Estimating Marginal Gas Costs: A Case Study

Carol Etter and Frank Stern, RCG/Hagler, Bailly, Inc.

The screening and evaluation of gas utility demand-side management programs requires dollar value estimates of avoided, or marginal supply costs. Determining marginal costs for gas utilities poses a substantially different problem than for electric utilities, due to shorter planning horizons for gas utilities and the less capital-intensive nature of the gas industry. A number of methods for valuing marginal gas costs have been suggested and implemented, including Weighted Average Cost of Gas, System Marginal, Targeted Marginal, and planning model approaches.

BC Gas, Inc., located in Vancouver, British Columbia, and RCG/Hagler, Bailly, Inc. recently completed an effort which resulted in estimates of marginal gas supply costs using the Targeted Marginal Cost approach combined with a planning model. The Targeted Marginal Cost approach involves targeting load and supply categories by time of year and temperature-sensitive nature. Each designated load reduction is matched with its most likely supply source. In the BC Gas application, a planning model was used to determine the cost of the marginal unit of gas with greater precision than could be achieved through qualitative approaches. Marginal costs were calculated for both a fixed and a percentage change in demand. The marginal costs associated with the fixed change captures the marginal cost of a reduction in non-temperature sensitive (base) load, while the marginal costs associated with the percentage change in load captures the marginal cost of a reduction in temperature-sensitive loads.

Introduction

Natural gas distribution utilities are moving (or being moved) towards increasing investment in demand-side management ("DSM") programs (defined here to include conservation, load management and strategic load growth programs), as well as integrated resource planning ("IRP"). This is partly a response to the increase in the complexity of resource options available to gas utilities, and partly a natural development on the regulatory side, based on the generally positive experiences of electric utilities in DSM and IRP.

The screening and evaluation of DSM programs require a relatively accurate estimate of the dollar value of gas impacted over the life of the program, usually at least 10 years, and often longer. This dollar amount is the "marginal cost" of gas supply on a particular system--the cost of purchasing one unit, more or less, of gas.[1]

Although the basic theory of determining marginal costs is similar for gas and electric utilities, the application for a gas utility is complicated by the following factors:

- an historically shorter planning horizon;
- the existence of fewer modeling tools appropriate for long-term planning and marginal cost analysis;
- the uncertain impact of FERC Order 636 that radically restructures traditional supply sources;
- the high percentage of commodity-related charges in rates; and
- the high degree of seasonal variation in gas acquisition prices.

This paper will review various options for determining the marginal cost of gas for screening DSM programs, and will present in more detail the Incremented Planning Model approach used recently by RCG/Hagler, Bailly on a project with BC Gas, Inc. It should be stressed that the determination of gas marginal costs is an ongoing process, and there continue to be key issues that require additional examination and refinement.

General Gas Impact Valuation Issues

The cost of gas, in general, varies seasonally, with the cheapest gas available during the summer season (often from spot purchases transported via interruptible transportation ("IT") contracts). Gas during the winter is typically more expensive, often composed predominately of pipeline contract gas and gas from storage. The most expensive gas (e.g., Liquified Natural Gas) is used to meet demand on the peak day (or days). In the short term, supply options are generally known, and many characteristics, such as pipeline contract volumes, are fixed. In the long term, however, new supply options will arise and most system characteristics are variable. The typical supply situation currently faced by gas utilities is shown in Figure 1.

The value of any DSM program depends on system specifics, supply options currently available and possible in the future, and characteristics of the program under consideration. Because of the strong seasonal variations in the marginal supply source and the prices of those sources, we believe development of seasonal marginal gas prices is necessary to be able to properly value the impact of gas DSM programs.

The following three examples demonstrate the complexity of the process of determining the value of DSM programs. First, a program that saves gas all year round (e.g., a gas water heater replacement program) would reduce the amount of gas that had to be purchased year-round. However, the question of which gas would be avoided is difficult to answer. In the short-term, when the annual quantity under the pipeline gas supply contract is fixed, cheaper spot gas would not be purchased. In the longer-term (perhaps even the next year), when the pipeline contract quantity could be reduced, the more expensive pipeline gas would be saved.

