of cost-effective DSM. The market imperfections are often characterized as barriers that prevent energy services markets from functioning in a competitive manner. Some of the commonly-cited barriers to economically efficient levels of DSM are described in Table 6-7.[24]

Rather than initially assert that markets work in a competitive manner or exhibit significant failures, PUCs and LDCs should first strive to account for all the costs and benefits that are involved in undertaking a DSM program. Such an accounting should be used in a comprehensive test such as the TRC or Societal Cost test and should include estimates of indirect costs (costs in terms of time lost, hassle, and—for commercial and industrial customers—the value of any lost production) and the impact of quality changes caused by the DSM program. If, after a full accounting of costs and benefits is made, the LDC or PUC still estimates large net benefits from the DSM programs, then it would be appropriate to seriously consider implementing the programs. If the programs have large rate impacts as measured by the RIM, PUCs or LDCs should examine whether the design of the programs can be structured to make participants pay for a larger share of the program's costs (see Chapter 7).[25] The consideration of market imperfections, especially environmental externalities, may, however, lead to programs with net benefits but unavoidable rate impacts. Further, some programs that fail the RIM test may be pursued for public policy objectives other than economic efficiency. As a result, there may be instances where a PUC or LDC will feel confident pursuing a DSM program that fails the RIM test.

6.4.4 Alternatives to the Standard Benefit-Cost Tests

Although the standard benefit-cost tests are widely used, other energy industry participants, mostly economists, have proposed alternative tests that focus on total value or net economic benefits (NEB) in an attempt to develop a more accurate measure of the net benefits of utility DSM programs. As part of a conservation plan, Connecticut Natural Gas (1988) sponsored the work of an economist that developed a set of tests that focused on changes in utility profits, total social costs, and participant benefits; the sum of which measures changes in total social welfare. Later, Hobbs (1991) defined a "most value" test and argued that it should be used instead of the standard tests. Recently, more

[24] It should be noted that the last two market barriers (environmental externalities and federal government R&D priorities) cited in Table 6-7, although potentially significant, may not cause the participants' value line to deviate from their market demand curve. Instead, the impact of externalities and federal R&D costs affect society at large.

[25] Any DSM program that has a significant rate impact on price-sensitive customer classes should also be examined to see what the resulting margin impacts are from the additional lost sales.

Table 6-7. Barriers to an Economically Efficient Market in Energy Efficiency

Barrier	Description
Barrier 1: Information Gap	Credible information on the performance of energy-related technologies is often lacking. Available information is often not well understood and is sometimes unreliable.
Barrier 2: Payback/Uncertainty Gap	Payback periods required by consumers for investments in energy efficiency are generally much shorter than those required for utility company investments. The gap may reflect the tendency of consumers to perceive the uncertainties of future demand, fuel prices, and the performance of DSM measures to be greater than the utility's perception of the same uncertainties.
Barrier 3: Third Party Transactions	Consumers often must use the energy technologies selected by landlords and others. This leads to an emphasis on first cost rather than life-cycle cost.
Barrier 4: Lack of Capital	Many customers, both residential and commercial, lack enough cash or credit (considering the competing demands on their financial resources) to pay the capital cost of making long-run cost-effective efficiency investments.
Barrier 5: Utility Regulation Imbalance	traditional rate regulation in most states encourages utilities to increase sales, imparting an implicit bias toward pursuing supply-side options.
Barrier 6: Environmental Externalities	In almost all states, the prices that consumers pay for fuels, including electricity, do not fully reflect all environmental and social costs associated with fuel production, conversion, transportation and use.
Barrier 7: Federal Government Policies	Traditionally, the Federal Government has provided greater support for energy production than for energy efficiency, both with respect to tax policies and R&D.

Source: Adapted from Wiel 1991

practical variations of value or NEB tests have been proposed. Braithwaith and Caves (1993) sponsor their own NEB test. Their NEB test adds at least three additional dimensions to the standard tests: (1) it allows flexibility regarding assumptions on the degree of failure in the market for DSM products, (2) it considers the full impact of price changes caused by utility DSM programs on nonparticipants, and (3) it considers the added value provided to program participants from "snapback." Similar to the NEB test is the Value test sponsored by Chamberlin and Herman (1993). The Value test appears to incorporate the NEB test, and, further, allows for the consideration of benefits that the utility DSM program provides to free riders. Although no PUC has yet adopted either the NEB or Value test for gas DSM program evaluation, the NEB/Value tests hold promise as being a more general framework for the analysis of DSM programs. Even environmental or other externalities could be added to the test to give it a societal perspective. The NEB/Value tests explicitly consider the degree of market imperfections, which, as has already been noted, are a crucial factor in the ongoing debate over which standard test is best. The NEB/Value tests do require more assumptions and data: explicit assumptions must be made regarding the degree of market imperfections and data on demand elasticities, snapback, and the characteristics of free riders is needed. These data and assumptions will, however, become increasingly important in the evaluation of DSM programs and the NEB/Value tests allows for an analysis using them.

Gas DSM Technologies and Programs

7.1 Overview

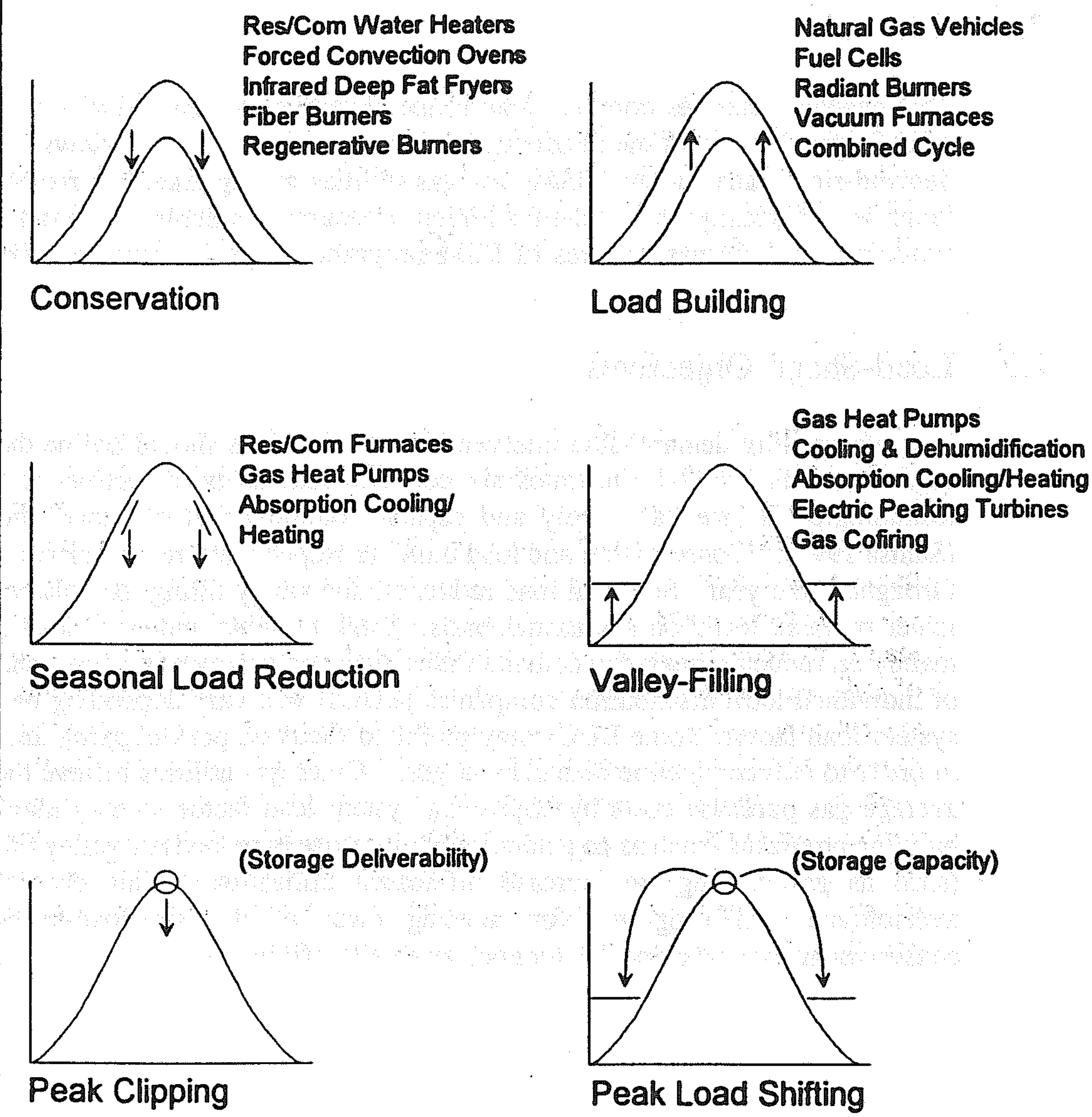
This chapter describes common load-shape objectives for gas utilities and the structure of U.S. gas demand in the residential and commercial sectors, reviews the potential for demand-side management (DSM) for gas utilities as suggested by recent assessments, identifies efficiency and fuel-substitution measures available for promotion in DSM programs, and discusses issues of DSM program design and implementation.

7.2 Load-Shape Objectives

In contemplating demand-side interventions, gas utilities should define their load shape objectives. Figure 7-1 illustrates six common load-shape objectives and gas end-use technologies (as well as supply and capacity options) that can meet these objectives (Samsa 1993).[1] Conservation and load building respectively reduce or increase gas loads throughout the year. Seasonal load reduction and valley filling load shapes respectively lower or raise loads on a seasonal basis. Peak clipping and peak load shifting focus mainly on reducing peak-day demand rather than energy savings. Load-shape objectives of individual local distribution companies (LDCs) will vary depending on their existing system load factor. Some LDCs may prefer to focus on peak clipping and load shifting in order to reduce pipeline demand charges. Other gas utilities believe they can reduce average gas purchase costs by improving system load factor so they may propose load building programs (such as cogeneration) to increase base loads or valley filling programs (such as gas cooling) to increase off-season utilization. This chapter focuses on technologies and programs for meeting three of the six load-shape objectives: conservation, seasonal load reduction, and valley filling.

[1] Many gas technologies do not produce impacts that fit neatly into these load shape categories, but instead they span several categories.

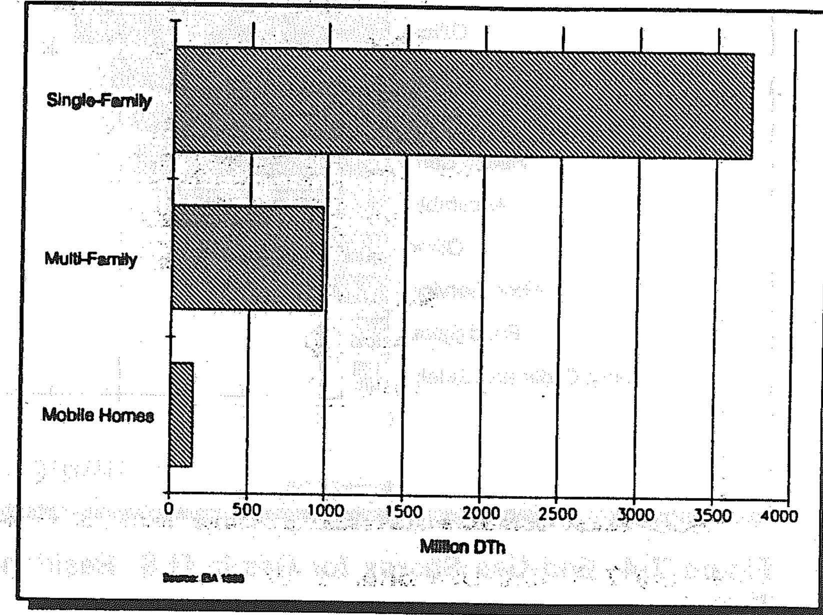
Figure 7-1. Utility Load Shape Objectives



Source: Samsa 1993

7.3 Gas Usage in Residential and Commercial Sectors

Figure 7-2. U.S. Residential Sector Gas Consumption by Building Type (1990)



The structure of gas end-use demand provides an initial reference point for determining where efforts to improve gas efficiency can best be focused.[2] More than three-quarters of residential gas consumption occurs in single-family dwellings (see Figure 7-2). There is much more diversity of gas consumption by building type in the commercial sector, with mercantile/service and education categories showing the highest levels, followed by office, warehouse, lodging, health care, and assembly categories at roughly comparable levels (see Figure 7-3).

Figure 7-4 compares the end-use distribution of gas consumption in the residential and commercial sectors, shown as a percentage of each sector's total. Space heating dominates in both sectors: 70% of residential and more than 50% of commercial. Water heating is the next most important end-use, accounting for 24% and 15% respectively of residential and commercial sector gas use. Process heat represents 12% of commercial sector gas consumption and cooking represents 10%. The predominance of space heating in the overall demand scheme for natural gas in the U.S. is illustrated in Figure 7-5, which plots monthly gas use by sector. The highly seasonal nature of residential gas demand has a significant effect on gas system load factors as evidenced by the fact that winter peaks in January are more than twice the summer minimum monthly load in June on a national basis.

[2] The structure of end-use gas demand for an individual utility may diverge significantly from the national pattern.

Figure 7-3. U.S. Commercial Sector Gas Consumption by Building Function (1989)

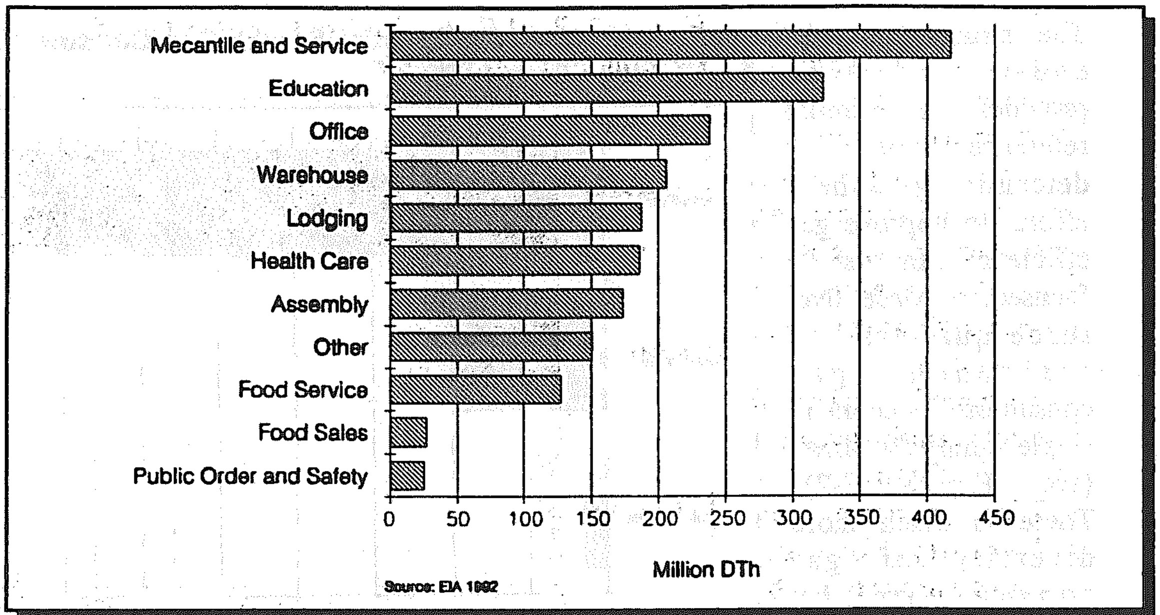
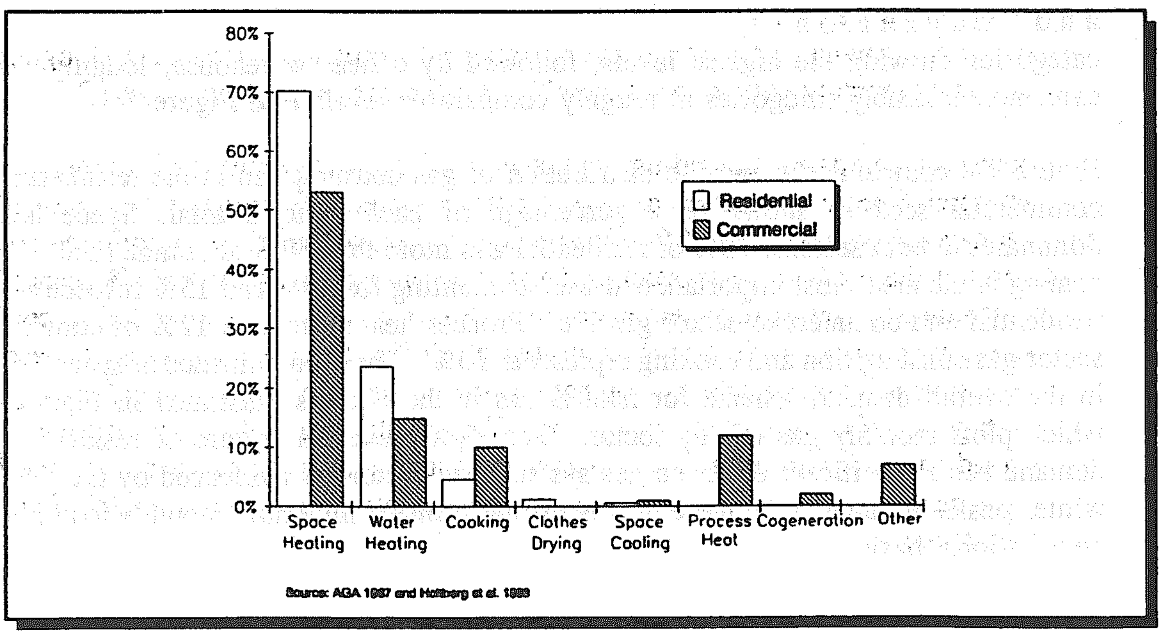
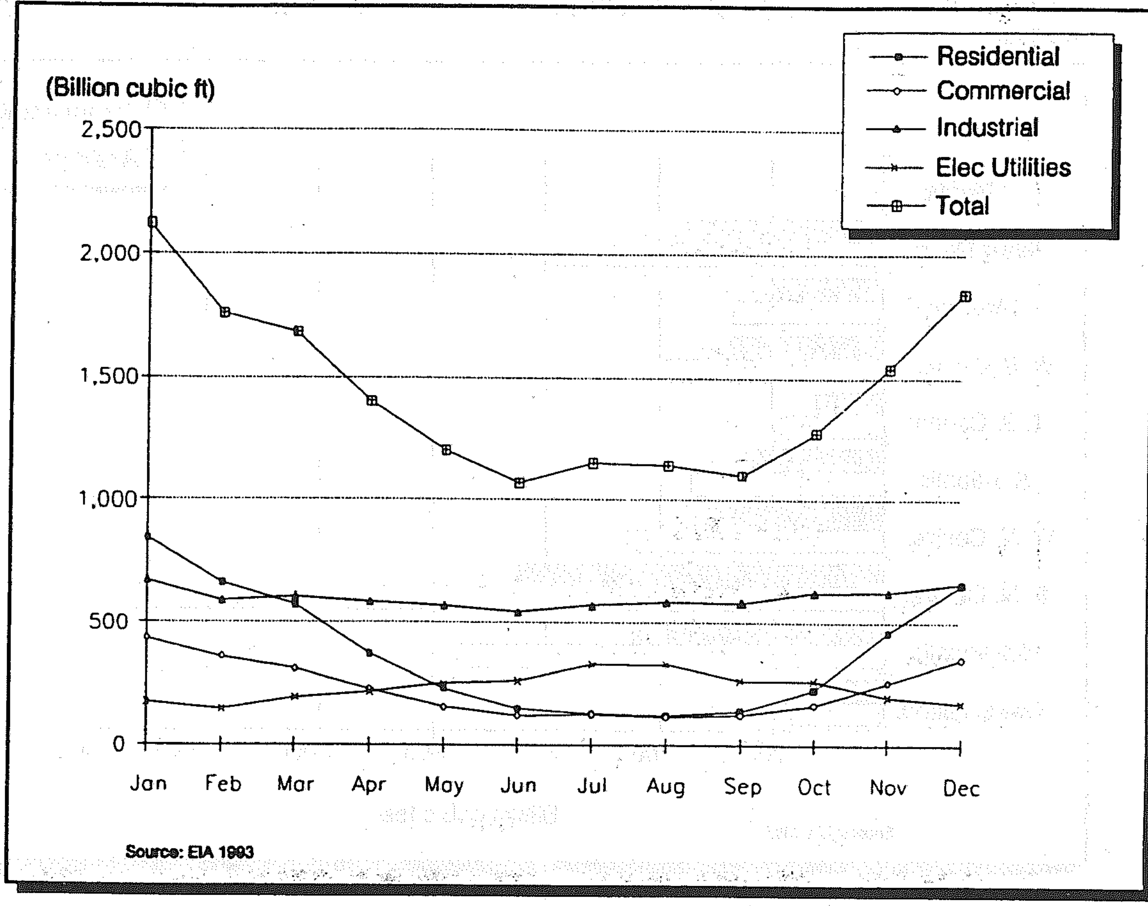


Figure 7-4. End-Use Shares for Gas in U.S. Residential and Commercial Sectors



Overall, gas demand in the residential sector is significantly greater than commercial sector demand (4.5 billion DTh vs. 2.8 billion DTh), with significant regional variations

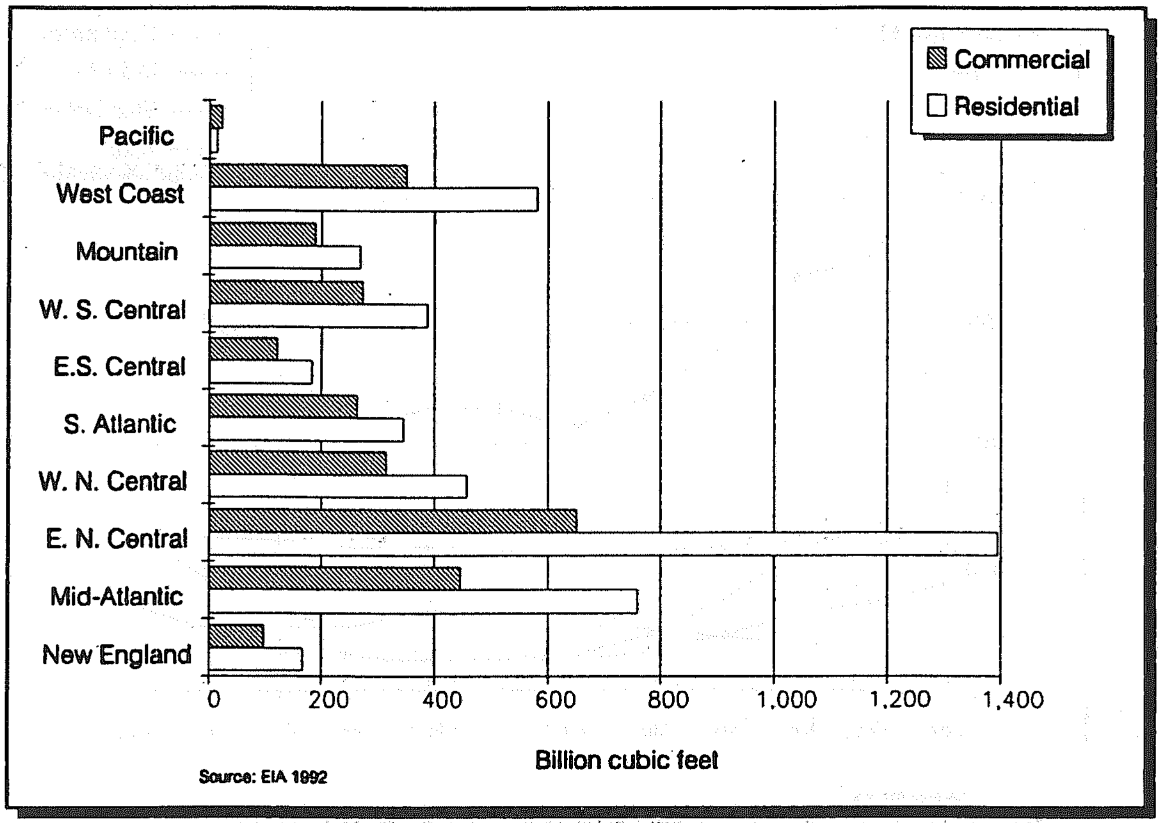
Figure 7-5. U.S. Monthly Natural Gas Consumption by Sector (1991)



(see Figure 7-6).[3] The relative shares of residential and commercial sectors in the overall gas market do not appear to result from climate severity, but from a host of other market conditions.

[3] Residential consumption is higher than commercial consumption in all census regions except for the Pacific (i.e., Hawaii and Alaska).

Figure 7-6. Residential and Commercial Gas Consumption by U.S. Census Region



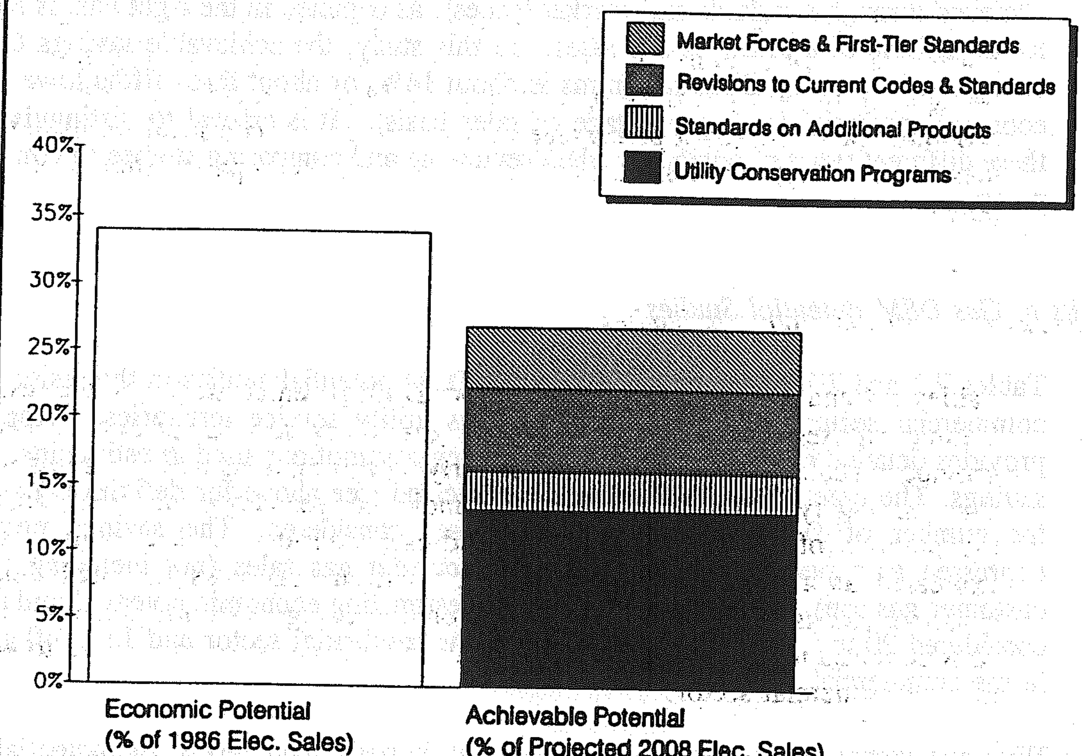
7.4 Opportunities for Increasing Gas End-Use Efficiency

7.4.1 Practical Constraints on Achieving Technical Energy Savings Potential

Energy savings that are achievable for gas utilities through programs aimed at increasing customer energy efficiency are constrained by a number of factors. The question of achievable energy savings potentials sometimes stirs controversy, to a large extent because of semantics. It is useful to distinguish three different types of "energy conservation potentials" cited in the literature.

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

Figure 7-7. Economic and Achievable Electricity Conservation Potential in New York State



Source: Nadel and Tress 1990

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

- *Program achievable potential* is an estimate of the portion of economic potential that would be achieved if all cost-effective, energy-efficient options promoted through utility DSM programs were adopted, excluding any energy-efficiency gains achieved through normal market forces and compliance with energy codes and standards.

Each type of conservation potential described above is a subset of the one that precedes it, which necessarily results in diminishing opportunities that can be captured by utility DSM programs. Figure 7-7 illustrates this phenomenon, calculated for electric utilities in New York state (Nadel and Tress 1990). The left bar shows the economic potential at 34% of current electricity sales. Achievable potential (which includes savings achieved through standards and market forces), as depicted in the right bar, is somewhat lower at 28% of a future year's sales. In this study, the achievable savings that could be captured by utility DSM programs is about 14%, or about three-fifths lower than the economic potential (on a percentage of sales basis). It is critical to distinguish among these different types of potentials when reviewing and comparing studies of conservation potential.

Results of Gas DSM Potential Studies

Tables 7-1 and 7-2 summarize results from DSM potential studies in the residential and commercial sectors, respectively, of 11 gas utility service territories. Appendix B provides detailed descriptions of the underlying assumptions used in estimating potential savings. The type of savings potential is indicated (see above for definitions) as well as the number of DSM measures and end-uses considered. The savings potential is expressed as a percentage of that sector's current gas sales (not including transport customer gas use). Most studies focused on estimating economic potential and typically considered 20 to 50 individual measures in the residential sector and 13 to 40 measures in the commercial sector.

With one exception, these studies suggest that, in percentage terms, the potential for gas DSM savings is greater in the residential sector than in the commercial sector. For the residential sector, economic savings potentials range from 5% to 47%, with most studies finding around 25%. For the commercial sector, economic savings potentials range from 8% to 23%, with most studies finding around 15%.

A few of the studies also assessed economic fuel-switching potential—switching from electricity to gas at the end use, primarily as a valley filling strategy for the gas utility. The economic fuel-switching potential was estimated to be higher in the commercial sector (2% to 49%) than in the residential sector (2% to 7%), primarily through the promotion of commercial gas cooling technologies to boost summer gas sales.

Avoided costs used in screening the technologies for estimating economic savings potential—arguably the most important variable in the screening process—varied considerably among the studies depending on: calculation method, extent of seasonal differentiation, estimated gas commodity cost escalation rates, and time horizon (see Appendix B). It is quite difficult to generalize from these gas savings potentials results because of methodological differences among studies as well as the diverse structures of gas use among individual LDCs. Nevertheless, the studies suggest the scale of the DSM resource that may be available in U.S. gas utility service territories.

Table 7-1. Residential DSM Potential for Selected Gas Utilities

Residential	LILCO	Brooklyn Union Gas	National Fuel Gas	Orange & Rockland	Southwest Gas	WP Natural Gas	Boston Gas	Commonwealth Gas	Bay State Gas	SoCal Gas	Atlanta Gas Light
Type of Potential											
Technical				36%	32%	24%				X	X
Economic	24-41%	34-47%	27-44%	16%	25%		11-20%	24-32%	32%	6-9%	X
Program Achievable				6%							
Fuel Switching	-3%	-2%	-6%	X	-7%						-2%
Measures Reviewed (#)	62	62	62	22	25	N/A	23	~20	28	28	26
End Uses Considered:											
Space Heating	X	X	X	X	X	X	25%	X	X	X	X
Space Cooling											
Water Heating	X	X	X	X	X	X	14%	X	X	X	X
Cooking	X	X	X								X
Clothes Drying	X	X	X		X						X

Table 7-2. Commercial DSM Potential for Selected Gas Utilities

Commercial	LILCO	Brooklyn Union Gas	National Fuel Gas	Orange & Rockland	Southwest Gas	Boston Gas		Commonwealth Gas		Bay State Gas	SoCal Gas	Atlanta Gas Light
						Com	Ind	Com	Ind			
Type of Potential												
Technical				16%	9%						X	X
Economic	18-19%	15-16%	17-20%	10%	8%	13-17%	9-14%	8-23%	11-23%	23%	8-14%	X
Program Achievable				5%								
Fuel Switching	-28%	-49%	-9%	X	-8%							-2%
Measures Reviewed (#)	40	40	40	16	39	20	21	~20		30	35	13
End Uses Considered:												
Space Heating	X	X	X	X	X	28%	22%	X	X	X	X	X
Space Cooling	X	X	X		X							X
Water Heating	X	X	X	X	X	5%		X	X	X	X	
Cooking	X	X	X					X			X	
Clothes Drying												
Process Heat							6%					X
Other					X							X

Impact of Standards

The potential DSM savings available to an individual gas LDC are determined to a great extent by the unique combination of existing building stock and equipment characteristics, weather severity, energy prices, and other factors unique to a service territory. However, existing and impending federal efficiency standards for gas appliances and heating, ventilating and air conditioning (HVAC) equipment are major considerations for every gas LDC attempting to assess its achievable DSM potential. These standards raise the floor of efficiency levels of gas equipment available on the market, and, over time through equipment replacement and installations in new construction, they increase average stock efficiency as well.

Table 7-3 summarizes minimum efficiency levels and timetables for instituting and updating standards for selected gas appliances and equipment used in residential and commercial applications.[4] At the state and local levels, energy standards for buildings and/or energy-using equipment have also been promulgated as voluntary guidelines or as mandatory regulations, with corresponding implications for gas utility DSM program efforts within those jurisdictions.

Utility DSM programs can accelerate these changes in the existing building stock through retrofit programs that promote early retirement of less efficient appliances and replace them with appliances that comply minimally with the standard. DSM programs can also focus on appliances and equipment that exceed the standard, promoting these in the retrofit, replacement, and new construction markets.

Impact of Previous Retrofits

Another significant factor affecting gas DSM potential is the extent to which customers have taken previous actions or utilities have promoted efforts to raise the efficiency of gas use. Generally each successive DSM measure implemented gives diminishing returns, where interactions among measures make the combined savings less than the sum of the individual savings. Early programs to reduce energy use in homes were conducted in the 1970s and 1980s under the auspices of the Residential Conservation Service; these were mainly focused on building shell measures to reduce home heating and cooling loads. Likewise, electric utilities with overlapping service territories may have already installed building shell measures in customers' homes, or other measures that might

[4] National standards were established by the National Appliance Energy Conservation Act of 1987 (NAECA) with timetables for various residential appliances and HVAC equipment; the Energy Policy Act of 1992 extended efficiency standards to cover commercial HVAC equipment and water heaters.

Table 7-3. Federal Energy-Efficiency Standards Levels and Timetables for Selected Gas Appliances and Equipment

Appliance/Equipment	Min. Level	Effective Date	Update Scheduled
Residential			
Furnaces	78% AFUE	1992	2002
Boilers	80% AFUE	1992	2002
Water Heaters	54% EF	1990	1995
Clothes Dryers	2.67 lbs/kWh	1994 (est.)	n/a
Ranges and Ovens	n/a	1996 (est.)	2000
Commercial			
Furnaces & Boilers		1994	
(> =225 kBtuh)	80%		
Water Heaters	77%	1994	

Notes:

AFUE = Annual Fuel Utilization Efficiency

EF = Energy Factor

Residential water heater EF dependent on storage tank size; listed value for 40-gallon tank.

Units for clothes dryer efficiency level are lbs. of clothes/energy input (in kWh).

Range and oven levels have not yet been mandated by DOE.

Commercial unit heaters not covered in standard.

Commercial water heater standard listed is for storage tanks larger than 100 gals.

Source: Geller and Nadel 1992

affect the savings potential for gas, such as night-setback thermostats or low-flow showerheads.

Time-Dependent End-Use Efficiency Opportunities

Studies of conservation potential often ignore the time dimension associated with any practical effort to capture identified savings. Some measures will only be cost-effective or even possible at the design stage for new buildings or at the time of a major remodeling or equipment replacement. These opportunities are time-dependent in the sense that they occur only when customers are making equipment replacement decisions. LDCs evaluating demand-side opportunities must account for the extended time periods required for these types of DSM programs to have a significant cumulative impact. For example, a study of gas DSM potential in New York conducted by the American Council for an Energy-Efficient Economy found that 40 to 50% of the savings opportunities in the residential sector were achievable through replacement programs; only the remainder were achievable in the short-term through retrofit programs. For the commercial sector, a smaller percentage (i.e., 20%) of the program achievable sector savings were tied to long-term replacement programs (Nadel et al. 1993b).

Persistence of Savings

Another practical issue relevant to the time dynamics of DSM programs is the persistence of energy savings. Persistence has emerged as a significant concern among DSM practitioners (Vine 1992). Previous studies of persistence have tended to focus on technical measure lifetime although both technology and human behavior affect persistence (Jeppesen and King 1993).

Table 7-4 lists factors that influence the persistence of DSM measures and programs, many of which are behaviorally-oriented (Hirst and Reed 1991).[5] Among the behavioral issues, the rebound effect (also known as "snap-back"or "take-back") can be particularly important (i.e., when customers increase their amenity level in response to lowered energy bills from installation of DSM measures). The opposite response can also occur, known as the surge effect where customers, because their awareness of energy-efficiency issues is raised through participation in the program, alter their behavior to lower their energy use or to invest further in DSM measures on their own. A number of strategies have been proposed to ensure the persistence of energy savings, including measurement and verification plans, program design, operations and maintenance, and building commissioning (Vine 1992).

[5] Note that program persistence includes all the measure persistence factors as well.

Table 7-4. Factors Influencing the Persistence of Energy Savings

Measure Persistence	Program Persistence [a]
Technical lifetime Measure installation Measure performance or efficiency decay Measure operation (behavior) Measure maintenance, repair, commissioning Measure failure Measure removal Changes in the building stock (i.e., renovations, remodels, alterations, additions) Occupancy changes (turnover in occupants; changes in occupancy hours and number of occupants)	Rebound (snap-back, take-back) effects Surge effect (additional measures added by customer after initial program participation) Replacement effect (replacing efficiency measures with less or more efficient measures) Energy use by control group

(a) Program persistence factors also include measure persistence factors.

Source: Misuriello and Hopkins 1992

Summary of Practical Constraints

Energy-efficiency standards, previous government and electric utility conservation programs, time-dependent savings opportunities, and issues related to the persistence of savings are important factors that must be accounted for in assessing the savings potential that can actually be achieved by gas utility DSM programs. Empirical evidence from electric utility DSM experience shows a significant gap between the economic potential for energy efficiency and savings reductions that have been achieved in utility DSM programs.

