MAKING CONSERVATION PROFITABLE: AN ASSESSMENT OF ALTERNATIVE DEMAND SIDE MANAGEMENT INCENTIVES[1]

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In July of 1988, the New York Public Service Commission (NYPSC) asked utilities to submit innovative ratemaking proposals which would remove current disincentives and provide a positive incentive for effective implementation of demand side management (DSM) programs. The authors participated as members of a New York Department of Public Service (NYDPS) DSM working group which analyzed utility proposals and ratemaking mechanisms, including those being considered by the National Association of Regulatory Utility Commissioners (NARUC). David Moskovitz provided consulting assistance to the working group and participated in many of the working group meetings. The working group recommended interim adoption of incentive ratemaking methods and identified key incentive ratemaking issues which should be examined over the longer term.

This paper discusses the authors' analyses of DSM incentive options with emphasis on the following issues: (1) removing DSM disincentives; (2) assessing utility performance in acquiring cost-effective DSM and supply side resources which reduce customer energy costs; and (3) coupling utility profitability to performance. The status of the NYPSC's efforts to adopt incentive ratemaking mechanisms is also summarized.

The authors conclude that the traditional ratemaking process used by New York utilities provides significant disincentives to implement DSM and significant incentives to market electricity use as a means of enhancing profitability. The Electric Rate Adjustment Mechanism (ERAM) used by the California Public Utilities Commission eliminates both problems and has other desirable properties, including incentives to reduce electricity supply costs. The Fuel Revenue Accounting (MFRA) method used by Central Maine Power can be modified to have most of ERAM's advantages with the added benefit of providing limited coupling of profitability to customers electricity use.

The authors also conclude that a DSM incentive based on a sharing of the net resource savings provides an effective motivational basis for rewarding utilities for their implementation of DSM programs. This DSM incentive should be integrated with a set of complementary incentive mechanisms which reward utilities for performance in reducing the costs of meeting customer end-use energy needs.

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[1] *The perspectives on DSM incentives and other incentive ratemaking issues described in this paper represent the authors and should not be interpreted as the official position of the NYPSC, the NYDPS DSM working group, NYDPS, and the Energy Research and Development Authority (NYSERDA).*

A conceptually appealing alternative to separate performance measures would be to develop global measures of utility performance which inherently capture and give appropriate weight to these separate performance factors, but in a self-consistent manner. The Effective Resource Cost of Electricity (ERCE) index developed by one of the authors appears to have many desirable attributes for assessing utility performance.

BACKGROUND

A study of the DSM potential in New York indicates that electricity consumption could be reduced by 22,000 GWh (22%) annually and peak demand reduced by 6000 MW (29%) (Geller 1989) if utilities would collaborate with their customers in implementing cost-effective energy efficiency and demand management techniques. Significant customer energy cost savings, reductions in power plant emissions and deferral of the need to construct new electricity supply and distribution facilities would be obtained if these DSM resources could be acquired.

The traditional ratemaking process results in the establishment of electric rates to recover both operating costs and the required return on invested capital. Electricity consumption that occurs when marginal revenue exceed marginal fuel and other operating costs directly contributes to utility profits. Since this net revenue can be several cents per kWh, there is a strong economic incentive for utilities to encourage electricity sales during such time periods. The New York utilities were concerned that the lost net revenue from customer adoption of more efficient end-use measures would decrease profitability[2]. Consequently, they expressed a reluctance to implement extensive DSM programs until new rate-making mechanisms were adopted which corrected this lost revenue problem. (NYPSC Opinion and Order 89-29 1989).

The impact of an incremental reduction in electricity sales on profitability is illustrated in Column 2 of the hypothetical utility example in Table 1. A 2% reduction in sales relative to the Base Case in Column 1 of 20 million kWh results in a 3.6% reduction in Net Income. Column 3 illustrates that a 2% increase in sales increases profitability by 3.6%.

In concept, it is possible for utilities to factor customer adoption of energy efficiency into the development of sales forecasts used in establishing rates. However, the traditional ratemaking process described above provides strong incentives for utilities to use conservative estimates of anticipated sales in the rate setting process and to then promote increased customer use of electricity as a means of enhancing profitability. And, these incentives are currently not balanced by a corresponding incentives to promote customer adoption of more efficient end-use equipment.

Two alternative ratemaking mechanisms are described below--ERAM and FRA--which eliminate both the utilities' concern over the effect of lost revenues on profitability and the strong incentive to market electricity as a means for increasing profits.

In addition to eliminating lost revenues as a disincentive, the NYPSC desired to modify the rate making process to include a positive incentive for the utility acquisition of cost-effective DSM resources. If the acquisition of such DSM resources became a significant contributor to increasing profitability, then a utility would have the incentive to allocate its management attention and qualified

2 Public utility commissions in many states (including New York) allow utilities to use some form of Fuel Adjustment Clause (FAC) to adjust rates in a manner which reconciles major differences between actual fuel costs and projected average fuel costs which are used in the rate making process. Because many DSM measures reduce actual fuel costs on the margin by an amount which is greater than projected average fuel costs, the net effect of the FAC is that utilities have a positive but relatively small incentive to implement DSM (on the order of 0.3-0.4 cents per kWh saved for New York utilities). However, this is significantly less than the net lost revenue disincentive of several cents per kWh saved.