The value of the gas saved by a program that impacts gas use primarily during the winter (e.g., a home insulation program, high efficiency furnace program) would depend on the relative amount and role of gas in storage as compared to either a winter pipeline supply contract or independent gas moving under a firm transportation ("FT") contract. If stored gas is used to meet daily demand all winter, then this would be the gas saved. However, if storage gas is only used to meet winter peaks, and another supply source is used to meet winter base load demand, then this other source would be the gas saved.

Finally, load building programs (e.g., gas air conditioners) present still a different problem. In this case, it would seem that the gas purchased to meet this increased summer demand would be spot gas moving under IT contracts. However, increased summer load could allow better optimization of the whole supply mix. Thus, additional pipeline system gas might be purchased during the summer with the improvement in the system load factor allowing better utilization of FT and storage during the winter. In the long run, increased summer load might

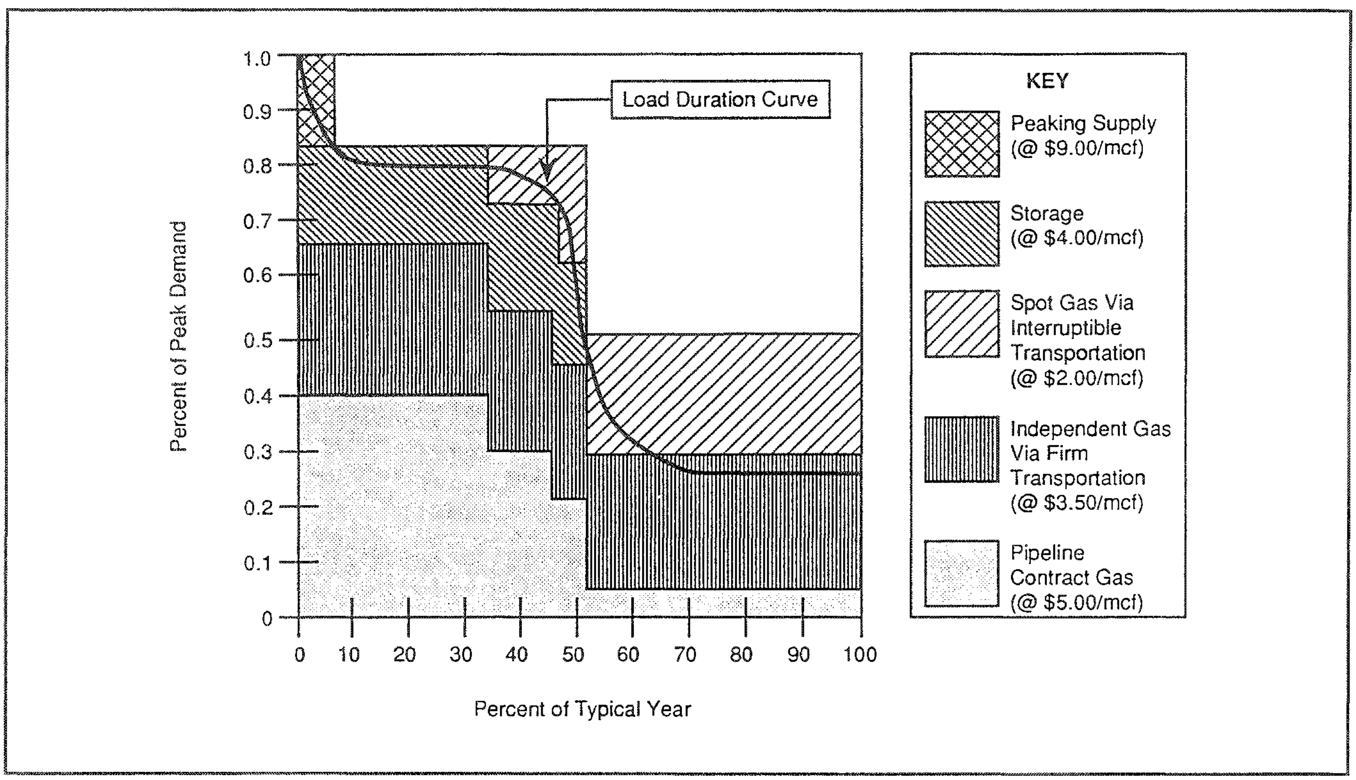

Figure 1. Typical Gas Utility Supply Situation

allow additional pipeline contract volumes to be converted to FT, thereby lowering the cost of gas year round.