Table 7-5 compares the performance of the best U.S. electric utility DSM programs in the commercial and industrial sectors by end use in terms of overall savings achieved against the size of the economic resource they were exploiting (Nadel and Tress 1990). Although several of the electric end-use categories are not directly applicable to gas utilities (nor can one assume that LDC DSM programs will exactly parallel those of

Table 7-5. Economic Potential vs. Actual Savings from Best Electric Commercial and Industrial (C&I) DSM Programs

End Use	Economic Potential	Savings from Best Programs
Lighting	60% of lighting use	25% of lighting use
HVAC	51% of commercial HVAC use	11% of A/C & heat pump use
Motors	17% of motor use	5% of motor use
New construction	50% or more	30%
Multiple end-use retrofits	45% in the commercial sector	18-23% in commercial buildings

Source: Nadel and Tress 1990

electric utilities), the general point is that the most successful utility DSM programs are capturing somewhat less than half of the cost-effective resource suggested by economic potential studies. Numerous factors contribute to this difference. Aggregate market penetration levels for a utility DSM program are very dependent on the program's ability to actually influence individual customer decision-making, DSM program budget and manpower levels, and building stock and equipment replacement turnover rates; actual savings are often lower than engineering estimates. Finally, while recognizing that the size of DSM resource that can be captured by utility DSM programs is substantially smaller than is suggested by economic DSM potential studies, unexploited cost-effective DSM resources most likely exist in most gas utility service territories. The next sections focus on end-use efficiency and fuel-switching options that can be promoted by gas LDCs through utility DSM programs.

7.4.2 Gas Efficiency Measures

The studies of DSM potential described above clearly suggest that many individual DSM measures and strategies have been considered by gas LDCs. Table 7-6 lists broad categories of DSM measures for LDCs—equipment, building shell, distribution for the space conditioning system, HVAC system control, and water heating control—and indicates their applicability to the residential and commercial sectors. A more detailed description of gas-fired equipment measures and their relative efficiencies is presented in Appendix D. Measures hold promise for gas savings depending on the demand for the end-use service and the current efficiency of consumption (base-line), both of which

Table 7-6. Gas Efficiency Measures

	Residential	Commercial
Equipment Measures		
High-efficiency furnace	X	
High-efficiency boiler	X	X
Gas engine heat pump	X	X
High-efficiency unit heater		X
High-efficiency water heater	X	X
High-spin-speed washer	X	
High-efficiency clothes dryer	X	
High-efficiency cooking equipment		X
Shell Measures		
Envelope insulation	X	X
Infiltration reduction	X	
Multiple-pane windows	X	X
Low-emissivity, argon gas-filled window systems	X	X
Distribution System Measures		
Distribution system duct or pipe insulation	X	X
Distribution system duct sealing	X	X
HVAC system zoning	X	X
HVAC Control Measures		
Setback thermostat	X	X
Thermostatic steam valves	X	X
Furnace fan thermostat adjustment	X	
Boiler water temperature modulation	X	X
Energy management system		X
HVAC supply-air temperature reset control		X
Water Heating Control Measures		
Water heater tank insulation	X	X
Water heater demand controller	X	
Water heater temperature modulation	X	X
Heat traps	X	X
Horizontal axis clothes washer	X	
Low-flow shower heads and faucets	X	X

are site-specific. Local climate, construction practice, and structure of the economy help dictate the technical feasibility of DSM measures. Also, many gas efficiency measures will have already been implemented through other electric utility, water utility, or government programs, or by normal market adoption of technologies.

7.4.3 Efficiency Measure Cost-Effectiveness

The benefits of high-efficiency gas equipment have to be compared to the cost incurred (if any) in determining cost-effectiveness. It is beyond the scope of this primer to comprehensively analyze the economics of these measures in all applications. However, key considerations for economic screening of *technologies* are discussed, followed by an example of one cost-effectiveness index commonly used in preparing supply curves of conserved energy.[6]

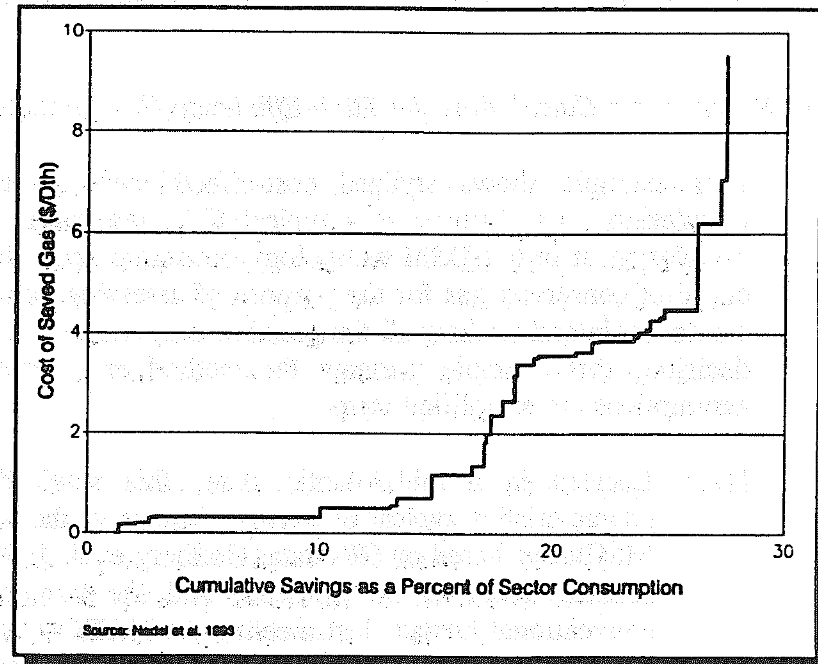
High efficiency equipment measures usually involve tradeoffs between higher first cost than some conventional alternative on the one hand and energy cost savings over the lifetime of the measure on the other. The appropriate costs to attribute to the measure for the purposes of the economic analysis depend on the situation. If the measure is under consideration when equipment is being replaced or selected for use in new construction, then the appropriate cost is the difference between the cost of the efficient technology and the conventional technology that would otherwise be selected. If a standard prescribes some minimum efficiency level, then the appropriate cost is the difference between the DSM measure's cost and the cost of a technology that simply complies with the standard. If the measure is to be installed in place of equipment that still has useful life (i.e., in a retrofit situation), then the full cost of the measure is appropriate to use in the economic analysis.

Intensity of use of equipment is a key parameter that drives economic analysis. Efficiency gains in equipment performance will be realized as monetary gains only if the equipment operates enough to generate savings over time. For instance, installing a high-efficiency furnace in Miami may not reap enough savings during the relatively short and mild heating season to justify the increased expenditure; however in Missoula, sufficient savings may accrue over the winter to justify the furnace. Economic analysis also depends on: the differential between conventional and DSM measure efficiencies; the incremental cost of a DSM measure; and fuel prices. Reducing the intensity of equipment use through other DSM or conservation actions can affect the attractiveness of any subsequent investment in efficient equipment. Heating and cooling loads for space conditioning are affected by weather, building construction, building operating hours and conditions, and other uses of energy in the building. Domestic and service hot water

[6] A complete presentation of the standard tests used in DSM *program* screening (i.e. following technology screening and aggregation of technologies into DSM programs) can be found in Chapter 6.

heating, cooking, and clothes drying demands vary by building use and function and can be altered by DSM activities.

Figure 7-8. Supply Curve of Saved Gas in Commercial Sector for Long Island Lighting Company



A convenient index for ranking and screening DSM measures is the cost of conserved gas (CCG). This index is used to construct supply curves of conserved energy, with the CCG on the vertical axis and savings on the horizontal axis. An example of such a supply curve of conserved gas prepared for a New York LDC is shown in Figure 7-8. CCG is formally defined as,

$$\text{Cost of Conserved Gas} = \frac{\text{Incremental DSM Cost x CRF}}{\text{Period Savings}}$$

where CRF is the capital recovery factor used for amortizing the initial investment into a periodic payment, analogous to a mortgage payment.[7] The CCG is typically calculated based on annual gas savings, but could in principle be calculated on a seasonal basis.

A principal advantage of the cost of conserved energy is that it is expressed in dollars per unit energy and therefore can be directly compared to the cost of the fuel displaced (either at the applicable retail rate or avoided cost). Future energy cost expectations are

[7] Capital recovery factor = $d/(1 - (1 + d)$ ^$-n)$, where d is the discount rate and n is the measure lifetime in appropriate time units, usually years.

also exogenous. A disadvantage is that CCG in its pure form ignores the capacity impacts of DSM measures although this limitation can be mitigated somewhat.[8]

Cost-Effectiveness Calculations for High-Efficiency Gas Furnace

This example shows stylized cost-effectiveness calculations for a high-efficiency (condensing) gas furnace in a typical U.S. residence. A utility might perform this calculation in initial DSM technology economic screening or in constructing a supply curve of conserved gas for the purpose of assessing economic savings potential. While we do not intend to show all the possible intricacies of a heating equipment replacement decision, this example presents the method and some of the sensitivities to input assumptions, in simplified terms.

(1) Located in a mid-Atlantic state, this single-family dwelling with thermal characteristics typical of existing homes in the region has a heating load of 65 MMBtu/yr based on GRI data (Holtberg et al. 1993). The existing 75,000 Btu/hr furnace needs to be replaced, and the homeowner is choosing between a conventional furnace just meeting the NAECA standards (AFUE = 78%) and a high-efficiency condensing furnace (AFUE = 92%), both with 30-year expected lifetimes. The first option will cost $2,000 installed while the second option costs $2,400. Assume that the utility uses a 6% *real* discount rate. The cost-effectiveness of choosing the high-efficiency furnace over the NAECA-conforming furnace is as follows:

$$\textit{Savings} = \textit{Heating Load} \times \left(\frac{1}{AFUE_{std}} - \frac{1}{AFUE_{ee}}\right)$$

$$= 65 \times \left(\frac{1}{0.78} - \frac{1}{0.92}\right) = 12.7\ DTh/yr$$

$$\textit{Capital Recovery Factor} = \frac{0.06}{1 - (1 + 0.06)^{-30}} = 0.0726$$

[8] One way is to calculate a separate index based on the capacity savings alone so that the denominator is annual peak savings instead of energy savings. Another approach is to incorporate the capacity cost savings into the CCE by subtracting the annual capacity cost savings from the amortized investment cost to yield a composite index.

$$\textit{Cost of Conserved Gas} = \frac{(2400 - 2000) \times 0.0726}{12.7} = \$2.3/DTh$$

The CCG can now be compared to the price of gas for this customer class (as a means of testing DSM measure cost-effectiveness from the recipient's perspective) or to the appropriate gas avoided cost (for a societal or utility perspective); the societal or utility perspectives customarily include program administration costs (see Chapter 4). Because gas tariffs for residential customers are generally higher than assumed here, the high-efficiency furnace appears to be cost-effective from the recipient's point of view.

(2) Now, suppose the home is located in another region with different building practices and local climate, and accompanying change in heating load. The heating load could be lower because of a warmer climate or because the home has higher thermal integrity; energy standards in many jurisdictions require new homes to be built with higher thermal integrity than existing homes. Assuming all other factors remain the same, the cost of conserved gas for these general locations would be:

Location	Annual Heating Load (MMBtu/yr)	CCG ($/DTh)
New England	100	$1.5
Pacific Coast	45	$3.3
Southwest	30	$5.0

This hypothetical situation illustrates the point that the intensity of use (i.e., heating load) is a key factor in DSM measure cost-effectiveness.

(3) Consider whether to retire the existing furnace early and install the high-efficiency furnace in its place. In this case, we are comparing the efficiency of the existing furnace to that of the high-efficiency furnace. Existing gas furnaces in U.S. homes have an average AFUE of around 65%. In the mid-Atlantic region with its heating load of 65 MMBtu/yr, we find annual savings of 29.3 DTh/yr from using the high-efficiency furnace. However, the cost in this situation is the full measure cost, i.e., $2,400. The resulting CCG is $5.9/DTh, which is higher than typical gas avoided cost estimates or residential customers' gas prices, so this application of a high-efficiency furnace does not appear cost-effective. However, the economics would be somewhat more attractive in a more severe heating climate.

(4) Different assumptions regarding furnace lifetime or consumer discount rate have an effect on DSM measure cost-effectiveness. Changes in these assumptions based on the scenario in (1) result in the following:

Real discount rate doubled to 12%:	CCG = \$3.9/DTh
Real discount rate halved to 3%:	CCG = \$1.6/DTh
Furnace lifetime halved to 15 years:	CCG = \$3.2/DTh

7.5 Opportunities for End-Use Fuel-Substitution

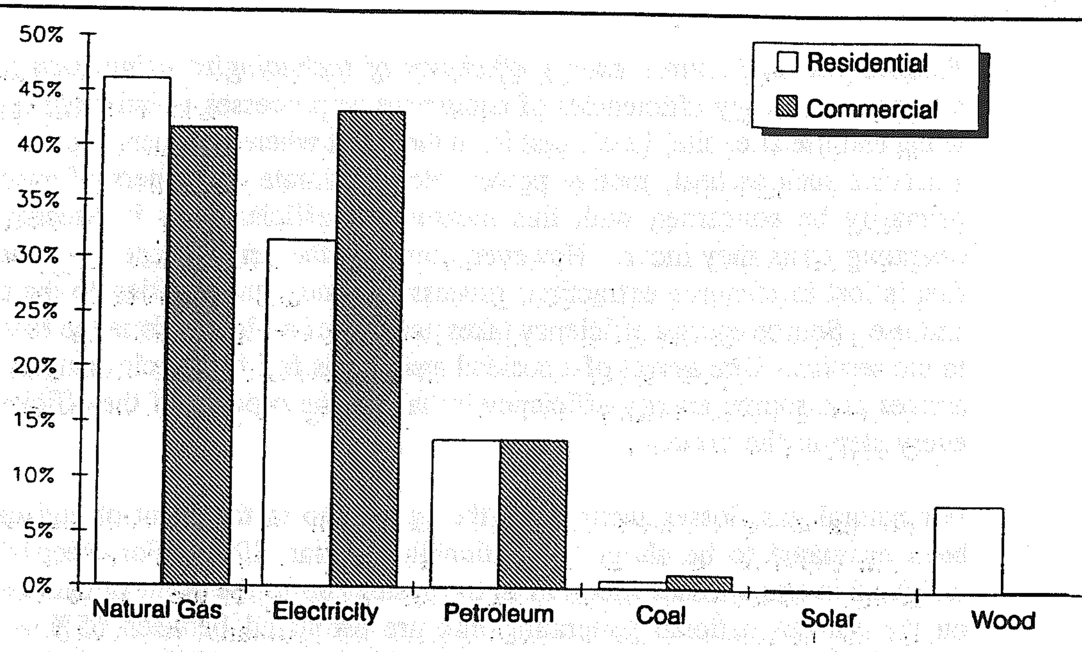
High-efficiency gas and electric equipment can substitute for one another in many applications. Like other DSM measures, equipment choices involving a substitution of one fuel source for another can be evaluated as potential DSM resource opportunities in terms of their potential advantages to customers, utilities (both gas and electric) and society.[9] This section focuses on fuel-switching between gas and electricity in the residential and commercial sectors. Assessing the merits of fuel-substitution is more complicated than assessing an intra-fuel technology choice; additional technical, economic, and other issues that should be considered by utilities and PUCs are identified and discussed briefly. The policy implications of end-use fuel-substitution are discussed in Chapter 8.

Figure 7-9 displays the current market shares (on an energy value basis) for natural gas, electricity, and other fuels in the residential and commercial sectors. Natural gas has a larger share of energy consumption than electricity in the residential sector (roughly 45% vs. 30%) whereas natural gas and electricity usage are comparable in the commercial sector. These relative shares reflect the differences in the two sectors in the services demanded, the equipment providing those services, and a host of economic and other considerations historically affecting consumer choice.

Table 7-7 highlights additional technical, economic, and other issues that should be considered in evaluating fuel-switching DSM opportunities.

[9] Each individual application has to be evaluated carefully to account for the particular circumstances, i.e., the characteristics of the technology/fuel combination that is being replaced or compared to the one under consideration, the relative cost of fuels, etc..

Figure 7-9. Fuel Market Share in the U.S. Residential and Commercial Sectors (1990)



Source: Holtberg et al. 1993

Table 7-7. Issues to Consider in Analyzing Fuel-Substitution Opportunities

Technical	• Relative site and source energy efficiency • Relative risk of savings performance degradation • Parasitic electricity consumption of some gas equipment • Load shape impacts of gas and electric technologies on each utility
Economic	• Relative gas and electric tariffs • Relative gas and electric avoided costs • Relative risk of price volatility and uncertainty • Access to gas service, including hook-up and line extension costs
Other	• Space, noise, and aesthetics • Environmental impacts and tradeoffs

Technical

- *Relative site and source energy efficiency of technologies using each fuel:* By convention, energy efficiencies of equipment or processes in buildings are given at the end use (i.e. site) level, that is, at the point where the fuel is converted into a service such as heat, motive power, etc. Ultimate consumers of energy will primarily be concerned with this measure of efficiency as it directly affects operating costs they incur. However, much of the original energy value of the fuel is lost in resource extraction, processing, and transportation to the point of end use. Source energy efficiency takes account of all losses from the fuel source to the service. One aspect of a societal analysis is full fuel-cycle analysis, which arrives at a source energy efficiency by taking the product of the efficiencies at every step in the cycle.

  For natural gas, losses incurred in the system up to the point of end use have been estimated to be about 9% nationally (Moran 1992). For electricity, the weighted average losses incurred in the system up to the point of end use based on the current national generating mix are estimated between 65% and 75% (Electric Power Research Institute (EPRI) 1992c; Moran 1992). Actual values for a particular utility will undoubtedly be different from these national averages. Losses in electric generation, transmission and distribution also have considerable variation with ambient temperature. On hot days, generator heat rates rise because condenser temperatures rise, and transformer and line losses increase. A further subtlety on the electricity side is that the average generation fuel mix even for a given utility may not be the best basis for estimating source energy efficiency. A more sophisticated and potentially more accurate representation of source energy efficiency would take into account the most likely electricity generation source(s) to serve the end use in question. For instance, the losses associated with a hot water heater operating on a more or less constant annual basis may best be represented by a baseload plant; for an air conditioner operating in a summer peaking utility service territory, they may best be represented by a peaking plant. In some circumstances, one might be able to draw such distinctions on the natural gas side as well. This point is relevant for considering environmental impacts as well.

  In sum, source energy efficiency is the product of the site energy efficiency of the device under consideration and the efficiency of the entire fuel-cycle up to the point of end use.

- *Relative risk of savings performance degradation:* Fuel-substitution DSM theoretically provides more reliable savings for utilities than intra-fuel DSM because it effectively solves problems of savings persistence and snap-back.

However, depending on the application, unanticipated user behavior could in fact lead to savings degradation. Utilities will need to experiment with fuel-substitution DSM to verify that actual savings meet expectations for high reliability.

- *Parasitic electricity consumption of some gas equipment:* Some gas equipment and appliances use electricity for ignition, venting fans, etc., and this consumption needs to be accounted for explicitly in any energy use or economic comparison.

- *Load-shape impacts of gas and electric technologies on each utility:* Making a choice between technologies has an effect on load patterns. The technology selected will create additional load on one utility; the technology that is displaced represents an absence of load on the utility that would have served it. The load-shape impacts of the competing technologies will likely be different and should be properly valued in estimates of avoided cost.

Economic

- *Relative gas and electricity tariffs:* In order for program participants to calculate bill savings and for the utilities who are respectively losing and gaining customers to calculate revenue impacts from a DSM program, the tariffs of both utilities must be addressed in the economic assessment including all applicable seasonal or time-of-use rates and demand or reservation charges.

- *Relative gas and electricity avoided costs:* The difference in avoided costs between the two utilities on an energy services basis is a key measure of the potential societal economic benefits of switching from one fuel source to the other.

- *Relative risk of price volatility and uncertainty:* Different fuels pose varying price risks to ratepayers. Because electricity is typically generated from a variety of fuel sources, the impact of a price change for any one fuel will tend to be dampened in the overall electricity price. However, both electricity and gas utilities are subject to other regulatory and market risks that can translate into price changes, and expectations of these changes should be incorporated into fuel-switching analyses.

- *Access to gas service, including line extension and hook-up fees for electricity to gas switches:* Some DSM programs promoting the substitution of gas in place of electricity may be constrained by lack of access to gas for some otherwise eligible customers. Line extension and hook-up costs should be considered in the economic analysis of these measures.

Other Factors

- *Space, noise, and aesthetics:* Competing electric and gas equipment can have different space requirements, both for size and location (i.e., interior, exterior, near an exterior wall, close to the point of end use, etc .) Noise and aesthetics can be an issue for some equipment in some circumstances, necessitating special consideration and mitigation.

- *Environmental impacts and tradeoffs:* Environmental consequences of energy use are a growing public concern. Land, water, and air pollution stemming from energy consumption can degrade human and ecosystem health. Comparing end-use technologies with this concern in mind should take into account the type of fuel consumed (and all its attendant impacts occurring throughout the fuel-cycle up to the point of end use), the end-use efficiency of the technology (i.e., how much fuel it consumes), the on-site impacts from installation and operation of the technology, and timing of the impacts during the day and from season to season. Ideally, one would account for environmental impacts of manufacturing and disposing of the end-use technology as well (i.e., upstream and downstream impacts) (Electric Power Research Institute (EPRI) 1992c).

  Generally for electric and gas equipment used in the commercial and residential sectors, air pollutant emissions from the combustion of fossil fuels are the area of greatest concern. The air pollutants often cited include carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), nitrous oxide (N_2O), volatile organic compounds (VOCs), methane (CH_4), chlorofluorocarbons (CFCs),[10] total suspend particulates (TSP), and air toxics including mercury, heavy metals, radioactive gases and particles. Air emissions can be classified by whether they are implicated in producing global impacts (as with CO_2, CH_4, CFCs, and N_2O in global climate change), regional impacts (as with SO_2 and NO_x in acid rain), or local impacts (as with NO_x, VOCs, and particulates). Power plant emissions of SO_2, NO_x, and CO_2 have been a primary concern of environmental regulators and more recently, state PUCs. Coal- and oil-based generation produces relatively higher levels of SO_2 and CO_2; gas-based generation produces relatively higher levels of NO_x. For gas-fired end-use equipment, NO_x

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[10] CFCs are not a combustion product but are used in refrigeration equipment and as a thermal insulation material.

emissions are the major concern although CO and NO_2 and, occasionally, particulate emissions from unvented equipment can contribute to indoor air quality concerns.

Air emissions at the power plant can be accounted for in a number of ways. One approach is to use an average fuel-mix considering the performance of plants (i.e., heat rate) and the presence of any emissions controls (e.g., selective catalytic reduction for NO_x or flue gas desulfurization for SO_2). A refinement of this approach is to distinguish the mix of generation resources by season because the level of demand and availability of some resources (e.g., hydro) often varies seasonally. The seasonal, average, generation fuel-mix-based emission rates would then be paired with seasonal load impacts of the end-use technology under consideration to arrive at the end-use emissions impact. A second approach is to consider the changes in air emissions that would occur at the margin from eliminating or adding the electric end-use technology, either as a mix of marginal plants or as a single marginal plant (e.g., combustion turbine). Whichever approach is used to account for the emissions of electric power plants serving electric end-use technologies, the geographic location of the emitting plants and the timing of emissions of certain pollutants can be critical to assessing local air quality impacts, a concern in many U.S. urban air-sheds.

For gas end-use technologies, the principal air emissions take place on site.[11] Because LDC residential and commercial customers are mainly located in urban areas, NO_x emissions from their gas-fired equipment and appliances can contribute to smog problems, depending on the coincidence of smog episodes and the use of the equipment. For instance, gas cooling technologies' emissions may be highly coincident with urban smog because many cities experience their worst smog during the hottest summer weather.

Another issue for air emissions impacts from end-use technologies is the evolution of environmental regulation at the federal, state, and local levels. Changes in environmental regulation may alter expectations of future emissions, especially from power plants. In some cases, regulations may effectively preclude some technologies from being marketed and could be incorporated as sensitivities in an analysis. At the federal level, the recently enacted Clean Air Act Amendments will significantly alter the SO_2 and NO_x emissions in some electric utility service territories. Likewise, a recent federal commitment to reduce U.S. greenhouse gas emissions to 1990 levels by the year 2000 is likely to have an impact on electric utility resource portfolios in the future. As an example at the local level,

[11] CH_4 emissions as losses along the pathway from production to end use are the primary off-site emissions.

environmental regulators with jurisdiction over air quality in the Los Angeles area have enacted strict controls over emissions from a variety of sources, including but not limited to power plants. Other urban areas may consider similar actions.

Finally, several state PUCs have adopted or are considering assigning environmental externality cost values to residual emissions (i.e., those not already covered by existing regulations) for use in benefit-cost analyses of resource decisions made by their regulated utility companies. Externality cost values (also known as "adders") for individual pollutants are based on an estimate of the cost of damage caused by the pollutants. Adders derived from this damage function approach are scientifically and ethically difficult to determine, so most PUCs are using a proxy approach that assigns the cost of some known control method for a given pollutant. Externality cost values (generally given in dollars per unit of pollutant emitted) are multiplied by a given technology's emissions to arrive at the externality cost penalty for that technology. To date, externality cost values are only being used by utilities in selecting new resources, although they could in principle also be used in system operation and plant retirement decisions as well. Exhibit 5-1 presents externality cost values and the ways in which they are being used in some jurisdictions.

7.5.1 Fuel-Switching Measures Between Electricity and Gas

This section provides an overview of gas technologies that could be substituted for electric technologies in residential and commercial applications. Many of the equipment measures for increasing gas efficiency listed in Table 7-6 are also candidate measures for fuel-switching from electricity to gas. Table 7-8 lists some of the relevant technologies for switching from electricity to gas and gas to electricity, respectively, indicating their applicability in the residential and commercial sectors. A more detailed description of these technologies and their efficiencies is included in Appendix D.

7.5.2 Fuel-Switching Measure Cost-Effectiveness

A comprehensive economic analysis of fuel-switching options is beyond the scope of this primer because of the many quantitative and qualitative factors that should be considered and because of the wide variability the values of options in different parts of the U.S. Instead, an example illustrating one method for assessing the economic merit of fuel-switching is presented. For the societal or utility perspective, assessing the cost-effectiveness of fuel-switching measures requires gas and electricity avoided cost estimates. There is less consensus about the methods for estimating gas avoided costs than about methods for avoided electricity costs (see Chapter 5). Therefore, in this

Table 7-8. Fuel-Switching Measures Between Electricity and Gas*

	Residential	Commercial
Electric to Gas Measures		
Gas engine heat pump	X	X
Engine-driven vapor compression chiller		X
Absorption chiller		X
Desiccant cooling system		X
Gas to Electric Measures		
Electric ground-source heat pump	X	X
Electric heat pump water heater	X	X
Refrigeration heat reclaim		X
Ozonated laundering system		X

* Measures listed here are in addition to the gas efficiency measures listed in Table 7-6.

example, fuel-switching cost-effectiveness is calculated in terms of a threshold gas avoided cost; actual gas avoided costs lower than the threshold value would indicate that a gas technology is the economically preferable choice. In other words, given an uncertain gas avoided cost, the break-even avoided cost for gas explicitly shows what gas avoided costs would have to be in relation to electricity avoided costs for a technology to be cost-effective. If gas avoided costs are well determined, other methods for fuel-substitution economic analysis could be employed. Like the cost of conserved gas economic indicator used in the previous example, fuel-substitution cost-effectiveness is useful primarily in *technology* screening. The break-even avoided gas cost is derived algebraically in Appendix C.

Break-Even Cost Calculation for Electric to Gas Fuel Substitution

This example shows a sample break-even gas avoided cost calculation for a commercial gas cooling application.[12] The break-even gas avoided cost is the threshold below which gas avoided costs would have to be in order for a DSM measure to be cost-effective. The building is 50,000 square feet with a cooling load of 2,100 MMBth/year (U.S. average cooling load for commercial buildings in this size category per GRI). The building is

[12] The method can be similarly applied in a gas-to-electric fuel-substitution case.

served by a 125 ton electric, water-cooled, reciprocating chiller with a seasonal COP of 3.5; the chiller consumes 175,850 kWh annually.

The proposed alternative cooling system is a gas engine-driven, water-cooled chiller of the same size with a seasonal COP of 1.4; the chiller consumes 1,500 DTh/yr. The gas chiller has a lifetime of 15 years an initial cost of $800/ton. For this example, we assume that the maintenance costs are 0.9¢/ton-hour higher for the gas chiller than the electric chiller. With electric avoided costs of $.047/kWh for energy and $65/kW/yr for demand, the annual avoided electricity cost from switching these two technologies (ignoring parasitic electricity use of the gas chiller) is $16,429.

As presented in Appendix C, the break-even gas avoided cost (BGAC) is (in simplified form for this example)

$$BGAC = \frac{\textit{Incremental Cost} \times \textit{CRF} - \textit{Annual Electric Avoided Cost} - \textit{Annual Incremental Maintenance Cost}}{\Delta\ \textit{Annual Gas Use}}$$

A capital recovery factor (CRF) of 10.3% is used, which annualizes the initial investment based on a 15-year lifetime and a 6% real discount rate. For equipment replacement at the end of the useful life of the electric chiller, the incremental cost is the difference between a new electric chiller (@ $600/ton) and the gas chiller (@ $800/ton). This results in,

$$BGAC = \frac{\$25{,}000 \times .103 - \$16{,}429 - \$1{,}575}{1500} = \$8.2/DTh$$

If the actual gas avoided costs are lower than $8.2/DTh, then replacing the electric chiller with the gas chiller under these circumstances would be advantageous.

Suppose that the electric chiller was displaced before the end of its useful life. In this instance, the incremental cost of the gas chiller is the full cost, i.e., $100,000. This produces a break-even gas avoided cost of $3.0/DTh. In order for this gas cooling application to be cost-effective, avoided gas costs would have to be lower than this amount.

7.6 Issues in Gas DSM Program Design and Implementation

This section summarizes issues that arise when gas utilities implement DSM programs and highlights lessons learned from the experience of gas and electric utilities in designing, delivering, and evaluating DSM programs.

7.6.1 DSM Program Design

DSM programs match end-use technologies, customer segments, and program delivery mechanisms (Hirst 1988a). Several strategic approaches to DSM program design are possible, but it is instructive to identify two ends of the spectrum: "bottom-up" and "top-down."

In the bottom-up approach, a utility starts with a comprehensive set of DSM measures and methodically screens them producing a short list of the best measures. Screening is often performed using both qualitative and quantitative criteria. One gas LDC used the following qualitative criteria: market potential, reliability, load shape objectives, customer objectives, net impact of utility action, expected cost-effectiveness, and balance among customer segments (Synergic Resources Corporation (SRC) 1991). Quantitative criteria often include the multiple benefit/cost tests discussed in Chapter 6, set at some threshold level (e.g., B/C ratio greater than 1.2). DSM programs are then built around measures that pass the criteria, with the measures "packaged" individually or together for specific market segments.

In the top-down approach, a utility begins with strategic market analysis, identifying DSM program opportunities that could satisfy a set of corporate objectives for DSM. These objectives might include: enhancing customer service, promoting equity among all customer classes, increasing system load factor, retaining elastic customers, minimizing rate increases, and maximizing customer participation. Applicable DSM measures are then mapped onto these program concepts and subjected to economic screening.

Program Design Options

Utilities have at their disposal a variety of design options or approaches for inducing changes in customer energy use (see Table 7-9). Types of DSM programs include: information, innovative rates and pricing, rebates, loans, comprehensive direct installation, performance contracting, and competitive bidding (Nadel 1992).

Information programs—brochures, advertising, bill inserts and energy audits—seek to motivate and inform customers about the benefits of increasing energy efficiency. Rebate programs offer anywhere from some nominal fraction up to the full DSM measure cost (provided it is below the avoided cost ceiling). Loan programs usually offer low or zero interest loans to facilitate energy conservation investment on the part of the customer. When given a choice, most customers prefer rebates over loans of equivalent value. Direct install programs provide a turnkey operation for customers offering a comprehensive range of services that typically includes financing, audits, measure installation, and follow-up operations and maintenance of installed measures. Performance contracting programs use third-party private firms, also known as energy service companies (ESCOs), to deliver DSM services to the utility's customers. ESCOs usually compete on the basis of qualifications to provide these services and are compensated by the utility for energy or capacity savings delivered. Bidding programs are similar to performance contracting except that the selection process is more complex and formalized, and bidders themselves propose a payment scheme. Experience with DSM bidding by electric utilities has shown that this type of program is most applicable to the commercial and industrial sectors. For most LDCs, the majority of DSM opportunities are in the residential sector; for this reason, DSM bidding may not be a particularly attractive program design option.

Each of these program mechanisms has different characteristics in eligible customer participation, savings, and cost. Very general comparisons among the DSM program mechanisms are given in Table 7-9, drawn primarily from electric utility experience. This table also highlights three common measures of DSM program success: participation rate, savings per customer, and utility cost per unit savings. At present, financial incentives in the form of rebates have been perhaps the most important element of DSM programs in moving customers toward increasing efficiency in their facilities and homes. Over time, it is likely that there will be increasing emphasis on DSM program designs that maximize cost contributions from the customer.

Rate Impacts

Utilities and regulators must balance the benefits from aggressive energy-efficiency initiatives with competitiveness and nonparticipant impacts in setting goals for DSM program design. Minimizing rate impacts of DSM programs is a major concern of gas utilities. A starting point for minimizing rate impacts is to base rates on marginal costs. The benefit of marginal-cost-based rates is that they improve the energy use decisions of all customers, not just the ones who participate in a DSM program. Cost-based rates, including additional seasonal differentiation where appropriate, should reduce the difference between prices and avoided costs and reduce the revenue loss and associated rate impacts of some DSM programs.

Table 7-9. Summary of Strengths and Weaknesses of Different Program Approaches

	Number of Customers Targeted	Number of Customers Served Per Year	Participation Rate	Savings Per Customer	Utility Cost Per Unit Savings
Information	high	moderate	low	low	varies
Load-Management	high	moderate	moderate	moderate-high	low
Rebate	high	moderate	low-moderate	moderate	low-moderate
Loan	moderate	low	low	moderate-high	moderate
Performance Contracting	moderate	low-moderate	low-moderate	moderate-high	moderate-high
Comprehensive/ Direct Installation	moderate (can be high over long-term)	moderate	high	high	moderate-high

Source: Nadel 1992

Another strategy for mitigating the effects of rate impacts is to allocate the cost of DSM programs only to classes of customers that are offered the programs. Assuming that a program is being offered to customers with relatively inelastic demands, such a strategy would minimize load losses from price-elastic customers to who choose alternative fuels or service providers. See Section 9.5 for examples of the impacts of alternative DSM program cost allocation approaches.

Another strategy for mitigating rate impacts is to recover the bulk of DSM program costs from participants. Several utilities have developed an energy services charge tariff in order to market and deliver DSM programs in a manner that can be considered "subsidy-free" (Cicchetti and Hogan 1989; Cicchetti and Moran 1992); participants pay for the full cost of the DSM although the utility, by selling it as a service, essentially provides the necessary capital and may take on some risk of nonperformance. Such a strategy in theory removes barriers to capital but does not saddle nonparticipants with rebate costs and lost revenues as is the case with more conventional utility rebate programs. Although actual experience is limited with energy service charge program designs, initial evaluations suggest that the energy services approach tends to dampen program

Exhibit 7-1. A Joint Gas-Electric DSM Program Designed to Mitigate Rate Impacts

Southern California Gas (SCG) and Southern California Edison (SCE) are developing a pilot DSM program that involves joint-delivery where their service territories overlap. The Total Energy Efficiency Management (TEEM) program was conceived as a way for both utilities to achieve joint economies while providing customers with a more comprehensive assessment of savings available in their facilities. The economies derive principally from two aspects of the program: (1) saving on program administration costs by operating one joint program rather than two separate, similar programs and; (2) shifting the financing of the DSM measures from the utility to participating customers and third parties without recourse to ratepayers or shareholders of the sponsoring utilities. This second feature addresses the concern over potential rate impacts from utility DSM.

TEEM is designed to provide commercial and industrial customers with "fuel-blind" information and assistance on energy conservation. The services offered through the program include project identification, engineering, construction, monitoring and maintenance, and project financing. The utilities play mainly a facilitation role in the program, matching up customers with technical and financial resources. It is envisioned that energy service companies (ESCOs) will assume a primary role in the delivery of the program's services.

A novel aspect of the TEEM program is its financing. Customers are given three options for funding DSM investments identified in the earlier phases of the project cycle: (1) loan arrangement in which TEEM makes program participants aware of local lending institutions and ESCOs who may wish to provide debt financing, (2) energy service charges on monthly bills with customers bearing performance risk once the project has been demonstrated to deliver savings at the expected level, and (3) energy service charges on monthly bills with the customer bearing no performance risk but sharing measured savings with a third party.

Program costs are to be financed through a 3% marketing fee charged to ESCOs and other trade allies carrying out the program for targeting customers and other utility staff time used in program marketing, a 1% processing fee for placing energy service charges on customer bills under financing option #2, and a 3% fee for bearing performance risk under financing option #3. In this way, the TEEM program is designed to become self-sustaining at a threshold level of participation.

Source: Occhionero 1993

participation rates in certain market sectors. Resolving this drawback is a major challenge for utilities and DSM advocates.

Exhibit 7-1 describes a pilot DSM program, undertaken jointly by Southern California Gas Company and Southern California Edison, that is designed to mitigate potential rate impacts using the energy services charge framework.