Table 1. Alternative Ratemaking Strategies

Case 1 - Base Case
Case 2 - Traditional Regulation; 2% Sales Decrease of 20 Million kWh
Case 3 - Traditional Regulation; 2% Sales Increase of 20 Million kWh
Case 4 - Net Lost Rev. Adjust. (NLRA); 20M kWh Sales Decrease due to DSM
Case 5 - NLRA; 20M kWh Net Sales Increase with 20M kWh DSM Program
Case 6 - Electric Rate Adjustment Mechanism (ERAM); 20 Million kWh Decrease from DSM
Case 7 - ERAM; 20M kWh Net Sales Increase with 20 Million kWh DSM Program

		1	2	3	4	5	6	7
A	Sales (Million kWh)	1000	980	1020	980	1020	980	1020
B	Price (¢/kWh) [Note 1]	10	10	10	10	10	10	10
C	Revenues ($M)	100	98	102	98	102	98	102
D	Fuel Cost ($M) [Note 2]	30	29.4	30.6	29.4	30.6	29.4	30.6
E	Rev. Adj. ($M)	0	0	0	2.2	2.2	2.2	-.6
		*****[Note 3]*****			---[Note 4]---		***[Note 5]***	
F	Non-Fuel Rev. ($M) [Note 6]	70	68.6	71.4	70.8	73.6	70.8	70.8
G	Expenses, Interest and Depreciation ($M)	30	30	30	30	30	30	30
H	Incr. DSM Cost ($M) [Note 7]	0	0	0	.8	.8	.8	.8
I	Taxable Income ($M)	40	38.6	41.4	40	42.8	40	40
J	Income Tax @ 37% ($M)	14.8	14.3	15.3	14.8	15.8	7.4	7.4
K	Net Income ($M)	25.2	24.3	26.1	25.2	27.0	25.2	25.2
L	Equity Portion of Rate Base ($M)	200	200	200	200	200	200	200
M	Equity Return (%)	12.6%	12.2%	13.0%	12.6%	13.5%	12.6%	12.6%

Note 1 - Electricity rate is set at 10 cents/kWh so that revenues will be equal to projected costs of $100 Million. All Revenues and Expenses quantities are exposed in $Million ($M).

Note 2 - Fuel Cost is assumed to be equal to average fuel cost of 3 cents per kWh times Sales. The impact of the FAC is reconciling differences between this average Fuel Cost and actual costs is not considered (see Footnote 2).

Note 3 - No Revenue Adjustment Mechanism considered in Cases 1, 2 and 3.

Note 4 - Revenue Adjustment is equal to 7 cents per kWh (i.e. Price less average fuel cost) times Lost Sales plus Cost of implementing DSM Programs (see Note 7). The total is 0.7*20+0.8=$2.2M.

Note 5 - Revenue Adjustment is set equal to the sum of Non-Fuel Revenue Requirement and Fuel Cost less Revenues.

Note 6 - Non-Fuel Revenue is Revenues minus Fuel Cost minus the Revenue Adjustment.

Note 7 - Costs of DSM efficiency measures is assumed to be 4 cents/kWh saved. Total cost is $0.8 Million.

staff to the implementation of its DSM programs. The general requirements for an effective DSM incentive are discussed below in the section on requirements for an effective DSM incentive. And, a particular DSM incentive mechanism recommended the authors which satisfies these requirements is also described.

The NYDPS DSM working group also evaluated the feasibility of integrating DSM incentives within the broader framework of coupling profitability to overall performance in reducing customer electricity service costs and facilitating least cost planning and resource acquisition. The initial results of this effort are discussed under the section on coupling profitability to performance.

ALTERNATIVE RATEMAKING STRATEGIES

Net Lost Revenue Recovery

Six New York utilities have submitted new ratemaking proposals in response to the NYPSC's request. The mechanism initially proposed by each utility for removing lost revenues as the principal DSM disincentive[3] was an automatic annual adjustment in rates to yield additional revenue to offset the following two DSM impacts: (1) recovery of DSM program costs expended in the prior year (in excess of levels forecasted in last rate case) and (2) the estimated net lost revenue (i.e., the projected lost revenues less operating cost savings) which would result from each customer's participation in a DSM program during the previous year.

As illustrated in Column 4 of Table 1, this net lost revenue estimation would conceptually remove the utilities' concern about the adverse impact of DSM on profitability. If the 20 million kWh reduction in sales were caused by the installation of DSM measures, the projected net lost revenue is $1.4 million, i.e., the 10 cents/kWh price less the 3 cents/kWh average marginal cost times 20 million kWh. And, the incremental program cost is assumed to be $0.8 million, i.e., 4 cents per kWh saved times 20 million kWh. Consequently, rates would be increased next year to recover additional revenue of $2.2 million. The net effect would be to yield the same net income as in the Base Case (Column 1).

However, the NYDPS DSM working group was concerned that this Net Lost Revenue Recovery mechanism did not eliminate a potential incentive for the utility to promote increased customer use of electricity as a means of increasing profitability. This situation is illustrated in Column 5 of Table 1. It is assumed that DSM investments reduce consumption by 2% (or 20 million kWh) but that electricity sales increase by 40 million kWh (a 4% increase), resulting in a net 20 million kWh or 2% increase in sales. In this case, Net Income is increased by the combined effect of increased sales and the Net Lost Revenue Recovery mechanism.