Overview of Different Approaches

Numerous approaches exist to value gas for the screening and evaluation of gas DSM programs. Five methods, representative of most approaches to marginal gas valuation, are discussed in this section.

Planning Model Method

The theoretically ideal way to evaluate possible DSM programs would be to use a long-term planning model. For each possible DSM program, a modified load duration curve ("LDC") would be developed for every year of the planning horizon. The planning model would be run in a base case (no program) configuration, and then would be re-run using the modified LDC for each possible program. Through an iterative process of comparing the total system costs under each possible program with the base case configuration, the value of the gas impacted by each program would be developed. This value could then be compared to the implementation costs to determine those programs that would pass the relevant cost/benefit tests. To fully assess the value of DSM programs, it would be desirable to evaluate possible programs in various combinations, at several penetration levels, and at different implementation times.

This evaluation method is only available to those gas utilities who have access to a long-term planning model, and it is resource intensive. In addition, the volume impacts of gas DSM programs are typically small in comparison to supply contract volumes (at least in the early years of program implementation), so the value of the DSM programs could easily be lost in the "noise" of the base case scenario.

The Weighted Average Cost of Gas Approach

The weighted average cost of gas ("WACOG") approach is straightforward in concept and implementation, using the typical volume-weighted average cost of gas to value DSM program impacts. The WACOG approach has been proposed for situations where a utility does not have a great deal of supply flexibility, or where sales growth equals or exceeds the gas savings from DSM programs. RCG believes that the WACOG approach is inadequate for DSM program screening because it does not address cost causation, softens the impact of seasonal gas costs, and underestimates the value of the gas impacts. Further, under Order 636, all gas utilities will have supply flexibility.

The System Marginal Cost Approach

In contrast to the WACOG approach, the System Marginal Cost approach identifies the most expensive unit of gas purchased in each time period and utilizes its cost as the value of the impacted gas. All of the gas saved within the specified interval of time is valued at this marginal cost.

There are two major criticisms of this method. First, higher-cost gas (i.e., pipeline supply) is often dispatched first to meet contractual volume requirements or system constraints. Thus the marginal gas (i.e., the last gas purchased) is frequently not the most expensive. Secondly, cost causation is not addressed. For example, valuing the impact of a program that saves gas year-round at the system margin during the winter would tend to overvalue the savings because, in the long term, this program will result in modifications to the base-load contract(s).

The Targeted Marginal Cost

The Targeted Marginal Cost approach to gas savings valuation is similar to the System Marginal Cost approach in several respects, but overcomes its limitations by partitioning both the conservation savings and the gas supply plan into their operational components. Thus, it directly addresses cost causation, from the view of both gas savings and supply planning.

The first step in applying this approach is to disaggregate expected gas impacts into their characteristic components--base load savings, non-peak, temperature-sensitive savings, and peak savings. At the same time, gas supplies are segregated into their functional categories--base load supplies, variable load supplies, and peaking supplies. Then the marginal supply source in each functional category is identified, and the marginal price associated with that supply is determined. Finally, the impacts by time period can be matched with the targeted marginal cost of gas for the same period.

Incremented Planning Model Approach

The Incremented Planning Model approach to estimating marginal gas costs was developed as a way to use the sophistication of a long-range planning model in a less time-consuming manner than described earlier for the full planning model approach. The Incremented Planning

Model approach applies the general theory of the Targeted Marginal Cost approach, but uses a utility's existing calibrated planning model to develop the marginal prices by increasing or decreasing the load used in the model by a small amount. We have used both a fixed increase and a percent-of-load increase. The fixed increment captures the system effects of changes in the base, non-temperature sensitive load (e.g., a water heater program). The percentage increment captures the system effects of changes in the temperature sensitive load. The resulting marginal prices are then used to value DSM programs with matching characteristics (i.e., temperature sensitive or non-temperature sensitive). Screening of possible DSM programs outside of the planning model itself allows for easier testing of sensitivity of the results to changes in market penetration or implementation timing.