Market Niches

Achieving widespread DSM program participation among all customer segments is another way of mitigating the potential equity impacts of DSM-related rate increases. This requires segmentation of customers into appropriate market niches. Utilities can then target marketing, services, and incentives to capture otherwise difficult or otherwise unattainable DSM opportunities within customer classes. For instance, low-income customers may respond very differently to information and incentives than typical residential customers, so reaching each group will require a different approach.

Market Transformation

Utility DSM programs have traditionally focused on customer service and resource acquisition objectives. DSM proponents have proposed market transformation activities in order to accelerate the shift towards energy-efficient products and services. Market transformation can involve early introduction, accelerated adoption, or expansion of the ultimate penetration of energy-efficient technologies (Nilsson 1992). A distinguishing feature of market transformation strategies is that utilities attempt to work directly with and influence "upstream" market actors (e.g., equipment manufacturers, builders) in a concerted fashion.

Schlegel et al. (1993) have developed a conceptual framework for gauging market transformation strategies along two dimensions: which market actors are affected and the mechanisms through which the actors' behavior is altered (see Table 7-10). Market actors include utility customers, trade allies (e.g., dealers, distributors, contractors, engineering and architecture firms, etc.), and manufacturers. The mechanisms that change behavior include altered options, incentives, education, and moral suasion. For any customer class, end use, or technology, the mode of market transformation is likely to vary.

The Super Efficient Refrigerator Program (SERP), also known as the "Golden Carrot" program, is an example of a DSM market transformation program. A consortium of environmental, utility, and government agencies instituted a competition offering a bounty of guaranteed multi-million dollar refrigerator sales and a sharing of development risk. The competition asks appliance manufacturers to develop and market refrigerators that exceed the energy-efficiency levels of federal standards by a specified amount, with the hope that losing manufacturers will feel compelled to offer comparable products to

Table 7-10. Examples of Market Transformation Strategies

How Behavior Changed	Whose Behavior Changed? Customers	Trade Allies	Manufacturers
Change in Actors' Options	•Increasing availability of efficient equipment •Bringing new technologies to market •Codes and standards		•Codes and standards
Change in Actors' Incentives	•Changing market availability of efficient equipment •Permanent financial incentives	•Changing what dealers stock by changing their perception of customer preferences •Building market infrastructure by directly or indirectly increasing demand •Forcing nonparticipants to change behavior to remain competitive •Changing what distributors order or push by changing perceived demand •Building an "efficient dealer" niche	•Golden Carrot approach (SERP) •Changing efficiency mix by changing perceived demand •Changing shipments to area by changing perceived *relative* demand •Accelerating transition to new Federal standards
Change in Knowledge (Education)	•Getting customer to take the crucial "first step" with other steps following •Causing customer to repurchase technology due to satisfactory experience •Making customers more aware of the range of efficient options •Changing customer perceptions of the costs of efficiency	•Making dealers aware of customer preferences •Informing dealers of the characteristics of efficient equipment and the options for energy services	•Making manufacturers aware of what products are needed in the marketplace
Change in Norms, Values, or Attitudes (Moral Suasion)	•Changing what customers perceive to be "normal" behavior	•Changing attitudes and values of business owners •Changing trade ally perceptions of "normal" behavior	

Source: Schlegel et al, 1993

those of the lone winner. Similar types of efforts are now being planned for other appliances (e.g., packaged air conditioners).

Another example of a market transformation program was conducted by Ontario Hydro to transform the market share for high-efficiency motors from 5% to 40% through a combination of education and incentives applied strategically throughout the market chain from manufacturers to vendors to customers.

The DSM efforts of gas utilities in Wisconsin offer an interesting example of (possibly inadvertent) market transformation for a gas appliance. Following years of gas utilities conducting DSM programs to promote pulse combustion furnaces for residential customers, this technology became the norm, achieving up to 90% of the gas furnace market (Kaul and Kihm 1992). A study of the diffusion of these high-efficiency gas furnaces concluded that the indirect effects of the DSM programs may have outstripped the direct effects (i.e., purchases made as a result of a utility incentive) by a margin of 3 to 1 (Schlegel et al. 1992). However, recently it appears that the market for these products in Wisconsin may be regressing (though nationally shipments of these furnaces are growing).

Market transformation programs pose particular challenges in program evaluation. Changes in the focus and methods of current program evaluation practice will almost certainly be required. Unless current methods for determining net savings from DSM programs evolve, utilities could be penalized for successful market-transforming efforts, essentially by obscuring the definition of nonparticipants (Prahl and Schlegel 1993).

Free Riders

Free riders are participants in DSM programs who would have installed the measure anyway without any inducement from the utility. Measures with already high market shares or quick paybacks often lead to high free ridership when promoted through DSM programs (Nadel 1992). Free riders do not diminish the savings accruing to society, but they do influence the savings attributable to the program and therefore the cost-effectiveness of the program from the utility perspective. DSM program design can help to minimize free ridership by offering rebates on only the highest efficiency DSM measures with longer customer paybacks and/or those products with a low market penetration.

7.6.2 DSM Program Delivery

The details of putting a DSM program "on the street" are highly specific to any program and beyond the scope of this primer. However, two issues are particularly relevant from a regulatory perspective and are briefly discussed: the cost of administering DSM programs and the potential for joint gas utility/electric utility DSM program delivery.

DSM Administrative Costs

Sometimes neglected in DSM potentials studies are the indirect costs incurred by utilities in administering DSM programs. Administrative costs could include any or all of the following: (1) program planning, design, analysis, and evaluation; (2) activities designed to reach customers, bringing them into the program and delivering services such as marketing, audits, application processing, and bid reviews; (3) inspections and quality control; (4) staff recruitment, placement, compensation, development, training, and transportation; (5) data collection, reporting, record keeping, and accounting; and (6) overhead costs such as office space and equipment, vehicles, and legal fees (Berry 1989). Many of these items could appear on the ledgers of utility departments other than the DSM program.

A limited national survey by Oak Ridge National Laboratory (ORNL) of electric utility DSM programs found that the cost of administering DSM programs on average—typically expressed as a fraction of the direct measure cost—was between 10% and 35% (Berry 1989).[13] Nadel found that administrative costs added a cost premium of 36% on average, over and above the direct measure costs to the utility in a study of 46 North American electric utilities (Nadel 1990). Another study by Joskow and Marron found administrative costs in the range of 7%–70% from ten U.S. electric utilities' overall DSM program efforts (Joskow and Marron 1992). There are no standardized accounting methods for reporting on DSM program administration costs, so some of the variation shown above is no doubt due to what is and is not included in these computations. In general, DSM program costs will vary according to many factors including: (1) stage of program development; (2) target market segment; (3) market penetration goal; (4) technology; and (5) types of services and/or incentives being offered. For instance, a comprehensive program that involved making site audits, arranging for measure

[13] In this study, the programs with the lowest administrative overhead are commercial lighting programs, in the range of 10% to 15% of direct measure costs; multiple measures programs, including audits and incentives for commercial customers, display higher administrative costs, in the range of 25% to 35%. Residential weatherization programs average administrative costs around 20%. Pilot programs of all types can have administrative costs over 100%.

installation and financing, and doing follow-up verification will entail much greater program administration resources than a standardized rebate program.

Jointly Delivered Gas/Electric DSM Programs

DSM programs delivered jointly by electric and gas utilities with overlapping service territories hold the promise of reducing not only the administrative costs of running separate yet similar DSM programs but also reducing customer confusion about competing utility programs (Nadel 1992). Market segments that focus on "lost opportunity" resources (e.g., new construction) or segments in which it is difficult to design cost-effective programs (e.g., low-income housing) have been suggested as particularly promising areas for joint DSM program delivery (Buckley 1992).[14] A mutually agreed upon method for cost-allocation among utilities would be a critical prerequisite to any such cooperative effort.

Energy service companies (ESCOs) are viewed as an appropriate vehicle by which joint gas-electric utility programs could be delivered. By acting as the joint agent of the two utilities, an ESCO can help to reduce customer confusion about the DSM program and provide some measure of objectivity on the best fuel for a given application, following agreed upon criteria and procedures. The role of ESCOs in providing utility energy services has evolved significantly since the early days of performance contracting to include DSM bidding, standard offers for DSM, and various partnerships with utilities in their DSM program efforts (Wolcott and Goldman 1992). Joint utility DSM program delivery would fit easily into the evolving ESCO industry.

7.6.3 DSM Program Evaluation

Evaluation has emerged as a key component of successful DSM programs, providing critical feedback to the program design process. Initially consigned to a minor role in utility DSM efforts, its importance has grown with the advent of DSM as a major resource in electric utilities' portfolios, and especially with more recent state regulatory initiatives to grant utility shareholder incentives based on measured performance of DSM programs. The audience for DSM program evaluations can include utility staff, ratepayers, PUCs, intervenors in utility regulatory proceedings, and others in the energy services industry.

[14] "Lost opportunities" occur in new construction (both commercial and residential) when DSM measures that are most cost-effective (or even only possible) at the design stage, but not later, are omitted.

The core purposes of DSM program evaluation are: (1) description and characterization, (2) measurement, and (3) optimization of programs.

Description and characterization involve detailing: the operation of a program, the market reached and the market that remains, the interaction of DSM measures with behavior, the DSM resource that remains to be captured, and the reasons for program results.

Measurement is made of: energy savings attributable to the program, demand impacts (including coincident peak load reductions), utility and societal costs, and persistence of savings.

Evaluations are also expected to provide the basis for *optimizing* programs. They do this by identifying: bottlenecks in program operation, problems in program goals (especially if goals are not shared throughout the utility), the features that worked well in programs, barriers to participation, barriers to persistence of savings, and measures that may not be performing as well as expected (Kushler et al. 1992).

Two broad categories of evaluation serve these purposes: impact and process. Impact evaluations examine the effects of a program, including the quantitative documentation of the program's costs and benefits, the rate of participation and measure adoption, the performance of the DSM technologies, and the energy and load impacts. *Process evaluations* estimate how well a program has been implemented, including the efficiency of service delivery, the effectiveness of promotional strategies, and the level of customer satisfaction (Electric Power Research Institute (EPRI) 1992d).[15]

Impact evaluation seeks to determine which savings are attributable to a program. The crux of the challenge for impact evaluators is to "compare what happened to program participants with what would have happened to participants if the program had not existed" (Hirst and Reed 1991). This involves determining two types of savings: gross (or total) savings of the participants and net savings. Figure 7-10 shows the distinction between gross savings, which are relatively easily measured, and net savings, which require use of sophisticated sampling and statistical methods to determine the "baseline" energy consumption of a comparative or control group in contrast to the program participants.

A number of approaches are used within each of these types of evaluation. Impact evaluations use engineering methods, statistical methods (often in conjunction with

[15] Market evaluation is subsumed in process evaluation in this framework although some define it distinctly.

customer billing records), surveys (qualitative and/or quantitative and administered by mail, by phone, in person, or through site visits), and metering. Process evaluations employ program information, surveys, in-depth interviews, and observation or case studies (Electric Power Research Institute (EPRI) 1992). For both impact and process evaluations, many of these methods are applied in combination, depending on the needs and constraints of the situation. Excellent methodological reviews can be found in (Hirst and Reed 1991) for DSM evaluation in general; in (Electric Power Research Institute (EPRI) 1991b) for impact evaluation; and in (Electric Power Research Institute (EPRI) 1992e) for process evaluation.

Some of the key issues in DSM program evaluation are identified in Table 7-11. These issues are not just relevant to program evaluation but to the viability of DSM as a utility resource. Each of these topics deserves an entire volume (some already have one); interested readers should refer to (Kushler et al. 1992) for a discussion of several evaluation topics listed in Table 7-11. Exhibit 7-2 describes a comprehensive, multi-year DSM program evaluation (Gas Evaluation and Monitoring Study or GEMS) that is being undertaken cooperatively by several New England gas utilities and was initiated by Boston Gas.

Table 7-11. Key Issues in Program Evaluation

Description and Characterization
Role of behavior in evaluation
Timeliness of information and feedback
Presentation of results—clarity, honesty, and objectivity
Measuring customer value
Determining participant costs

Measurement
Net and gross savings
Estimating coincident peak load savings and load shape impacts
Persistence of savings
Limits to measurement
Dealing with uncertainty
Maximizing precision versus minimizing bias
Assessing market transformation
Quality assurance, confirmation, and validation
Verification versus evaluation of program savings

Optimization of Programs
Predicted versus measured savings
Avoiding lost opportunities and cream skimming
Integration of impact evaluation and process evaluation

Other
The role of process evaluation
Comparability of results (across programs, utility services territories, states, and countries)
Generalizing results from metered subsamples to larger populations
Incorporating environmental externalities
Definition of key DSM program evaluation terms
R&D needs for measuring technology performance

Adapted from Kushler et al. 1992

Exhibit 7-2. A Cooperative DSM Evaluation Study in New England

The Gas Evaluation and Monitoring Study (GEMS) is a cooperative, multi-year effort of 11 gas utilities in four New England states to track the performance of each company's DSM programs. The study, spearheaded by Boston Gas, was conceived as a way to economize on expensive data gathering and analysis by cost-sharing and transferring data and results among the participating LDCs. The study is currently in progress, initially focusing on the residential and multi-family sectors while evaluation plans for the commercial and industrial sectors are being formulated.

GEMS has three elements: impact and process evaluations, and end-use metering of customer facilities (which supports impact evaluation). The main objective of the impact evaluation component of the study is to produce estimates of net gas savings from DSM measures. Net savings are developed using a combination of end-use metered data, survey responses, and monthly billing data.

A central feature of the GEMS analysis is the use of end-use metered data collected from a random sample of customers for estimating "gross" savings. These data are collected on an hourly basis to track gas consumption both before and after installation of DSM measures. The change in gas consumption is then corrected for confounding variables in order to isolate the impact attributable to the DSM measures. Transferability of these data among the cooperating LDCs is a major component of the evaluation design.

For estimating the net savings in residential buildings, a combination of techniques is being employed including:

- stratified sampling by housing type, geographical location, and time of DSM measure installation;
- cross-sectional analysis (i.e., comparisons across a variety of dwellings at one point in time) and pooled time series/cross-sectional analysis (i.e., comparisons before and after DSM measure installation among various dwellings)
- "matched-pair" analysis for multi-family buildings; participant buildings are compared to a control building within the same complex

Specific issues the process evaluation is designed to address include:

- progress toward implementation goals
- effectiveness of marketing strategies
- appropriateness of program design in reaching the target market
- adequacy of data compilation for supporting program management, evaluation, and regulatory needs
- reasons that customers choose to participate or not
- attributes and short-comings of the program
- satisfaction of customers, trade allies, vendors, and utility staff
- changes to the program that would improve implementation success
- explanations for free-riders, free-drivers, persistence of savings, and snap-back effects

Source: Greenblatt 1993

End-Use Fuel Substitution

8.1 Overview

This chapter focuses on natural gas/electricity sector rivalries in end-use markets. The interfuel substitution issues addressed include the regulatory treatment of:

- electricity to gas end-use fuel conversion;
- gas to electricity end-use conversion;
- gas vs. electricity end-use selection; and
- unregulated vs. regulated fuels in end-use markets (e.g., oil to gas end-use conversion or selection).

Fuel-switching issues related to transportation end-use markets (e.g., use of natural gas or electricity to replace gasoline in automotive vehicles) and industrial customers with multi-fuel capability are not addressed.[1] The discussion also does not include fuel choice issues that arise in the regulation of wholesale electric generation markets (e.g., value of fuel diversity).

Opportunities for end-use fuel substitution occur wherever fuel competition for an end use occurs. The natural gas and electricity sectors compete for the residential space heating, water heating, cooking, and drying equipment markets in many parts of the country. Struggles over market share occur for similar commercial sector end uses and certain industrial processes. Competition is only natural in our society because businesses are built upon differences in product characteristics and prices. Nonetheless, the competition between these two sectors has been and continues to be profoundly influenced by federal and state regulation.

With the advent of IRP and the explicit consideration of DSM as a "supply substitute," PUCs have encouraged utilities (primarily electric utilities) to intervene more actively in end-use markets. Proponents of fuel substitution argue that these interventions should not be de facto restricted to higher efficiency products using the same fuel, but that utilities should identify and recommend (if necessary) cost-effective fuel substitution opportunities for their customers as part of their IRP processes. Opponents argue that mandatory fuel substitution, in effect, requires one utility to subsidize competitors' sales

[1] However, the development of electric and gas vehicle markets will be significantly impacted by the policies and decisions made by state PUCs, energy planning agencies, and local governments, particularly the treatment of utility company investments in retail automobile refueling facilities.

(i.e., competing opposite fuel utility) at the expense of its remaining customers (Kahn 1991b).

For regulators, a central issue is whether the efficient selection of fuels in certain end-use markets by consumers can be improved through an IRP planning process that explicitly considers fuel substitution options or whether current utility practices result in a better social outcome. At a minimum, controversies over fuel substitution policies may result in some PUCs reviewing their policies on promotional practices and DSM program implementation in order to insure that existing utility DSM programs are not introducing undesirable distortions into consumer's fuel choice decisions. The gas industry has raised concerns that electric utility DSM programs have the effect of encouraging customers to adopt electric technologies when gas options would be more economically efficient. In practice, policies on promotional practices and DSM implementation (where applicable) are not always consistent, either within a utility or (especially) between competing utilities. In some cases, a PUC may need to impose restrictions (e.g., limiting the scope or size of rebates) or to mandate new activity.

A primary objective of this chapter is to identify policy approaches on fuel substitution, mandatory or otherwise, that are available to state regulators. We describe types of fuel substitution programs, review the arguments that have been raised by proponents and opponents in the fuel substitution debate, present case studies which summarize the experience of eight state PUCs on this issue, and discuss major policy and programmatic issues that regulators are likely to confront if they address end-use fuel substitution directly. It is clear that differing state political environments and social goals may dictate different approaches.

8.2 Types of Fuel Substitution Programs

In the broadest sense, fuel substitution programs are demand-side management (DSM) programs designed to influence the efficiency and timing of customers' demand for gas or electricity, to shave peak loads, to fill valleys in the utility's load curve, and to lower customers' bills. Fuel substitution tries to achieve these goals by substituting energy-using equipment of one energy with a competing energy source (CPUC 1992d).[2] Fuel substitution programs promote or provide an incentive for efficiency improvements associated with the fuel conversion.

[2] The CPUC has limited "energy source" to utility-supplied electricity and natural gas but noted that this stipulation may be broadened as the analytical constraints for evaluating unregulated alternative fuels become less restrictive.

- *Gas fuel substitution programs* promote the customer's choice of gas service for an appliance, group of appliances, or building rather than the choice of service from a different energy source. These programs increase customers' usage of natural gas and decrease usage of an alternative fuel.

- *Electric fuel substitution programs* promote the customer's choice of electric service for an appliance, group of appliances, or building rather than the choice of a different fuel. These programs increase customers' electric usage and decrease usage of utility-supplied natural gas (CPUC 1992d).

It is useful to distinguish two aspects of fuel choice, which are related to the circumstances and timing of customer decisionmaking: "conversion" and "fuel selection." "*Conversion*" refers to situations in which customers discontinue the use of an existing appliance that uses one kind of energy source and switch to an appliance that uses a competing energy source. The conversion may be either from electricity to natural gas or vice versa and typically occurs at the time of equipment replacement. "*Fuel selection*" refers to situations in which customers are selecting new appliances rather than replacing existing ones. Fuel selection occurs whenever new buildings are constructed and, in some cases, when existing buildings are remodeled or new end uses are added. These concepts of "conversion" and "fuel selection" apply throughout the building sector in residences, businesses, and industries.

Approaches that PUCs adopt towards fuel substitution are often influenced by the context in which these programs are proposed by utilities. In reviewing fuel substitution proposals, many regulators will consider both existing promotional practices policies and the extent to which competing utilities are actively involved in end-use markets as indicated by their DSM programs. Some PUCs have used promotional practice and DSM policies as the basis for determining cost recovery treatment because fuel substitution programs typically have varying load shape impacts and objectives for each utility (e.g., conservation, peak-clipping, valley-filling, load-building). For example, in approving an IRP plan submitted by Atlanta Gas Light, the Georgia PSC found that the cost of DSM programs that result in more efficient and effective use of either electricity or gas could be recovered through a cost recovery rider. Costs of fuel substitution programs judged by the PSC to be primarily load-building in character, because they would result in increased revenues for the gas utility, were not eligible for recovery through the rider; instead, they were treated as a promotional expense and reviewed during the utility's rate case (Georgia Public Service Commission 1993b).[3] Assessing the actual load shape impact(s) and objective(s) of fuel substitution programs is important for

[3] The Georgia PSC categorized each DSM program proposed by Atlanta Gas Light as either being conservation or load-building for cost recovery purposes.

PUCs because of the different financial impacts on utility shareholders. Some may regard these definitional issues as hair-splitting, but they can help PUCs develop consistent policies and treatment for DSM programs that have different financial impacts on utility shareholders and ratepayers.

8.3 Fuel Substitution Debate

The debate on fuel substitution and fuel choice is often couched in ideological terms—the virtues and evils of competition, concerns about hindering or correcting market forces, and warnings for and against regulatory interference in customers' equipment selection choices. Often, proponents and opponents seem to be talking past each other because they are addressing very different questions in some cases (see Tables 8-1 and 8-2).

Proponents of electric-to-gas fuel substitution argue that:

- A key rationale for integrated resource planning—addressing problems of inefficient resource allocation caused either by market imperfections or price signals that do not reflect societal costs—requires that fuel substitution opportunities be considered by utilities as a potential least-cost option.

- In certain end uses, there are major opportunities to reduce customer's utility bills significantly by replacing electric equipment at the end of its useful life with new gas-fired equipment. Often, these opportunities arise because the existing stock of buildings and equipment reflects choices that were made under very different conditions and expectations of absolute and relative prices of electricity and gas. For example, in the Pacific Northwest, a life-cycle cost analysis found that electric water heating equipment should be replaced by gas water heating equipment (WSEO 1993).

- For other end uses (e.g., space conditioning), proponents argue that there are significant opportunities for "win-win" situations for both electric and gas utilities to reduce overall costs and environmental impacts. For example, gas air conditioning can reduce summer electric peak loads while providing a valley-filling option for winter-peaking gas utilities. Load reduction due to end-use fuel substitution can also reduce emissions of SO_x and CO_2 for coal- and oil-based electric utilities.

- Fuel switching can often reduce electric load cost effectively and should be included in electric utility DSM programs. From a DSM planning perspective, fuel substitution options have certain advantages because, in many situations,

Table 8-1. Typical Arguments for Fuel Substitution

Resources:	Significant market barriers currently prevent the efficient use of energy. Fuel substitution is needed to efficiently allocate fossil fuel resources.
Environment:	Fuel substitution reduces environmental emissions from electric generation.
Utility Bills:	Fuel substitution can provide the least-cost energy service to all ratepayers in certain end uses.
Company Impact:	Fuel substitution can reduce electric peak load. In some circumstances, both utilities benefit.
Competition:	Fuel substitution efficiently allocates market share between electric generating capacity and gas capacity.

Table 8-2. Typical Objections to Fuel Substitution

Resources:	Market barriers don't prevent the efficient use of energy. The market already allocates resources efficiently.
Environment:	Utility regulation is not a proper place for environmental regulation; environmental benefits of fuel substitution are often overstated.
Utility Bills:	The greater uncertainty and potential volatility in future gas commodity costs compared to electric rates means that expected bill savings from fuel conversion are problematic.
Company Impact:	A fuel substitution program will retard the growth/market share of the utility losing the customer.
Competition:	It is preferable to rely on competition rather than government regulation in regard to customer's fuel choices.

demand reductions are quite reliable and "persistence of savings" is not an issue, particularly if the electrical equipment has been removed.

Opponents of electric-to-gas end-use fuel substitution argue that:

- The underlying rationale for utility DSM programs is flawed in this context. The rationale typically given is that market barriers and imperfections justify interventions into end-use markets to increase the efficiency of energy use and provide a boost for the creation of a larger market for high-efficiency products that are often underdeveloped. However, there is no evidence demonstrating that there are significant market barriers in the fuel choice market. In fact, gas has substantial market share in many contested end uses and currently there is an active market among competing energy sources.

- Requiring electric utilities to promote fuel substitution is fundamentally different than other types of electric DSM because it results in a lowered long-term market share for the electric utility conducting the program.

- Requiring electric utilities to support their customers switching to other fuel sources moves too far in the direction of centralized, governmental control over specific markets and is anti-competitive. It is inequitable to ask a utility to give its customers financial assistance to induce them to switch their patronage to its competitors, recovering the costs by raising the price of its own products. Relative prices for gas and electric regulated services already provide the proper signals for customers to make efficient fuel choice decisions. It is preferable to rely on competition among different suppliers of competing fuels to best serve consumer interests. This type of competition provides incentives for suppliers of equipment and appliances to refine their goods and keep prices competitive. There is no evidence that managed competition is needed or will improve energy efficiency.

In light of the controversy about interfuel competition issues, this candid statement from the Strategic Planning Manager for the Illinois Department of Energy and Natural Resources accurately reflects the initial reaction of many regulatory agencies to fuel substitution:

> **Like a bad dream, we have pushed the thought of confronting interfuel competition issues into a dark corner of the Illinois planning process. The Illinois Public Utilities Act actually suggests that the Statewide Plan is to be a joint gas/electric plan, but because we could not conceive of how we would resolve interfuel policy issues (or perhaps because we could perceive the resolution all too well), the planning process was bifurcated from the start based on arguments of administrative and methodological necessity.**
>
> **While I continue to believe that a truly integrated planning process incorporating both gas and electricity is methodologically and administratively complex, it is increasingly clear that soon the issues must be addressed. Complexities notwithstanding, the correct way to address them is**

through an integrated plan. However, for a variety of reasons, the correct way is not likely to be the way chosen, at least in the near term (Jensen 1991).

One aspect of the dilemma for regulators in sorting out interfuel competition issues is that representatives of the gas and electric industries often present starkly contrasting views. The following stylized summaries attempt to reflect claims often found in the trade press, journals, and hearing rooms:

Many involved in the gas industry believe:

> Replacing gas for electric equipment and appliances in certain end uses represents sound economic and environmental policy for customers, the nation, and even the utility sector. However, the competitive situation currently favors the electric industry because electric utilities are generally larger than gas LDCs in rate base, staff, and number of customers. Moreover, major equipment manufacturers derive the vast majority of their revenues (85%) from electrical equipment and thus may tend to be more responsive to electric utilities. Furthermore, access to electricity is more widespread than gas. High-efficiency gas equipment generally has higher initial cost than corresponding electric equipment. This cost differential favors the electric utility industry, even though lower gas prices often makes gas preferable on a life-cycle cost basis. However, low gas avoided costs mean that the net benefits of gas DSM are smaller, justifying lower customer incentives for gas. The offering of customer incentives for high-efficiency electric equipment distorts the marketplace and adding gas DSM will not correct this distortion. Even with gas DSM, electric equipment and appliances subsidized by an electric utility DSM program will usually end up in a dominant position. Regulatory intervention is needed to assure a true "level playing field."

Many involved in the electric utility industry believe:

> Electric utilities have an obligation to serve all electric end-use customers while the gas industry's more flexible service obligation often provides them with a competitive advantage. The best available electric technologies rate as well as or better than competing products. This competition provides incentives for competing suppliers of equipment and appliances to refine their goods. The benefits of interfuel competition (e.g., additional choices for customers) far exceed the potential societal gains of mandated fuel substitution. Moreover, requiring electric utilities to pay financial incentives to customers to switch to other fuel sources is anti-competitive and runs counter to utility regulators' basic justification for DSM, which is to correct market imperfections.

Fuel substitution raises many tough questions for regulators, which include: Is current fuel selection economically efficient, or are there substantial market barriers/imperfections? Are there significant societal benefits to be realized from end-use fuel substitution? How does one judge from a societal perspective what fuel use is more economically efficient? Do we need to develop new regulatory approaches either to compensate for failure in our gas and electric markets or to assure that there are consistent policies regarding utility interventions in end-use markets? For example, is fuel choice being unduly influenced by utility financial incentives to developers or favorable line extension or hook-up policies? If market barriers or imperfections exist in fuel choice markets, are they large enough to compensate for the efficiency losses that inevitably occur from regulatory intervention? If regulation is desirable, do commissions have the authority to intervene in the fuel choice market?

In the next section, we examine the procedural and analytic approaches that various state PUCs have used to address these questions.

Table 8-3. Vermont Public Service Board (PSB): Assessing Fuel Substitution Opportunities

1.	When might fuel switching be cost effective? The PSB asked that potential end-use opportunities be identified, and that assumptions about future relative fuel prices, measure lives, risks, and reliability be made explicit and folded into the analysis.
2.	For cases where cost-effective fuel switching is likely, are there market barriers that require intervention?
3.	Where barriers exist, what interventions are necessary to overcome them (e.g., information-only, loans, or direct investment)?
4.	Who is the most appropriate entity to assist in overcoming each barrier?
5.	If some form of financial incentive from the utility is necessary, what is the appropriate incentive and program design for each measure type?
6.	If a utility encourages customers to switch to an alternative fuel, should it also pay for other DSM measures associated with that end use? Also, if DSM cannot be guaranteed in conjunction with fuel switching, is society better off keeping the end use as an efficient electric end use?
7.	Should a utility be allowed to develop programs for cost-effective fuel switching from nonregulated fuels to electricity?

Source: Raab and Cowart 1992; Vermont Public Service Board (PSB) 1991a

8.4 Case Studies: Experiences with Fuel Substitution Programs

A review of the experiences of various regulatory commissions that have addressed fuel substitution issues provides a useful foundation for understanding alternative approaches. PUCs in five states—Vermont, Wisconsin, California, Oregon and New York—have encouraged or condoned fuel substitution and have developed procedures for it. Fuel substitution is currently being addressed in Nevada, Maine, and other states without resolution. In some states (e.g., Georgia), electric utilities are challenging commission efforts to impose fuel substitution programs. In many states, PUCs have not developed explicit positions on the issue and no commission-approved fuel substitution programs are being conducted.

In Vermont, the state commission mandated fuel substitution even though the electric utility industry was unwilling. In a relatively short time, the Vermont Public Service Board (Vermont PSB) ordered its regulated electric utilities to consider fuel substitution as a demand-side measure and to provide incentives for fuel substitution if it was beneficial to society. Moreover, the Vermont PSB withstood a legal challenge from the utilities, which was resolved by the passage of state legislation affirming the Vermont PSB's authority to mandate fuel substitution. The commission's decisions on fuel substitution were based on the following policy principles:

(1) Cost-effective fuel switching should be identified and actively pursued by utilities as part of their IRP processes,

(2) Utilities should seek to spend as little as possible on fuel substitution opportunities but must be willing to pay to acquire these resources if necessary when they are more cost-effective than expenditures for alternative supply resources (Raab and Cowart 1992).

In carrying out this decision, the Vermont PSB asked utilities to address a set of questions in order to systematically analyze fuel substitution opportunities which, in Vermont, are mostly to unregulated fuels, and better understand the level of utility involvement which was most appropriate (see Table 8-3). Several electric utilities were particularly upset by the Vermont PSB's decision but have proposed programs which they assert comply with the Board's order. The Vermont PSB and utilities are currently addressing several thorny implementation issues, such as how fuel substitution costs and risks should be allocated among utility companies (see Exhibit 8-1).

Georgia provides another example of a state commission proceeding along an aggressive path instituting fuel substitution policies. Electric utility executives as irate as those in Vermont, resisted the Georgia Public Service Commission's directions to consider fuel

Exhibit 8-1. The Vermont PSB Mandates Fuel Substitution

In Vermont, the Public Service Board (Vermont PSB) has historically interpreted a 1973 state land-use law requiring "the best available technology for efficient use or recovery of energy" to require the installation of equipment that minimizes life-cycle cost irrespective of fuel used. Vermont's largest utilities have provided residential customers with information on fuel substitution since the mid-1980s and limited state financing has been available to assist customers who want to switch from electricity to propane, oil, wood, and natural gas for space and water heating. Switching to natural gas in Vermont has been relatively limited as it is not widely available (Raab and Cowart 1992).

The Vermont PSB "expressed its view that fuel switching should be a two-way street in the context of integrated resource planning (IRP), and should be evaluated on the basis of total societal costs and benefits" (Vermont Public Service Board 1990).

In 1990, the Vermont PSB ordered utilities to invest in "efficiency programs that are *comprehensive*, including aiming at cost-effective savings from ... economical fuel switching." Central Vermont Public Service (CVPS) and several nonutility organizations attempted to implement the order through complex settlement negotiations. This resulted in a motion to compel CVPS to acquire cost-effective energy efficiency resources. CVPS opposed the motion and challenged the PSB's legal authority to order a utility to offer financial assistance to its customers for cost-effective fuel substitution. After further investigation, the Vermont PSB ordered CVPS and other parties to analyze the merits of specific fuel substitution measures and file within 45 days a plan for the acquisition of those energy efficiency resources found to be cost effective. CVPS appealed to the Vermont Supreme Court but withdrew its appeal after state legislation was passed in 1991 which affirmed the Board's jurisdiction. A settlement was reached with the nonutility parties in which CVPS agreed to offer a comprehensive fuel substitution audit, to provide information on the costs and benefits of fuel substitution, and to help secure market-based financing for cost-effective fuel substitution (Vermont Public Service Board 1991b).

Since early 1991, five of Vermont's largest electric utilities have included fuel substitution components in their DSM programs. Burlington Electric Department (BED) and Washington Electric Coop offer financial incentives to customers for fuel switching. CVSP, Green Mountain Power, and CUC have committed to helping customers secure conventional bank loans. The roughly 15% cost-effectiveness advantage applied to DSM for its greater flexibility and lower environmental impact has been applied to fuel substitution programs. Disputes about customer incentive levels still remain to be resolved.

The Vermont PSB has resolved a disagreement between BED and Vermont Gas Systems (VGS) over who should pay for a substantial amount of weatherization installed concurrently with fuel substitution installations. The board concluded that VGS should pay because it benefited from the improved efficiency once the customer switched to natural gas, and the remaining BED customers would have no further interest once they had paid for the conversion. The board has also approved procedures authorizing utilities to recover investments in other types of DSM programs from customers who subsequently switch fuel (Raab and Cowart 1992).

Exhibit 8-2. The Georgia PSC Mandates Fuel Substitution, but Georgia Power Objects

The Georgia Legislature passed the Integrated Resource Planning Act in March, 1991 (Georgia Official Code 1992). In December, 1991, the Georgia Public Service Commission promulgated rules implementing the Act (GAPSC 1991). The hearings on the rules were hotly contested, with Georgia Power and Savannah Electric & Power Company, both owned by the Southern Company, objecting to many of the recommended filing requirements. The two companies were vehemently opposed to any provisions regarding fuel substitution. Both companies submitted their first integrated resource plans on January 10, 1992. Neither company included an assessment of fuel substitution opportunities in its integrated resource plan.

The two companies not only questioned the jurisdiction of the commission but also argued that the term "facilities which operate on alternative sources of energy" in the rule refers to supply resources only although several intervenors argued that the term is used in reference to "other...demand-side options" and includes such options. Both utility companies subsequently filed for a waiver from the fuel substitution assessment requirement of the rule. Both requests for a waiver were denied, and the companies were ordered to develop information and perform evaluations of end-use fuel substitution for potential DSM measures, the details of which were to be dealt with in the subsequent certification documents (GAPSC 1992).

In September 1992, each company refiled its application for certification of DSM programs that it had initially submitted in January along with its integrated resource plan pursuant to the rule. Both companies withdrew the bulk of their commercial and industrial demand-side programs, stating their intent to file them at a later time. Neither company submitted an analysis of potential fuel substitution DSM measures. In its orders granting certificates for the primarily residential DSM programs of Georgia Power and Savannah Electric, the commission (1) acknowledged the failure of both companies to fully assess the potential of fuel substitution, (2) stated in the body of the Georgia Power Order that "Georgia Power should continue to assess this potential, and shall be required to include the results of its assessment in its next IRP filing" and, (3) put in motion action to resolve issues surrounding the level of incentives for fuel promotion programs, but did not further address fuel substitution in the ordering language in either order (GAPSC 1993a).

Subsequently, the Georgia Commission addressed the issue of fuel substitution in Atlanta Gas Light Co.'s IRP filing (GAPSC 1993b). The Commission appears to have resolved the fuel substitution issue in its August 1993 Letter Order in Reconsideration in that case by (1) distinguishing between load building (self-promotion) and conservation (promotion of programs which reduce load, including switching to a competitor's product) in both industries, (2) treating conservation as DSM with special cost recovery and treating load building as normal business expense, (3) specifying that DSM incentives are only for efficiency improvements above and beyond code, and (4) balancing the customer rebates offered by the two industries based on savings to the individual utilities.

There has been no experience yet under this ruling.

substitution in their DSM programs. In an August 1993 Order, the Georgia Commission instituted policies designed to ensure balanced competition between the electric and gas utilities (see Exhibit 8-2).

The California Public Utilities Commission (CPUC) has mandated that fuel substitution be considered as a natural element of DSM. California's utilities (including the nation's largest combined utility and the nation's largest all-electric utility) did not object. The CPUC, which initially developed and formalized the standard economic tests that are used by many PUCs in evaluating the cost effectiveness of DSM programs, has revised its standard procedures manual to specifically treat fuel substitution. California utilities have begun to propose fuel substitution programs under the new guidelines (see Exhibit 8-3). These new guidelines are more restrictive than the criteria for other DSM programs and serve the intended purpose of limiting the amount of ratepayer-funded fuel substitution that will occur.

Exhibit 8-3. California Prescribes Fuel Substitution Procedures

In October 1992, the California Public Utilities Commission (CPUC) issued an interim opinion that established rules for evaluating fuel substitution programs. The CPUC concluded that fuel-substitution programs may offer resource value and environmental benefits although fuel switching should only be promoted by utilities if it has a neutral or beneficial effect on the environment. To be considered for funding in California, a fuel-substitution program now must pass the following "three-prong test:"

(1) the program must not increase source-BTU consumption;
(2) the program must have a Total Resource Cost (TRC) benefit-cost ratio of 1.0 or greater...
(3) the program must not adversely impact the environment. To quantify this impact, respondents should compare the environmental costs with and without the program, using the most recently adopted values for residual emissions in the Update (i.e., the CPUC's resource planning process) (CPUC 1992).