The NYDPS DSM working group examined a number of alternative ratemaking mechanisms which would: (1) remove the DSM incentive as well as significantly reduce or eliminate the incentive to market electricity sales as a means for increasing profitability; and (2) provide positive incentives for implementing DSM. This included mechanisms being considered by the NARUC Conservation Committee (Moskovitz 1989) and other promising approaches presented in the utility regulatory and economics literature. Emphasis is given in the subsequent discussion to what the authors consider to be the most promising approaches.

Electric Rate Adjustment Mechanism (ERAM)

In 1981, the California Public Utility Commission (CPUC) adopted ERAM as the basis for the rate making process. (Ziering 1986) ERAM eliminates the lost revenue disincentive for a utility to implement DSM and decouples profitability from the amount of electricity sales. As illustrated in column 6 of Table 1, ERAM adjusts allowable revenue to achieve a "target" Non-Fuel Revenue

3 *Because the then prevailing NYPSC accounting practice deferred recovery of DSM program costs (which were not included in base rates) until the next rate case, several New York utilities were concerned the NYPSC's desire to significantly increase DSM expenditures would subject their DSM expenditures to prudency disallowance uncertainty. However, the NYPSC has subsequently revised accounting treatment of DSM program expenditures including amortizing them in a manner similar to supply side investments, including forecasts in base rates, and deferring only variations between forecasted and actual expenditures.*

Requirement, which is equal to $70.8 million in this example. This includes an additional $0.8 million in DSM Costs which were not include in the Base Case projections. The Non-Fuel Revenue obtained from existing rates is the $98 million in total Revenues less the $29.4 million in Fuel Costs, or $68.6 million. (Although we conceptually attribute the reduced sales of 20 million kWh to DSM in this example, this reduction in sales could be due to weather, downturn in the local economy, general consumer conservation, etc.) Rates during the next year would be automatically adjusted under ERAM to collect additional revenue equal to Revenue Adjustment of $2.2 million.

Column 7 of Table 1 illustrates how ERAM removes the incentive for utilities to market electricity to enhance profitability. Because of increased sales of 20 million kWh, Non-Fuel Revenue from existing rates is the $102 million in total Revenues less the $30.6 million in Fuel Costs, or $71.4 million. Rates during the next year would be reduced to give back the $0.6 million balance in the Revenue Adjustment account.

ERAM has the following additional advantages: (1) it protects utilities from adverse impacts on profitability from conditions which are outside of its control (such as lower sales because of weather, increased distribution costs because of greater than anticipated growth in number of customers, etc.); (2) it focuses regulatory agency and utility concern on the costs of providing electricity service and provides incentives for utilities to control costs below projected levels as a means of increasing profits; (3) it lowers next year's rates if additional revenues are collected because of increased sales (due to weather, an economic upturn, and other effects); and (4) as compared with the Net Lost Revenue Recovery mechanism, it eliminates the adverse impacts on the utility or its ratepayers of errors in estimating net lost revenues[4].

[4] *Analysis by the authors has shown that errors in estimating lost revenues from DSM programs can significantly effect the program benefits retained by ratepayers. This is another major reason to prefer a decoupling mechanism to administered lost revenue recoveries. Errors in estimating the shared resource savings DSM discussed in Section 4.6 have a much smaller impact on retained ratepayer benefits.*

Several New York utilities and intervenors expressed opposition to the adoption of ERAM. (NYPSC Opinion and Order 89-29 1989) One of the principal concerns was the increased risk of "buypass". Since ERAM would automatically adjust rates so that it would receive a targeted amount of Non-Fuel Revenue Requirement independent of the level of customer consumption, there was concern that the utility did not have an incentive to inform those customers considering on-site generation about energy efficiency and other alternatives which might be more cost-effective. And, any significant ERAM deficit resulting from bypass decisions would automatically raise rates in the following year and further aggravate this buypass problem.

Another potential disadvantage of ERAM is that it does not provide any positive incentive for utility implementation of cost-effective DSM programs. However, in concept, this could be readily corrected by including a separate profitability incentive for DSM or developing a global performance index which implicitly accomplishes the DSM goals outlined below in the section on effective DSM incentives.

The retention of ERAM by the CPUC was the subject of a proceeding that was initiated in 1986. (Ziering 1986) Following this extensive review (including consideration of concerns similar to those identified by New York utilities and intervenors), the CPUC decided to retain ERAM. However, the CPUC also concluded that ERAM did not include adequate incentives for utilities to implement cost-effective DSM and initiated a collaborative process to identify and implement DSM incentive mechanisms on a pilot basis. (California Collaborative Process 1990)

Following review of the NYDPS DSM working group recommendations and comments received from New York utilities and other interested parties, the NYPSC requested that Orange and Rockland Utilities (O&R) submit a ERAM-type revenue decoupling proposal as part of an upcoming rate case and established a generic proceeding to examine issues of concern to O&R and other New York utilities (NYPSC Opinion and Order 89-29

1989) However, in order to avoid further delays in implementing aggressive DSM programs while this proceeding was conducted, the NYPSC approved the use of the estimated Net Lost Revenue Recovery approach discussed above by O&R and Niagara Mohawk on an interim basis. (The NYPSC has also adopted interim DSM incentive ratemaking mechanisms for 4 other New York electric utilities which include estimated Net Lost Revenue Recovery and a DSM incentive.)