Once a package of probable programs has been identified through cost/benefit screening, the combined load impact of this package is examined through the long-range planning model. This feedback step is necessary to determine if the combined effect of the programs has significantly changed the behavior of the system--that is, if the marginal costs have changed significantly. In addition, the planning model run allows quantification of the total system benefits of the package of programs selected. If the planning model run shows marginal costs "significantly" different from those used to screen the programs, some of the programs may need to be re-evaluated.[2] The DSM program screening process using the Incremented Planning Model approach is shown in Figure 2.

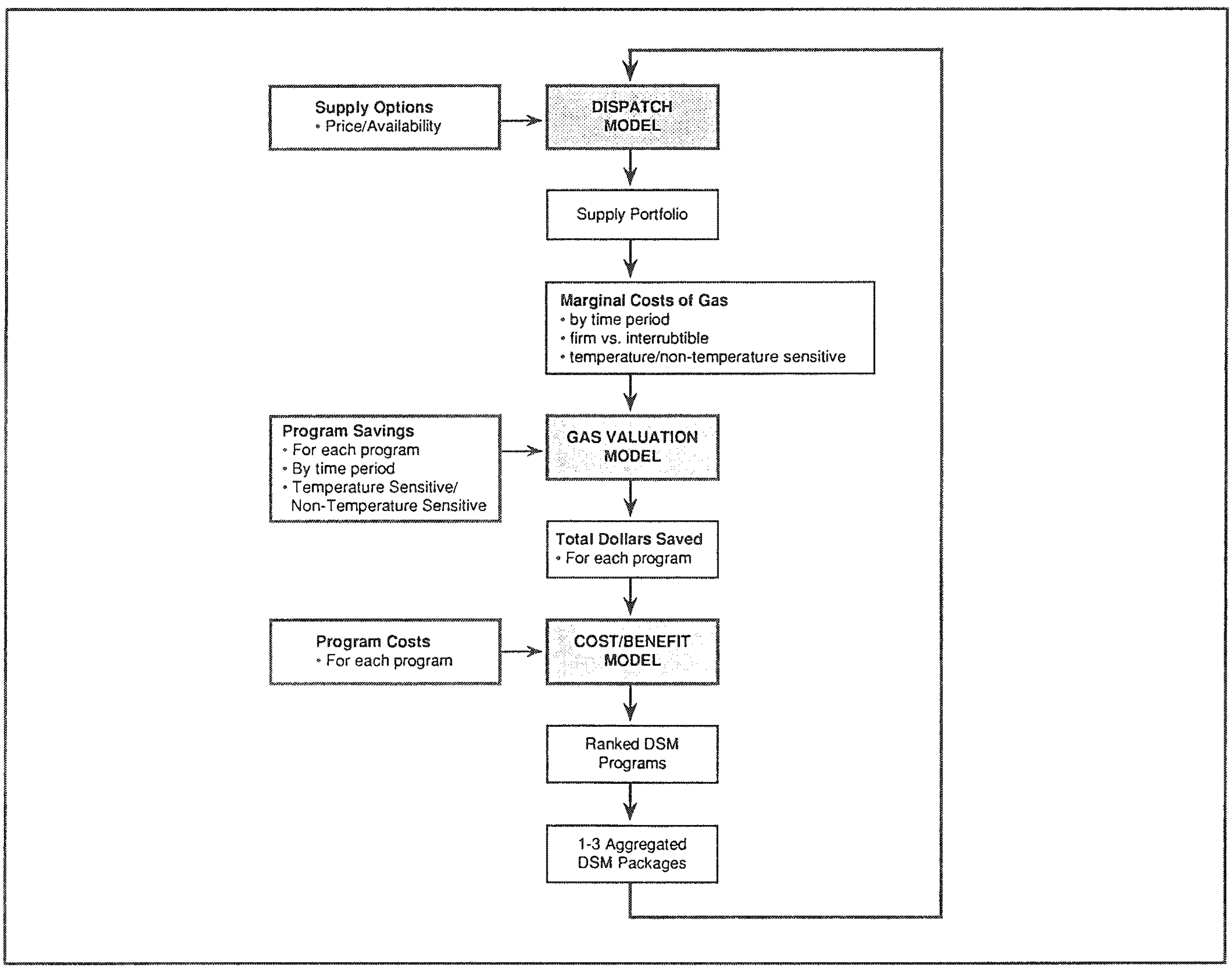

Figure 2. Overview of DSM Screening Process Using the Incremented Planning Model Approach

Case Study: BC Gas, Inc.