The California Commission did not otherwise specify analytical procedures for fuel-substitution programs that are different from those used for other DSM programs.

This "three-prong test" sparked further hearings on implementation methodology. The CPUC subsequently adopted a conservative definition of the baseline reference to be used in the TRC test in order to constrain fuel substitution programs rather than adopting the "existing equipment" standard offered by the utilities intended to foster fuel substitution.

All four of California's major investor-owned utilities began fuel substitution programs in the late 1980s or early 1990s and are now redesigning their programs to fit the new rule. (Only San Diego Gas and Light had initiated a major program.) Little experience has yet been accumulated under the new rules.

Table 8-4. Wisconsin's Revised Interfuel Substitution Principles

1. 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.

2. Resource options involving fuel switching or use of other energy sources may have revenue requirement and customer service benefits for an electric utility.

3. Electric utilities can capture those benefits, but they should pay no more than is necessary to get customers to take action.

4. If the supplier of the other fuel or energy source is providing incentives to take the action, the electric utility may show that it is unnecessary to provide further incentives, or some partial incentive may be justified. The principle to be applied is that enough must be provided to induce the action, but no more than that, whatever the source.

5. Electric utilities must give clear, accurate, and current information to customers on the benefits and costs of fuel substitution, or any other energy use question for which information is available. In particular, electric utility advertising, program literature, and presentations should specifically address the availability of incentives for fuel substitution of energy sources other than electricity.

6. Gas utilities should pay a fair share of the incentive to encourage interfuel substitution.

7. The application of these principles should be periodically reviewed on a case-by-case basis.

8. Combined electric and gas utilities should coordinate their programs.

The Wisconsin Public Service Commission (PSC) has also urged consideration of fuel substitution as DSM since around 1989. But the Wisconsin PSC has stopped short of *mandating* consideration of fuel substitution programs. It has focused much of its attention on customer rights to choose, specifically addressing balanced incentives and making available full and unbiased information developed jointly by the relevant utilities. The Wisconsin PSC has issued a set of fuel substitution principles to guide the development of utility fuel substitution DSM programs in Wisconsin (see Exhibit 8-4).

Exhibit 8-4. The Wisconsin PSC Stops Short of Mandating Fuel Substitution

The Wisconsin Public Service Commission (PSC) has urged Wisconsin's utilities to pursue fuel substitution, has provided interfuel substitution principles as guidance, and has approved fuel substitution measures proposed by various utility companies. In September 1992, the PSC mandated a fuel substitution measure, only as a joint utility pilot project.

The Wisconsin PSC addressed fuel substitution directly in its 1989 Order approving Advance Plan 5 (the Wisconsin utility companies' fifth biennial integrated resource plan) with the following statements:

> The commission finds that substituting alternate fuels or energy sources for electricity is likely to produce resource benefits to an electric utility. ... It is not consistent with least-cost planning to deny these benefits to ratepayers. ... It is reasonable and equitable that electric utilities and vendors of other fuels pay fair shares of incentives for fuel switching. ... Utilities which assume the role of energy advisor to customers have an obligation to provide information that is correct and complete on interfuel substitution, as well as other energy issues. ... Electric utilities shall follow the interfuel substitution principles attached... (Wisconsin PSC 1989).

Generally speaking, Wisconsin's smaller, combined utilities did some fuel substitution DSM and the one large all-electric company didn't.

In early 1990, the PSC opened an investigation into methods for evaluating natural gas sales promotion and allocating the costs of programs that cause fuel substitution. In October 1991, the PSC ordered gas utilities to use the TRC test and the total technical cost test where regulated fuels are substituted for each other (Wisconsin PSC 1991). The TRC and total technical cost tests are identical except for the exclusion of DSM program costs from the total technical cost test.

In September 1992, the Wisconsin PSC revised its interfuel substitution principles in its Advance Plan 6 order, strengthening its position on fuel substitution (Wisconsin PSC 1992). The commission's eight principles address: the criteria for evaluation, criteria for designing customer incentives, customer information, sharing of program costs, and coordination of programs by combined electric and gas utilities (see Table 8-4). The PSC specified that the societal cost test is to be used for evaluating competing fuel sources and that "the Commission finds interfuel substitution to be a cost-effective demand-side option. Every major utility's plan contains end uses for which electrical equipment can be replaced with natural gas as a least cost energy service."

The PSC again focused on customer rights to choose using full, complete, and unbiased information developed jointly by the relevant utilities; the commission stopped short of requiring utilities to institute fuel substitution programs. However, the PSC ordered Wisconsin Gas Company and Wisconsin Electric Power Company (WEPCO) to embark on a pilot effort to cooperatively develop a fuel substitution program but only to test the efficacy of such an effort. The PSC praised the current practice of some Wisconsin utilities of allocating fuel substitution program costs. The commission encouraged balancing customer incentives for electric technologies with those for gas technologies and, in order to help achieve this, limited the incentives electric utilities may offer. It also suggested employee incentives to help change corporate cultures.

Wisconsin Gas and WEPCO have responded to the commission's direction to develop a joint pilot program. In March 1993, they announced agreement on a joint pilot program to promote hybrid cooling units to customers as an option to total electric units. The units will use gas during the electric peak to reduce electricity demand and will be eligible for the respective electric and gas rebates (Thomas 1993).

Table 8-5. Madison Gas & Electric Approach to Evaluating Fuel Substitution Options

1. Select low annual load factor electric options
2. See if conversion of gas passes or comes close to passing participant test.
3. Perform electric revenue requirements test to screen option.
4. If option passes, perform electric nonparticipant test to be sure rate impact is lower than rate of inflation or some other acceptable proxy.
5. Perform gas nonparticipant test to assess value to gas utility.
6. If option passes "5," see if total value (benefit) indicated in "5" + "3" is enough to move the market (pass the participant test).
7. If yes, set minimal needed incentive.
8. Assign up to five years' marginal gas revenue (NPV) to rebate. Take remainder needed from electricity revenue in "3." Any good promotional program should pay back in five years or less.

Source : Hobbie 1992

Madison Gas & Electric, a combined utility, has made these principles operational by focusing on options that are cost-effective and attractive to the customer (i.e., relatively short payback with high reliability, convenience, and comfort level), have a low annual electric load factor, and could be converted into high annual load factor gas options (see Table 8-5).

The Oregon PUC, like the Wisconsin PSC, has urged its regulated utilities to consider fuel substitution as an element of DSM and adopted principles to guide the practice but has stopped short of *mandating* fuel substitution programs. In contrast to Wisconsin, no Oregon utilities have proposed fuel substitution programs (see Exhibit 8-5). In Oregon, there are no combination utilities, which may contribute to the lack of activity; combined electric/gas utilities have taken the lead in proposing fuel substitution programs in Wisconsin.

New York provides an example of a state PUC that has relied on an ad hoc approach which has led to the development of several cost-effective fuel substitution programs. The New York Public Service Commission (NYPSC) staff has encouraged fuel substitution, and some New York utilities have implemented fuel substitution programs. Until recently, the NYPSC had not promulgated rules and has not issued general orders or adopted principles regarding fuel substitution. The NYPSC has not required any utility

Exhibit 8-5. The Oregon PUC Invites Fuel Substitution; No One Accepts

The Oregon Public Utility Commission (PUC) has issued standards for evaluating fuel substitution programs filed for approval by its regulated utilities and has publicly stated its "observations" on the subject. No Oregon utility has filed for approval of such a program.

In March 1990, the Commission's staff formed an advisory group that included major stakeholders to examine potential fuel substitution opportunities. With the advisory group's oversight, the staffs of the Commission and the Oregon Department of Energy evaluated the cost effectiveness of converting electric water heaters to natural gas systems and of converting electric forced-air furnaces to either heat pumps or natural gas heating plants. In an August 1991 report to the PUC, the PUC/DOE staffs found that: (1) the conversions appear to be cost effective in most cases, (2) electric utilities should evaluate residential fuel substitution as a resource in their least-cost plans, (3) utilities should compare fuel substitution with other resources on the basis of total resource costs including environmental costs, and (4) the PUC should adopt standards contained in the report for evaluating utility activities that promote fuel substitution (Oregon PUC 1991a).

In October 1991, the Oregon PUC issued a letter adopting standards that require a utility sponsoring a program promoting fuel substitution between electricity and natural gas to demonstrate that:

- the program is economical in terms of a resource cost comparison between electrical and gas service
- the fuel substitution is not occurring rapidly enough without the program
- existing customers of the sponsoring utility will benefit
- the program promotes only fuel substitution that is cost effective
- energy efficiency is aggressively pursued as part of the program (Oregon PUC 1991b).

The PUC encouraged reasonable fuel switching program proposals by any utility—natural gas or electric, invited utilities to file joint programs, and also invited proposals to minimize financial disincentives and provide financial incentives.

As of March, 1993, no Oregon utility had applied to the commission for approval of a fuel substitution program.

to conduct such a program but has approved fuel substitution programs proposed by individual utilities as part of the companies' long-range DSM planning requirements. Several combination utilities and one gas-only utility are currently offering electric-to-gas fuel substitution programs, and some of these programs are quite large. In 1993, based on staff recommendations, the NYPSC got more deeply involved by ordering that any fuel substitution program must pass the TRC test, such programs must be offered to all customers, and consideration must be given to sharing costs and benefits with the affected alternate fuel suppliers (see Exhibit 8-6).

Exhibit 8-6. Easing into Fuel Substitution in New York

> The New York Public Service Commission (NYPSC) has not developed formal policies or guidelines on fuel substitution, but its actions approving utility companies' fuel substitution programs beginning in 1989 form a de facto policy of encouragement.
>
> Although the NYPSC had previously promoted the use of natural gas in general, a gas air conditioner program proposed by Consolidated Edison in 1989 was the first fuel substitution program approved by the PSC. This was a major milestone as the program represented a $10 to 14 million annual investment by the utility. Since then, Long Island Lighting Company, Rochester Gas and Electric Corporation, Brooklyn Union Gas Company, and National Fuel Gas Distribution Corporation have also instituted fuel-substitution DSM programs.
>
> Although it is still not officially promoting or mandating fuel substitution programs, the New York PSC is increasing its influence and control in this area. In a recent DSM proceeding, the PSC Staff encouraged the continued implementation and expansion of fuel substitution programs in instances where they would assure more efficient use of the state's energy resources. The PSC accepted the specific recommendation of its staff and did not approve any 1994 fuel switching programs unless the utility submits a satisfactory plan for coordinating efforts and allocating costs and benefits with affected alternate fuel suppliers by January 1, 1994 (NYPSC 1992).

Maryland has had limited opportunity to address fuel substitution issues directly. The Maryland Public Service Commission has not issued generic orders on the subject. It has carefully set its DSM policy to be fuel-blind on the grounds that there may be benefits to customers from competition among alternative energy suppliers. One uncontested fuel substitution program has been approved for Baltimore Gas and Electric Company. The Maryland PSC, like so many commissions around the country, expects to be dealing more directly with the fuel substitution issue in the near future (see Exhibit 8-7).

Nevada, Florida, Massachusetts, Rhode Island, and other states have addressed fuel substitution issues sporadically during the last several years with relatively little resolution. In Florida, electric utilities were initially ordered to engage in fuel substitution strategies, but the commission backed away from this position in response to a challenge to its authority. The District of Columbia specifically prohibits DSM programs that involve fuel substitution, denying recovery of the cost of programs that result in even incidental fuel switching. Some states, including Kansas, Mississippi, and Arkansas, have recently begun to address the issue. A number of PUCs have rules or orders that deal with the fuel substitution issue less directly, requiring their regulated utilities to consider fuel substitution as part of integrated resource planning. Often such a mandate gets lost in the intricacies of the planning process or is too recent to have been

Exhibit 8-7. Maryland's Approach: "Fuel-Blind" DSM

The Maryland Public Service Commission (Maryland PSC) has not dealt with fuel substitution on a generic basis. In general, Maryland's DSM programs are fuel blind, offering incentives for enhanced efficiency of either electric or gas appliances but including no incentive for the selection of one fuel over the other. In 1991, the Maryland PSC approved a fuel substitution program proposed by Baltimore Gas and Electric (BG&E), involving rebates to promote commercial gas air conditioning. The approved rebate is $200 per deferred kW offered to new gas air conditioning customers plus dollar-for-dollar matching of engineering feasibility study costs up to $15,000. This is the same incentive offered under BG&E's commercial cool storage program. In addition, a lower gas air conditioning rate was approved.

As a combination utility, BG&E's purpose in offering the program was to shift almost the entire temperature-sensitive summer load from the electric "peak" to the natural gas "valley," thereby improving load factors on both its gas and electric systems. Technologies eligible for the fuel substitution program are: (1) direct gas-fired absorption chillers with integrated boilers, (2) indirect gas-fired absorption chillers with separate on-site boilers, (3) gas engine-driven chillers, and (4) gas-fired desiccant dehumidification systems. In its proposal to the Maryland PSC, BG&E noted that gas air conditioning was increasingly becoming economically attractive for customers with large cooling needs and special uses for waste heat although the technology was still less efficient than today's electric cooling systems. Other benefits of the program cited by the utility included its potential to reduce Chlorofluorocarbons (CFC's) and offer customers additional energy service options (Baltimore Gas and Electric 1990).

incorporated into practice. However Colorado's experience is an exception; the Colorado Public Service Commission has stimulated improved efficiency through fuel substitution by relying on DSM bidding plus one large collaboration with the Public Service Company of Colorado (PSCo) and local governments (see Exhibit 8-8).

In July 1992, the Washington State Energy Office initiated a project with several of the state's largest electric and gas-only utilities to develop a collaborative model for coordinating gas and electric utility integrated resource planning—also referred to as "fuel blind" IRP. The study, still underway, will soon issue reports on cost-effective opportunities and regulatory, financial, or other barriers to improve efficiency from:

- line extension policies
- joint trenching
- cogeneration facility siting
- district heating and cooling.
- fuel substitution or fuel choice
- pipeline capacity sharing
- fuel cells

Exhibit 8-8. Colorado: A Utility DSM Bidding Program Reveals Fuel Substitution Opportunities

The Colorado Public Service Commission enacted IRP rules in 1992 which require that fuel substitution be considered by utilities in their integrated resource plans. A bidding process established by the PSC in 1988 produced many fuel substitution proposals.

Public Service Company of Colorado (PSCo), a combined utility, is the major supplier of natural gas and electricity in Colorado. PSCo initiated a pilot DSM bidding program in mid-1989 for 2 MW, followed by a 50-MW solicitation for DSM in late 1990. The 50-MW bidding program attracted 63 proposals totaling 131 MW, of which one-third (43 MW) were conversions of electric heating and cooling to natural gas and steam. PSCo awarded thirty-two contracts totaling 55.2 MW, of which 40% (21.5 MW) involved fuel substitution (Chi and Finleon 1993).

The success of PSCo's DSM bidding program, including verification of over three-quarters of the contracted pilot demand reduction, shows that there is a large amount of electricity being consumed in applications where natural gas use appears to be more economically efficient from a societal point of view. Because the avoided costs underlying the bid offer have not yet been formally established, PSCo and the Colorado Commission staff agreed to slow the process by placing a cap on fuel substitution in a second 50-MW DSM solicitation issued in mid-1992, for which bids are currently being evaluated. The 30%-of-demand-reduction cap on fuel substitution was accepted by the commission and is apparently based on concerns about: measures that reduce demand on only the winter peak, equity, and the fact that fuel substitution bids are relatively more attractive financially to the utility than other types of DSM bids (i.e., conservation) given current ratemaking.

In addition to the DSM bidding program, the Colorado Commission has worked cooperatively with PSCo and the appropriate local governments to lower the peak electricity demand of the new Denver International Airport by selecting natural gas chillers instead of electric chillers. The city and county are building a new international airport near Denver, scheduled to open in December 1993. The airport was initially designed to a peak load of 90 MW of which 7.3 MW was for electric chillers. Gas chillers were considered but would have cost an extra $2.4 million. The extra money was not budgeted even though it would have paid back the investment in five to six years from lower operating costs.

When PSCo became aware of the opportunity to cost-effectively avoid 7.3 MW of peak load, there was little time to effect a change in the airport design without delaying the opening. The Colorado Commission provided special treatment to authorize the utility to provide a $1.5 million rebate to the city and county for selecting gas chillers instead of electric chillers and investing an extra $0.9 million. PSCo paid $200 per kW to avoid 7.3 MW of peak power, saving almost $1 million during the next ten years (Alvarez 1993).

Many states have avoided addressing fuel substitution altogether although it is likely that these PUCs will soon be confronted with the issue, because of the attention and controversy generated by fuel substitution.

8.5 Major Policy and Program Issues

In this section, we discuss six policy and programmatic issues that state regulators are likely to confront if they choose to address fuel substitution policies explicitly. These include: (1) alternative approaches to incorporating fuel choice efficiency in an IRP process, (2) economic and other criteria that can be used to evaluate fuel substitution programs, (3) debates over "best" vs. "better" efficiency options, (4) cost allocation and responsibility, (5) customer equity issues, and (6) treatment of unregulated fuels. (Technical considerations related to analysis of fuel substitution options are discussed in Section 7.5).

8.5.1 Approaches to Incorporating Fuel Choice Efficiency in an IRP Process

There are three fundamental approaches available to state PUCs that choose to address fuel choice selection explicitly as part of an IRP process. These approaches derive from how PUCs separate or combine three major functions: (1) setting social criteria, (2) technically comparing and selecting alternatives, and (3) developing a resource plan.

One option is for a PUC to have electric, gas, or combination utilities propose fuel substitution criteria as part of their resource plan preparation. This approach essentially combines all three functions (criteria setting, alternative comparison/selection, and plan development) into a single process. This has probably been the most common approach and has been utilized in Vermont, Georgia, and New York.

A second alternative is for a PUC to preset fuel choice criteria for natural gas and/or electric utility companies to use in their planning processes. The companies then use these criteria to compare and select among fuel substitution programs and to prepare their resource plans. The criterion would be reviewed less frequently than the evaluation of alternatives, which takes place regularly. The California and Oregon have set fuel substitution criteria in separately established proceedings. Other PUCs (e.g., Nevada) have opened dockets for this purpose but have either abandoned the effort or have not yet reached consensus. The Wisconsin PSC established fuel substitution criteria as part of its IRP plan review process. The evolution of ad hoc decisionmaking into formalized guidelines on fuel substitution, as in Wisconsin, is a path that many other PUCs could follow.

Table 8-6. Regulatory Approaches to Fuel Selection

#1	**Utility Selects Fuel and Plans to Its Own Criteria (Utility Designed)**	
Pros	•	Provides frequent opportunity to review criteria
	•	Allows flexibility for utility to compare all fuel-substitution opportunities in any specific setting
	•	Can be initiated relatively quickly by commission order with simpler hearing than #2 or #3, if any
Cons	•	Commission review of fuel comparison and utility plan is complicated by limited analysis of alternative criteria unless appropriate analytical requirements are prescribed
#2	**Utility Selects Fuel and Plans to Preset Criteria (Utility Designed to Commission Standards)**	
Pros	•	Allows planning to known criteria
	•	Allows independent scheduling of criteria review
	•	Allows flexibility for utility to compare all fuel substitution opportunities in any specific setting
Cons	•	Requires longer, two-step process to initiate than #1 but shorter (or at least less contentious) than #3
#3	**Utility Plans to Preset Criteria and Fuel Preferences (Commission Designed)**	
Pros	•	Allows planning to known criteria
	•	Allows independent scheduling of criteria review
	•	Guarantees generally efficient fuel use
Cons	•	Limits flexibility for utility to create new, more efficient fuel substitution programs

A third option is for a PUC or state legislature to predetermine preferable fuel choices. Utilities would then develop their resource plans within the fuel choice constraints imposed by the commission. Such an approach has been used, notably in restrictions or outright bans on electric resistance heating in some parts of the country. However, government specifications regarding fuel use are not in favor in the U.S., and we have found no instances of states considering this approach to resolve controversies about fuel substitution.

Table 8-6 summarizes the major implications for regulators of these three approaches for addressing fuel choice selection. The three approaches are presented as idealized concepts although, in practice, PUCs will have to fashion processes that serve their specific needs.

8.5.2 Selection Criteria for Evaluating Fuel Substitution Programs

In thinking about the criteria that should be used to analyze fuel substitution programs, it is useful to focus on additional considerations for assessing this type of program in contrast to other DSM programs. Fuel substitution programs involve the additional considerations of multiple fuels, often more than one regulated utility company, and complexity in accounting for net environmental impacts. A few PUCs have considered and accounted for fuel shifts outside the company implementing a DSM program in a qualitative fashion when evaluating the proposed program. However, with fuel substitution programs, it is essential that evaluation criteria be applied to the affected utility companies in combination as well as individually.

Table 8-7 illustrates criteria that can be used individually or in combination to evaluate fuel substitution programs. The table also shows the relevant figure of merit (i.e., appropriate economic test) that can be utilized to conduct the analysis as well as the elements involved for a particular criterion. It is important to recognize that the criteria used to evaluate fuel substitution programs are similar to those used in resource integration of demand-side and supply-side alternatives (see Section 3.1).

The Societal and Total Resource Cost (TRC) tests have been favored as the primary analytical tools among PUCs that have addressed fuel substitution directly. California's *Standard Practice Manual*, which provides guidelines for analyzing DSM programs, offers one rationale for this choice:

> For fuel substitution programs, the TRC test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC (and Societal Cost) test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric) (CPUC and CEC 1987).

For fuel substitution programs, either the Utility Cost test or Ratepayer Impact Measure (RIM) test may be applied to affected utilities individually or in combination. However, results from the two tests applied individually to each company have to be interpreted quite cautiously. For example, results from the Utility Cost test for each company provide little useful information because by their very nature, fuel substitution programs will change the number of customers of both the electric and gas companies for the

Table 8-7. Potential Criteria That Can Be Used to Evaluate Fuel Substitution Programs

Criterion	Elements	Figure of Merit
optimize source energy use	energy consumed by utility	total source energy
optimize customer utility bills	utility bills only	Utility Cost test
optimize total customer costs	all private costs	Total Resource Cost test
optimize customer societal costs	private costs plus externalities	Societal test
minimize customer rate increases	utility rates	Nonparticipant test
minimize impact on DSM nonparticipating customers	utility rates	Nonparticipant test
achieve other specific social goals	e.g., remove market barriers, maximize consumer choice, control pollution, minimize unemployment, or protect a utility company's market share	---

relevant end use.[4] The Utility Cost test results for the affected utility companies in combination will give an indication of the change in average combined energy bills, but such information should be used cautiously if customers of the two companies are not in overlapping service territories. The RIM test applied separately to each company provides useful information for allocating costs among the affected utility companies. Reviewing the combined results of the RIM test for both affected companies in

[4] The Utility Cost test indicates changes in average customer bills only so long as number of customers is approximately the same with and without the DSM program.

combination is useful in assessing average net rate increases or decreases and for judging their social acceptability.

8.5.3 Promoting "Best" vs "Better" Efficiency Options

Another aspect of the fuel substitution debate involves differing interpretations of providing least-cost energy services within end-use markets. Some analysts have argued that "the goal of IRP should be to put the least-cost energy service in place for every end use." Efficiency options that have the lowest economic life-cycle costs to customers and society (i.e., "best" option) should be promoted through utility DSM programs (Kaul and Kihm 1992).[5] Within an end use, if a fuel substitution option is determined to be more cost effective than other DSM options, then it should be pursued so that consumers receive the maximum benefit from utility interventions in end-use markets (Raab 1991).

The contrasting view is that PUC policies should allow utilities to promote DSM options that are more economically efficient than the customer's current use for retrofit applications and more efficient than minimum standards for new applications (i.e., the "better" option). In this approach, financial incentives are typically available to customers to upgrade high-efficiency equipment or appliances using either fuel. Arguments for this approach are that it offers customers more choices and limits the potential inefficiencies that may arise from judgments of regulatory bodies.

Both the "better" and "best" approaches are being applied. Wisconsin, for example, allows incentives for the promotion of any appliances that exceed a commission-specified minimum efficiency standard. Vermont, on the other hand, requires that utilities look only to the "most efficient energy use on the market today."

The "best" approach requires PUCs to specify the least-cost energy service for every end use. The "better" approach requires PUCs to balance incentives offered to customers by gas and electric utilities in order to insure that the competition is not artificially tilted toward one company and fuel. In some end uses and sectors, this balancing can be quite challenging.

In end-use markets where market barriers and imperfections might be endemic (e.g., new construction where end users are not the ultimate decisionmakers determining equipment

[5] In most cases, there is a mismatch between lifecycle costs of alternative technologies seen by users and the costs incurred by the respective utilities to serve the same end use. For example, the economics of gas absorption chillers in large office buildings (in Wisconsin) are marginal compared to electric screw or absorption chillers from customers' perspectives (i.e., 10 to 12 year simple payback) but provide significant avoided capacity benefits to a summer-peaking electric utility.

fuel choices), PUCs have to be especially vigilant that equipment/appliance fuel choice is not being unduly and unfairly influenced by utility financial incentives to builders or developers or favorable line extension and hookup policies. Instead, fuel choice should be determined on the basis of technologies and fuels that have the lowest overall life-cycle economic costs to customers and society.

8.5.4 Joint DSM Programs: Cost Allocation

Some DSM advocates argue that PUCs should require electric utilities to aggressively pursue cost-effective fuel switching and have electric ratepayers finance such conversions (Chernick 1991; Boonin 1992; Raab and Cowart 1992). Others maintain that natural gas utilities should promote and pay for incentives to encourage the use of natural gas and that electric utility companies should promote and pay for incentives to encourage the use of electricity because this arrangement maintains the fundamental forces of competition on which a market system is based (Flaim 1992; Tempchin and White 1993).

These perspectives represent the ideological poles in the end-use fuel substitution debate and illustrate the point that DSM program coordination and cost allocation among competing utilities is one of the most contentious program design and implementation issues. Some observers argue that electric and gas utilities should develop and pay for programs jointly if both benefit, but only after correcting gas pricing (Chamberlin and Mayberry 1991). Even if fuel substitution programs are considered to be economically efficient or otherwise desirable, it is difficult for regulators to force joint DSM programs or even coordinated DSM programs between competing utilities. It is also difficult to allocate program costs among competing utilities in a fair and efficient manner. Unlike single fuel DSM programs, fuel substitution programs introduce a new set of utility shareholders and nonparticipants.

Ideally, customers or groups that benefit from a fuel substitution program should pay the bulk of the associated costs, preferably in direct proportion to the benefits that they receive (Flaim 1992). For example, if a large proportion of the benefits accrue to program participants, it would be desirable to have participants pay for the program through an energy services charge or to reconsider the level of the incentive payment. If such changes to program design are not possible or significantly affect program participation, then program costs can be allocated to equalize the rate impacts as much as possible. However, certain societal benefits, such as reduced externalities, are not as easy to allocate among the electric utility and the natural gas company and their respective ratepayers (Weinstein and Pheifenberger 1992).

The debate has been clouded by those searching for a general approach that encompasses all DSM programs. As a practical matter, the cost allocation problem may be separated into four general categories based on the balance of utility revenue impacts. Each category reflects a different set of utility company and customer interests.[6] The issue of who pays the DSM program costs, and especially the contentious issue of who pays the customer incentive portion of program costs, is best addressed separately for each of these four categories.

Both Companies' Net Revenues Potentially Increase

For some fuel substitution options, the customers of both utilities could benefit. This happens in a gas conversion program when the gas company's revenues from its added sales are more than its costs to provide these sales and when the costs avoided by the electric company are more than its revenues would have been from the avoided sales. For example, significant benefits of some types of gas equipment conversions, such as conversion to gas air conditioning for a summer peaking electric utility, often occur on the electric side (Kaul and Kihm 1992). In this situation, there is an opportunity for the two utilities both to promote the same fuel substitution and to share in paying customer incentives without harming customers of either utility.

One economic rationale for this sharing is for the two companies to pay proportionally to their potential revenue impacts on the nonparticipating customers. For example, consider a modification to the fuel substitution program example in Figure 6-4 of Chapter 6 in which the program becomes a win-win situation by changing the electric company's average price to be slightly lower than its costs for the particular sales that are avoided.[7] In this situation, both companies would experience an increase in net revenues before considering program costs and customer incentives. The fuel substitution would potentially add about $4.4 million to the gas company's revenues and $1.7 million to the electric company's revenues. If the responsibility for paying for program costs and customer incentives were then allocated proportionately to this potential revenue impact on nonparticipating customers, the gas company would pay 72% and the electric company would pay 28%.

The computation of this cost allocation is shown in Table 8-8 and is somewhat similar to an approach used by Northern States Power, a combined utility, to determine how fuel substitution program costs would be allocated to electric and gas ratepayers (Kaul and

[6] The customers who change fuel by participating in the DSM program benefit in all four circumstances.

[7] For various business considerations beyond simple shareholder economics, some electric utility executives might still not consider this situation as a "win."

Table 8-8. Rate-Impact-Based Incentive Allocation for "Win-Win" Fuel Substitution

Example: a DSM program replacing electric chillers with gas absorption chillers (see Exhibit 6-3 and Figure 6-4 in Chapter 6)

		Combined	Nonparticipants Gas Company	Nonparticipants - Electric Company
1.	Avoided Supply Cost	$12,736,575	($4,141,756)	$16,878,331
2.	Measure Cost (extra cost of gas chillers)	$(2,500,000)		-
3.	Net Societal Benefit Before Program Costs and Customer Incentives [1.+2.]	$10,236,575	-	-
4.	Utility Sales Impact Net of Lost Revenue Recovery	($6,581,052)	$8,562,779	($15,143,831)
5.	Net Utility Revenue Impact Before Program Costs and Customer Incentives [1. + 4.]	$6,151,523	$4,421,023	$1,734,500
6.	Maximum Available for Program Costs and Customer Incentives [same as 5.]	$6,155,523	$4,421,023	$1,734,500
7.	Fair Share of Actual Program Costs and Customer Incentives[1]	-	72%	28%

[1] Calculated by dividing values in row 6 for gas and electric company by combined value

Kihm 1992).[8]

A sharing approach generally works in this situation because the shareholders of both utilities are likely to benefit from the fuel substitution, depending on the regulatory

[8] However, for the NSP case, short-term rate impacts were used instead of long-term. Rate impact concerns were so dominant that incentives were capped at a level that insured that no rate increases occurred for either gas or electric customers.

treatment of lost sales. The nonparticipating customers of both utilities may also benefit, depending on the level of incentives needed.

Only Gas Company Net Revenues Potentially Increase

For some fuel substitution programs, gas company net revenues will increase while electric company net revenues decrease. This happens when customers switch from electricity to gas and the gas company's revenues rise more than its costs rise while the electric company's revenues decrease more than its costs decrease. For example, conversion to gas air conditioning for an electric utility with average summer rates well above marginal costs might result in little benefit on the electric side. When this situation occurs, there is no easy economic rationale for the two utilities to share in paying program costs.[9] The customers who change fuels still benefit, but to which company should they be associated with—the electric company they are leaving or the gas company they are joining? Under these circumstances, joint participation of the two utilities is more difficult, and allocation of costs is contentious.

Only Electric Company Net Revenues Potentially Increase

It is also possible that a fuel substitution option causes electric company net revenues to increase while gas company net revenues decrease. This happens when customers switch from gas to electricity, and the electric company's revenues rise more than its costs rise, while the gas company's revenues decrease more than its costs decrease. The impacts on the affected utilities are similar to those in the previous case.

Both Companies' Net Revenues Decrease

Regulators might mandate some fuel substitution programs that produce societal benefits even though the net revenues of both companies might decrease. This happens in a gas conversion program when the gas company's costs rise faster then its revenues rise, and the electric company's revenues decrease more than its costs decrease. This is more likely to occur when the societal cost test is used, and program costs exceed net resource benefits (excluding externalities). In such a case, there is little guidance on how to allocate program costs although fairness would suggest an allocation that equalizes the net revenue impacts to the greatest degree possible.

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[9] The fuel substitution example presented in Figure 6-4 in Chapter 6 illustrates this situation.

8.5.5 Customer Equity Issues

Balancing equity among customers has always been a central focus of utility regulation. Fuel substitution programs often raise additional customer equity issues, such as the availability of gas service to electric customers and noncoincident service territories. Natural gas customers and electricity customers are often largely, but not exactly, the same people. Is it equitable for the customers to be considered the same? Is it acceptable to ignore the situation of even a few electric customers who do not have natural gas available or connected?

The problem of noncoincident jurisdictional boundaries complicates program design, implementation, and cost allocation even for combined utilities. For example, Baltimore Gas and Electric (BG&E) offers a program that replaces electric chillers with commercial gas air-conditioning equipment. The program is offered to all electric customers within the utility's electric service territory. However, BG&E's gas service territory is smaller, and some of BG&E's electric customers receive natural gas from Washington Gas Light Company. Washington Gas Light has applied to the Maryland PSC for approval to conduct an almost identical program to BG&E's but with a larger incentive. If approved, customers served jointly by BG&E and Washington Gas who respond to the commercial gas air-conditioning programs would apply to BG&E for its incentive and to Washington Gas for the additional incentive payment. Encouraging or requiring utilities to develop fuel substitution programs jointly is another option that regulators may consider if serious implementation problems arise in "coordinated" programs that are offered separately by electric and gas utilities. Electric, gas, and combined utilities in several regions of the U.S. (e.g., California, New York, and Wisconsin) are jointly developing pilot fuel substitution programs.

8.5.6 Treatment of Unregulated Fuels

In regulating utilities, state PUCs have always had to consider the impacts of their policies on unregulated energy service providers. Changes in the rates of any fuel potentially affect the competition among competing energy sources. Similarly, DSM programs that provide financial incentives to purchase high-efficiency gas or electric equipment may also affect the overall end-use market share and fuel mix among gas, electric, and unregulated fuels for that type of equipment. On occasion, fuel oil or propane dealers have intervened in regulatory proceedings to argue that they would be adversely affected by a particular DSM program.[10]

Depending on the availability of gas service, evaluation of fuel substitution opportunities in certain end uses (e.g., space heating) may also involve comparison between electricity and unregulated fuels such as oil, propane, and wood. For example, in Vermont only about 15% of the homes and businesses currently have access to natural gas, and fuel substitution is primarily conversion from electricity to unregulated fuels. In this context, several issues arose when electric utilities were ordered by the Vermont Public Service Board (PSB) as part of their IRP plan to evaluate all potential fuel substitution opportunities. Concerns were raised by utilities regarding: (1) "free riders" in the sense that there was already significant fuel switching away from residential electric space heat as a result of natural market forces, limited financing provided by the state, and information provided by utilities, (2) appropriateness of applying existing environmental externality credits for DSM to fuel substitution because of localized impacts from consumption of alternative fuels, and (3) risk—in the form of potential price volatility from increased reliance on unregulated fuels. Other parties raised concerns about potential "lost opportunities" that outweigh any societal benefits from conversion whenever conversion of electric end uses to unregulated fuels occurs without concurrent installation of cost-effective weatherization measures and efficient new appliances. In the face of these concerns, the Vermont PSB decided that fuel switching should only be required when there is strong evidence that it is cost effective, and that the incremental benefits of a fuel switching measure must exceed the benefits from a nonfuel-switching DSM measure by at least 10% to be eligible for utility-assisted financing (Raab and Cowart 1992).

Despite the extra complexity and uncertainty that unregulated fuels add to the evaluation of fuel substitution, these fuels play an important role in competing with natural gas and electricity in some communities and cannot be ignored in these circumstances.

[10] During the late 1970s and 1980s, many regions and states (e.g., New England, New York, Florida) adopted policies to reduce their oil dependence both in electricity generation and end-use consumption. PUC actions were often intended to implement these policies.

8.6 Summary

Fuel substitution complicates the regulatory process by adding another dimension of "integration" to integrated resource planning (IRP). IRP was originally created to integrate risk and uncertainty considerations into electric utility capital budgeting and to integrate demand-side opportunities into power plant decisions. During the past decade, IRP has achieved this goal in many states. In most cases, it has not integrated planning for natural gas with planning for electricity.

Table 8-9 provides an overview of the current legal and/or administrative status of fuel substitution policies in various states, including our summary of the apparent motivation, the underlying regulatory strategy, and the primary evaluation criterion. It should be clear from the preceding discussion that there is no "right" answer or single course for fuel substitution policies. Electric utilities and industry associations (i.e., Edison Electric Institute) have vigorously opposed fuel substitution programs perceived to be "mandatory" although some electric utilities are willing to look at fuel substitution opportunities on a case-by-case basis. Not surprisingly, combination utilities have been in the forefront of trying out fuel substitution programs. In several states (e.g., Washington, Oregon), regulatory agencies and other interested stakeholders are pursuing innovative strategies that allow electric and gas utilities to look for areas where there are mutual benefits to cooperation. In California, Southern California Edison and Southern California Gas Company are jointly developing a "fuel-neutral" DSM program without regulatory mandate. The program is targeted at large commercial customers and is being pilot tested in one geographic region. Likewise, Consolidated Edison and Brooklyn Union Gas have developed a joint program to promote gas cooling, which has been underway for over a year. Similar programs are being developed by electric and gas utilities in several other states. These efforts are the exception, but they do suggest that it is possible to create "win-win" situations even in the interfuel-competition arena.

Based on the experiences of PUCs and utilities that have already addressed fuel substitution, the following elements are a starting point for PUCs seeking to develop explicit policies on cost-effective fuel substitution:

- The societal efficiency of fuel substitution ultimately depends on the relative costs and performance of respective gas and electric end-use technologies and the relative prices of both electric and gas service. To the extent possible, gas and electric rates should reflect the same relationship to long-run marginal costs.