Following review of the Revenue Decoupling Mechanism proposal submitted by O&R, the NYDPS DSM working group recommended that the NYPSC adopt a modified version, including provisions which would couple profitability to O&R's performance in acquiring cost-effective DSM resources and meeting customer service needs as described briefly below. (Brew 1990)

Fuel Revenue Accounting (FRA)

The NYDPS DSM working group sought to identify other potential mechanisms for reducing the coupling between profitability and sales in a manner that would overcome the first disadvantages of ERAM highlighted above. David Moskovitz suggested that the working group consider adaptations of the Fuel Revenue Accounting (FRA) implemented by Central Maine Power (CMP) in 1988. (Dumais 1990)

FRA was developed by CMP to eliminate a potential problem inherent in the design of most time-of-day (TOD) rates which provide utilities with an incentive to encourage customer electricity use during the on-peak period. This incentive results from the higher contribution to Non-Fuel Revenue which is often derived from on-peak consumption as compared to off-peak electricity use. (Moskovitz 1988) With FRA, CMP reduced the Non-Fuel Revenue contribution during the on-peak period and increased the contribution during the off-peak period. The remaining revenue resulting from the difference between the electricity price in each period and the contribution to Non-Fuel Revenue for each customer was allocated to the Fuel Revenue Account. Any positive difference between actual fuel costs and the Fuel Revenue Account is returned to customers and any negative difference is recovered from customers through an automatic adjustment in rates in a manner similar to ERAM.

The following describes a adaptation of the FRA approach developed by the first author, subsequently referred as Modified Fuel Revenue Accounting (MFRA), which allocates revenues to the Non-Fuel Revenue and Fuel Revenue accounts based on the aggregate level of customer consumption during the billing period. This allocation process is designed so that total revenues from electricity sales will be reduced if a customer's electricity use falls below a specified threshold. Any differences between actual fuel costs and the Fuel Revenue Account would be reconciled in a manner similar to the FRA method summarized above. However, any shortfall in total revenues with MFRA might be offset by DSM and other incentive mechanisms such as described in the sections that follow.

This MFRA decoupling mechanism is illustrated in Table 2 for a hypothetical flat-rate example, although the basic approach could be applied to TOD rates in a manner similar to FRA. This example assumes: (1) a rate of 10 cents/kWh is established to recover a projected Non-Fuel Revenue Requirement of $70 million and a projected Fuel Cost of $30 million; (2) the average consumption for a particular billing period is 500 kWh; (3) the MFRA revenue allocation process for this particular month is set up so that a specified percentage, in this case 87.5%, of the revenue associated with the first 400 kWh is allocated to an Allowable Non-Fuel Revenue account; this percentage allocation will ensure that the Allowable Non-Fuel Revenues will yield the $70 million target if all customers consume more than 400 kWh; if consumption falls below 400 kWh for any customer, there will be a shortfall in the Non-Fuel Revenue Account; and (5) the remaining 12.5% of the revenue associated with the first 400 kWh and 100% of the revenue associated with consumption in excess of 400 kWh is allocated to a second account, referred to as the Available Fuel Revenue Account. Table 2 illustrates how revenues are allocated to these various accounts depending on the distribution of consumption by the customer class. For convenience purposes, it is assumed in Table 2 that monthly consumption is the same for each month.

Table 2. Modified Fuel Revenue Accounting (MFRA) Example

Column Definition:

1 = Monthly Consumption Distribution: Fraction of Customers
2 = Monthly Consumption Distribution: Electricity Consumption in kWh
3 = Average Monthly Sales in kWh
4 = Total Annual Revenue Received in $Million (see Notes 1 and 2)
5 = Allowable Non-Fuel Revenue in $Million (see Notes 2 and 3)
6 = Available Fuel Revenue in $Million (see Note 4)
7 = Fuel Cost in $Million (see Note 5)
8 = MFRA Credit (+) or Deficit (-) in $Million (see Note 6)
9 = Unrecovered Non-Fuel Revenue in $Million (see Note 7)

Case	1	2	3	4	5	6	7	8	9
	.10	450							
1	.80	500	500	100	70	30	30	0	0
	.10	550							
	.10	500							
2	.80	550	550	110	70	40	30.3	9.7	0
	.10	600							
	.10	400							
3	.80	450	450	90	70	20	29.7	-9.7	0
	.10	500							
	.10	350							
4	.80	450	450	90	69.1	20.9	29.7	-8.8	.9
	.10	550							
	.30	350							
5	.40	450	450	90	67.4	22.6	29.7	-7.0	2.6
	.30	550							

Note 1 - It is assumed 166,666 customers consume an average of 500 kWh per month and 600 kWh annually. Total annual consumption is 1000 Million kWh.

Note 2 - Projected Non-Fuel Revenue Requirement is assumed to be $70 Million and Fuel Cost is assumed to be $30 Million. Rate is set to 10 cents/kWh to recover Revenue Requirement of $100 Million. Average cost of fuel is 3 cents/kWh.

Note 3 - 7/8 of monthly revenue received from each customer for first 400 kWh is allocated to Allowable Non-Fuel Revenue Account.

Note 4 - Available Fuel Revenue is Column 4-Column 5.

Note 5 - Marginal cost of fuel is 4 cents/kWh if consumption differs from monthly average of 500 kWh.

Note 6 - MFRA Credit or Deficit is Column 6-Column 7. If positive, MFRA Credit is deferred and next year rate is increased to recover additional revenue. If negative, MFRA Deficit is deferred and next year rate increased to recover additional revenue.

Note 7 - Unrecovered Non-Fuel Revenue is $70 Million Target - Column 5.