BC Gas, Inc., British Columbia's main gas distribution utility, recognized in early 1989 the challenge posed by the fact that its transmission contracts were due to expire in November 1991, at which time it would enter a period of full supply deregulation. In particular, instead of having a single supply contract, there was the possibility that contracts might need to be structured with 100 or more gas producers, involving a diverse range of contract and pricing provisions. There also were indications that there could be a wider availability of contract storage services with neighboring United States utilities. In view of the considerable complexity involved in planning and scheduling gas supplies in this deregulated environment, BC Gas concluded it would be necessary to acquire or develop optimization models to be used in support of these activities. After reviewing the software options available in the market, BC Gas decided to develop their own model that would be guaranteed to meet their planning requirements--both short term (i.e., dispatch), and long-term.

Overview of the BC Gas Model[3]

The optimization model developed for BC Gas by Quantalytics, Ltd. is a linear program with all characteristics of supply options potentially variable. The model considers a single year for scheduling purposes or a sequence of years for planning purposes. In both the planning and scheduling modes, the objective is to minimize the expected annual cost of gas supply, where this includes the fixed and variable costs of gas purchases, transportation and storage, and revenue losses due to curtailment of interruptible customers. The term "expected" is used in a probability sense, as the model explicitly accounts for uncertainty in future daily demand resulting from weather variability.

The focus in the planning mode is on optimizing the variables that represent maximum daily quantities for supplies and deliverability, and capacity of storage. To identify optimal solutions, however, the model must simultaneously optimize the daily scheduling of supplies, storage and curtailment. For this reason, the planning mode is actually a generalized form of the scheduling model. For example, the daily quantities of most gas supplies are fixed in the scheduling mode to reflect contract provisions already in place. In contrast, in the planning mode, daily quantities are represented by variables for most supply options in order to determine an optimal contract mix. The planning mode tends to have more supply options than the scheduling mode, representing potential future supply options. Similarly, parameters describing storage capacity or deliverability are generally fixed in the scheduling mode but may be variables in the planning mode.

Modification for Marginal Cost Determination

BC Gas liked the basic philosophy of the Targeted Marginal Cost approach used by RCG on other projects, but wanted to use their new planning model if possible. After reviewing the operation of the model, and in conjunction with the gas supply department of BC Gas, RCG developed the Incremented Planning Model approach, described in general above. BC Gas implemented the Incremented Planning Model approach by first running a "Base Case" (ten-year) supply portfolio through the gas dispatch model. Then two variations were run--one that reduced the load duration curves by a fixed volume each day (the "fixed delta" run) and a second that reduced the load duration curves by small percentage every day (the "percent delta" run). The fixed delta was equal to 1% of the total annual load divided by 365 while the percent delta was equal to 1% of each day's load. From each of these runs, the expected total cost for each gas supply source for each month for each year can be extracted. Mathematically the expected total cost for a single month for a given model run k is:

$$ETC_{ik} = \sum_{j}^{W} (P_{ik} * Q_{ijk} * p_j) \qquad (1)$$

where ETC_{ik} = expected total cost for the ith supply source in each model run, k
P_{ik} = price of the ith supply source in each model run, k
Q_{ijk} = quantity of the ith supply source in the jth weather pattern in each model run, k
p_j = probability of the jth weather pattern
W = the number of weather patterns, j
k = model runs: Base, Fixed Delta, Percent Delta

The marginal costs for each month are then calculated as follows:

$$MC_{fixed} = \frac{\sum_{i}^{N} ETC_{i,base} - ETC_{i,fixed}}{\sum_{i}^{N} Q_{i,base} - Q_{i,fixed}} \qquad (2a)$$

and

$$MC_{percent} = \frac{\sum_{i}^{N} ETC_{i,base} - ETC_{i,percent}}{\sum_{i}^{N} Q_{i,base} - Q_{i,percent}} \tag{2b}$$

where MC_k = marginal cost from a fixed or percent change in load

ETC_{ik} = expected total cost for the ith supply source in each model run (base, fixed, percent)

Q_{ik} = total quantity of gas purchased from the ith source in each model run (base, fixed, percent)

N = number of supply sources

If the change in Q ($Q_{i,base}$ - Q_{ik}) is small, Equations 2a and 2b approach $\frac{dC}{dQ}$, the mathematical definition of marginal cost. The fixed marginal cost captures the marginal cost of a reduction in non-temperature sensitive load, including the reduction in short term gas volume and related demand charges, while the percent marginal cost captures the marginal cost of a reduction in temperature sensitive loads, and assumes more gas saved on cool days than on warm days, mirroring the reduction as a function of degree days.