- For utilities that assume the role of energy advisor to customers, PUCs should ensure that comprehensive and unbiased information be provided to customers on competing end-use equipment and technologies.

Table 8-9. Status of State PUC Approaches to Fuel Substitution

State	Status	Apparent Motivation	Regulatory Approach	Evaluation Criterion	Baseline Approach	Approach to Joint DSM
VT	Consideration Required	Optimize Social Cost	Utility Design	Does It Optimize Societal Costs	Best Technology	Encouraged
GA	Consideration Required	(not addressed)	Utility Design	(not addressed)	Better Technology	(not addressed)
CA	Consideration Required	Environmental Policy	Utility Design to PUC Standards	Must Not Increase Energy; Must Decrease Private Costs; Must Not Increase Pollution		Encouraged (one in progress)
WI	Consideration Encouraged	Customer Treatment	Utility Design to PSC Standards	Does It Optimize Private Costs	Better Technology –	Encouraged based on costs avoided (one in progress)
OR	Consideration Encouraged	(not apparent)	Utility Design to PUC Standards	Does It Optimize Societal Costs		(not addressed)
NY	Consideration Encouraged	(not apparent)	Utility Design	Does It Optimize Societal Costs		Encouraged (a few in place)
MD	Substitution Allowed	Efficient Utility Operation	Utility Design	Does It Optimize Utility Bills	Better Technology	(not applicable)
CO	Substitution Allowed	(not apparent)	Utility/Contract or Design	(not addressed)	(not applicable)	
FL	Policy ordered and then rescinded	-	-	-	-	
NV	Active Docket/No Resolution	-	-	-	-	
MA	Discussed Without Resolution	-	-	-	-	
RI	Discussed Without Resolution	-	-	-	-	

- PUCs should ensure that all DSM incentives offered by utilities are fairly balanced between competing fuel technologies and competing companies.

- Gas and electric utilities should be strongly encouraged to evaluate fuel substitution opportunities as part of their IRP or DSM planning processes. This will involve identifying and analyzing potential options to determine whether they might be cost effective (and under what assumptions) and assessing the extent to which market barriers exist and the types of intervention necessary to overcome barriers. If a fuel substitution program is deemed appropriate, the program should, to the extent possible, be developed cooperatively by gas and electric utilities, including methods to share program costs.

- The regulatory and ratemaking framework should be structured so that electric or gas utilities are no worse off financially as a result of supporting cost-effective fuel substitution.

Chapter 9

Financial Aspects of Gas Demand-Side Management Programs

9.1 Overview

This chapter characterizes the impact of gas demand-side management (DSM) programs on utility finances and describes ratemaking methods that remove some or all of the financial disincentives that may be associated with DSM. The ratemaking methods described include: ratemaking practices to assure recovery of prudent DSM expenditures, net lost revenue adjustment mechanisms, mechanisms that decouple revenues from sales to remove the incremental incentive to market gas, and shareholder incentives for the acquisition of DSM resources. Because many gas consumers are price sensitive, and because competitive impacts can affect gas local distribution company (LDC) profitability, the chapter also examines various methods to allocate DSM program costs among customer classes.

Since 1989, a number of reports, books, and studies have analyzed the disincentives under traditional regulation for electric utilities to pursue energy efficiency and suggested incentive mechanisms to reward utility shareholders for exemplary DSM performance (Moskovitz 1989; Wiel 1989; Nadel et al. 1992). These issues are also beginning to be explored by the gas utility industry (RCG/Hagler, Bailly Inc. 1991). Resolution of financial and incentive issues associated with acquiring DSM resources is critical for many gas utilities because they face flat or declining sales in traditional market segments while large customers have many alternative service options (e.g., unregulated suppliers and bypass options).

9.1.1 DSM and Supply-Side Resources Compared

To a utility, a therm conserved is unlikely to have the same financial impact as a therm sold. Despite the cost effectiveness of certain DSM resources, managers of gas utilities may not seriously consider DSM unless they expect it will bring financial benefits. Thus a serious attempt to treat DSM as a resource requires a review of, and possible modifications to, traditional ratemaking mechanisms. It is important to acknowledge, however, that ratemaking methods and practices significantly vary among PUCs because of individual commission policies and state laws. Key areas of differences among states include: choice of historic versus future test year, frequency of rate cases, presence or absence of provisions to adjust historical or forecasted demands for weather effects, and extent to which utilities are allowed pricing flexibility. Moreover, different cost-recovery mechanisms may be appropriate for different jurisdictions and for various types of DSM programs and may change over time depending on the level and rate of change in DSM expenditures (RCG/Hagler, Bailly Inc. 1991). Many of the ratemaking changes necessary to remove financial disincentives associated with utility-funded DSM programs are more evolutionary than revolutionary and some of the changes have already been employed by other jurisdictions or by the same jurisdiction at an earlier time. In the electric industry, three main forms of disincentives have been noted, and they apply generally to the gas industry as well: (1) failure to recover all DSM program costs, (2) loss of net revenues, and (3) loss of financial opportunity (Reid and Chamberlin 1990).

Failure to Recover DSM Program Costs

Although gas LDCs have long been providers of gas procurement and distribution services, LDC DSM programs represent a relatively new service; thus, DSM program budgets are not a traditional part of LDCs' requested revenue requirements. This may lead a PUC to consider requests for recovery of DSM expenditures outside of general rate cases. Regulatory lag (i.e., delay in the recovery of costs because of the regulatory process) may increase utility reluctance to invest in DSM, particularly in situations where DSM expenditures have been significantly increased and the utility perceives that the risk of under-recovery is high.[1] DSM programs represent a new type of utility-customer interaction, so there is little experience on which to base forecasts of DSM program participation. Under conventional regulation, expenses in excess of those estimated during a "test year," which provide the basis for rates, might not be recovered from ratepayers. Use of a future test year can mitigate this problem, but some method of quickly adjusting rates to cover program costs may be appropriate because the ultimate *market acceptance* of a DSM program can be uncertain. Ways to address the uncertainty of DSM program cost recovery are discussed in Section 9.2.

Net Lost Revenues

Despite a wide array of ratemaking practices, most gas utilities have base rates set in relatively infrequent (every 2 to 5 or more years) general rate cases and the commodity rates set more frequently in purchased gas adjustment (PGA) clause proceedings.[2] Most utilities have a financial incentive to make incremental gas sales because many expenses

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[1] DSM will enhance financial health if the reduced demand defers capacity-related projects that have their own disallowance risks. In other words, the risk of recovery of DSM expenditures should be evaluated in comparison to the risks created by a scenario that excludes cost-effective DSM.

[2] Many gas LDCs have been given limited pricing flexibility when providing transportation services to customers in competitive market segments.

included in base rates are invariant of short-run changes in sales, and any increases in unit commodity costs are covered by the PGA clause. Thus, incremental sales typically provide a positive contribution to margin. Even in the longer term, the benefits of DSM in reducing capacity costs may not outweigh the incremental revenue loss. This rate-to-cost relationship can make gas DSM unattractive unless a utility is given assurance that all or most of the lost margin will be recovered in some fashion. Ways to address net lost revenues are discussed in Section 9.3.

Loss of Financial Opportunity

Even if expenditures for DSM programs are recovered and if lost revenues are made up in some fashion, DSM may not be attractive if it makes the utility forego more profitable investments in supply-side resources. Whether a gas LDC favorably views a capacity- or supply-related investment depends on the available options, the utility's authorized rate of return, and the PUC's regulatory procedures for the recovery of supply-side investments. It may be desirable in some cases to consider positive financial incentives for DSM investments in order to overcome real or perceived losses in financial opportunity. Positive incentives for shareholders are discussed in Section 9.4.

9.2 DSM Program Cost Recovery Methods

From the perspective of energy utilities and PUCs considering investment in DSM, three cost recovery issues are critical. First, PUCs must decide whether to base the level of DSM expenditures reflected in rates on activity recorded during a fixed historical test year, on actual expenditures as they are made, or on expenditures set for a forecast test year. Second, to the extent that there is a mismatch between the timing of the DSM expenditure and its recovery, PUCs must decide whether to allow utilities to recover accrued interest. Third, once the decision to recover DSM expenditures is made, PUCs or utilities must set an amortization period.

9.2.1 Timing of DSM Cost Recovery Proceedings

Investor-owned gas utilities often have two rate components, which are authorized in different types of regulatory proceedings. Base rates are set in general rate cases and typically do not change between general rate cases, except for discounts to customers who have competitive alternatives. The frequency of general rate cases can vary from yearly to once every several years. The rate treatment for gas commodity costs typically is handled through a PGA clause, in which rates are adjusted more frequently (e.g., sometimes monthly). Changes to this component usually are automatic, subject to after-the-fact reasonableness reviews, but states' handling of PGA clauses varies widely (Burns et al. 1991).

The type of DSM expenditure can also affect the timing of cost recovery. DSM expenditures may be grouped into four general cost categories: program administrative costs incurred by the utility; utility-to-customer incentives; shareholder incentives, if applicable; and measurement and evaluation costs. There are several general ways that commissions authorize cost recovery, as demonstrated below.

Conventional General Rate Cases

Table 9-1. DSM Costs Recovered through General Rate Cases

Pros	•	Attention to DSM budgets is similar to that given other base-rate budgets; this appears fair and may decrease administrative costs.
	•	The utility has greater latitude in the allocation of its budgets to particular programs and has a cost minimization incentive.
Cons	•	Given uncertainty in utility resource needs, technological change, and program participation, it is difficult to set forecasted DSM budgets for a rate case cycle which may last for several years or indefinitely.

A utility's DSM program budget may be reviewed, along with other nonfuel expenses, in the general rate case. Budgeting DSM expenditures requires adjustments to historic-test-year data or the use of a future test year. The level of program participation is hard to forecast, but it determines a large part of the DSM budget, especially the cost of utility-to-customer incentives. Thus, it is not uncommon for the utility to be subject to some post-rate-case adjustments. For example, in California, if the utility underspends its DSM budget or wishes to reallocate budget monies among programs, it must seek regulatory approval through an advice letter. In some cases, utilities have been required to give back unspent monies. Table 9-1 summarizes the advantages and disadvantages of using general rate cases for DSM cost recovery.

For gas utilities that have the opportunity to earn shareholder incentives for gas DSM program accomplishments, earnings typically are contingent on achievement of measurable savings. Cost recovery for these earnings initially may require a supplemental proceeding to the general rate case until such program evaluation procedures become routine.

Recover As You Go: Using Frequent Rate Cases or Deferred Accounting

Many commissions use frequent proceedings, deferred accounting, or both to allow for accurate recovery of DSM program costs (National Association of Regulatory Utility Commissioners (NARUC) 1992). Frequent rate cases specific only to DSM expenditures are akin to PGA clauses because rates are frequently adjusted in both types of

Exhibit 9-1. Recovery of Incremental DSM Costs Through a Rate Adder

In 1993, The Illinois Commerce Commission (ICC) authorized rate adders for the recovery of DSM program costs for two gas utilities in Illinois: North Shore Gas Co. and The Peoples Gas Light and Coke Co. (Peoples Gas). The adder allowed the utility to recover the following DSM program costs:

- training and educating DSM personnel
- efficiency seminars
- administration
- advertising
- collecting and evaluating data used for cost-benefit analyses
- energy audits
- billings from corporate affiliates, consultants, contractors, and other service providers
- incentives, rebates, or subsidies to customers
- energy conservation measures installed at customer premises
- incremental tax liabilities

The utilities track costs incurred in these categories, which are not already included in existing rates. Every month an adder is computed to all gas volumes, including transport-only volumes, to recover total recorded costs. If the adder is less than a $0.001/Dth threshold, the allowable costs are retained in a deferred account until accrued costs reach the threshold. The ICC retains the right to disallow costs that were improperly recorded to the account, based on a review of the utilities' programs.

Currently, DSM activities offered by these utilities are mostly pilot programs. Peoples Gas, which has an annual throughput of approximately 250 Bcf, has not accrued enough costs yet to hit the adder threshold of $0.001/Dth. Net lost revenues from reduced demand cannot be recovered through the rate adder.

proceedings. In this approach, a utility typically operates programs in conjunction with guidelines that have been approved in general rate cases or integrated resource planning (IRP) investigations. Actual expenses are not put into base rates. Instead, the utility is allowed to add the expenses to its PGA account or some other account that receives rapid cost recovery (see Exhibit 9-1). Although expenses may be recovered quickly, some PUCs (e.g., the Illinois Commerce Commission) still reserve the right to conduct reasonableness reviews. Other states, such as Massachusetts and Wisconsin, effectively preapprove DSM program expenses; poor performance by the utility will primarily influence future program authorizations. Table 9-2 summarizes the major advantages and disadvantages of frequent rate proceedings

Table 9-2. Recovery of DSM Expenditures via Frequent Rate Proceedings

Pros:	• The utility is authorized to pursue particular programs or objectives but is not required to hold to a certain budget until the market response is determined.
Cons:	• DSM is given special treatment.
	• There are few inherent cost minimization incentives because rapid recovery is a form of cost-plus regulation; however, after-the-fact reasonableness reviews can mitigate such behavior.

To mitigate the mismatch between current rates and current DSM expenditures, at least 13 PUCs have established some form of "true-up," balancing, or escrow accounting to allow for the accurate and timely recovery of gas DSM program costs (National Association of Regulatory Utility Commissioners (NARUC) 1992). A deferred account records expenses that are not yet recovered in rates and can exist in several guises. They may be called deferred debit or credit, reconciliation, memorandum, tracking, or balancing accounts. In some cases, differences in terminology represent important differences in presumptions regarding recovery and, thus, risks borne by utility management. For example, a balancing account is a special form of a deferred account that usually guarantees recovery of costs subject only to prudence reviews. Thus, balancing accounts are relatively safe, and utilities typically report undercollections as assets much like accounts receivable. Other deferred accounts, such as memorandum or tracking accounts, may not guarantee recovery. In these instances, a utility must argue for recovery in a specified proceeding and, even if recovery is granted, may only have "one shot" at recovery (i.e., future balancing account protection is not provided).

A deferred account for DSM program costs operates in a manner very similar to PGA clauses operated in many states. A PUC may authorize a set of DSM programs but not a specific level of spending. The PUC may also reserve the right to review expenses before authorizing recovery. To meet these ratemaking goals, the PUC will set up a deferred account that allows certain DSM expenses to be recorded to the account. At some later date, possibly in conjunction with a review of the DSM program's performance, the commission will authorize recovery of dollars recorded to the account. Utilities typically are allowed to earn interest on the account to reflect the time value of money. In some states, such as California, deferred accounts earn only the cost of short-term money. In other states, deferred accounts earn the utilities' approved cost of capital. The appropriate degree of earnings depends on the degree of disallowance risk faced by the utility and the level of financial incentive that the PUC wishes to give the utility for DSM endeavors. Recovery is achieved by taking the balance of the account and amortizing it over a certain rate period. If the account is amortized within a year, it may be seen as a form of expensing. If the account is amortized over a period of time greater than one year and earns the utility's cost of capital, the account becomes a form of ratebasing (see next section).

9.2.2 Expensing versus Ratebasing

Once a utility has made a DSM expenditure and recovery has been authorized, a general decision must be made about whether to treat it as an expense or as a long-term investment. The mechanics of either method are relatively simple in concept. With expensing, allowable expenditures are considered a component of revenue requirements. With ratebasing, the expenditure is put into an asset account, which is depreciated or amortized over time. The utility earns a return on the remaining balance in the account.[3] Annual revenue requirements associated with ratebasing include the depreciation or amortization component, the return component, and any taxes incurred on the return. DSM expenditures in one year will affect revenue requirements for the life of the depreciation or amortization period chosen.

Ratebasing, which spreads DSM program costs over a multi-year time period, is considered as a DSM cost recovery method because DSM measures typically provide energy savings over a multi-year period. Reasons for choosing ratebasing over expensing include: the timing of the recovery in rates better matches the stream of benefits, the economic efficiency of prices are improved, rate impacts are mitigated, and, if the

[3] The appropriate return for investments in DSM should reflect the risk associated with the investment. It may be hard for PUCs to hold utilities at risk for nonperforming DSM investments. If this is the case, then the utility's risk on approved DSM investments is low. On the other hand, investments in DSM are not bondable like supply-side investments and, thus, may require a higher return due to the necessity for equity financing.

authorized rate of return is considered attractive to shareholders, the return provides an incentive to pursue DSM (Reid 1992).

Ownership of a DSM measure is typically given to the customer; thus the physical DSM asset cannot be considered a part of the utility's rate base in a strict accounting sense. However, regulatory agencies that view DSM as a resource can consider the portion of the DSM measure paid for by the utility as a *regulatory asset*. Regulatory assets may be given recovery treatment that makes them as financially attractive as investments in traditional utility assets.

Despite the conceptual attraction of ratebasing DSM, it has not been very popular compared to expensing, for what appears to be several reasons. First, many gas LDCs consider the certain and full recovery of DSM program expenditures, including any accrued interest, to be a top priority. Whether the expenditures are ultimately expensed or ratebased appears relatively unimportant. Second, under the assumption that a utility only receives an authorized return that matches its cost of capital, LDCs may be financially indifferent when choosing between expensing and ratebasing. Third, earnings on ratebased DSM investments may be small relative to the net lost revenues caused by DSM programs. In three states where PUCs authorized enhanced rates of return for DSM investments—Kansas, Washington, and Montana—there is little evidence that gas utilities have vigorously pursued DSM programs as a result of ratebasing.

9.3 Accounting for Net Lost Revenues

DSM programs that reduce gas demand may have a negative financial impact on gas utility earnings. Under most adopted rate designs, a reduction in sales between general rate cases will result in a near-term reduction in contribution to margin. In the long run, utilities may avoid costs that were fixed in the short run; however, prices may be set so that the DSM program still causes a reduction in margin. Therefore, in the short run and possibly in the long run, gas utilities usually experience a negative financial effect from unforeseen reductions in demand. The term *net lost revenues* characterizes these margin impacts. Whether DSM programs cause revenue losses that harm the utility financially depends on, of course, whether the net effect of the DSM program is to increase or decrease sales. If fuel substitution programs are considered in gas IRP, then the net effect of a gas utility's DSM programs may be to increase sales, and earnings will increase rather than decrease. Ratemaking practices can also affect the magnitude of lost revenues. If marginal rates are set close to marginal costs, then net lost revenues will be small. Finally, there will be a lost revenue "problem" only to the extent that reduced demand is not incorporated into the demands used to set rates. Whether the demand forecast incorporates the demand impacts of DSM depends, in part, on whether the PUC sets rates using a historic or future test year.

9.3.1 Measuring Net Lost Revenues

As the introduction to Section 9.3 implies, defining net lost revenues precisely is difficult; however, between general rate cases practical definitions can be made. Usually, net lost revenue is defined as the difference between the incremental revenue impact of a DSM program and the incremental cost impact. An accurate estimate of incremental revenues requires an estimate of the DSM program's impact on participant billing determinants relative to the determinants used to set rates in the last general rate case.[4] The change in billing determinants times the applicable rates is a measure of a DSM program's incremental revenue impact. On the cost side, it would be ideal to use a current estimate of the LDC's avoided costs. As a practical matter, it is most common to simply use the weighted average cost of gas (WACOG) of the LDC's PGA as a proxy.[5,6] Defining net lost revenues beyond the next rate case is more difficult to do (Eto et al. 1993). Many of the costs that are considered fixed in the short run may begin to be affected by a utility's DSM programs. More importantly, the billing determinants used to set rates begin to be affected by DSM programs and, thus, the revenues may no longer be "lost" to shareholders.

If decoupling is used as an approach to respond to net lost revenues (discussed further below), there is no need to "measure" net lost revenues. Instead, the challenge becomes determining which cost accounts to include in the sales balancing account. Those costs are then recovered by the LDC regardless of the impact of DSM programs or other factors that affect sales. In California, where gas sales have been decoupled from revenues, the sales balancing account covers nearly all gas LDC costs *except* purchased gas costs, pipeline demand charges, and certain transition costs.

[4] Billing determinants are components of demand used to compute bills. For example, if a residential customer buys gas from a tariff with a customer charge and a two-tier inverted block rate design, the customer's consumption in any month will be made up of three billing determinants: its customer count and its first and second tier consumption.

[5] If the DSM program participant is a transport-only customer, then the LDC will receive only transportation service revenues, and incremental costs will not include any purchased gas costs.

[6] For sales customers, it is common to simplify the calculation by setting net lost revenues equal to the DSM program savings (in therms) times the LDC's average base rate (in $/therm).

9.3.2 Historic and Future-Test-Year Ratemaking

Historic year ratemaking is still the norm in most states. According to a recent survey, only 10 PUCs in the U.S. allow for full future-test-year ratemaking for some or all of their utilities (Phillips 1988; National Association of Regulatory Utility Commissioners (NARUC) 1992). There are several ways that the effects of DSM programs can be incorporated by PUCs that rely on historic test years. First, a "known and measurable" demand adjustment could be made to incorporate the effects of DSM programs in the historical test year. Other known and measurable changes have been accepted for other utility budget items; for example, it is standard practice for gas utilities to adjust test-year demands for average weather-year conditions and expected changes in industrial demand, which often fluctuate significantly from year to year (American Gas Association 1987b). Second, frequent rate cases could be conducted; with them, the amount of DSM not reflected in the test-year demands in any given year would be small. Third, a commission could authorize a net lost revenue adjustment or revenue decoupling mechanism to eliminate the disincentives for utility DSM investments.

A future test year can naturally incorporate the effects of utility DSM programs on test-year demands. The potential for net lost revenues still exists, but only to the extent that the future-test-year demand forecast does not accurately estimate DSM program impacts. As with historical test year ratemaking, strategies can be used (e.g., frequent rate cases, decoupling, or net lost revenue adjustment mechanisms) to mitigate net lost revenues if they are a major concern.

9.3.3 Net Lost Revenue Adjustment Mechanisms

A number of PUCs have attempted to remove disincentives to DSM by adopting net lost revenue adjustment mechanisms.[7] Under this approach, utility net revenue losses associated with specific DSM programs are estimated or measured and the utility is allowed to recover these losses in rates. Critics maintain that this approach does not remove the utility's incentive to increase gas sales, limits the type of DSM activities that can be readily accommodated (compared to decoupling), and can lead to perverse incentives for the utility (Moskovitz et al. 1992).[8] Proponents argue that net lost revenue adjustment mechanisms are workable, relatively easy to implement, and represent a less fundamental change in utility regulation than decoupling (Tempchin 1993).

[7] States that have adopted net lost revenue adjustment mechanisms for electric utilities include Massachusetts, Rhode Island, Ohio, and Indiana.

[8] If net lost revenues are based on estimated savings, the utility could be rewarded twice: once with assumed lost revenues and twice with revenues from therms that were not successfully saved.

9.3.4 Revenue Decoupling Mechanisms

Revenue decoupling mechanisms (RDMs) are ratemaking approaches that make a utility financially indifferent to changes in sales. This approach can be applied to varying degrees. For example, 27 LDCs in 11 states or provinces have some type of weather normalization procedure (Marple 1991; Marple 1992). Most of these weather adjustment mechanisms are *not* full decoupling mechanisms, but they do allow for revenues to be recouped when weather-sensitive customers experience warmer-than-expected winters and for revenues to be returned to customers after colder-than-expected winters.

With a full decoupling mechanism, an LDC is authorized to create a sales balancing account. Revenues intended to recover certain fixed cost accounts (usually base rate accounts) are flowed through the balancing account mechanism. Actual revenues are compared to those authorized in the latest rate case or attrition proceeding, and any deviations are logged to the balancing account rather than flowed through to the LDC's income statement. The end result is that the LDC reports authorized revenues instead of actual revenues. Balances in the sales balancing account are amortized in future rates. Sales balancing accounts protect the LDC from variations in sales but not from variations in base-rate expenses. For example, the LDC is at risk for any increases in wages that are not reflected in the revenues authorized in the last rate case or attrition proceeding.

Decoupling has been adopted for electric utilities in several states, specifically as a way to eliminate disincentives for DSM. For gas LDCs, a full RDM was first adopted by the California Public Utilities Commission (CPUC) in 1978 (Marnay and Comnes 1992). The CPUC's primary rationale for adopting decoupling for gas utilities was to stabilize earnings in response to sales variations caused by wide fluctuations in the price and availability of natural gas, rather than to eliminate financial disincentives for gas DSM. Currently, the CPUC still regards decoupling as an appropriate response to demand fluctuations caused by weather variability and, to a certain extent, alternative fuel competition (see Exhibit 9-2). Since 1988, California investor-owned LDC revenues are fully decoupled from sales for smaller gas "core" customers and are partially decoupled for larger "noncore" customers. As a result, California's gas LDCs have been at risk for some or all of the revenues allocated to noncore customers. Specifically, if sales do not occur as forecasted, the utilities cannot recover all of the lost margin from other customers or future customers. Noncore customers (primarily industrial, electric power, and wholesale) comprise about 20% of the utility's margin and the CPUC has concluded that putting the utility at risk for noncore sales will help keep utilities competitive with alternative fuels and bypass pipelines.

Decoupling mechanisms have been hotly debated by several PUCs and the pros and cons discussed at great length (see Table 9-3). One of the challenges in designing effective decoupling mechanisms is the way in which authorized base-rate revenue requirements

Exhibit 9-2. Revenue Decoupling for California's Gas Utilities

A full decoupling mechanism insulates utilities from all variations in sales, not just those resulting from the implementation of DSM programs. Because of the variability of gas demand in response to weather, decoupling can have a significant impact on prices from year to year. Figure 9-1 shows annual fluctuations in Southern California Gas Company's sales balancing accounts—known as its core and noncore fixed cost accounts—from 1988 to 1993. Full balancing account protection is given on fixed costs allocated to the core, but the protection is only partial for noncore sales. Imbalances in the fixed cost accounts primarily represent fluctuations in sales. In the noncore fixed cost account, imbalances are also caused by the LDC discounting its rates. These imbalances produced average rate impacts of over 10% in certain years. During the time period shown, balances in fixed cost accounts were considerably larger than balances accrued in SoCal's PGA account. These unexpected sales fluctuations have not been disaggregated systematically, but the available evidence indicates that the fluctuations are attributable to unexpected variations in weather, changes in the economy, and alternative fuels competition. The impact of unforecasted demand effects of DSM is estimated to be small compared to these other factors.

Figure 9-1. Recent Sales Balancing Account Activity: Southern California Gas Company

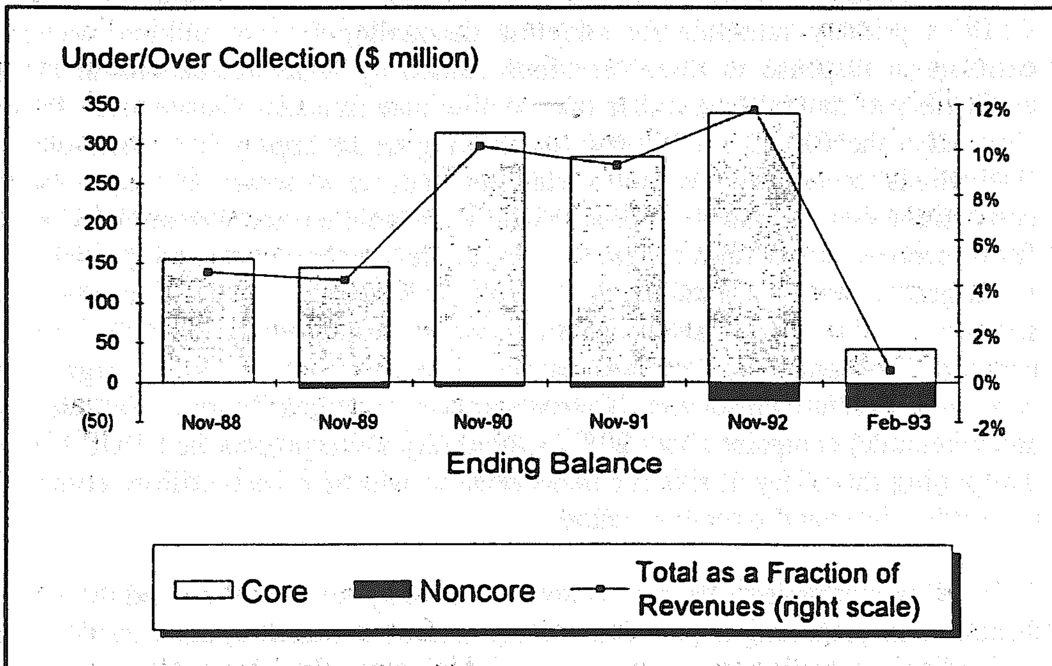

Table 9-3. Decoupling

Pros	•	Makes the utility indifferent to incremental sales, which provides impetus for implementing DSM programs effectively.
	•	Removes short-run incentives to market gas or gas transportation services.
	•	Provides the utility with financial stability including protection from sales variations caused by weather.
	•	Makes innovative rate design easier to implement because errors in forecasted billing determinants do not financially harm the utility.
Cons	•	Requires frequent rate cases, attrition, or "revenue per customer" like mechanism.
	•	Requires frequent, possibly large, year-to-year variations in rates.
	•	If applied to industrial markets, gives the utility a weak incentive to minimize unit costs; utility may lose market share needlessly.
	•	Can cause cross subsidies among customer classes if the under collections caused by one class are reallocated to other classes.

are adjusted on an ongoing basis. Under traditional ratemaking, the revenue requirement was only an intermediate product of regulation and rates were considered to be the final product. Decoupled utilities essentially are guaranteed their authorized revenues regardless of sales. Thus, decoupling requires one of the following: (1) frequent, future-year rate cases, (2) regular proceedings to adjust previously authorized revenues for current conditions (these commonly are known as *attrition* proceedings), or (3) a streamlined or mechanical revenue adjustment process like the "revenue per customer" proposal (Moskovitz and Swofford 1992).[9] Such adjustments to authorized base-rate revenues are necessary to account for inflation and because some base-rate expenses *are* a function of sales or customer growth.[10]

[9] The revenue per customer approach normalizes base rate revenues to the number of customers. Between rate cases, the utility is decoupled but its authorized base rate revenues are adjusted for customer growth at the predetermined revenue-per-customer rate. The revenue per customer approach has been adopted for at least two electric utilities: Central Maine Power Co. and Puget Sound Power and Light Co.

[10] Actual adjustments need only to respond to cost increases that are expected *after* taking into account utility productivity improvements.

Weather and alternative fuels competition can affect gas sales (and earnings) quite significantly, and in relative terms, these are probably more important factors than any unforeseen demand changes from DSM. Commissions that adopt decoupling mechanisms for gas utilities must recognize the potential for large annual rate changes (see Exhibit 9-2). There are at least two ways to mitigate the potentially large rate impacts caused by full decoupling. First, accrued balances could be amortized over periods of time longer than one year. However, longer amortization periods may provide a false sense of security, because it would only delay large rate impacts if a utility continues to record undercollections. Also, if a utility wants to be able to report accrued revenues as current revenues, the amortization period must be two years or less (Financial Accounting Standards Board (FASB) 1992). Second, a utility could attempt to separate the effect of DSM from the other sources of sales variations and only allow the utility to adjust rates for over- or under-collections attributable to DSM.[11]

9.4 Shareholder Incentives for DSM

DSM cost recovery, decoupling, and net lost revenue adjustment mechanisms primarily focus on eliminating regulatory disincentives to the promotion of DSM by gas utilities. Despite the availability of these mechanisms, DSM is a new activity for gas utilities and may still be perceived by gas utility managers to be less attractive than supply-side investments. Thus, many DSM proponents argue that incentives to utility shareholders (or managers) are necessary for the following reasons:

- Shareholder incentives are required to make utility management interested in gas DSM. It is likely that serious management attention will only be given when a utility's DSM programs provide contribute significantly to profits (Moskovitz 1992).

- For many states, disincentives—such as uncertain cost recovery or the absence of net lost revenue adjustment mechanisms—are still a part of prevailing ratemaking practices. Explicit shareholder incentives are one way to overcome such real or perceived opportunity costs of pursuing DSM programs.

- Incentives can be structured to reward exemplary performance and to penalize the utility for inadequate performance. Thus, incentives can provide an opportunity to make the utility not only pursue DSM but pursue it effectively.

[11] At this point, however, the decoupling mechanism will become complicated and begin to operate like a net lost revenue adjustment mechanism.

9.4.1 Types of Incentives

As of May 1993, at least seven PUCs had approved shareholder incentives for gas utilities.[12] There are three general types of shareholder incentives: *incentive rates of return, bounties, and shared savings.*

Incentive Rates of Return

An incentive rate of return probably is the simplest approach to incorporate into existing regulation. For DSM expenditures that are capitalized or amortized with interest, a utility could earn either a higher or lower rate of return, depending on the success of its efforts. A PUC would raise the utility's allowed rate of return if it did a superior job implementing its DSM programs and, conversely, would lower it if the utility's performance was judged inadequate. The incentive rate of return could either be specified in advance and linked to particular accomplishments (similar to the bounty approach), or it could be awarded based on an after-the-fact determination by a PUC. Ratebasing was discussed in more detail in Section 9.2.2.

Bounties

Bounties pay utilities for specified achievements based on a predetermined formula: e.g., X dollars for every therm saved. Exhibit 9-3 describes a bounty approach that has been adopted for Boston Gas. The major advantage of bounty approaches is their administrative simplicity; in addition, bounty approaches do not require explicit forecasts of gas long-run avoided costs (LRACs). This latter advantage is valuable for PUCs and utilities that either have limited experience in developing LRACs or believe that there is substantial uncertainty in their forecast of long-term gas commodity prices. However, it should be noted that many bounty approaches are initially developed by estimating the net resource value of a portfolio of DSM programs, given target participation levels. Thus, estimates of gas avoided costs are implicitly used to determine the bounty (see Exhibit 9-3). Disadvantages of this approach are: the utility has no incentive to minimize DSM program costs and, because bounties are not directly tied to a program's net benefits, the bounty may exceed the value of the DSM program.

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[12] Commissions include California, Iowa, Kansas, Massachusetts, Minnesota, New Jersey, Washington, and Montana.

Exhibit 9-3. DSM Shareholder Incentives: Massachusetts

Shareholder incentives have been approved for five of the eight investor-owned gas distribution companies regulated by the Massachusetts Department of Public Utilities (DPU). Boston Gas's incentive is structured as a bounty. The utility earns no incentive if actual savings are less than 25 percent of the target savings of 451 billion Btu/year (see Figure 9-2). The company receives an incentive of $5.62 per million Btu saved if actual savings exceed the 25% minimum threshold level. The incentive payment at the 100% target level of savings is $1.9 million, which is equivalent to 31% of estimated net resource benefits provided by these DSM programs. With this target incentive payment, Boston Gas will increase its return on equity by about 50 basis points. Boston Gas must demonstrate actual savings per measure and number of installations of each measure type before collecting any incentive payment.

The incentive mechanisms for most other gas LDCs in Massachusetts have used a shared-savings approach, and utility shareholders can receive about 5 to 7% of the net resource benefits provided by the programs for superior performance. Few LDCs actually have received incentive payments yet because the incentives are linked to actual program performance, and the programs have been in place for only a relatively short period.

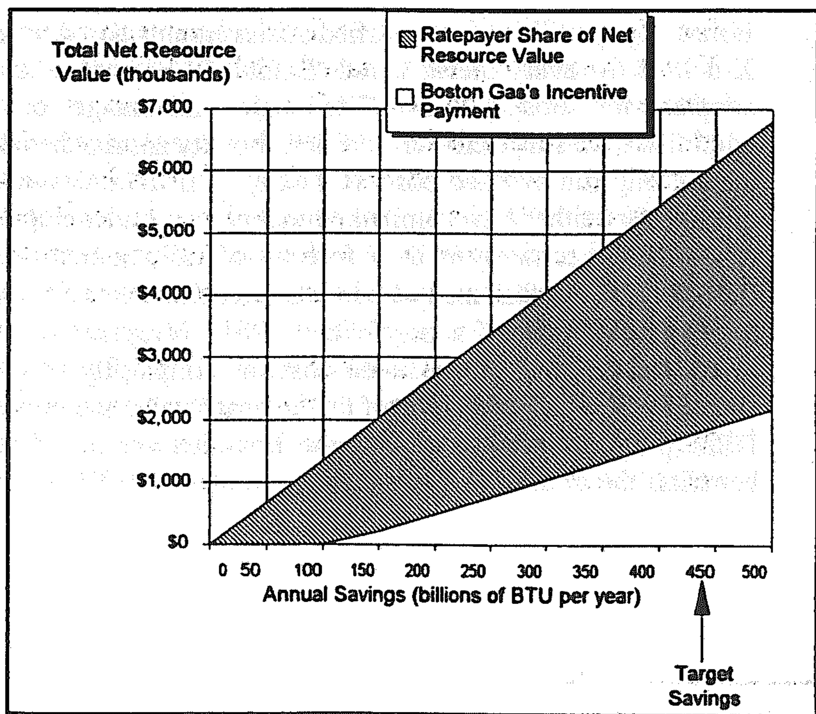
In Massachusetts, DSM program costs are recovered through each utility's Cost of Gas Adjustment Clause (CGAC), which essentially allows program costs to be expensed. Program costs are preapproved as a part of the proceeding that authorizes the programs. Allowable costs also include net lost revenues incurred as a result of reduced sales.

Source: Massachusetts DPU (1990)

Shared Savings

Various types of shared savings mechanisms have emerged as the most popular type of shareholder incentives for electric utilities. With a shared savings mechanism, the utility keeps a fraction (e.g., 5 to 30%) of the *net resource value* provided by a DSM program. Net resource value is computed as the difference between total program benefits and costs. Total benefits typically are estimated by multiplying estimated

Figure 9-2. Bounty Incentive for Boston Gas's Shareholders



(or measured) gas savings by the avoided cost of gas. Some PUCs also include the value of avoided externality costs in their incentive mechanisms. Program costs typically include the utility's administrative costs, financial incentives to customers, and DSM measure costs paid by the participating customer. Thus, net resource value is analogous to the Total Resource Cost test. However, in some cases, the Utility Cost test is used; that is, DSM measure costs paid for by the participating customer are excluded from the determination of net resource value (Eto et al. 1992).