In Case 1, the customer consumption distribution assumed in Columns 1 and 2 is such that average monthly consumption is equal to 500 kWh and all customers consume more than the 400 kWh threshold. As a result, the Allowable Non-Fuel Revenue is equal to the targeted value of $70 million and Available Fuel Revenue is equal to the projected Fuel Cost of $30 million. And, in this case, there is no need for any Revenue Adjustment.

Case 2 illustrates the situation where all customers consume greater than 400 kWh threshold but the average consumption of 550 kWh exceeds the projected sales for the billing period. As a consequence, the Allowable Non-Fuel Revenue is equal to the target value of $70 million but the Available Fuel Revenue of $40 million exceeds actual Fuel Costs of $30.3 million by the MFRA Credit of $9.7 million. Column 8 indicates that rates would be reduced in the following year to return this $9.7 million excess revenue to customers.

Case 3 illustrates the situation where all customers consume greater than the 400 kWh threshold but where average consumption of 450 kWh is below the projected 500 kWh average sales level used in setting rates. As a consequence, the Allowable Non-Fuel Revenue is equal to the target level of $70 million but Available Fuel Revenue of $20 million is less than the actual Fuel Costs of $29.7 million. Rates would increased in the next year to collect an additional $9.7 million to cover this MFRA Deficit.

Case 4 illustrates the situation where some customers (10%) consume less than the 400 kWh threshold and where average consumption is below the projected 500 kWh sales level. In this case, the Allowable Non-Fuel Revenue Requirement is below the $70 million target by $0.9 million. And, the Available Fuel Revenue of $20.9 million is less than the actual Fuel Costs of $29.7 million by $8.8 million. Rates would be increased in the next year to collect additional $8.8 million to cover this MFRA Deficit. But, the utility would not be allowed to recover the $0.9 million deficit. However, this MFRA partial decoupling scheme would presumably also include a DSM and other profitability incentives as described previously.

In practice, it would be desirable to implement MFRA so that it exhibits the other desirable properties of ERAM. This would require that the Allowable Non-Fuel Revenue Target to be adjusted in a manner similar to the ERAM Non-Fuel Revenue Requirement to reflect conditions which are outside the utility's control. For example, changes in allowable distribution investment costs based on the actual number of new customers connected and allowable operating expense categories which are based on actual kWhs sold could be included. And, the Allowable Non-Fuel Revenue Target could be varied on a billing period by billing period basis. If this were done, then MFRA would essentially have the attributes of ERAM with the added incentive to be concerned about customer consumption.

COUPLING PROFITABILITY TO PERFORMANCE

The ERAM and MFRA mechanisms can be used to couple profitability to performance by adjusting the Allowable Revenue Requirement to achieve a targeted level of Net Income which would reward the utility for good performance or penalize it for poor performance. ERAM and MFRA inherently include an incentive to reduce operating costs and the three year rate cycle used in California enables the utility to capture the benefits of a cost reduction program. Any additional increases in the allowable return on equity based on performance should be adjusted to be compatible with this implicit cost reduction incentive.

If feasible, it would be desirable to directly link the supply/demand side neutral indicator of utility performance in accomplishing least cost planning and customer service goals. David Moskovitz recommended that the incentives to reduce operating costs inherent in ERAM be supplemented by the following additional components: (1) a global performance index based on analysis of customer bills and/or other available utility data (Moskovitz 1988); (2) an index which would reward utilities for providing reliable service and meeting other customer service needs which could not be readily measured in monetary terms; and (3) other components which also cannot be measured in monetary terms but which for policy or other reasons may have special significance. The following two global performance index methods were considered by the NYDPS DSM working group.

Index Based on Average Customer Bills

The following is a summary description of the average customer bill method (Moskovitz 1988). A group of utilities (index group) having characteristics similar to a regulated utility (A) would be selected. In year 1, the average customer bill for the index group would be calculated and compared to the average bill for customers of utility A. In year 2, the index would be recalculated and utility A would be rewarded if the average bill of its customers had declined relative to the average bills of customers served by the index group. Conversely, a relative increase in average bills would be penalized.

Index Based on Total Resources Test

One of the authors (Cummings 1988) has proposed an alternative index based on the total resources test which is intended to provide incentives for implementing least cost planning. An overall performance indicator of the "effective resource cost of electricity" (ERCE) would be established. This indicator would be defined as the sum of: (1) supply side costs; (2) demand side costs; and (3) environmental externality costs; divided by the sum of: (1) kWh actually generated by the utility; and (2) "virtual kWhs" of end use energy services resulting from the utility's DSM programs. Supply side costs would include current fixed and variable revenue requirements as well as estimates of the present value of future capacity additions required by current sales forecasts. Similarly, some demand side costs would be deferred or amortized to reflect the impact of current DSM expenditures on future capacity requirements. "Virtual kilowatts" would be measured using valid and comparable program evaluation methodologies.

As in the case of the Bill Index, the relative change over time in Utility A's performance on the global indicator would be compared to the performance of an index group of utilities. It is possible that the index could be administered as an economically efficient zero-sum game which would require utilities to compete for profits (and losses) awarded by a PUC based on index results (Cummings 1984). Table 3 illustrates and compares the operation of the two indicators. For simplicity of exposition, the index groups have been omitted from the analysis. A single utility's year 2 performance for four different situations is compared with a year 1 base case. In the base case the hypothetical utility sells 1000 MWh at a price of $.08/kWh. Short run marginal fuel costs of 5 cents/kWh, long-run marginal supply costs of 6 cents/kWh, DSM costs of 3 cents/kWh saved and environmental costs of 1.4 cents per kWh generated are assumed. Customer bills average $80 and the "effective resource cost of electricity" is $.094/kWh.