Preliminary Results from BC Gas Analysis

The BC Gas model was modified as described above, and preliminary results for a Reference Case and a case encompassing additional storage capacity in 1996 are described below. The BC Gas model is set up to produce separate marginal costs for fixed and percentage deltas in both firm and interruptible demand (i.e., four marginal costs), for six monthly periods in each year. As currently configured, the six monthly periods consist of each month during the winter (November through March) and a single "month" covering the seven-month summer period.

The historic period used to build the load duration curves includes an extended, extreme cold-weather period in November, so November currently contains the peak day. The severity of this weather in the November LDC seems to be causing extremely high marginal costs in November. These high costs are partly a reasonable response to the possible variations in weather. The high costs also may represent inappropriate allocation of fixed changes to peak demand. This possibility is being investigated, together with various options for improving the treatment of peak days and the related marginal costs.

In the results presented below, a modified November marginal cost is used for the peak period, the maximum marginal cost from December, January and February is used for the winter period, and March marginal cost is used for the shoulder period (March and November). It should be stressed that these results are preliminary, and final marginal costs used by BC Gas in their DSM screening and IRP development may differ significantly from those shown here.

(1) As would be expected given typical characteristics of gas utility supply options, the marginal cost of supplying one additional unit of gas is higher in the winter than during the summer. (See Figure 3.)

(2) The addition of supplemental storage in 1996, in substitution for high- priced peaking supply and additional long term contracts, reduces marginal costs for peak demand periods from those in the Reference Case until that storage capacity is exhausted in 2001 (see Figure 4). The additional storage capacity increases marginal costs for all other periods, probably because of spreading the fixed costs associated with the new storage. Despite the increase in marginal costs, the total costs of system operation are lower in the case with the additional storage. Analysis by BC Gas indicates the net present worth of the Reference Case is \$CN 3,065 million, while the net present worth of the alternative case is \$CN 2,901 million. This implies that the benefit to the system of

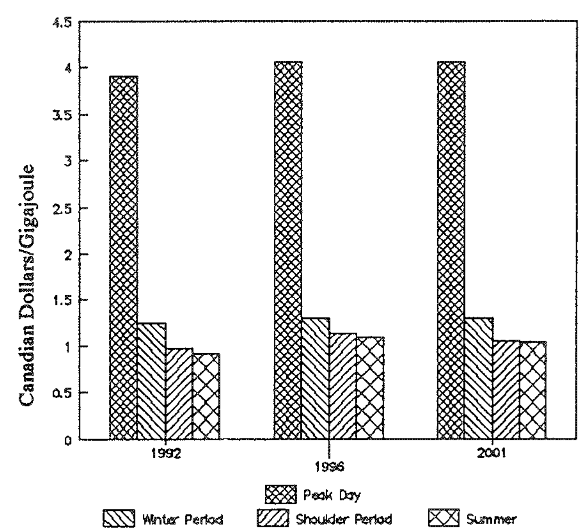

Figure 3. Marginal Cost of Gas (Reference Case-Fixed Increment)

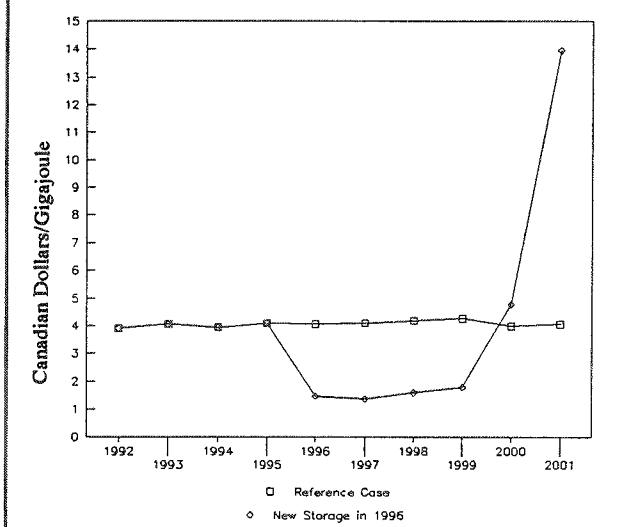

Figure 4. Marginal Cost of Peak Day Supply Under Two Scenarios (Fixed Increment)