9.4.2 Scope of Incentives

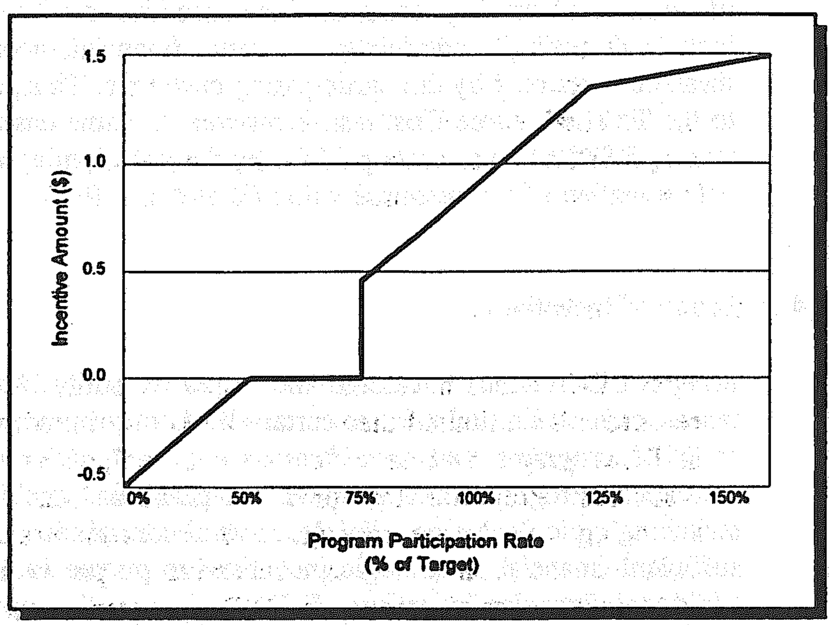
Many PUCs that have offered incentives to utility shareholders for acquiring DSM resources have limited them to certain kinds of programs. Often, incentives are targeted at DSM programs that have "resource value" and reduce the need for supply-side resources. Programs that promote off-peak load building or load building via fuel switching typically are not eligible. Several commissions have found that gas LDCs have sufficient financial or strategic incentives to pursue fuel substitution programs without additional financial incentives. DSM programs that are primarily offered for equity reasons (e.g., direct assistance to low-income customers) or programs that provide general or specific information on DSM opportunities to customers often receive different kinds of incentive treatment. For example, it is difficult to reliably estimate savings attributable to information and audit-type programs. One option is to provide a shareholder incentive that is structured as a "cost-plus" bounty (e.g., the utility receives incentive equal to a fixed percent of program expenditures with a cap on program costs). This approach may be useful in the case of low-income weatherization programs where the net benefits are negligible but the program is offered to address equity concerns.

9.4.3 Establishing the Basis for Incentive Payments: *Ex Ante* versus *Ex Post* Estimates of Energy Savings

Incentive mechanisms can reward or penalize a utility's performance in accomplishing IRP and DSM goals. Defining appropriate performance measure for DSM shareholder incentives has been a controversial issue; specifically, there is debate over the relationship and linkage between measurement and evaluation (M&E) of program savings and shareholder incentive payments. Often, this debate has centered on whether DSM incentive payments should be based on predetermined savings or participation-rate estimates (*ex ante*) or on the actual results of the DSM program (*ex post*).

Those who favor the *ex ante* approach argue that: (1) the primary purpose of M&E studies should be to improve program design and resource planning, (2) M&E studies involve significant time lags, and the results are often subject to interpretation, which can lead to contentious and lengthy regulatory proceedings and increased uncertainties regarding incentive payments, (3) long-term M&E studies are expensive, and it is not feasible to tie shareholder incentive payments to actual measured savings when the DSM measures have 10 to 15 year lifetimes, and (4) because the *ex ante* approach is more straightforward and less risky than an *ex post* approach, shareholders can receive a lower share of the net benefits, all else being equal (Schlegel et al. 1991; Wisconsin Energy Conservation Corporation 1993). In the *ex ante* approach, the utility is placed at risk for program parameters that are relatively easy to measure, such as achieving target participation rates. For example, in Figure 9-3, the utility receives an incentive if participation rates are greater than or equal to 75% of the forecasted target participation rates. The utility's earnings are reduced if participation rates fall below 50% of target levels, and there is a dead-band range, between 50 to 75% of the target participation rate, in which the utility does not earn an incentive. Typically, the utility will receive its share of the net benefits for the program's expected life cycle over a one- to three-year period while the actual benefits are realized over many years.[13] In the *ex ante* approach, results of M&E studies would be used to update and modify prespecified savings estimates only for future program years.

Figure 9-3. Illustrative Shareholder Incentive Payment Mechanism



Proponents of the *ex post* approach argue that (1) paying shareholder incentives based on actual savings as measured over time gives the utility the maximum incentive to acquire long-lasting, cost-effective DSM resources, and (2) *ex post* approaches reduce the risk that ratepayers are worse off after shareholder incentives have been paid if actual savings are much lower than expected. Most *ex post* approaches that have been proposed tie the

[13] Utilities tend to strongly favor accelerated payments of incentives because they believe this overcomes the perceived risk that the commission will later "take back" the shareholder's share of the expected benefits.

shareholder savings to the actual program savings as estimated in an M&E study.[14] When using an incentive mechanism based on the *ex post* approach, a particularly critical issue is the time period and intervals over which program savings are to be measured. At a minimum, benefits could be determined based on M&E studies of first-year savings. The utility would then receive incentive payments based on the estimated net present value of life-cycle savings and a predetermined economic life for each measure. At the limit, multi-year impact evaluations with test and control groups would be required to measure savings over the actual economic lifetimes of the installed DSM measures; this approach may be administratively burdensome and could be expensive in terms of the incremental value of information relative to the additional M&E costs incurred.

9.5 Allocation of DSM Program Costs to Classes of Customers

Cost allocation is the process of assigning a utility's revenue requirement to broad categories of customers known as customer classes. Cost allocation usually is an intermediate step in the ratemaking process because actual rates paid by individual customers are subject to the rate design chosen for each customer class. In reviewing alternative cost allocations, PUCs strive to meet their legal mandate, which is usually to set rates that are "just and reasonable" (Phillips 1988). In practice, setting just and reasonable rates has become a practice of balancing several goals including the goals of efficiency and equity. Efficiency involves making customers pay for the costs they cause on the gas system. Economists attempt to define the goal precisely by saying that efficiency is maximized when prices are set at or as close as possible to marginal costs. Equity, or fairness, is the goal of ensuring that the benefits of the utility system and incremental decisions made by the utility or PUC are shared by all. Often, the ability of a cost allocation to meet equity goals is evaluated in terms of how it satisfies human needs or social justice goals or by how it affects specific customer classes relative to the status quo. [15]

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[14] Thus, most ex post incentive mechanisms only protect ratepayers from the risk that DSM savings will be less than expected. Uncertainties associated with future avoided costs are also important. Importantly, if shareholder incentives are based on the present value of net benefits over the program's life cycle, then ratepayers have essentially absorbed all the risk surrounding avoided cost estimates. An alternative ex post shareholder incentive mechanism would be to calculate and pay shareholder incentives over a program's life using actual avoided gas costs rather than forecasted avoided costs.

[15] For example, a regulatory body may take steps to minimize the negative impacts of rate changes on disadvantaged classes or will authorize programs to assist these customers in receiving and paying for utility energy services.

As with any decision regarding cost allocation, a PUC will evaluate DSM cost allocation proposals in terms of their ability to meet efficiency, equity, and other ratemaking goals. Because debates about general allocation policies are far from resolved, no prescriptive guidance can be given for the allocation of DSM program costs. Instead, this section discusses allocation methods and their implications.

9.5.1 Cost Allocation Methods

There are several allocation methods for assigning direct DSM program costs (see Table 9-4). An important related allocation issue is how changes in gas demand resulting from DSM programs affect allocation of base-rate revenue requirements in future rate cases. These methods and the base-rate-revenue reallocation issue are discussed briefly below. Readers who are interested in a more detailed discussion of various cost allocation methods should refer to Centolella et al. (1993), which focuses on the DSM program cost allocation for electric utilities.

Allocation by Number of Customers

Historically, some commissions have allocated gas DSM costs based on a weighted average of number of customers.[16] This approach was used in cases where DSM programs primarily or exclusively targeted smaller (residential) customers.[17] However, as DSM programs become more comprehensive (i.e., are offered to commercial and industrial customers), this approach becomes unattractive because the allocation of costs will be unlikely to match the allocation of benefits provided by the DSM program (Newman 1993).

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[16] Marketing services, customer information, and customer relations expenditures frequently are allocated on a basis of weighted number of customers. The weighting method is typically based on the size of meters and service lines or on customer throughput and, thus, will typically assign more costs to larger customers than would an unweighted customer count.

[17] Because residential customers historically have received almost all of the benefits of DSM programs, major problems were not created when 80-90% of program costs were allocated to the residential class using this method.

Table 9-4 Summary of Methods of Allocating DSM Program Costs

Allocation Method	Description of Method
Number of Customers	• Costs are considered to be a customer cost and allocated by number of customers accordingly.
Participating Customers	• Costs are directly allocated to participating customers. • Method is equivalent to an "energy services" charge.
Customers Offered the Program	• Costs of programs offered to a class are solely allocated to that class; costs are not allocated to nonparticipating customer classes.
Existing Volumetric Allocators	• Some or all DSM program costs are allocated according to each customer class's per-therm sales or throughput. • Method is often equivalent to "equal cents per therm."
Existing Demand Allocator	• Allocates some or all DSM program costs in proportion to the allocators used to allocate capacity costs. • Method is usually used in conjunction with other allocation methods.
Marginal Cost Revenues	• Costs are added to the "residual revenue requirement" and are allocated according to the total marginal cost revenue requirement (capacity and commodity-related) of each class. • Method is applicable only to PUCs using marginal-cost-based allocation methods.

Allocation to Program Participants or Classes who are Offered the Programs

Under this method, the costs of a DSM program are directly allocated to the classes or subclasses of customers who either participate in or are eligible for participation in a program; e.g., residential program costs are only allocated to the residential class. This approach is quite popular and is used by at least 11 PUCs; they favor it because it minimizes concerns that nonparticipating classes are subsidizing DSM programs (National Association of Regulatory Utility Commissioners (NARUC) 1992).[18] If program costs are solely allocated to participants, this type of allocation method is equivalent to an energy services charge that fully charges the participating customer for the cost of the DSM measure.

Equal Cents Per Therm

Broad allocations of DSM program costs, such as equal cents per therm or other volumetric allocations are used because they are considered simple to implement or because there is an expectation that the program provides benefits to all ratepayers. Relative to other allocation approaches, an equal-cents-per-therm allocation will tend to allocate more DSM program costs to high load factor customers.

The equal-cents-per-therm method may be implemented as an adder to the transportation component of all rates or to the PGA rate. For utilities with significant quantities of customer-owned transportation, the choice of the basis for the adder can yield significantly different results. The first method (adder applied to all rates) will allocate some DSM costs to transport-only customers. Such a method has been adopted in Illinois for allocating DSM program costs at two gas LDCs (see Exhibit 9-1). The second method (adder applied to sales only) allocates the DSM program costs only to gas sales customers of the LDC while transport-only customers are not allocated program costs. Overall, a broad volumetric-based allocation is relatively popular among PUCs; at least seven reporting that they use such a methodology.

[18] Of the 51 PUCs (including the District of Columbia) surveyed in the 1992 NARUC survey on utility regulatory policy, 29 PUCs either did not have gas DSM programs, were still undecided on their allocation policy, or did not report an answer. Thus, the 11 PUCs that rely on participating-class-based cost allocation method represent about 35% of the 31 PUCs that responded.

Allocation According to Existing Capacity Allocators

Similar to the logic used for volumetric allocations is the notion that DSM programs offer a certain amount of capacity benefits and, consequently, a portion of DSM program costs ought to be allocated in a manner similar to the way existing LDC or pipeline capacity costs are allocated. No one has proposed to allocate an entire DSM program according to this method, but it has been proposed for use in conjunction with other allocation methods. For example, if a gas DSM program saved therms and reduced peak day demand, the costs of the program could be allocated to customer classes on the basis of their annual throughput and peak-day demands (Newman 1993).

Marginal-Cost-Based Allocation Methods

With marginal-cost-based allocation methods, nongas revenue requirements are first allocated according to marginal costs estimated for each major utility function: commodity-related, transportation, storage, distribution, and customer costs. Usually, the total utility revenue requirement does not equal the revenues that would accrue under marginal cost pricing, so some sort of "reconciliation" is necessary. The most common form of reconciliation is known as equal percentage of marginal costs (EPMC), which means that all residual dollars are allocated in proportion to marginal cost revenues. The residual revenue requirement can also be allocated using the inverse of each class's demand elasticity. This type of method is commonly known as Ramsey pricing. At least two states—California and Massachusetts—use marginal costs in allocating nongas costs, although marginal cost allocation principles have not been extended to purchased gas costs.

Under the general framework of marginal cost allocation approaches, there are at least three ways to allocate DSM program costs. First, the cost of providing utility DSM services can be included in the marginal customer costs, which will have the effect of predominantly allocating DSM program costs to small customers (similar to the "number of customers" allocation method already described). Second, DSM program costs can be excluded from the general nongas allocation and included in the PGA rate component. This is the method used in Massachusetts. Third, DSM program costs can be excluded from the PGA account or any of the marginal cost estimates. The DSM program costs will then, by default, fall into the residual revenue requirement and will be allocated either by EPMC or by inverse elasticities. California uses this third method in conjunction with EPMC. The logic behind a residual allocation using EPMC is that DSM represents an alternative to supply, and its costs should be allocated to customer classes in proportion to marginal supply-side costs.

Reallocation of Base-Rate Expenses in Future Rate Cases

PUCs are obligated to provide utilities with a reasonable opportunity to earn their authorized rates of return. As a practical matter, this means that most commissions allow, in the rate case, for the adjustment of demands in response to DSM programs.[19] Although the effect of the rate case is to give the utility an opportunity to be made "whole," there may be significant impacts on the reallocation of base-rate expenses to individual customer classes. When considering the use of the general allocation methods described above, it is important to consider the interaction of these methods with changes in the levels of the allocators for other components of base-rate revenue requirements. For example, if a DSM program reduces the peak sendout of a customer class, it is reasonable to expect that that class's allocation of peak-day costs should be reduced. The impact of such a reallocation on nonparticipating customers depends to a great extent on the relationship of avoided capacity costs to the average (embedded) capacity costs. If avoided costs are low relative to embedded costs, the nonparticipating customers (or classes) may be adversely affected even if they do not share in the direct costs of the DSM program because they will be allocated more embedded capacity costs than they would receive without the DSM program. Conversely, if avoided costs are high relative to embedded costs, then nonparticipating classes will benefit because the total cost of capacity will drop by more than the increase in the nonparticipating class's percentage allocator. The effect of different assumptions regarding demand allocators is illustrated in the example presented in the following section.

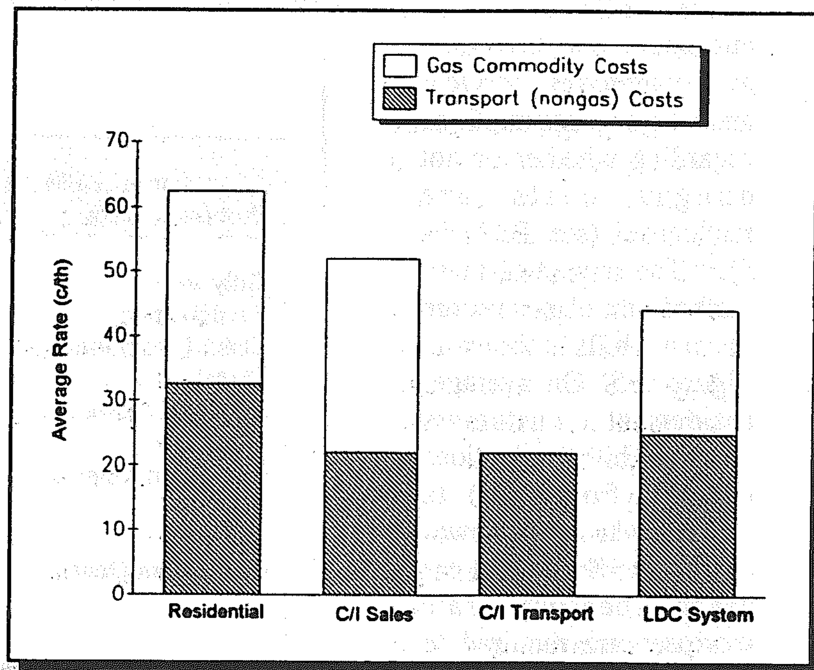
9.5.2 Illustration of Different Cost Allocation Methods

Different cost allocation methods can affect participating and nonparticipating customer classes in significantly different ways, particularly in cases where DSM program expenditures are large. To illustrate the issues involved, three methods of allocating DSM program costs are shown for a hypothetical LDC conducting an aggressive, large-scale residential DSM program. The hypothetical LDC has three customer classes: residential customers with a 40 percent load factor that receive bundled service from the utility (sales and transport), commercial/industrial (C/I) customers that receive bundled service, and C/I customers that are transport-only customers.

[19] For states that practice historical test year ratemaking and do not allow for adjustments in test year therms to account for DSM program effects, a new rate case may not fully adjust for DSM if the demand effects of DSM programs are growing over time.

The LDC's costs are aggregated into two general categories: commodity costs and nongas costs (i.e., the LDC's margin).[20] Average rates for residential customers are $0.63/therm prior to the utility DSM program, which occurs in part because of the class's low load factor (see Figure 9-4). Rates for C/I transport customers are the lowest ($0.22/therm) and the utility's average rates for its entire system are $0.48/therm.

Figure 9-4. Class Average Rates for a Hypothetical LDC



Assume that the DSM program is targeted only at the residential customer class and reduces residential class sales and demand by 5% annually and on a peak day at a cost of $0.30/therm to the utility. DSM program expenditures are assumed to be ratebased and amortized for the life of the program. Assume that total avoided costs are $0.45/therm consisting of $0.30/therm for marginal commodity costs and $0.15/therm for marginal nongas costs. These avoided costs are, however, lower than average residential rates, so there is a net loss of revenues to the utility absent a reallocation of costs. Further, it is assumed that, although participating customers may pay for some of the measure's costs on their own, they do not contribute to the utility's DSM program costs, other than their share of program costs allocated to their class.

As long as the LDC is made whole, there is, on average, a 0.5% decrease in bills and a one percent increase in rates regardless of the chosen allocation policy. However, bill and rate impacts significantly vary among the three customer classes depending on the cost allocation method (i.e., costs allocated only to participating class, costs allocated to

[20] Commodity costs are allocated to all sales customers, while nongas costs are allocated according to a weighting of peak day demand and average-year throughput.

all customers on an equal cents per therm basis, and costs allocated to customers that buy only gas commodity service) and varying assumptions regarding whether or not nongas costs are reallocated (see Table 9-5).[21] The impact of these methods on class average rates and bills is shown in Figure 9-5. On average, residential customers receive bill reductions ranging from 0.5 to 3.5%, which is lower than their 5% reduced gas usage because rate increases are required to offset lost margins (see Figure 9-5a).

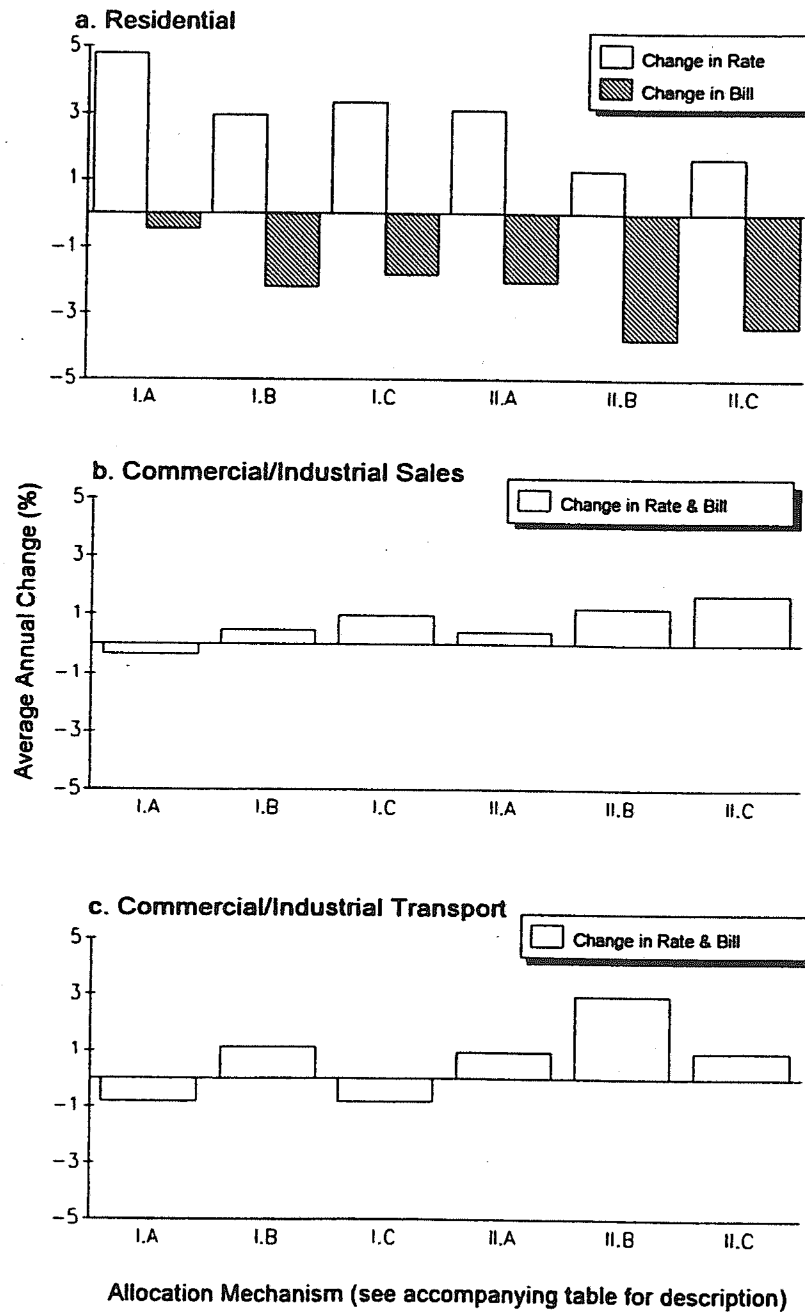
Table 9-5. Identification of Allocation Mechanisms Shown in Figure 9-5

	Change Nongas Allocations in Response to Change in Demand?	
Allocation of DSM Program Costs	No	Yes
Only to Participating Class (Residential Class)	I.A	II.A
Equal Cents per Therm	I.B	II.B
Equal Cents per Therm to Sales Customers Only	I.C	II.C

The residential customer class receives the highest bill reductions in the type "II" allocations, which change the nongas allocators to reflect the demand impacts of the DSM program. C/I sales customers (who are nonparticipants) receive a rate reduction only under allocation mechanism I.A, which allocates all DSM program costs to the participating class (i.e., residential customers) and does not reallocate nongas costs (see Figure 9-5b). With other cost allocation methods, rate and bill increases range from 0.05-2%. C/I transport-only customers (also nonparticipants) receive a rate reduction only under allocation mechanisms I.A and I.C (see Figure 9-5c). Bills and rates increases for transport-only C/I customers range from 1-3% if nongas cost allocators are changed.

[21] In this example, if nongas costs are reallocated, then each class's base rate is adjusted to incorporate demand impacts of DSM.

Figure 9-5. Impact of DSM Program on Average Rates and Bills Using Alternative Allocation Methods



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Glossary

Action Plan - A component of a utility's integrated resource plan, describing specific utility actions in the short-term (about two years) to meet supply- and demand-side objectives of the plan.

Annual Fuel Utilization Efficiency (AFUE) - Efficiency measure for gas heating equipment based on testing procedures defined by the Department of Energy.

Avoided Cost - Incremental cost that a utility would incur to purchase gas supplies and capacity equivalent to that saved under a demand-side management (DSM) program. Components of avoided cost may include energy, capacity, storage, transmission and distribution. Avoided cost has been used as a yardstick to assess and screen the cost-effectiveness of DSM programs and supply-side resources.

Base Load - As applied to gas, a given sendout of gas remaining fairly constant over a period of time, usually not temperature sensitive.

Base Rates - Gas utility rates designed to cover nongas costs. *See also Purchased Gas Adjustment (PGA) Clause and Nongas Costs.*

Bcf - 1,000,000,000 cubic feet; billion cubic feet.

British Thermal Unit (Btu) - The amount of heat required to raise the temperature of one pound of pure water one degree Fahrenheit under stated conditions of pressure and temperature.

Broker - A person acting as an agent for a buyer or seller of gas in a transaction. The broker does not assume title to the gas.

Burner-Tip - Generic term commonly used to indicate the ultimate point of consumption for natural gas.

Buyout/Buydown - The costs of contract realignment by a pipeline company. Specifically, they represent the negotiated costs of altering or walking away from contracts.

Bypass - Construction of a physical connection between a large end user and a supplier, other than historic or common suppliers, when the economics dictate; that is, the system supply price of the local utility supplier is higher than the total price of off-system supplies available through the market and separate transport of the purchase via the alternative (bypass) delivery point.

Capacity, Peaking - The capability of facilities or equipment normally used to supply incremental gas under extreme demand conditions; sometimes available only for a limited number of days at a maximum rate.

Captive Customer - Natural gas user who cannot readily leave or switch a system supplier due to physical or economic factors, availability of alternative fuels, or lack of fuel-switching capability. *See also Core Customer.*

Casinghead Gas - Unprocessed natural gas containing natural gasoline and other liquid hydrocarbon vapors produced from oil sell. *Synonyms: Wet Gas, Associated Gas (but not all wet gas or associated gas is casinghead gas).*

City Gate - Generally, a location at which gas changes ownership, from one party to another, neither of which is the ultimate consumer. It should be noted, however, that the gas may change from one system to another at this point without changing ownership. *Also referred to as city gate station, town border station, or wholesale delivery point.*

Combination Utility - A utility which supplies both gas and some other utility service (electricity, water, etc.).

Commodity Price - The current price for a supply of natural gas, charged for each unit of gas supplies, as determined by market conditions or tariff.

Compression - Increasing the pressure of gas in a pipeline by means of a mechanically driven compressor station to increase flow capacity.

Compressor Station - Any permanent combination of facilities which supplies the energy to move gas at increased pressure from fields, in transmission lines or into storage.

Conservation Supply Curve - A graph showing the quantity of energy savings of individual efficiency measures on the X-axis and the total cost-per-unit-of-energy saved on the Y-axis.

Contract Demand (CD) - The maximum daily, monthly or annual quantity which the supplier agrees to furnish, or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

Core Customer - Customer designation originally defined in California to represent smaller customers without alternative fuel capability. Typically made up of residential and small commercial classes.

Cost Allocation - Distribution of functionalized facility costs and operating expenses to rate classes or other identifiable customer groups on the basis of peak demand and energy use characteristics of the customer groups. Allocation may be calculated for historical or future periods and may be average or incremental for that period.

Cost-of-Service - Total cost of providing utility service to a system or to a customer group including operating expenses, depreciation, taxes, and a return on invested capital.

Cream Skimming - Designing and implementing only a limited set of the most cost-effective DSM measures while disregarding other cost-effective opportunities. Cream skimming becomes a problem when lost opportunities are created in the process, which means that it is either uneconomic and/or impractical to return at a later time to that facility to implement additional measures that were cost-effective at the time of the initial site audit. *See also Lost Opportunities.*

Cubic Foot (cf) - The most common unit of measurement of gas volume. It is the amount of gas required to fill a volume of one cubic foot at a temperature of sixty degrees Fahrenheit (60°F) and at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute (14.73 psia).

Curtailment - A restriction or interruption of gas supplies or deliveries. May be caused by production shortages, pipeline capacity or operational constraints or a combination of operational factors.

Cushion Gas - The gas required in a reservoir, used for storage of natural gas, so that reservoir pressure is such that the storage gas may be recovered. *See also Working Gas.*

Demand-Side Bidding - A process in which a utility issues a request for proposals (RFP) to acquire DSM resources from energy service companies (ESCOs) and customers, reviews proposals, and negotiates contracts with winning bidders for a specified amount of energy savings.

Demand-Side Management (DSM) - Deliberate effort to decrease, shift or increase energy demand through organized utility activities that affect the amount and timing of gas use.

Design Day - A 24-hour period of demand which is used as a basis for planning gas capacity requirements.

DSM Potential

> **Technical Potential** - Estimate of possible energy savings based on the assumption that existing appliances, equipment, building shell measures, and industrial processes are replaced with the most efficient commercially available units, regardless of cost, without any significant change in lifestyle or output.
>
> **Economic Potential** - Estimate of that portion of the 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** - Estimate of amount of energy savings that would occur if all cost-effective, energy-efficient options promoted through utility DSM programs were adopted. Achievable potential excludes those efficiency gains that will be achieved through normal market forces and by existing or future standards or codes.
>
> **Market Potential** - Estimate of the possible energy savings that would occur because of normal market forces (i.e., likely customer adoption over time of various actions without a DSM program).

Economic Carrying Charge Rate (ECCR) - A method of allocating capacity costs over time in such a way that the annual value stays constant in real terms.

Econometric Model - A set of equations, developed through regression analysis and other quantitative techniques, that mathematically represents relationships among data.

Electric Fuel Substitution - Programs which promote the customer's choice of electric service for an appliance, group of appliances, or building rather than the choice of service from a different fuel. These programs increase customers' electric usage and decrease usage of an alternative fuel.

Energy-Efficiency Options - Measures or strategies that reduce energy consumption by substituting more efficient equipment or operating practices without degrading services provided.

Externalities - Cost and benefits that are not accounted for in the market prices paid for a good or service. For example, costs of physical damage from the presence of certain pollutants are negative environmental externalities.

Federal Energy Regulatory Commission (FERC) - An agency of the Department of Energy (DOE) charged with regulation of interstate sales and transportation of natural gas, wholesale electric rates, hydroelectric licensing and oil pipeline rates.

Firm Service - Service offered to customers (regardless of Class of Services) under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in Off-Peak Service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency. *Compare to Interruptible Service and Off-Peak Service.*

Force Majeure - An unexpected event or occurrence not within control of the parties to a contract which alters the application of the terms of a contract; sometimes referred to as "an act of God." Examples include severe weather, war, strikes and other similar events.

Free Drivers - Customers who take recommended actions because of a DSM program but who do not impose a cost on the program (e.g., they do not claim monetary incentives offered by the program). Free drivers also include customers that enhance their consideration of energy efficiency in nonprogram purchase decisions after their participation in a utility program.

Free Riders - DSM program participants who would have undertaken DSM measures, even if there were no utility DSM program.

Gas Fuel Substitution - Programs which promote the customer's choice of natural gas service for an appliance, group of appliances, or building rather than the choice of service form a different energy source. These programs increase customer usage of natural gas and decrease usage of an alternative fuel.

Gas Inventory Charge (GIC) - A charge by a pipeline assessed for standing ready to serve sales customers. The Gas Inventory Charge is designed to prevent the occurrence of take-or-pay liability by charging the customer for all the costs associated with maintaining a gas supply.

Gas, Natural - A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Associated - Free natural gas in immediate contact, but not in solution with crude oil in the reservoir.

Dissolved - Natural gas in solution in crude oil in the reservoir.

Dry - Gas whose water content has been reduced by a dehydration process. Gas containing little or no hydrocarbons commercially recoverable as liquid product. Specified small quantities of liquids are permitted by varying statutory definition in certain states.

Liquefied (LNG) - Natural gas which has been liquefied by reducing its temperature to minus 260°F at atmospheric pressure. It remains a liquid at -116°F and 673 psig. In volume it occupies 1/600 of that of the vapor.

Liquids - Those liquid hydrocarbon mixtures which are gaseous at reservoir temperatures and pressures but are recoverable by condensation or absorption. Natural gasoline and liquefied petroleum gases fall in this category.

Nonassociated - Free natural gas not in contact with, nor dissolved in, crude oil in the reservoir.

Sour - Gas found in its natural state, containing such amount of compounds of sulphur as to make it impractical to use, without purifying, because of its corrosive effect on piping and equipment.

Sweet - Gas found in its natural state, containing such small amount of compounds of sulphur that it can be used without purifying, with no deleterious effect on piping and equipment.

Wet - Wet natural gas is unprocessed natural gas or partially processed natural gas produced from strata containing condensable hydrocarbons. The term is subject to varying legal definitions as specified by certain state statutes. (The usual maximum allowable is 7 lbs./MMcf water content and .02 gallons/Mcf of Natural Gasoline).

Heating Degree-Day - A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a baseline temperature, usually 65° Fahrenheit. A daily average temperature usually represents the sum of the high and low readings divided by two.

Hydrocarbon - A chemical compound composed solely of hydrogen and carbon. The compounds having a small number of carbon and hydrogen atoms in their molecule are usually gaseous; those with a larger number of atoms are liquid, and the compounds with the largest number of atoms are solid.

Incremental Cost - In economic analysis of DSM, difference in price between an efficient technology or measure and the alternative standard technology.

Injection - The process of putting gas into a storage facility. Also called liquefaction when the storage facility is a liquefied natural gas plant.

Integrated Resource Planning (IRP) - A planning process, used by regulated energy utilities, to assess a comprehensive set of supply- and demand-side options in order to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost.

Interruptible Service - Low priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the claim of firm service customers and higher priority users. Gas is available at any time of the year if the supply is sufficient and the supply system is adequate. *Synonym: Nonfirm. See also Noncore.*

Interstate Pipeline - Natural gas pipeline company that is engaged in the transportation, by pipeline, of natural gas across state boundaries, and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act.

Linear Programming - A mathematical method of solving problems by means of linear functions where the variables involved are subject to constraints.

Line Pack, Gas Delivered from - That volume of gas delivered to the markets supplied by the net change in pressure in the regular system of mains, transmission and/or distribution. For example, the change in the content of a pipeline brought about by the deviation from steady flow conditions. *Synonym: Pipeline Fill.*

Liquefaction - Any process in which gas is converted from the gaseous to the liquid phase.

Liquefied Natural Gas (LNG) - *See Gas, Natural.*

Load Duration Curve - An array of daily peak-day sendouts observed that is sorted from highest sendout day to lowest to demonstrate both the peak requirements and the number of days they persist.

Load Factor - The ratio, in percent, of average load of a customer, a group of customers, or an entire system, to the maximum load. Load factor can be calculated over various time periods (e.g., monthly, annual).

Load Forecasting - Projections of customer energy and peak day demand requirements on either a short-term or long-term basis.

Local Distribution Company (LDC) - A utility that purchases gas for resale to end-use customers and/or delivers customer's gas supplies from interstate pipelines to end-users' facilities reducing pressure from pipeline levels to appropriate delivery levels.

Looping - The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

Lost Opportunities - Efficiency measures which offer long-lived, cost-effective savings that are fleeting in nature. A lost opportunity occurs when a customer does not install an energy efficiency measure that is cost-effective at the time, but whose installation is unlikely to be cost-effective later.

Mcf - A unit of volume equal to a thousand cubic feet; see *Cubic Foot.*

MDQ - Maximum Daily Quantity

MMBtu - A unit of heat equal to one million British thermal units (Btu). It is also approximately equivalent to 1,000 cubic feet of gas.

MMcf - 1,000,000 cubic feet; million cubic feet; see *Cubic Foot.*

MMth - 1,000,000 therms; see *Therm.*

Margin - Revenues minus incremental operating expenses over the time period specified *See also Nongas Costs, Base Rates.*

Multi-Attribute Analysis - A method which allows for comparison of options in terms of all attributes which are of relevance to the decision maker(s). In IRP, common attributes are financial cost, environmental impact, social impact and risk.

Natural Gas Vehicle (NGV) - May be dedicated, meaning that the vehicle runs only on natural gas, or dual-fuel, which means that the vehicle is equipped to operate on natural gas or gasoline.

Net Energy Demand Forecast - The Gross Energy Demand Forecast less the effect of all DSM.

Net Lost Revenues - Utility lost revenues resulting from a DSM program net of avoided supply and capacity cost savings. May also be defined as the net margin impact of a DSM program. *See also Margin, Lost Revenues.*

Nomination - The scheduling of daily gas requirements.

Noncore Customer - Customer designation originally defined in California to be customers that consume more than 250,000 therms per year and have alternative fuel capability. *See also Core Customer.*

Nongas Costs - Gas utility expenses net of purchased gas costs and, often, pipeline demand charges. *See also Purchased Gas Adjustment Clause (PGA) and Base Rates.*

Nonparticipants test - Test used to evaluate the benefits and costs of utility DSM program from the perspective of utility customers who do not participate in the program. *Also called Ratepayer Impact Measure (RIM) and No-Losers test. See also Total Resource Cost test.*

Off-Peak Service - Service made available on special schedules or contracts but only for a specified part of the year during the off-peak season.

Open Access - The nondiscriminatory access to interstate pipeline transportation services. This enables end-use customers the option of securing their own gas supplies rather than relying upon local distribution companies.

Participants test - Test used to evaluate the benefits and costs of utility DSM program from the perspective of utility customers who participate in the program. *See also Total Resource Cost test.*

Peak Day - The 24-hour day period of greatest total gas sendout assuming a specific weather pattern. May be used to represent historical actual or projected (budget) requirements.

Peak-Day Curtailment - Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for gas exceed the maximum daily delivery capability of a pipeline system.

Peak Shaving - The process of supplying gas for a distribution system from an auxiliary source (typically of limited supply and higher cost) during periods of maximum demand to avoid exceeding the demand on the primary source and to reduce wide fluctuations in gas takes. *Synonym: Needle Peaking.*

Persistence - Refers to any decline in energy-saving effectiveness that may take place over a conservation measure's life. This is a function of both consumer behavior and equipment degradation.