As shown on line M average bills are lowest ($79), and the utility would be awarded the highest incentive if the utility's sales decline by 20 MWh and the company conducts no DSM programs (Case 1). Average bills are highest ($81) if sales increased and the utility conducts no DSM program (case 2). But the combination of lower sales and an exceptionally vigorous DSM program (case 4) also results in higher average bills ($80.20) than the base case. This analysis raises concern that, in some circumstances, an average bill index might reward utilities for declining sales due to weather, economic conditions or utility efforts to restrict supply, but fail to reward the utility for aggressive DSM programs.

Line P shows the operation of the ERCE (effective cost of electricity) index. The resource cost of energy services (9.4 cents per kWh equivalent in the base case) decreases as low cost DSM kWhs replaces high marginal cost supply side kWhs, and reaches a minimum (9.2 cents) in case 4. In case 4, as a result of decreased sales more than outweighed by "virtual kWhs" from DSM efficiency improvements, customers have the maximum amount of energy services available at the minimum average resource cost.

The ERCE is demand and supply side neutral and could reward utilities for increased sales but only if the sum of short and long run marginal and environmental externalities is less than average supply and average demand side costs. Similarly, the ERCE index will reward utilities for demand side investments if short and long run marginal demand side

Table 3. Comparison of Average Bill Index and Effective Resource Cost of Electricity Index

Column Definition:
0 = Base Case: 1000 MWh Sales with no DSM
1 = Case 1: 20 MWh Sales Decrease with no DSM
2 = Case 2: 20 MWh Sales Increase with no DSM
3 = Case 3: 20 MWh Sales Decrease with 20 MWh of DSM
4 = Case 4: 20 MWh Sales Decrease with 40 MWh of DSM

	$/kWh	0	1	2	3	4
A MWh Supply Side		1,000	980	1,020	980	980
B MWh Demand Side		0	0	0	20,000	40,000
C MWh Total Services		1,000	980	1,020	1,000	1,020
D # of Customers		1,000	1,000	1,000	1,000	1,000
Revenue Requirement ($)						
E Base Revenues	0.08	80,000	80,000	80,000	80,000	80,000
F Marginal Cost	0.05	0	-1,000	1,000	-1,000	-1,000
G SupplySide Revenues		80,000	79,000	81,000	79,000	79,000
H Demand Side Costs	0.03	0	0	0	600	1,200
I Total Revenue Req.		80,000	79,000	81,000	79,600	80,200
Other Resource Costs ($)						
J Environmental External.	.014	14,000	13,720	14,280	13,720	13,720
K Long Run Marginal Cost	0.06	0	-1,200	1,200	-1,200	-1,200
L Total Resource Cost		94,000	91,520	96,480	92,120	92,720
Performance Measures						
M Average Bill ($)		80.00	79.00	81.00	79.60	80.20
(Rank)			(1)	(4)	(2)	(3)
N $/kWh (supply only)		0.0800	0.0806	0.0794	0.0812	0.0818
(Rank)			(2)	(1)	(3)	(4)
O ERCE ($/kWh w/o EE)		0.0800	0.0794	0.0806	0.0784	0.0775
(Rank)			(3)	(4)	(2)	(1)
P ERCE ($/kWh w/EE)		0.0940	0.0934	0.0946	0.0927	0.0921
(Rank)			(3)	(4)	(2)	(1)

costs are less than average supply side costs and average demand side costs. Although not illustrated, the ERCE index would also reward utilities for cost effective reductions in emissions from power plants.

The primary short term obstacle to implementing the ERCE index is the difficulty of obtaining consistently measured DSM and environmental data from utilities in an index group. Measurement of "Virtual kilowatt hours", a critical variable in the index, would require that all utilities use comparable "state of the art" program evaluation methodologies for estimating program impacts. NYSERDA and the NYPSC have undertaken studies to develop model DSM Program Evaluation Protocols and methods for quantifying the environmental externalities of power generation and transmission. NARUC is considering undertaking a study to identify DSM data that should be reported in FERC statistical series. These steps should facilitate implementation of an ERCE index in the future.

Current Status of Performance Indices

An evaluation of the feasibility of Moskovitz's average customer bill-based indices and the Cummings' "resource cost of electricity services" index is being conducted by Niagara Mohawk at the NYPSC's request. (NYPSC Opinion and Order 89-29 1989)

Because the feasibility of establishing a suitable global performance index has not been demonstrated, the NYDPS DSM working group recommended that the NYPSC augment the existing operating cost reduction incentives inherent in ERAM with a profitability incentive which included a DSM incentive similar to that described below and a Customer Service incentive component. The latter consists of a combination of separate reliability, customer complaint response, billing accuracy and other customer service components. (Brew 1990)

The authors also conclude that it would be desirable to include an improved fuel adjustment clause as part of the package of separate performance incentive measures. This improved FAC should, as a minimum, include an incentive to improve the efficiency of electricity production and distribution.