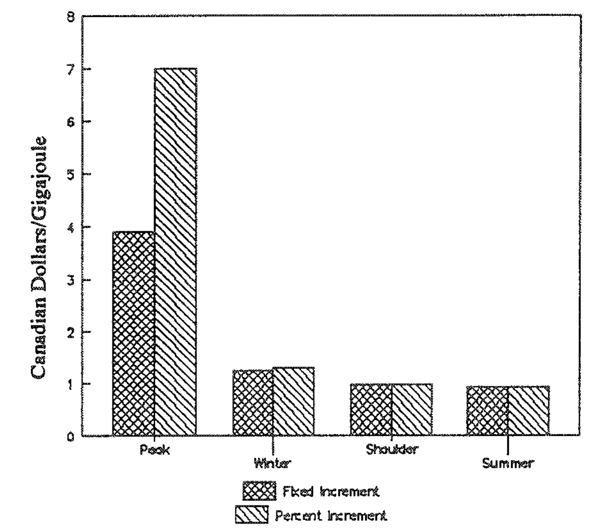

Figure 5. Fixed Increment Marginal Costs Compared to Percentage Increment Marginal Costs (Reference Case - 1992)

the additional storage outweighs the cost of that storage when the benefit of reducing purchases of peaking supply are included.

(3) The marginal cost of a percentage increase in demand is greater than for a fixed increase (see Figure 5). The difference in marginal costs is greatest in the winter and non-existent in the summer. This is as would be expected, since a one percent increase in daily demand represents more gas in the winter than in the summer. The large change in marginal costs for the peaking period are somewhat to be expected given the generally high cost of serving peak demands and the relatively large volume of gas represented by a one percent increase on the peak day. This also illustrates the large benefit to ratepayers of minimizing increases in the peak day firm demand.[4]

(4) Marginal costs for interruptible demand are lower than, or equal to marginal costs for firm demand, representing the possibility that this demand could be interrupted during periods of high firm demand.

(5) The addition of new storage capability raises the marginal costs for interruptible customers. This may reflect the fact that the interruptible customers pay a portion of the costs of the storage facilities. These customers receive little benefit from the facilities, because they are mostly serving peaking needs when interruptible demand is at risk of interruption.

Conclusions

The Incremented Planning Model approach combines the accuracy of a full-planning model with the flexibility and ease of use of the Targeted Marginal Cost approach. The Incremented Planning Model approach has performed well in applications by BC Gas. If a long-term planning model is available for a gas valuation project, this approach may provide the most cost-effective estimates of marginal gas costs for use in screening gas DSM programs. Additional research is needed on the treatment of demand charges in the application of this approach at BC Gas. Of particular concern is the behavior of the marginal costs in the month containing extreme weather behavior. As a result of additional research, the specifics of the application at BC Gas may be changed, resulting in revised marginal costs.

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Endnotes

1. We prefer the term "marginal cost" for this dollar value, rather that "avoided cost." Avoided cost is used in the electric industry, implying the cost associated with the next generating unit, whose construction can be avoided by the purchase of independent power or investment in DSM. Because the gas industry is less capital intensive, the value of investment in DSM is essentially the cost of gas that the utility does not have to purchase. Utilities that are peak constrained may be able to delay or eliminate additional peaking facilities through investment in DSM.

2. "Significant" differences in marginal costs would be any change large enough to change the decision to include or exclude a possible program.

3. The model is described in more detail in "Optimal Planning and Scheduling of Gas Supplies: Canadian LDC uses Optimization Model to Respond to Complexity of Supply Deregulation," Cary Swoveland, Jack Cawdery and Jeff Lydiatt, to appear in Pipeline and Gas Journal, April 1992, pp 32-37.

4. This may also be an example of the possibly inappropriate treatment of fixed changes in the peak period.