Pipeline - All parts of those physical facilities through which gas is moved in transportation, including pipe, valves and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.

Program Evaluation - Activities related to the collection, analysis, and reporting of data for purposes of measuring program impacts from past, existing or potential program impacts. Activities include program-specific evaluations as well as activities which evaluate more generic issues which are relevant to more than one program.

Propane (C_3H_8) - A gas, the molecule of which is composed of three carbon and eight hydrogen atoms. Propane is present in most natural gas and is the first product refined from crude petroleum. It has many industrial uses and may be used for heating and lighting. Contains approximately 2,500 Btu per cubic foot.

Propane Air - Propane mixed with air and natural gas to allow burning in a natural gas system to supplement natural gas supplies for customers on peak days.

Purchased Gas Adjustment (PGA) Clause, Rate, Provision, or Account - A rate, account, or ratemaking mechanism that allows for frequent updating of gas utility rates to reflect changes in purchased gas costs. Usually, but not always, includes pipeline demand charge expenses in addition to gas commodity costs.

Rate Base - The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return. Generally, this represents the amount of property used and useful in public service.

Reserves, Energy - Refers to the bank of natural resource, such as natural gas, natural gas liquids, petroleum, coal, lignite, and energy available from water power, and solar and geothermal energy.

> **Estimated Potential Natural Gas Reserves** - Refers to an estimate of the remaining natural gas in a specified area which are judged to be recoverable.
>
> **Estimated Proved Natural Gas Reserves** - An estimated quantity of natural gas which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs, under anticipated economic and current operating conditions. Reservoirs that have demonstrated the ability to produce by either actual production or conclusive formation test are considered proved.

Saturation, Appliance - Ratio of the number of specific types of appliances or equipment to the total number of customers in that class, expressed as a percentage. For example, gas space heat saturation refers to the fraction of homes and buildings with gas space heating.

Sendout, Gas - Total gas produced, purchased (including exchange gas receipts), or net withdrawn from underground storage within a specified time interval, measured at the point(s) of production and/or purchase, and/or withdrawal, adjusted for changes in local storage quantity. It comprises gas sales, exchange deliveries, gas used by company and unaccounted for gas. Expressed in various units such as therms, Btu's, cubic feet, etc.

Sendout, Maximum Day - The greatest actual total gas sendout occurring in a specified 24-hour period.

Service Area - Territory in which a utility system is required or has the right to supply gas service to ultimate customers.

Service Line or Pipe - The pipe which carries gas from the main to the customer's meter.

Shrinkage, Natural Gas - The reduction in volume of wet natural gas due to the extraction of some of its constituents, such as hydrocarbon products, hydrogen sulfide, carbon dioxide, nitrogen, helium, and water vapor.

Societal Cost test - Cost determined from a social perspective as opposed to a private perspective. All externalities should be included, if their monetization is feasible.

Spot Market Gas - Gas purchased under short-term agreements as available on the open market. Prices are set by market pressure of supply and demand.

Storage, Local - The storage facilities, other than underground storage, that are an integral part of a distribution system, i.e., on the distribution side of the city gate.

Storage Mains - Those mains used primarily for injection and withdrawal of gas to and from underground storage.

Storage, Underground - The utilization of subsurface facilities for storing gas which has been transferred from its original location for the primary purposes of load balancing. The facilities are usually natural geological reservoirs such as depleted oil or gas fields or sands sealed on the top by an impermeable cap rock. The facilities also may be artificial or natural caverns.

Aquifer Storage - The storage of gas underground in porous and permeable rock stratum, the pore space of which was originally filled with water and in which the stored gas is confined by suitable structure, permeability barriers and hydrostatic water pressure.

Base Gas - The total volume of gas which will maintain the required rate of delivery during an output cycle. *Also called Cushion Gas.*

Current Gas - The total volume of gas in a storage reservoir which is in excess of the base gas. *Also called Working Gas.*

Extraneous Gas - *See Stored Gas, this section.*

Foreign Gas - *See Stored Gas, this section.*

Native Gas - The total volume of gas indigenous to the storage reservoir.

Storage Reservoir - That part of the storage zone having a defined limit of porosity and/or permeability which can effectively accept, retain, and deliver gas.

Stored Gas - Gas physically injected into a storage reservoir.

Ultimate Reservoir Capacity - The total estimated volume of gas that could be contained in storage reservoir when it is developed to the maximum design pressure.

Working Gas - Gas in an underground storage field that is available for market. *May also be called Current Gas.*

Take or Pay - The clause in a gas supply contract which specifies amount of gas required to be purchased whether or not delivery is accepted by the purchaser. Some contracts contain a time period in which the buyer may take later delivery of the gas without penalty.

Tariff - A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Tcf - 1,000,000,000,000 cubic feet; trillion cubic feet.

Therm (th) - A unit of heating value equivalent to 100,000 British thermal units (Btu).

Total Resource Cost (TRC) test - Test used to evaluate the benefits and costs of utility DSM program from the perspective of all utility customers. Test excludes externality costs or benefits. *See also Societal Cost test.*

Trade Allies - Organizations (e.g., architects and engineering firms, building contractors, appliance manufacturers and dealers) that influence the energy-related decisions of customers who might participate in utility DSM programs.

Transportation Gas - Gas purchased from a source other than the pipeline which delivers it. This gas is purchased either directly from the producer or through a broker and is used for either system supply or for specific end-use customers, depending on the transportation arrangements.

Unaccounted for Gas - The difference between the total gas available from all sources and the total gas accounted for as sales, net interchange and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times. In cycle billings, an amount of gas supply used but not billed as of the end of a period. *Compare Sendout, Gas.*

Utility Cost test - Test used to evaluate the change in total costs to the utility (i.e., the utility's revenue requirement) caused by a DSM program. *See also Societal Cost test. See Nonparticipants test, Total Resource Cost test.*

Vaporization - Any process in which gas is converted from the liquid to the gaseous phase.

Weather Normalization - Method for adjusting gas consumption to remove the effects of weather, which usually involves estimation of the average annual temperature in a typical or "normal" year based on examination of historical weather data. The normal year temperature is used to forecast utility sales revenue under a procedure called sales normalization.

Weighted Average Cost of Gas (WACOG) - The average price paid for a volume of gas purchased from a pipeline based on the prices of individual volumes of gas that make up the total quantity supplied. WACOG is sometimes equal to the total PGA rate. *See also Purchased Gas Adjustment (PGA) Clause.*

Withdrawal - The process of removing gas from a storage facility, making it available for delivery into the connected pipelines. Vaporization is necessary to make withdrawals form an LNG plant.

Working Gas - *See Storage, Underground.*

Major Federal Regulatory Policy Reforms on Unbundling of Interstate Pipeline Transportation

Date	*Order/Case*	*Summary*
1983	Special Marketing Programs (SMPs) Transco 4/83 Columbia 11/10/83 Tenneco 11/20/83 Panhandle/Trunkline 3/19/84 Texas Eastern 6/29/84 El Paso 8/24/84 Various Producers 1983-85	Transco established first SMP as part of rate settlement. Under Industrial Sales Program, Transco purchased and set prices for gas. Producer-suppliers and eligible end users who wished to participate could then sell gas to or by gas from the program. Transco's SMP expanded in June 1983 to include Contract Carriage Program (CCP). CCP allowed producers and end users to enter into direct sales agreements with the pipeline company acting as transporter. Transco's two programs were models for all later SMPs. As of April 1985, more than 30 SMPs had been approved. The programs were aimed primarily at fuel-switchers, so captive customers could not purchase this market-priced gas.
8/83	FERC Order 319 - Blanket Certificates to Transport Gas for High Priority Users	Allowed interstate pipeline companies to use blanket certificates to transport gas for high priority end users (process, feedstock, commercial, essential agricultural users, school, hospitals).
8/83	FERC Order 234-B - Blanket Certificates to Transport Gas for Non-Priority Users	Allowed interstate pipeline companies to use blanket certificates to transport gas for users covered by Order 30, in effect creating a spot market of direct sales from producers and other intrastate suppliers to industrial boiler fuel users. Gas could be sold and transported for up to 120 days without prior approval. Longer agreement required prior notice and allowed for protest.
5/84	FERC Order 380	Required pipelines to remove variable costs from minimum commodity bills; these costs represented up to 90% of minimum commodity bill.

9/84	Extension of SMPs	Term of SMPs extended for one year to 10/31/85. Conditions substantially eased: purchases could be made for gas originally priced at less than the system WACOG as long as the contract price remained above that of NGPA Section 109 gas; reporting requirements reduced; SMP gas could by used to serve up to 10 percent of the pipeline company's core market.
5/10/85	Maryland People's Counsel v. FERC F. 2nd No. 84-1019	Courts ruled SMPs in current form illegal because they discriminated against core customers.
5/10/85	Maryland People's Counsel v. FERC F. 2nd No. 84-1090	Courts ruled blanket certificate transportation for end users illegal as then conducted because it discriminated against pipeline company core customers. The two Maryland People's Court cases, in effect, outlawed any spot market not open to all buyers.
10/85	FERC Order 436	Issued in response to Maryland People's Counsel cases, allowed interstate pipelines to become "open-access" transporters for gas bought directly from producers. For open-access pipelines, Order would separate pipelines' merchant and transportation functions.
6/23/87	Associated Gas Distributors et al. v. FERC, No. 85-1811 et al.	U.S. Court of Appeals for D.C. Circuit remanded Order 436. Strongly affirmed open-access transportation and rate conditions of Order, but reversed and remanded nondiscriminatory access and Contract Demand (CD) reduction/conversion on grounds they aggravate pipeline take-or-pay problems.
8/7/87	FERC Order 500	Interim response to Court's vacating Order 436. Readopted 436, with modifications including: (1) producers must offer to credit gas transported by pipeline against pipeline's take-or-pay liability; (2) pipelines may seek to recover take-or-pay buyout/buydown costs associated with past liability; (3) pipelines allowed to design future gas supply charges to prevent further take-or-pay liability; and (4) eliminates CD reduction provision of Order 436.

2/5/88	FERC Order 490	Allowed sellers and purchasers to automatically abandon all first sales of natural gas under Section 7(b) of the Natural Gas Act, upon 30 days' notice, where the underlying contract has either (1) expired, or (2) been terminated or modified by mutual agreement of the parties. Promoted open-access transportation by making possession of Order 436/500 certificate a prerequisite for pipelines to abandon purchases unilaterally.
4/2/92	FERC Order 636	Mandates unbundling of basic pipeline merchant function and implements straight fixed-variable rate design. Unused LDC capacity claims released back to pipeline for brokering.

Source: Energy Information Administration (EIA) 1989

Summary of Gas DSM Potential Studies

B.1 Overview

Tables B-1 and B-2 (see end of this Appendix) summarize results from recent DSM potential studies of various gas local distribution companies (LDCs). The studies include the residential and/or commercial sectors. In most cases, the studies were conducted by consultants working for LDCs, while in one case, the project was jointly sponsored by a state research agency (New York State Energy Research and Development Authority) and a utility industry group (New York Gas Group). In this appendix, we discuss the procedures used by LBL in compiling information shown in the various columns of Tables B-1 and B-2, and provide an annotated description for individual studies. Key findings and overall trends are discussed in more detail in section 7.2.

B.2 Field Definitions

Definitions used and explanatory information to interpret data presented in Tables B-1 and B-2 are as follows:

Type of Potential - The definition and distinctions between technical, economic, and program achievable DSM potential are defined in Chapter 7. In most cases, studies estimated either technical or economic potential, although there are a few examples where more than one type of DSM potential was estimated. Based upon the review of each study, LBL calculated percentage savings for a particular sector (residential or commercial) or end use (e.g., space heating, water heating) where possible. In cases where it was not possible to estimate percentage savings by end use, those that were nonetheless included in the utility's overall sectoral results are indicated by an "X".

Decision rules used in calculating percentage savings varied by type of DSM potential study and data availability:

(1) For technical potential studies, percent savings are typically calculated based on overnight savings potential divided by current (base) year gas sales.

(2) Percentage savings were calculated in various ways for the economic potential studies because of data availability problems in defining the baseyear. In one case (Southwest Gas), percentage savings were calculated

based on projected savings and forecast sales values ten years into the planning period because these data were available. In several studies (the American Council for an Energy Efficient Economy (ACEEE) study of three New York utilities and studies conducted by Energy Investment for three Massachusetts utilities), percentage savings were calculated based on overnight replacement of all measures divided by recent (base) year sales.

It is important to note that suppressing the time dynamics in the calculation of percentage savings will tend to overstate savings potential somewhat because savings that are realized in the future (e.g., 10 years) are estimated relative to current year sales, rather than future year sales. For example, if gas sales are growing at 2%/year, future year sales will increase by 22% in year ten, absent a DSM program. If the DSM savings potential were estimated at 15% of current year sales, the savings would represent about 12.3% of sales in year ten.

Fuel Switching - Several studies included estimates of the potential for fuel switching from electric equipment and appliances to high-efficiency gas equipment. A negative sign indicates an increase in gas use as a result of fuel substitution. Percentage savings are typically calculated based on their impact relative to current (base) year gas sales within the corresponding sector.

In addition to the efficiency of the existing building and equipment stock and the size of heating and cooling loads (which are strongly influenced by climate severity), the following factors related to the scope, methodology, and key input assumptions used in the studies that may affect the magnitude of gas efficiency or fuel-switching potential are given in the tables.

Number of Measures Reviewed - The total number of individual measures considered in the potential study is reported as an indicator of the studies' comprehensiveness.

End Uses Considered - The end uses under which efficiency measures were covered. Differences among utilities reflect variations in gas end uses that are significant for various LDCs, whether the focus of the study was on fuel substitution opportunities (e.g., space cooling), and possibly degree of comprehensiveness.

Avoided Gas Costs - The magnitude of the DSM economic and achievable potential is influenced to some extent by the current or projected level of avoided gas costs. Information on the utility's estimated avoided costs are differentiated by season: "year-round," "winter," and "summer." The "Basis of Costs" line indicates the time horizon of the avoided cost forecast and whether the costs are levelized or not. Where range of avoided costs are reported, these represent the initial year and last year of the forecast period. "Gas Escalation Rate" indicates the annual rate at which the winter gas commodity portion of avoided costs is increasing.

The ACEEE study of three New York utilities and the WP Natural Gas study reported levelized avoided costs. The other utilities included yearly values of avoided costs over the study time horizon in real or nominal terms:

- Orange and Rockland calculated real summer and winter avoided costs for twenty years.

- Southwest Gas reported a range of nominal avoided costs for different end uses over 20 years. Space heating values were used for "Winter," and clothes drying values were used for "Year-round."

- Boston Gas reported real total avoided costs and measure life for each type of measure. Average annual avoided cost for each measure was calculated by dividing the total avoided cost by measure life. Space heating measures were assigned to "Winter" and water heating measures to "Year-round."

- Commonwealth Gas and Bay State Gas reported a range of average annual avoided costs based upon measure lifetime. Commonwealth's avoided costs are in real dollars, while Bay State's avoided costs are in nominal dollars. Both companies reported space heating values, which were used for "Winter," and annual base load values, which were used for "Year-round."

- Southern California (SoCal) Gas reported a 20-year range of nominal avoided costs that include environmental externalities.

- Atlanta Gas Light reported avoided costs in nominal dollars for a ten-year period.

Gas Escalation Rate - The assumed average annual rate at which gas commodity prices are assumed to escalate over the analysis period, which is embedded in the avoided cost calculation.

Discount Rate - The rate used to present value future benefits and costs attributable to DSM programs.

Nets Measure Interactions - A "Yes" in this row indicates that the study accounted for the interactive effects in determining savings per building when more than one measure is used in a building.

Externality Costs - A "Yes" in this row indicates that the study included the costs of environmental externalities in one or more of its screening tests.

Sensitivity Analysis - Indicates whether the study analyzed changes in potential savings from varying critical inputs. For example, many studies evaluated potential savings levels given a range of avoided costs, expected measure savings, and program costs.

B.3 Results

B.3.1 Residential Sector

Technical Potential

The Orange & Rockland Utilities (ORU), Southwest Gas (SWG), and WP Natural Gas studies estimated the DSM technical potential in the residential sector at 24%, 32%, and 36% respectively. While the aggregate estimate of technical potential are comparable for ORU and SWG in the residential sector, the end use sector potential varies significantly, primarily because of climatic differences. ORU, which is located in New York state, reported that 79% of the estimated savings potential were from space heating measures, while Southwest Gas, which is located in Nevada, reported that 69% of the savings potential were from water heating measures.

Orange & Rockland and WP Natural Gas estimates assume overnight adoption of available measures. The study conducted for WP Natural Gas, whose service territory spans across the states of Washington and Oregon, drew heavily on a 1990 Washington State Energy Office report that estimated savings associated with weatherization measures. WP Natural Gas also estimated savings associated with furnace upgrades. Eligible households in which measures could be installed were estimated based on a study performed for the state of Oregon. Technical potential was calculated by multiplying the number of measures (equal to the number of homes) by the savings-per-measure.

Southwest Gas reported savings for each year between 1991 and 2010. Percentage savings are calculated based on 1997 savings divided by 1991 residential sales. The year 1997 was selected because it is after the program ramp up period. Southern California Gas and Atlanta Gas Light calculated technical potential for a range of measures, but did not present results in aggregate.

Economic Potential

Estimates of the DSM economic potential varied substantially among studies. The American Council for an Energy Efficient Economic study of three New York utilities represents the upper end with savings ranging between 29-42% of current sales, assuming levelized avoided gas costs of $2.50/Dth, and 44-48% of current sales assuming avoided costs are in the $4.00/Dth range.[1] About half of the savings are only cost-effective at the time of equipment replacement. The ACEEE study used a TRC test to set the cost-effectiveness threshold and incremental measure costs were increased by 50% to account for estimated program administrative costs.

Orange and Rockland's estimate of DSM economic potential at 15% is substantially lower than the ACEEE study. At first glance, this large discrepancy is surprising given that all of the utilities are located in New York. Several factors partially account for these differences: (1) the ACEEE study included more individual measures and additional end uses than the ORU study, (2) ORU reduced its economic potential to account for savings attributable to codes and standards, and (3) ORU assumed measures would be implemented gradually, while ACEEE assumed immediate implementation of measures.

SoCal Gas estimate of DSM economic potential is substantially lower, ranging between 5-9% of current sales (depending on the base year upon which savings are based).[2] Of the total economic potential, water heating and space heating accounted for 60% and 30%, respectively. One reason for the relatively low economic potential is Southern California's warm climate, which reduces space heat savings.

Percentage savings values were calculated for each utility as follows:

- The ACEEE study of Long Island Lighting, Brooklyn Union Gas, and National Fuel Gas - The economic potential value is based on overnight replacement of all measures and 1991 sector sales.

- Southwest Gas - Savings potential is based on savings and sales in year 2000. Southwest Gas study does not explicitly account for measure interactions.

[1] It should be noted that the ACEEE study is a draft report and that the utilities don't necessarily endorse the ACEEE findings.

[2] Economic potential for SoCal Gas ranges from 5% in 1994 to 9% in 2010. Their report did not include sufficient information to calculate percentage savings in terms of savings divided by forecasted sales in year ten.

- Orange and Rockland reported future savings, but future sales were not provided. Accordingly, their economic potential is based on 2003 savings and 1993 sales.

- Boston Gas, Commonwealth Gas, and Bay State Gas contracted separately with Energy Investment Inc. to develop estimates of DSM economic potential. For all three companies, economic potential is based on overnight savings. The lower values reported for Boston Gas and Commonwealth Gas represent sensitivity analysis which discounts the engineering estimate of savings-per-measure by 20%, while the higher value assumes 100% of projected savings. For Bay State Gas, LBL reports the average of savings associated with low income, single family, and 2-plus family houses, all of which were close to 32%.

- Atlanta Gas Light calculated economic potential for a range of measures, but did not present an aggregate estimate of savings for the service territory.

Program Achievable Potential

Orange and Rockland reported DSM program achievable potential of 5%, based on 75% market penetration evenly distributed over 20 years. The program achievable potential is based on 2003 savings divided by 1993 sales.

B.3.2 Commercial Sector

Technical Potential

The two utilities that developed estimates of the DSM technical potential in the commercial sector reported lower values (9-16%) than their estimates for the residential sector (32-36%).

Percentage savings values were calculated for each utility as follows:

- Orange & Rockland assumes overnight adoption of available measures.

- Southwest Gas reported savings for each year between 1991 and 2010. Southwest Gas' technical potential is expressed as 1998 savings divided by 1991 commercial sales. The year 1998 was selected because it follows the program ramp up period.

- Southern California Gas and Atlanta Gas Light calculated technical potential for a range of measures, but did not present an aggregate estimate of savings in their service territories.

Economic Potential

The DSM economic potential ranged between 8-24% of total commercial sector sales among the nine utility case studies. Savings potential was more comparable across utilities than those in the residential sector and typically focused on only three end uses (space heating, water heating, and cooking).

Percentage savings values were calculated for each utility as follows:

- The ACEEE study of Long Island Lighting, Brooklyn Union Gas, and National Fuel Gas based economic potential value on overnight replacement of all measures and 1991 sector sales. The range of savings reported is based on two avoided cost values. The low value assumes an avoided cost of $2.50/DTh, while the high value assumes an avoided cost of $4.00/DTh. As for the residential sector analysis, the ACEEE study used a TRC test to set the cost-effectiveness threshold and incremental measure costs were increased by 50% to account for estimated program administrative costs.

- Southwest Gas' economic potential, which does not account for measure interactions, is based on savings and sales in 2000.

- Orange and Rockland reported future savings, but future sales were not provided. Accordingly, their economic potential is based on 2003 savings and 1993 sales. They added an 18% premium to measure costs to reflect average program costs.

- For Boston Gas, Commonwealth Gas, and Bay State Gas, economic potential is based on overnight savings. The lower values reported for Boston Gas and Commonwealth Gas represent sensitivity analysis which discounts the engineering estimate of savings per measure by 20%, while the higher value assumes 100% of projected savings.

- Southern California Gas' economic potential ranges from 8% of current sales in year 1994 to 14% of current sales in year 2010. Their report did not include sufficient information to calculate the intermediate ten-year value.

- Atlanta Gas Light calculated economic potential for a range of measures, but did not present consolidated savings estimates.

Program Achievable Potential

Orange and Rockland reported DSM program achievable potential of 5%, based on 75% market penetration evenly distributed over 20 years. The program achievable potential is based on 2003 savings divided by 1993 sales.

B.3.3 Fuel Switching: Residential and Commercial Sectors

Six of the eleven DSM potential studies included estimates of the potential for fuel switching in the residential sector, while five studies included estimates in the commercial sector. Only the potential for switching from electricity to gas were estimated in these studies. As in the assessments of savings from efficiency measures, different types of fuel switching potential (e.g., technical, economic, achievable) were estimated in the respective studies. LBL calculation of percentage impact relative to gas sales varied among utilities depending on the availability of data:

- ACEEE study of Long Island Lighting, Brooklyn Union Gas, and National Fuel Gas assume an overnight change from electricity to gas and are based on 1991 gas sales levels.

- The Southwest Gas value is based on fuel switching potential in 2005, which is after their program ramp-up period. In the residential sector, it should be noted that space cooling, which does not pass the TRC test, represents 96% of Southwest Gas' fuel switching potential. Thus, this estimate of fuel switching primarily represents a technical potential.

- Atlanta Gas Light - Value represents existing program fuel switching potential.

- Orange and Rockland examined fuel switching in their study, but did not report any consolidated numbers.

Table B-1. Residential DSM Potential for Selected Gas Utilities

Residential	LILCO (1) & (2)	Brooklyn Union Gas (1) & (2)	National Fuel Gas (1) & (2)	Orange & Rockland (3)	Southwest Gas (4) & (5)	WP Natural Gas	Boston Gas (6)	Commonwealth Gas (6)	Bay State Gas (7)	SoCal Gas (8)	Atlanta Gas Light (9)
Type of Potential											
Technical				36%	32%	24%				X	X
Economic	24-41%	34-47%	27-44%	15%	25%		11-20%	24-32%	32%	5-9%	X
Program Achievable				5%							
Fuel Switching	-3%	-2%	-5%	X	-7%						-2%
Measures Reviewed (#)	52	52	52	22	26	N/A	23	~20	26	28	26
End Uses Considered: (10)											
Space Heating	X	X	X	X	X	X	25%	X	X	X	X
Space Cooling											
Water Heating	X	X	X	X	X	X	14%	X	X	X	X
Cooking	X	X	X								X
Clothes Drying	X	X	X		X						X
Avoided Gas Costs (11)											
Year-round ($/Dth)					3.32-14.61	4.10	3.02	2.90-3.61	3.80-12.96	4.53-9.68	1.50-4.32
Winter ($/Dth)				3.05-6.22	5.21-18.87	4.98	3.56-4.93	3.23-4.86	4.37-15.40	3.63-7.98	1.39-20.88
Summer($/Dth)				1.61-3.47							1.39-3.60
Basis of Costs				22yr range	20yr range	30yr level	20yr range	20yr range	25yr range	18yr range	10yr range
Gas Escalation Rate				4%	10%			8%	4%	4%	4%
Key Assumptions											
Discount Rate	5.0%*	5.0%*	5.0%*		10%	9%		11%	10%	9%	9-12%
Nets Measure Interactions	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	
Externality Costs	No	No	No	No	No	Yes	No	No/Yes	Yes	Yes	Yes
Sensitivity Analysis	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes

(1) Economic potential and fuel switching based on overnight savings divided by 1991 sector sales.
(2) Range of economic savings based on avoided costs of $2.50/DTH AND $4.00/DTH and incremental measure cost + 50% scenario.
(3) Technical potential based on overnight savings and 1993 sales; economic potential based on 2003 savings and 1993 sales; achievable potential based on 2013 savings
(4) Technical potential based on 1997 savings and 1991 sales; economic potential based on 2000 savings and sales.
(5) Fuel switching based on 2005 technical potential and sales. The number reported reflects potential that passes the TRC test.
(6) Economic potential based on overnight savings; low value assumes 20% discounted savings; high value assumes 100% of savings.
(7) Economic potential based on overnight savings.
(8) Economic potential based on 1994 and 2010 savings.
(9) The range of discount rates includes societal, corporate, and participant discount rates.
(10) Percentages represent estimated savings for that end use.
(11) Southwest Gas, Bay State Gas, SoCal Gas, and Atlanta Gas Light used nominal $'s; all others used real $'s.

* Real Value

Sources: Nadel 1993, Orange & Rockland 1993, Southwest Gas 1991, WA Water Power 1993; WP Natural Gas 1993; Boston Gas 1990; Commonwealth Gas 1991; Bay State Gas 1991; SoCal Gas 1992; Atlanta Gas Light 1992.

Table B-2. Commercial DSM Potential for Selected Gas Utilities

Commercial	LILCO (1) & (2)	Brooklyn Union Gas (1) & (2)	National Fuel Gas (1) & (2)	Orange & Rockland (3)	Southwest Gas (4) & (5)	Boston Gas		Commonwealth Gas		Bay State Gas (7)	SoCal Gas (8)	Atlanta Gas Light (9)
						Com (6)	Ind (6)	Com (6)	Ind (6)			
Type of Potential												
Technical				16%	9%						X	X
Economic	18-19%	15-16%	17-20%	10%	8%	13-17%	9-14%	8-23%	11-23%	23%	8-14%	X
Program Achievable				5%								
Fuel Switching	-28%	-49%	-9%	X	-6%							-2%
Measures Reviewed (#)	40	40	40	16	39	20	21	~20		30	35	13
End Uses Considered: (10)												
Space Heating	X	X	X	X	X	28%	22%	X	X	X	X	X
Space Cooling	X	X	X		X							X
Water Heating	X	X	X	X	X	5%		X	X	X	X	
Cooking	X	X	X					X			X	
Clothes Drying												
Process Heat							6%					X
Other					X							X
Avoided Gas Costs (11)												
Year-round ($/Dth)					3.32-14.61	3.02		2.90-3.61		3.80-12.96	4.53-9.68	1.50-4.32
Winter ($/Dth)				3.05-6.22	5.21-18.87	3.56-4.93		3.23-4.85		4.37-15.40	3.63-7.98	1.39-20.88
Summer($/Dth)				1.61-3.47								1.39-3.60
Basis of Costs				22yr range	20yr range	20 yr range		20yr range		25yr range	18yr range	10yr range
Gas Escalation Rate				3.66%	9.54%			8%		4%	4%	4%
Key Assumptions					9.84%							
Discount Rate	5.0%*	5.0%*	5.0%*		0.0984			11%		10%	9%	9%
Nets Measure Interactions	Yes	Yes	Yes	Yes	No	Yes		Yes		Yes	Yes	Yes
Externality Costs	No	No	No	No	No	No		No/Yes		Yes	Yes	Yes
Sensitivity Analysis	Yes	Yes	Yes	No	Yes	Yes		Yes		Yes	Yes	Yes

(1) Economic potential and fuel switching based on overnight savings divided by 1991 sector sales.
(2) Range of economic savings based on avoided costs of $2.50/DTH AND $4.00/DTH and incremental measure cost + 50% scenario.
(3) Technical potential based on overnight savings and 1993 sales; economic potential based on 2003 savings and 1993 sales; achievable potential based on 2013 savings
(4) Technical potential based on 1998 savings and 1991 sales; economic potential based on 2000 savings and sales
(5) Fuel switching based on 2005 technical potential and sales.
(6) Economic potential based on overnight savings; low value assumes 20% discounted savings; high value assumes 100% of savings.
(7) Economic potential based on overnight savings.
(8) Economic potential based on 1994 and 2010 savings.
(9) The range of discount rates includes societal, corporate, and participant discount rates.
(10) Percentages represent estimated savings for that end use.
(11) Southwest Gas, Bay State Gas, SoCal Gas, and Atlanta Gas Light used nominal $'s; all others used real $'s.

* Real Value

Sources: Nadel 1993, Orange & Rockland 1993, Southwest Gas 1991, WA Water Power 1993; WP Natural Gas 1993; Boston Gas 1990; Commonwealth Gas 1991; Bay State Gas 1991; SoCal Gas 1992; Atlanta Gas Light 1992.

Calculating the Breakeven Avoided Cost of Gas for DSM Measures

Lifecycle costs of electric versus gas technologies cannot be calculated without a well-defined avoided cost for gas. However, since the other costs required by such a lifecycle analysis can be specified, for example, the capital and operating cost of both technologies, the real discount rate, and the avoided cost of electricity, a breakeven gas avoided cost can be calculated by determining the price of gas at which the lifecycle costs of competing electric and gas options are identical. At this price, one would be indifferent (on economic grounds) to the choice of technology. Thus, if the actual avoided cost of gas is lower than the breakeven price, then the gas technology would be more cost-effective than the electric technology and vice versa. Whether the base technology is a gas or electric technology switching to the other, the breakeven avoided cost is interpreted in the same way: as the gas avoided cost level below which the gas technology is preferred, and above which the electric technology is preferred.

To better understand this concept, a simplified algebraic derivation of the gas breakeven avoided cost is provided (adapted from Nadel et al. 1993b). The breakeven gas price is always calculated in reference to the lifecycle cost of an electric technology compared to a gas technology. For the total lifecycle costs (LCC) of the competing base and alternative technologies (gas or electric) to be equal:

$$LCC_{bse} = LCC_{alt} \qquad \text{(C-1)}$$

The total lifecycle cost of each option is the sum of the capital and installation costs of each option (CI), its nonfuel operating and maintenance cost (OM), its electricity cost (EL), and its gas cost (GS). That is:

$$LCC = CI + OM + EL + GS \qquad \text{(C-2)}$$

Since a societal perspective on the economics of fuel switching is desired, the costs of electricity and gas are evaluated using long-run avoided costs for both energy sources and future operating costs are present-valued using an appropriate real discount rate.

Of course, the gas cost is unknown, since it is the product of the quantity of gas consumed (GQ) times the long-run avoided cost for gas (GAC) which is unknown.

$$GS = GQ \times GAC \tag{C-3}$$

The breakeven gas price is based on the concept that, if the two lifecycle costs are equal, simple algebraic manipulation of the terms will allow one to solve for the unknown GAC. That is, substituting Equation (C-3) into Equation (C-2), and Equation (C-2) into Equation (C-1) yields,

$$\begin{aligned} CI_{bse} + OM_{bse} + EL_{bse} + GQ_{bse} \times GAC &= \\ CI_{alt} + OM_{alt} + EL_{alt} + GQ_{alt} \times GAC & \end{aligned} \tag{C-4}$$

Then, solving for GAC:

$$GAC = \frac{(CI_{alt} + OM_{alt} + EL_{alt}) - (CI_{bse} + OM_{bse} + EL_{bse})}{GQ_{bse} - GQ_{alt}} \tag{C-5}$$

Equation (C-4) says, given that two options have different nongas lifecycle costs, the price of gas that will make the total lifecycle costs of the two options equivalent is just this difference in nongas lifecycle costs divided by the difference in gas consumption.

A high breakeven gas price means that the gas technology will be generally cost-effective compared to the electric competitor. Conversely, if the gas breakeven cost is lower than the likely range of gas avoided costs, the electric technology would remain more cost-effective than the gas technology. Put another way, under this latter scenario gas must be very cheap for the gas technology to compete successfully against the electric technology. If the gas breakeven cost, for example, is negative, then the gas alternative will never be cost-effective at any gas price.

Gas DSM Technologies

D.1 Overview

This appendix reviews gas measures and technologies for energy efficiency and fuel substitution between electricity and gas. It is not intended to be comprehensive, but rather to highlight potentially attractive gas savings opportunities for further investigation. The focus is primarily on gas-fired equipment measures for the following reasons. First, equipment measures are generally specific to natural gas and thus uniquely relevant to LDCs, whereas other types of measures that reduce loads for space-heating or cooling, or water-heating, are independent of the type of fuel consumed for meeting those loads. Second, many PUC and utility staff are more familiar with building shell retrofits because these measures have often been implemented through first-generation gas utility audit programs, electric utility DSM programs, or government programs such as Residential Conservation Service or state building energy codes.

The measures include those that are commercially available, or likely to be marketed in the near future. Because of the myriad technologies, applications, operating environments, and other site specific variables, the performance of equipment is described where possible with generally agreed upon measures of efficiency. Seasonal efficiency indices determined in industry standard test procedures are relied upon where available, although where such indices are not in use, other figures of merit are used (e.g., savings as compared to some base technology) as a way of comparing the relative performance of different DSM measures.[1]

This appendix approaches the subject of gas efficiency measures and strategies at the level of technology screening akin to the level at which a technical potential assessment would be approached. Obviously, the economics of gas DSM are critical and many of the measures presented here would not pass cost-effectiveness tests in particular circumstances. One should not interpret the focus on technical efficiency as a denial of the overriding importance of cost-effectiveness in judging the desirability of these technologies. However, a comprehensive economic analysis of each technology on a national scale is beyond the scope of this primer.

The first section reviews gas efficiency measures, followed by electric-to-gas fuel substitution measures, and finishes with gas-to-electric fuel substitution measures.

[1] For some types of equipment, no such measures exist. In those cases, savings estimates are based on literature reviews, though caution is urged in extrapolating these estimates to other circumstances.

D.2 Gas Equipment Efficiency Measures

D.2.1 Residential Space Heating

A number of space heating technologies exist or are near commercialization for improving gas efficiency in residences (see Table D-1). The estimated seasonal efficiency of existing gas warm air furnaces and hot water (hydronic) or steam boilers in the current U.S. housing stock ranges between 60-68% (Dutt 1990; Holtberg et al. 1993).[2] This conventional unit is likely to be of the type that has a continuously burning pilot and in which exhaust gases from combustion are vented using the natural buoyancy effect (also known as "atmospheric" venting). A buoyancy driven exhaust process requires high stack temperatures (in the neighborhood of 300- 500°F) in which a significant portion of the heat of combustion is lost to the outdoors.

This basic design has been improved upon in a number of ways. Gas can be saved by replacing the pilot with an intermittent ignition device (IID) and by installing a damper in the vent to reduce heat losses when the burner is not operating, which improves the seasonal efficiency of a unit equipped with these devices to about 75%. By adding a fan or power burner to induce or force vent gases up the stack, more heat can be extracted from the exhaust stream and seasonal efficiency can be further increased to around 80%. The most dramatic efficiency improvements in gas heating equipment come from modifications to the combustion process and/or extraction of heat from that process.

Condensing furnaces and boilers condense some of the moisture from the flue gases in order to extract part of the latent heat of water vapor that would otherwise be lost with the other exhausted combustion products. Systems designed in this way can achieve seasonal efficiencies in excess of 90%. The dew point of natural gas combustion products is 140°F and so combustion gases must be cooled to this level or below for condensation to occur. It is difficult for boilers to maintain temperatures this low since the return water temperatures are often well above 140°F and for this reason, boilers are usually of the near condensing type. Near-condensing systems exhibit seasonal efficiencies around 82%.

Pulse combustion technology alters the steady flow of gas and air into the burner and continuous operation of conventional burners to operating on a series of periodic (60 to

[2] Seasonal efficiency is determined by means of a DOE test procedure applied to residential central furnaces. Called the Annual Fuel Utilization Efficiency, or AFUE, it differs from the maximum capacity steady state or thermal efficiency in that it accounts for warm-up, cool-down and off-cycle losses. Off-cycle losses include any standing pilot losses as well as room air losses through the venting system due to air flow through the combustion chamber and draft diverter.