REQUIREMENTS FOR AN EFFECTIVE DSM INCENTIVE

Promotes Acquisition of Cost Effective DSM Resources

There is an increasing recognition by public utility commissions that customer energy costs can be substantially reduced, fuel consumption and environmental reduced, and the need to construct new electricity supply facilities deferred if utilities would cooperate with customers in implementing DSM measures. The NYPSC has requested that utilities use the total resource test illustrated in Column 1 of Table 4 as the principal criteria for identifying cost-effective DSM resources. Because the avoided cost benefits exceed the costs incurred by the customer and the utility in acquiring it, this DSM resource is a potentially cost-effective option. The decision by a utility to select this DSM measure must be viewed within the broader context of other DSM resources. Given a budget constraint, the utility should select those DSM measures which have the highest benefit to cost ratios.

In this example, avoided environmental impacts from implementing the DSM measure are valued at 1.5 cents/kWh saved (expressed in $1990). This is approximately equal to the 1.4 cents per kWh estimate developed by NYDPS staff in the context of a NYPSC review of O&R's integrated resource bidding plan. (Putta 1989) The NYPSC has requested that utilities internalize environmental impact costs in analyzing the cost-effectiveness of DSM and supply side resources. A major study directed at quantifying environmental impacts is in the planning stages.

Bases DSM Incentives on Actual Impacts

The NYDPS DSM working group agreed that it is important to base any DSM incentives on the best feasible measures of actual program performance. Because methodologies for DSM performance measurement are still being developed and because utility resources to implement rigorous program evaluation differ, the working group recognized that it may be necessary to rely on engineering estimates during a transition period. The NYDPS and the NYPSC have taken steps to improve the quality of DSM program evaluations conducted by New York utilities. These include: (1) establishing a NYDPS evaluation unit; (2) requiring that each utility establish a program evaluation unit; (3) requiring that utilities file program evaluation plans and budgets for each DSM program in a standardized format prescribed by the NYDPS evaluation unit; (4) initiating a cooperative project with NYSERDA to develop and implement a uniform statewide methodology for evaluating commercial and industrial DSM programs; and (5) establishing a statewide Evaluation Task Force to conduct evaluation research of Statewide significance.

The NYDPS DSM working group also examined other alternative approaches for measuring DSM impacts which might be more accurate or less expensive to implement than this indepth program evaluation. One of these alternatives is the "internal

Table 4. Illustration of DSM Incentive Requirements

Column Definition:
1 = Resource Test
2 = Recommended Strategy: Rate Impact Test
3 = Recommended Strategy: Participant Test
4 = Recommended Strategy: Consumer Economics (see Note 4)
5 = Utility Acquisition: Rate Impact Test
6 = Utility Acquisition: Consumer Economics (see Note 4)

	1	2	3	4	5	6
Benefit Components						
Avoided Capacity [Note 1]	1400	1400	N/A	N/A	1400	N/A
Avoided Energy	1450	1450	N/A	N/A	1450	N/A
Avoided Environmental Impacts @1.5 C/kWh in $1990	410	410	N/A	N/A	410	N/A
Utility Bill Savings	N/A	N/A	1785	1125	N/A	1125
Incentives Received	N/A	N/A	390	260	N/A	0
Equipment Depreciation	N/A	N/A	N/A	180	N/A	0
Total Benefits	**3260**	**3260**	**2175**	**1565**	**3260**	**1125**
Cost Components						
Installed Cost	1250	0	1250	1250	1250	0
Acquisition Costs [Note 2]	250		250	250	250	
Equip. O&M Costs [Note 3]	152	0	152	65	0	65
Program Marketing & Admin. [Note 3]	125	125	N/A	N/A	125	N/A
Program Evaluation	63	63	N/A	N/A	63	N/A
Incentives Paid	N/A	390	N/A	N/A	0	N/A
Lost Revenues	N/A	1785	N/A	N/A	1785	N/A
Total Costs	**1839**	**2363**	**1652**	**1565**	**3473**	**65**
Net Benefit	**1421**	**898**	**523**	**0**	**-213**	**1060**

Note 1 - The DSM measure is assumed to reduce end-use electricity demand by 1 kW and electricity use by 2300 kWh per year over a 10 year period. Avoided cost and marginal C&I customer revenue impacts were obtained from Con Edison's Demand Side Management filed in September of 1989. The assumed inflation rate is 4.5% and the utility discount rate is 10%.

Note 2 - Annual incremental O&M costs are assumed to be 2% of installed cost.

Note 3 - Program marketing and administration costs are assumed to be 10% of installed cost. Program evaluation costs are assumed to have a present value of 5% of installed cost.

Note 4 - Customer is assumed to have an after-tax discount rate of 25% and a marginal income tax rate of 34%. Because of income tax effects, the Customer effectively receives only 2/3 of the benefits and experiences only 2/3 of the operating cost.

bill index" concept recommended by David Moskovitz. This concept is based on comparing the average bills of a customer class, including those who participated in DSM programs, to the average bills of a representative control group of customers who had not participated in DSM programs. Control group members who chose to participate in DSM programs would be dropped from the control group. The control group would be dissolved and reconstituted every year or two. In concept, the difference in average bills would be a measure of the bill savings resulting from participation in DSM programs. However, if customers who drop out of the control group to participate in DSM programs have different pre-participation energy consumption than the customers who remain in the control group, self selection bias may obscure the actual impacts of DSM programs. Periodic selection of a new control group may make result in underestimation of savings from DSM measures with long useful lives. The NYPSC requested that Niagara Mohawk evaluate the feasibility of this concept. (NYPSC Opinion and Order 89-29 1989)

