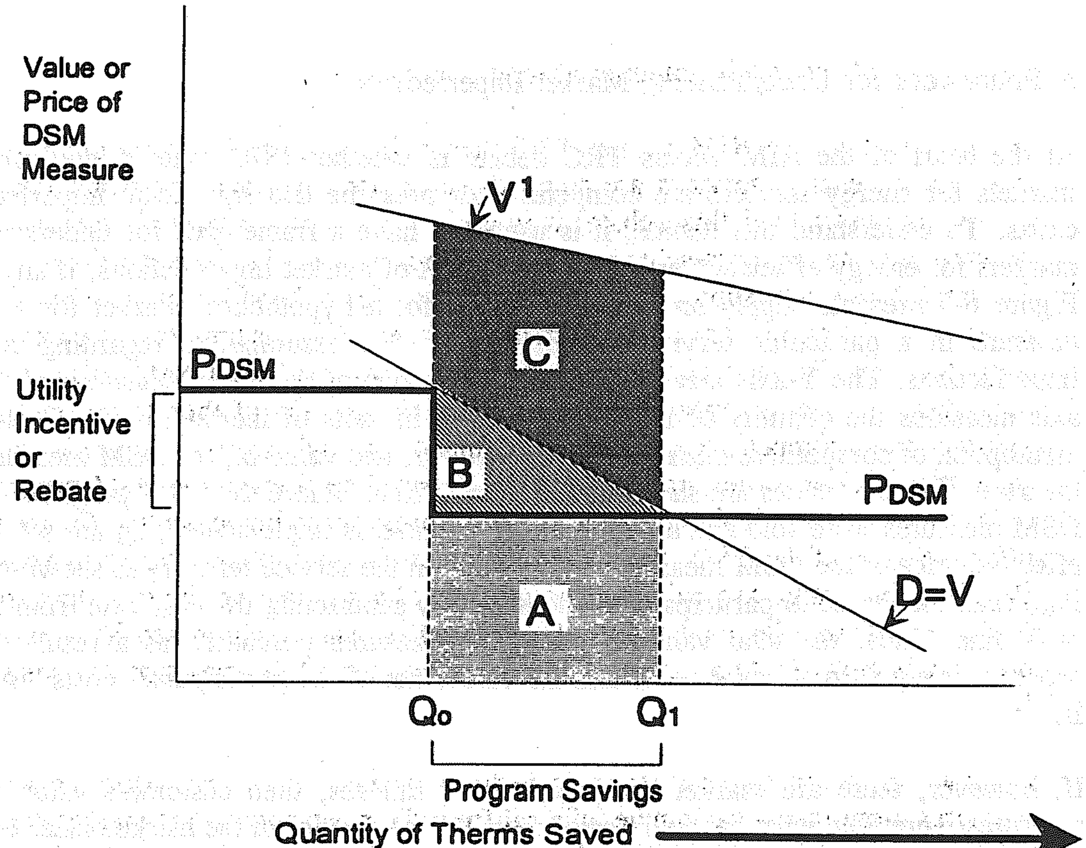
If, however, there are market imperfections or failures, then customers value DSM measures more than what can be inferred from their behavior in the marketplace. Figure 6-5 also shows the value of DSM measures in the situation where market imperfections exist. The line V^1 is the value to program participants under the assumption of market imperfections. It diverges from the market demand curve, D. V^1 is usually estimated as the utility bill savings provided by the adoption of a DSM measure.[23] Total value of the DSM measures purchased as a result of the program in this case is equal to Area A + B + C and, net of participants' measure costs, is equal to Area B + C.

Proponents of the TRC test tend to believe that market imperfections for energy efficiency exist (i.e., V $\neq$ D), especially if studies indicate that there are large quantities

[22] This way of estimating participating customers value is based on their observed behavior and is sometimes known as a "revealed preference" methodology.

[23] The V_t line is shown as downward sloping to reflect the fact that some program participants will save more energy than others. Also, it should be noted that other items besides bill savings can affect participant value. A DSM measure's enhancement of quality should also be included if not accounted for explicitly elsewhere.

Figure 6-5. Value of DSM Program to Program Participants



Key to Symbols

D = market demand curve for DSM measure

V^1 = participants' value vased assuming some degree of market failure

V = participants' value assuming no market failures

P_{DSM} = price of DSM measure, including any rebates or incentives offered by utility

Qo = level of energy efficiency before utility program

Q_1 = level of energy efficiency after utility program

Area A+B = net value of DSM measure to participants assuming no market failures

Area B = value, net of cost, no market failures

Area A+B+C = value of DSM measures to participants assuming market failures

Area B+C = value, net of cost, market failures exist