Table D-1. Residential Space and Water Heating Efficiencies

Technology	Efficiency (%)
Residential Space Heating	(AFUE)
Typical Existing Furnaces/Boilers	60-68[1]
IID and vent damper	75[2]
Condensing furnaces	85-96[3]
Modulating furnaces	92[4]
Condensing hydronic boilers	84-91[3]
Near-condensing steam boilers	82[4]
Gas engine heat pumps (heating only)	120-150[5]
Residential Water Heating	(EF)
Typical Existing Storage Heaters	54[1]
IID and vent damper	54-61[6]
2" jacket insulation	57[6]
Flue baffling and power venting	66[6]
Submerged combustion chamber and power venting	72[6]
Eliminate center flue and indirect heating	74[6]
Pulse combustion, condensing	80[6]
Condensing unit	86[6]
Instantaneous Heaters	70[4]
Typical MF combo SH/DHW boilers	40-45[4]
Dedicated DHW boiler in MF	65[4]

Sources:
[1] Holtberg et al. 1993
[2] Dutt 1990
[3] GAMA 1993
[4] Nadel 1993b
[5] Klausing et al. 1992
[6] Paul et al. 1991

70 times per second) ignitions that are self-perpetuating. Very high heat transfer coefficients are achieved, leading to correspondingly high thermal and seasonal efficiencies. Pulse combustion systems can also be condensing, and achieve the seasonal efficiencies shown in Table D-1.

Another alternative burner design is the modulating type. Burners used in furnaces and boilers are typically designed to fire at full capacity and track heating demand by cycling on and off. Modulating systems operate the burner at less than full capacity thereby producing savings by firing closer to the demand; these systems can achieve seasonal efficiencies of 92%. At present, only two-stage modulating type furnaces are available, which operate at low or high firing rates and achieve seasonal efficiencies around 90%.

An emerging technology for gas space heating (as well as space cooling) is the gas engine heat pump (GEHP). GEHPs operate on the same vapor compression refrigeration cycle that electric heat pumps operate on except that the compressor is powered by a natural gas-fired internal combustion engine instead of an electric motor. GEHPs are technically attractive in the heating mode because their efficiencies have been shown to exceed those of the technologies cited above based on direct-fired combustion heating. Waste heat recovered from the engine jacket and exhaust supplementing the vapor compression cycle in the heating mode and variable-speed operation both boost seasonal efficiency. Heat pump efficiency is subject to a number of factors, the most important of which are the outdoor temperature regime and the indoor temperature setpoints, but GEHPs have realized heating mode seasonal efficiencies in field tests between 120- 150% (Klausing et al. 1992).

GEHPs were commercially introduced in Japan in 1987, where currently about 35,000 units per year are being sold. In the U.S., GEHPs are nearing commercialization with one manufacturer expected to bring some residential units to market in 1994. Due to the lack of field experience, concerns have been raised about likely maintenance burdens and the lack of infrastructure for servicing this new technology.

GEHPs are discussed further in Section D.3.1 as a fuel switching technology because when operating in cooling mode, GEHPs would be displacing electric technologies in a market that electricity currently dominates.

The National Appliance Energy Conservation Act of 1987 (NAECA) requires a minimum seasonal efficiency (as measured by the Annual Fuel Utilization Efficiency, i.e., AFUE) of 78% for gas furnaces and 80% for gas boilers manufactured after 1992.[3] Therefore, only the more advanced gas savings measures pertain to the space heating equipment replacement market because the standard will result in naturally-occurring efficiency improvements up to these efficiency levels as existing equipment are replaced.

A number of operational issues arise with the advent of newer, more efficient designs in furnaces and boilers. Proper venting of exhaust gases is particularly important, with specific recommendations depending on vent pressures and whether or not condensation is expected. Condensing and near-condensing type units have experienced past problems

[3] Because the rating for furnaces is determined by a slightly different test than for boilers, the standard specifies a roughly similar efficiency level for the two equipment types.

of corrosion of flue pipes and heat exchangers from acidic condensate. These problems have been mitigated by the use of corrosion resistant materials such as high temperature plastics, stainless steel, or ceramics, but are more expensive than conventional materials used for these system components.[4] With these types of systems, condensate drains also have to be installed and this increases total installed system cost (though condensing furnaces are often paired with air conditioners and use the same condensate drain, thus saving costs overall).

In some cases, either local codes specify or manufacturer's recommend that outdoor air be provided for combustion with heating equipment located indoors. Because off-cycle losses have been significantly reduced in high-efficiency equipment, oversizing apparently has a lower energy penalty associated with it than with conventional units.[5] Past design practice of many existing furnaces and boilers led to oversizing relative to the loads they served. With oversized units, the excessive cycling occurs with attendant increased standby losses, leading to degraded energy performance. This condition is exacerbated by the later introduction of building shell measures to reduce heating loads. An additional benefit of replacing an existing furnace or boiler with a new, energy efficient unit is the opportunity to more closely match the capacity to the load, thereby reaping additional efficiency improvements.

Finally, while not specific to high-efficiency equipment, duct and piping heat losses will decrease overall efficiency of the heating *system* and reduce the potential benefits from implementation of equipment efficiency measures and can lead to moisture and indoor air quality problems as well.

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[4] A related problem sometimes occurs when an old gas furnace sharing a flue with another combustion device (typically a water heater) is replaced with a new, efficient furnace that vents exhaust gases elsewhere, leaving the "orphan" appliance with inadequate stack conditions to properly vent its gases. This can cause corrosion in the existing flue and necessitate additional expense to correct the problem—a hidden cost of the new technology.

[5] An exception to this is with condensing boiler units where oversizing may increase return water temperatures and thereby reduce condensation and the efficiency gains associated with it.

D.2.2 Residential Water Heating

Hot water loads are a function of the volumetric demand for hot water, the inlet water temperature (which varies by location and time of year), and the temperature setting (typically in the range of 110-140°F). Storage type water heaters with 30-60 gallon tank and a standing pilot light dominate the U.S. market for residential gas water heating. Slightly over 50% of the residential-scale water heaters (i.e., with heating capacity less than 75,000 Btu/hr) sold each year in the last decade have been gas-fired (Gas Appliance Manufacturers Association (GAMA) 1992). The NAECA standards require all new gas water heaters to have an efficiency of approximately 54% (as measured by the Energy Factor) which varies somewhat depending on the unit size.[6] Technologies for improving water heater efficiency include: increasing jacket insulation, IID and flue damper, increased flue baffling and power venting, multiple flues, submerged combustion chamber, pulse combustion, and condensation of flue gases (Paul et al. 1991). The efficiencies of each of these design options are shown in Table D-1.

Instantaneous or "tankless" gas water heaters can save gas by eliminating the standby losses from the hot water tank during idle periods. The savings have been estimated for versions with IIDs to be in the range of 30-50% of total water heater gas use depending on hot water draw quantities (Nadel et al. 1993a), and Energy Factors are estimated to be around 70% (Nadel et al. 1993b). Widely used in Europe and Japan, instantaneous gas water heaters have little market share in the U.S due to the challenge of locating exhaust vents near the unit and the perception that they possess inadequate heating capability. Also, the current versions on the U.S. market use pilot lights and therefore offer significantly less savings than those quoted above.

In multifamily buildings where a central boiler provides both space and water heat, substantial energy savings can be produced by installing a dedicated high-efficiency boiler for water heating alone. Savings for this measure depend highly on the particular circumstances, but have been estimated to improve efficiency from 40% or 45-65% (Nadel et al. 1993b).

Measures to reduce hot water loads include low-flow faucets and shower heads, horizontal-axis clothes washers, and low-water-use dishwashers. A horizontal-axis clothes washer saves hot water by allowing the clothes drum to operate with roughly half the water used for a comparably-sized load in a conventional vertical-axis clothes washer. Potential gas water heat savings over a conventional unit are estimated to be 64% (Nadel

[6] The Energy Factor defines an overall efficiency for water heaters while delivering 64.3 gallons of hot water per day in a standard test procedure. It takes into account both the effectiveness of the burner in transferring energy to the water during firing and standby losses when the burner is not operating.

et al. 1993a). Manufactured as either front or top loading, horizontal-axis clothes washers are widely used in Europe but are reported to have only 5% or less of the U.S. market. DOE is purported to be considering horizontal-axis technology for the 1999 NAECA standard for clothes washers.

Low-water-use dishwashers save energy beyond those meeting the 1994 NAECA standard primarily through savings in hot water use of approximately 25% (Nadel et al. 1993a). Dishwashers of this type are just beginning to enter the U.S. market.

D.2.3 Residential Cooking

Relatively little gas is consumed in residential gas ranges and ovens, particularly since the NAECA standards stipulated new units equipped with an electrical connection use nonpiloted burner ignition. Most new residential gas ranges use IIDs as their ignition device, though ovens commonly use a hot surface ignition device ("glo-bar") that draws close to 400W of electricity while the burner is on. While replacing the glo-bar with an IID in the oven unit would save energy, it is technically not a gas saving device. Other design options for reducing cooking gas use in conventional ranges and oven include thermostatically controlled burners, insulation and reflective surfaces for the range and/or oven, reduced vent size, reduction of thermal mass, forced convection during cleaning, and use of an oven separator. Infrared burners for ranges have also been touted as a gas saving technology, but the claim has not been substantiated using standard test procedures. Given the small quantity of gas used for cooking, besides IIDs few of these technologies are viewed as attractive for increasing efficiency in this area (Nadel et al. 1993b).

D.2.4 Residential Clothes Drying

While gas appliances have a relatively low penetration in the residential clothes drying market, there are a number of potentially attractive gas savings measures applicable to them (shown in Table D-2). As with other gas appliances using pilot lights, savings can be achieved through replacement of pilots with IIDs (annual savings of about 30 therms have been estimated for this measure) (Meier et al. 1983).

Automatic shutoff controls that are either temperature or moisture activated can produce savings of about 12% over conventional dryers that operate on a timer cycle and rely on user guesswork to set the cycle duration (Nadel et al. 1993b).

A significant clothes drying load reduction measure is the use of a high spin speed washer that reduces the water content of clothes from a typical 70-40%. Removing

Table D-2. Residential Clothes Drying Savings

Technology	Savings
Residential Clothes Drying	
Electronic ignition	30 therms/yr[1]
Automatic shutoff control	12%[2]
High spin-speed washer	40%[3]

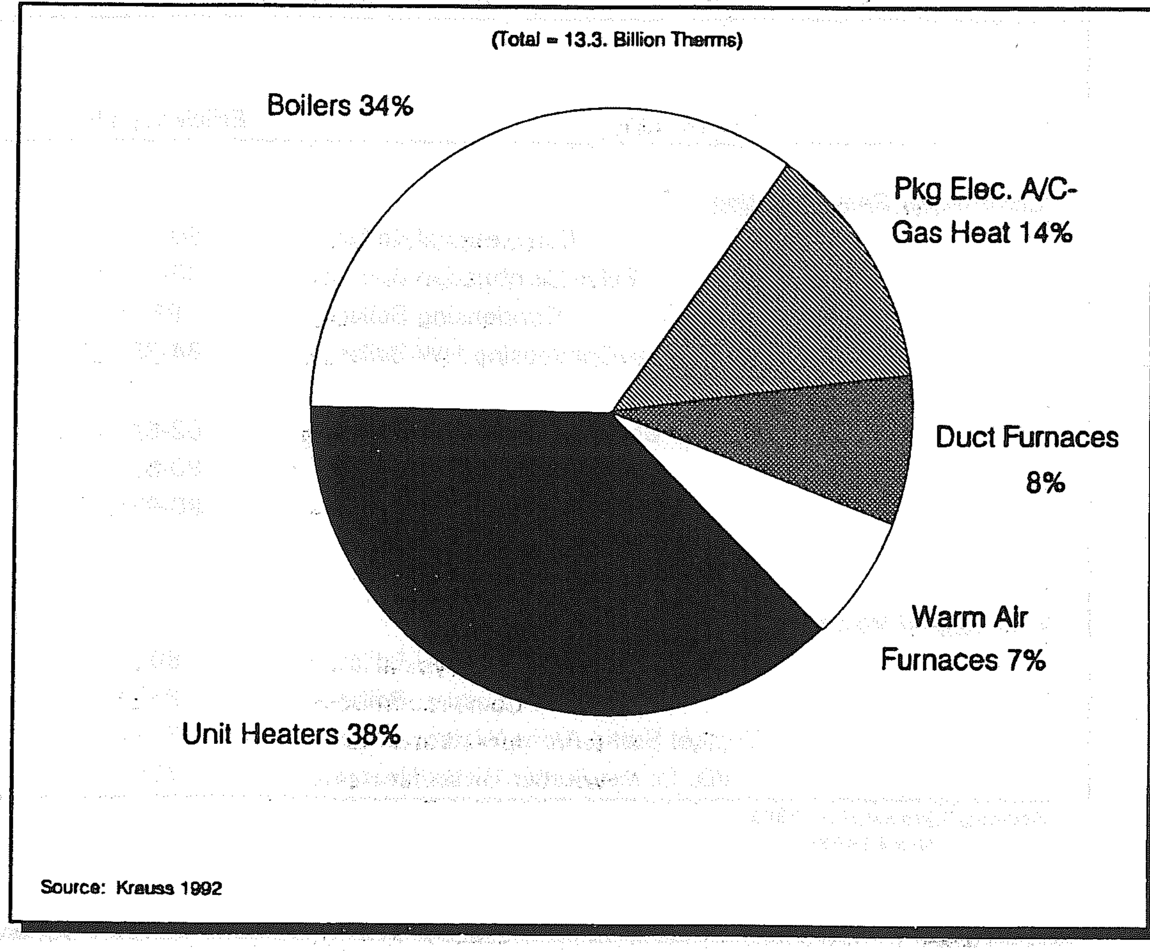
Sources: [1] Meier et al. 1983
[2] DOE 1990
[3] Nadel 1993a

moisture from clothes in this range by spinning is far more energy efficient than thermal drying. Gas clothes drying savings have been demonstrated in the range of 28- 47% from this technology (Nadel et al. 1993a).

D.2.5 Commercial Space Heating

Space heating requirements in the commercial sector are met by a variety of equipment types fueled by natural gas. Figure D-1 shows the market share (by annual gas consumption) for unit heaters, boilers, packaged gas heating/electric cooling units, duct furnaces and warm air furnaces. Unit heaters serve the largest portion of the current market for commercial heating applications, followed by hot water and steam boilers. Together, these two types of equipment make up nearly three-quarters of the commercial space heating market, so our discussion of suitable energy efficiency measures focuses on these two types of equipment. This section on commercial space heating equipment and measures draws extensively upon a detailed study conducted by (Krauss et al. 1992).

Figure D-1. Annual U.S. Commercial Gas Heating Share by Equipment Type



Unit Heaters

Gas-fired unit heaters provide warm air for space heating by means of a furnace typically suspended above the floor or work area. They are most often used in open spaces such as repair facilities, warehouses, or where aesthetics are not a large concern. Unit heaters come in three major types: gravity vented, power vented, and separated combustion. Gravity vented unit heaters are reported to account for 75-80% of shipments annually. Therefore, this type constitutes the conventional technology against which more energy efficient types are compared.

Table D-3. Commercial Space and Water Heating Efficiencies

Technology	Efficiency (%)
Commercial Space Heating	
Conventional Boiler	50-81[1]
Pulse Combustion Boiler	86-95[1]
Condensing Boiler	95[1]
Near-Condensing HW Boiler	84-88[1]
Conventional Unit Heaters	62-64[1]
Power-Draft Unit Heaters	80-83[1]
Condensing Pulse unit Heater	90-95[1]
Commercial Water Heating	
Typical Boiler	80[2]
Pulse Combustion Boiler	85[2]
Typical Stand-Alone Water Heater	54[2]
IID, Power Burner Water Heater	72[2]

Sources: [1] Krauss et al. 1992
[2] Nadel 1993b

As shown in Table D-3, the seasonal efficiency of conventional unit heaters is around 63%.[7] Power vented and separated combustion unit heaters represent an improvement in the seasonal efficiency up to around 80%. Power vented types make up only 15-20% of annual sales of unit heaters, while separated combustion types achieve only about 5% of sales (apparently primarily for reasons other than energy efficiency). A condensing pulse unit heater is commercially available with an AFUE purported to be in the range of 90-95%, but with less than 1% of the national unit heater market due in part to a limited range of sizes currently offered.

[7] Note that for these and other commercial heating equipment there are currently no industry-standard test procedures for determining seasonal efficiency. The numbers quoted in this section are based upon test procedures used for residential-type equipment.

Retrofit options for unit heaters include vent dampers, intermittent ignition devices, and setback thermostats, with savings varying depending on the existing equipment, the usage pattern, and local weather.

Boilers

For purposes of understanding energy use of boilers, they can be classified by distribution medium, heat exchanger material, or burner type. The market trend is towards the use of hot water as the distribution medium for boilers in commercial space heating applications, with estimates as high as 95% in new construction. Hot water boilers tend to have higher seasonal efficiencies than steam boilers because the former have lower return water temperatures and are often better controlled and matched to loads. Steam boilers are apparently sold primarily for retrofit steam heating and process applications. Cast iron heat exchangers form the overwhelming majority of boilers sold in commercial sizes (i.e. above 200,000 Btu/hour output rating), with steel and copper heat exchanger-based boilers serving a relatively minor market segment. Among burner types, roughly half of the boilers sold for commercial heating applications are equipped with atmospheric burners and half with power burners.[8] Boilers with power burners offer efficiency advantages over atmospheric burners through better control of the fuel to air ratio in combustion and reduction in standby heat losses.[9] In Table D-3, the upper range of conventional boiler efficiency comprises hot water boilers with power burners, while the lower range comprises steam boilers with atmospheric burners. Boilers equipped with condensing or near-condensing technology are commercially available in efficiencies upwards of 85% also shown in Table D-3. Currently these are only manufactured as hot water boilers.

Boiler retrofit measures for increasing efficiency include a number of options for improving the control of the equipment. Reset devices provide better control of the water temperature to match the heating load. Outdoor cutout controls shut off the boiler when the outdoor temperature is above some set level, thus saving energy during those periods in the swing seasons (Spring and Fall) when the boiler would otherwise be running in standby mode. Thermostatic zone temperature controls can produce savings by more closely meeting the diversified loads in distributed zones rather than treating the building as a single (or few) zones. Thermostats often also provide nighttime temperature setback capability.

[8] Other burner types are available, one of which we discuss later, but they collectively hold a small share of this market (2-5%).

[9] No standard test procedure exists for boilers in sizes above 300,000 Btu/h so the seasonal efficiencies cited here are approximate and for comparative purposes only.

Boiler energy use can be reduced by employing a modular design approach in which a number of smaller boilers are used instead one large one. Large boilers often have poor part-load efficiencies, so savings accrue from operating smaller boilers closer to their rated capacity where their efficiency is highest. These modular boilers are staged in such a way to bring them online with heating demands. One NBS study showed the savings from a modular system over a single boiler to range from 5-15% depending on the degree of oversizing. As a retrofit option for the modular boiler approach, a "front-end" boiler can be added to meet smaller loads and staged with the larger existing boiler.

General maintenance of the distribution system to reduce hot water or steam heat losses also offers potentially cost-effective savings potential, but is very site specific.

More than a third of all boilers sold are not listed as dedicated gas-fired equipment, but rather are dual fueled using either oil or gas. Many of these are purported to use gas as the primary fuel and oil as the backup.

Other Equipment

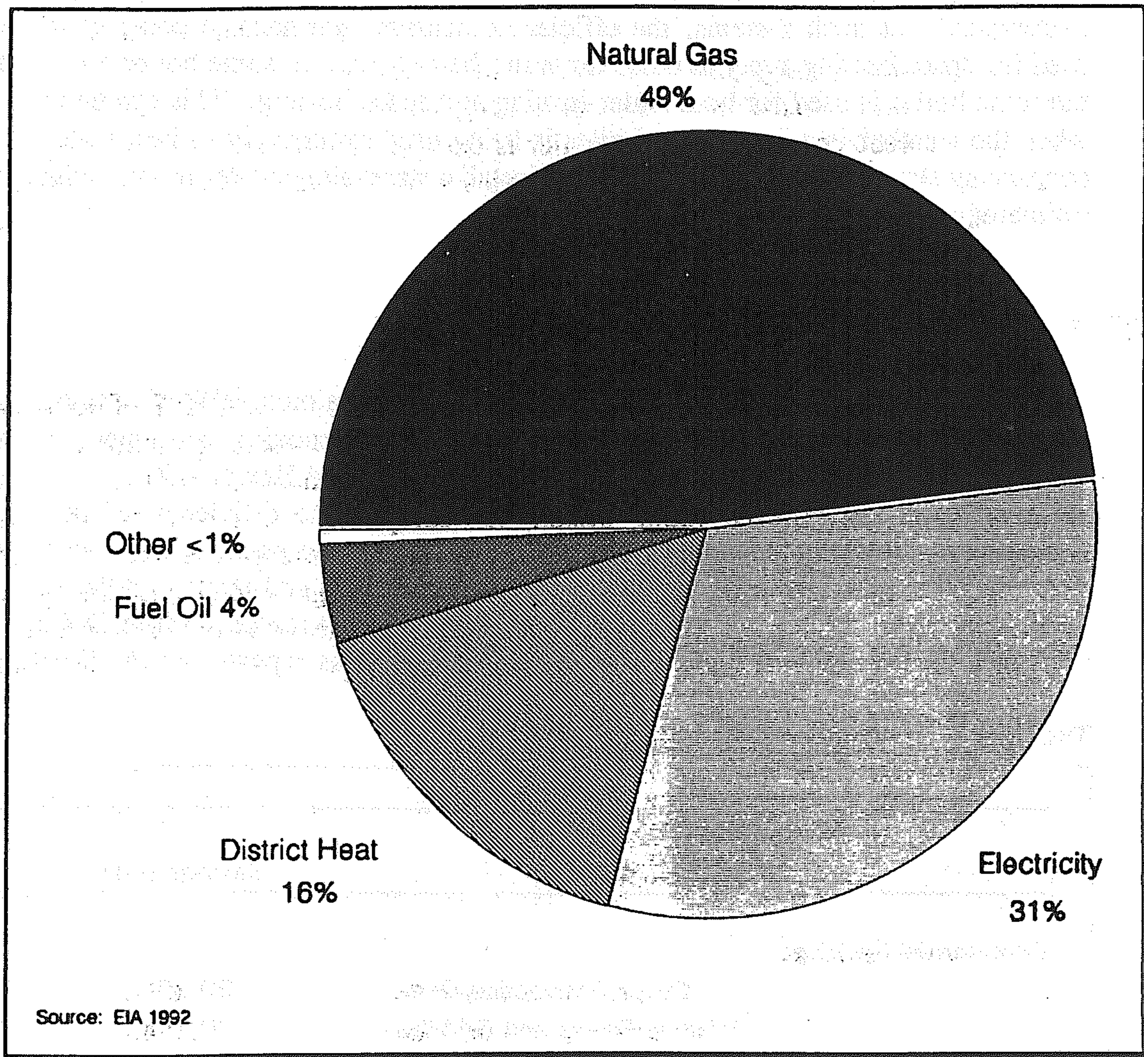
Packaged gas heating/electric cooling equipment currently consumes the third largest portion of gas for space heating (i.e., 14%). These units are typically equipped with IID and power venting and as such, offer fewer gas savings opportunities compared to other types of gas heating equipment. However, units using pulse combustion technology packaged with high-efficiency air conditioning are under development. Also, gas heat pumps, described previously under residential space heating measures, are under development for serving the same small commercial market as combination gas/electric packaged units (also known as unitary equipment) currently serve.

D.2.6 Commercial Water Heating

Water heating is the second largest gas end use in the commercial sector and gas has the largest market share in this sector (see Figure D-2). Shipments over the last decade of commercial-scale, storage-type water heaters using gas have ranged from 82-90% of the total storage-type market (Gas Appliance Manufacturers Association (GAMA) 1992).[10] Still, by comparison to the residential market, the market for commercial storage water heaters is small. In 1991, manufacturers of gas-fired equipment shipped nearly 4 million residential units compared to less than 100,000 commercial units. It is estimated that 80% of water heater sales are replacement units in existing commercial buildings

[10] Little market information is available for other commercial water heating system types.

Figure D-2. Annual Shares of Fuel Consumption for Commercial Water Heating in the U.S.



(Electric Power Research Institute (EPRI) 1992b).

Many small commercial buildings or applications in larger commercial buildings with modest demands for hot water employ equipment similar to that found in residences (i.e., storage-type water heaters), in which case the efficiency measures discussed under residential water heating apply to these applications as well. Instantaneous water heaters (also described under residential water heating) have potential application in the commercial sector as well.

In large commercial hot water systems, a boiler and storage tank configuration is typical, where the boiler heats the water in the storage tank directly or indirectly through a heat exchanger.[11] In such systems, the efficiency measures germane to commercial boilers used for space heating apply to those for water heating too. In some boiler/tank systems, the same boiler is used for both water heating and space heating. This can be inefficient when the weather is mild and the boiler is being used exclusively to heat water. A gas conserving strategy in these instances is to install a stand-alone water heater, with savings estimated at 65% (Nadel et al. 1993b).

D.2.7 Commercial Cooking

Commercial ranges, fryers, griddles, and ovens make up almost 90% of both annual gas consumption and the market for new commercial food cooking equipment, of which about two-thirds is replacement equipment (Lobenstein and Hewett 1991). At present, there is no standardized rating system for comparing the efficiency of commercial cooking equipment, though test procedures are under development through an industry-wide cooperative effort involving representatives of the gas and electric utility industries and the food service industry (among others). For this reason, Table D-4 presents typical savings over "standard" equipment of each type as reported in the literature.

Table D-4. Commercial Cooking Savings

Technology	Savings (%)
Commercial Cooking	
Direct Convection Oven	30-50[1]
Infrared Fryers and Griddles	20-40[2]
Power Burner Range	24[2]

Sources: 1 Nadel 1993b
2 Lobenstein and Hewett 1991

One technology for improving the efficiency of gas use in ovens of all kinds is the direct convection oven which circulates heated air inside the oven by means of a fan while

[11] Boilers made out of cast iron or steel are subject to corrosion if continuously exposed to fresh, oxidized water. Thus, such systems typically use indirect means of heating water in the storage tank.

reclaiming some of the heat from the flue gases. The savings for this measure over a standard oven are estimated at 50% (Nadel et al. 1993b). The market for these ovens is fairly strong already and so there may be limited opportunity for increasing their penetration (Lobenstein and Hewett 1991).

Ranges equipped with power burners instead of atmospheric burners can save an estimated 24% (Lobenstein and Hewett 1991).

Infrared fryers and griddles use a technology that transfers heat directly to the food by means of electromagnetic radiation. This technology has a savings potential estimated in the neighborhood of 30-40% applied to fryers, and 20-40% for griddles (Lobenstein and Hewett 1991). Market penetration of this technology appears to be low. While not currently available due to practical concerns, griddles and fryers utilizing pulse combustion technology offer potentially high savings.

D.3 Electric to Gas Fuel-Switching Measures

This section provides an overview of gas technologies that could be substituted for electric technologies in residential and commercial applications. Of course, many of the high-efficiency gas measures described previously are also candidate measures for fuel-switching from electricity to gas. The discussion will not duplicate presentation of those technologies but focuses instead on technologies whose principle application would be in substituting for electricity.

D.3.1 Residential Space Cooling and Heating

Gas-engine heat pumps (GEHPs) are regarded by the gas industry as an important technology for space cooling (and heating), an end use in which electricity currently dominates. Moreover, over three-quarters of new single-family dwellings in the U.S. are equipped with air conditioning. Heating mode performance of GEHPs was discussed in section 7.4.2. Seasonal cooling mode efficiency of GEHPs has been demonstrated in the range of 90-120% (Klausing et al. 1992). On a *site energy basis*, the cooling performance of GEHPs is below that of electric technologies (as measured by coefficient of performance), although on a *source energy basis* GEHPs compete with electric technologies served by a national average power generation fuel mix (Walrod 1992).[12]

[12] The distinction between site and source energy is that the latter encompasses the energy content of the fuel consumed to produce electricity. Therefore the GEHPs operating in cooling mode are expected to just meet or slightly exceed the equivalent of the 1993 NAECA standard in terms of total source energy consumed of

One study showed that GEHPs had the highest source energy efficiency over a range of climates of any competing air-source technology (or combination of technologies) (L'Ecuyer et al. 1993).

Heat pumps in heating mode operate like an air conditioner in reverse: they extract heat from the outdoors and dump it indoors. At very low temperatures, as the heat pump efficiency decreases and the heat loss of the residence increases, some form of backup heating is required. With electric heat pumps the backup heating is electric resistance. For a winter peaking utility with a large residential heating load, this resistance heating from heat pumps can be highly coincident with, and a significant contributor to the system peak. One fuel-substitution approach is to "replace" the electric heat pump with a gas furnace, using the heat pump exclusively for air conditioning. An alternate technology is to bundle gas-fired heating coils as auxiliary heating with electric heat pumps (also known as the dual-fuel heat pump) instead of using electric resistance as the auxiliary heating.[13]

Another measure for shifting from electricity to natural gas for residential heating is a gas furnace or boiler replacing electric resistance heating. In a retrofit or replacement application of a gas warm-air furnace, the feasibility of such a conversion would depend greatly on whether there was existing ductwork for warm-air distribution, or on the features of the site for installing ductwork. For a gas hydronic boiler replacing electric resistance baseboard heating, baseboard hot water distribution systems are commercially available.

D.3.2 Residential Water Heating, Cooking and Clothes Drying

For these end uses the opportunities for switching from electric appliances to gas appliances are straightforward. Options include gas storage water heaters that meet the future NAECA standard or have higher efficiencies that replace electric resistance storage water heaters and gas ranges or clothes dryers that can replace their electric appliance counterparts.

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minimum complying electric heat pumps served by electricity generated using an average fuel mix of electric utilities nationwide.

[13] While this does provide some market for gas that otherwise would be served by electricity in a conventially configured electric heat pump, the gas sales from the duel-fuel heat pump would come only during colder periods when some gas utilities experience their highest capacity and commodity costs, and could lead to lower load factors. Given typical rate-making practice, revenues paid by these customers would not be likely to cover costs.

There are situations in which special opportunities may exist for electric to gas fuel switching depending on particular equipment configurations for space and water heating. If, for example, there is a gas hydronic boiler serving space heating loads and an electric resistance storage water heater, the gas boiler can be connected to meet the water heating load too, effectively converting the water heater into a storage tank. A gas hydronic boiler system serving both hot water and space heat needs could also be employed to replace an electric resistance baseboard heat and storage water heater configuration.

D.3.3 Commercial Space Heating and Cooling

Electric boilers, electric resistance baseboard, air-source heat pumps, packaged electric resistance heating and compressive cooling are the primary electric technologies used for space heating in the commercial sector. Gas heating technologies that could potentially replace these electric technologies include the gas boilers discussed in Section D.2.5 under commercial heating efficiency measures.

Considerable attention has been paid to examining the potential for gas-fired cooling technologies to displace electric powered cooling. Gas utilities looking to improve system load factors regard gas cooling as an opportunity to increase gas usage in the typically low load summer and swing season periods. Meeting space cooling loads also contributes significantly to peak demands for some electric utilities. Thus shifting from electricity to gas could be potentially advantageous for both utilities.

Electric technologies currently dominate the market for commercial space cooling. This was not always the situation. Prior to the 1960's and the advent of increasingly efficient electric cooling technologies, gas served a considerable share of this market. In recent years, gas cooling technologies have evolved to the point where they can compete with electric cooling in many instances.

There are three main technologies for gas-fired cooling: absorption, engine-driven vapor compression, and desiccant cooling. Gas engine-driven cooling technology use the same refrigeration cycle as electric vapor compression machines but substitute the electric motor powering the compressor with a gas-fired engine. The gas engine drive has improved part load performance because of the inherent variable speed capability of the gas engine. Seasonal COPs of gas engine chillers are currently as high as 1.6 to 1.7 (American Gas Cooling Center (AGCC) 1992). Waste heat from the engine jacket and exhaust can be harnessed to further increase the effective COP to greater than 2.0 depending on the amount of useable waste heat (American Gas Cooling Center (AGCC) 1992). In the future, gas turbines are anticipated to replace the reciprocating engines used today for further efficiency gains.

Table D-5. Efficiencies of Commercial Gas Cooling Equipment

	Seasonal COP
Engine-Driven Vapor-Compression Chiller	1.62-1.71[1]
with Heat Recovery	>2.0[1]
Absorption Chiller (direct & indirect)	
Single Effect	0.67 - 0.70[1]
Double Effect	0.95-1.2[1]
Triple Effect	1.4-1.5[2]
Desiccant Cooling System	0.7-1.5[2]

Sources: [1] AGCC 1992, [2] EPRI 1992

Absorption cooling works on a different refrigeration cycle from vapor compression, replacing the compressor with an absorber, generator and two working fluids (i.e., the absorbent and refrigerant). Absorption systems were the earliest commercial gas-fired cooling technology. Absorption systems are classified by whether they utilize waste heat (indirect) or burn fuel (direct) to power the generator. They are also classified by the number of generators staged in the absorption cycle as single-effect, double-effect, and triple-effect.[14] Higher efficiencies are achieved with the double- and triple-effect technologies. Typical COPs of absorption machines are shown in Table D-5.

Desiccant cooling uses a substance with highly absorbent properties to absorb water vapor and its associated latent heat, dehumidifying (and warming) the air it comes in contact with. This air may then be cooled by indirect and/or direct evaporative cooling or by conventional air-conditioning. In contrast, vapor compression and absorption cooling systems provide dehumidification by cooling air below the dew point, condensing water vapor on the cooling coils. This latter process can lead to overcooling in order to achieve the desired humidity level, thus necessitating reheating to maintain desired ambient temperature level. Desiccant cooling is particularly suited to applications where the latent portion of the cooling load is high, such as in hot and humid climates in buildings with high fresh air requirements or in supermarkets, restaurants or sports

[14] Triple-effect absorption chillers are not yet commercially available. At least one manufacturer has them under development but they are not expected to be available on the market for several years.

facilities. Natural gas is used in the desiccant cooling process to generate heat to drive off the collected moisture and regenerate the desiccant for further absorption. Desiccant cooling systems have approximate COPs in the range of 0.7 to 1.5 (Electric Power Research Institute (EPRI) 1992a).[15] Desiccants can be paired with evaporative cooling systems as a packaged "total" desiccant cooling system or in a hybrid desiccant/ vapor compression (or absorption) system.

Gas cooling technologies can be configured together with different equipment depending on the application and strategy, either as packaged or built-up systems. Packaged heating and cooling systems are commercially available in which one or both of the space conditioning functions utilize gas instead of electricity, either with gas-fired heating and electric compressive cooling, or with gas-fired heating and gas engine-driven cooling. GEHPs for small commercial applications mentioned earlier are also options for fuel-substitution. Gas and electric cooling equipment can be combined together in the same central system and staged to meet cooling loads in the most cost-effective manner, tuned to the local utility tariffs.

Finally, though not strictly end-use fuel-switching *per se*, gas-fired cogeneration systems can be advantageously configured to utilize the waste heat from the electricity generator prime mover put towards an absorption cooling (indirect system), desiccant regeneration, or water heating application.

D.4 Gas to Electric Fuel-Switching Measures

This section describes several electric DSM options that could be substituted for gas technologies.

D.4.1 Residential Space Heating

The majority of electric heat pumps sold in the U.S. use outdoor air as the source of heat (i.e., "air-source"). Electric ground-source heat pumps (GSHP) are also available that draw heat out of some external source of heat other than air, such as groundwater, surface water, city water, stored solar energy, or the ground itself. The advantage of ground-source over air-source heat pumps is the temperature constancy of the heat source; U.S. groundwater temperatures range from about 42-77°F (Electric Power Research Institute (EPRI) and the National Rural Electric Cooperative Association 1989).

[15] Calculating COP for desiccant systems is not strictly equivalent to the COP calculated for other refrigeration systems.

On the other hand, air-source heat pumps suffer degraded efficiency and capacity during cold weather and must utilize supplementary heating (typically electric resistance heating). The increased performance of GSHPs comes at a cost, however, as the first cost of ground-source heat pumps is considerably higher than air-source types (L'Ecuyer et al. 1993).

D.4.2 Residential Water Heating

Electric heat pump water heaters are an option for exploiting the efficiency advantages of vapor-compression technology for residential water heating. The technology is fundamentally no different than that used for space heating and cooling except that these units operate only in the heating mode. Energy factors for units now on the market are in the range of 1.5 to 2.5 (Gas Appliance Manufacturers Association (GAMA) 1993). At present, electric heat pump water heaters have less than 1% of the residential water heating market.

D.4.3 Commercial Water Heating

Electric heat pump water heaters are also an option for commercial water heating applications. COPs of 2.0 to 5.0 are common in commercial applications (Electric Power Research Institute (EPRI) 1992b). In addition, with minor modification and connections, they can provide useful space cooling as a by-product of the process.

Refrigeration heat reclaim is a related option for water heating because the heat rejected from food storage refrigeration or air-conditioning systems can be reclaimed for water heating.[16] The heat is reclaimed by means of a heat exchanger connected to the condenser of the "host" equipment. Large chillers and heat pumps are available with heat recovery features as a standard option. Whether refrigeration heat reclaim is desirable or not will depend on the specific circumstances at the commercial facility. A limiting factor of this type of system is that the heat is available only when the host equipment is operating, although storage and/or diversity of host equipment can mitigate this disadvantage (Electric Power Research Institute (EPRI) 1992b). A more generalized form of the same concept is waste heat water heating which utilizes the unused heat from fluid streams in commercial facilities, though these may not necessarily originate from electric equipment.

[16] Because virtually all refrigeration equipment is powered by electricity, this is considered an electric fuel-switching option.

For commercial laundering, an ozonated system has been developed that significantly reduces or even eliminates the need for hot water (Nadel et al. 1993a). Because this technology consumes electricity that would in most instances be displacing gas (given its position in the commercial water heating market) this is also a gas-to-electricity fuel-switching option. In this system, which also virtually eliminates the use of detergent, the wash water is saturated with ozone, a powerful oxidant that is widely used to disinfect drinking and swimming pool water. The technology is currently in the prototype phase, but in two field demonstrations has reduced gas usage for hot water by 50-76%.

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