Evaluates Consumer Requirements for Participation in DSM Programs

In order to encourage a customer to adopt a DSM measure, the utility must inform the customer about its potential benefits and make a convincing argument that sufficient value can be derived from adopting the DSM measure to offset the DSM measure acquisition, equipment and installation costs, incremental O&M and other costs. As illustrated in Column 4 of Table 4, the principal value to a customer from adopting the technology are the Utility Bill Savings, any Financial Incentive paid by the utility, and, if the case of a Commercial and Industrial (C&I) customer, a modest Equipment Depreciation deduction from income taxes. In determining the present value of the benefits and costs in Column 4 of Table 4, it is assumed that this C&I customer has a 25% nominal and 19.5% real after-tax discount rate and a marginal income tax rate of 34%. Because of these tax considerations, a C&I customer receives only about 2/3 of the utility cost saving and incentive benefits (and 2/3 of the incremental operating costs) from adopting the DSM measure. In this example, the customer is assumed to require an upfront $390/kW incentive from the utility to adopt the DSM measure. Because of tax effects, this is equivalent to the $260/kW after-tax incentive illustrated in Column 4.

It is important to note that the required Financial Incentive is significantly different from what would be anticipated if the *idealized* Participant Test were used. The Net Benefit of $523 in the Column 3 Participant Test would lead one to conclude that the customer does not require any incentive to adopt the DSM measure. From an overall perspective, the DSM incentive should be structured so that the utility is motivated to determine what level of financial and other incentives to offer to meet real customer needs and not be limited by the Participant Test or other unrealistic criteria, which may not accurately reflect the consumer's discount rate and technical performance and risk perspective. And, if the utility is able to package the DSM program in a manner which is more acceptable to the customer (e.g., perhaps through some combination of financial incentive, equipment cost sharing, equipment performance guarantees and/or equipment leasing arrangements), then it should have the flexibility to implement such arrangements.

The DSM incentive mechanism that is adopted should encourage the utility to evaluate whether customers are interested in participating in a DSM program, how they perceive the risks of participating, and what are their financial and other requirements for participation. The data collected by a utility in the process of conducting in-depth program evaluation as described above can help in this assessment process.

Minimizing the Costs of Acquiring DSM Resources

Columns 6 and 5 of Table 4 illustrate the impact on the hypothetical C&I Customer and other Ratepayers (i.e., the Rate Impact Test), respectively, if the utility offers to install the DSM measure at no cost to the customer. A "just say yes" DSM acquisition strategy may be appropriate for residential and small commercial customers because lack of awareness, inability to evaluate benefits and costs, uncertainty about cost saving impacts, lack of access to capital for cost sharing and other barriers may be particularly severe. However, high DSM acquisition costs may have an adverse impact of future rates. Essentially, non-participants in the same and other customer classes are subsidizing the benefits received by participants. And, this acquisition strategy ignores the significant benefits received by participants. Consequently, the utilities should be encouraged to implement DSM programs which achieve significant customer participation but also acquire the DSM resources at the lowest cost. For example, the acquisition approach illustrated in Columns 3 and 4 would be much more desirable if it could be achieved. Other ratepayers receive a net long-term benefit of approximately $900/kW and the C&I customer receives the required 25% discount rate from the transaction.

General Requirements for a DSM Incentive

Based on the above discussion, the authors conclude that a DSM incentive should have the following properties: (1) promotes utility acquisition of DSM resources which achieve the greatest resource cost savings; (2) encourages utilities to inform customers about the cost saving and other benefits of implementing the DSM measure; (3) stimulates the utility to provide adequate incentives and other financial and technical assistance in implementing the DSM measure; (4) rewards the utility if it can lower the program marketing, financial incentive and administrative costs required to induce the customers to acquire the DSM measure; and (5) encourages the utility to continuously monitor that the DSM measure is achieving avoided cost benefits for the utility and the customer.

A Recommended DSM Incentive Mechanism

The authors recommend that a desirable DSM incentive is to increase the utility's net income by a share of the long-term net benefits that accrue to all ratepayers from acquiring the DSM resources. Specifically, it is recommended that the net income incentive be a percentage (say 10%) of the difference between: (1) the present value of the avoided cost and other benefits received by ratepayers (including avoided environmental impacts) obtained from deploying and operating the DSM measure over its service life in cooperation with the customer; and (2) the present value of the program costs (marketing, financial incentives, administration, and evaluation) required by the utility to maintain the DSM Measure over its service life. Program evaluation and other statistical field performance verification techniques can be used for verifying that the avoided cost and other benefits are being received over its service life. This DSM incentive encourages the utility to maximize the avoided cost benefits and to minimize program costs, including the amount of the financial incentives that are offered.

The overall DSM incentive for the utility could be structured in several ways: (1) either as a percentage of the aggregate avoided cost benefits less the aggregate program cost; (2) or on a disaggregated program by program basis. If this latter case applies, a utility which acquires the DSM measure illustrated in Columns 1, 2 and 4 of Table 4 would receive an incentive of 10% times [$3260 -($125+$63+$390)] or $268.20/kW on each measure.

Because this DSM incentive does not internalize customer costs, it must be coupled with a least cost planning process which selects eligible DSM measures based on a total resource test, including customer costs. And, the program evaluation process should include a review of customer satisfaction with a random sample of DSM transactions.

An alternative and, in the authors view, a slightly less desirable approach is to base the DSM incentive on the percentage of the net resource cost savings which internalize the customer costs. This approach does provide the utility with an incentive to maximize avoided cost and other benefits and to minimize total costs, including program marketing, administration, and evaluation. However, this approach does not reward the utility for creativity in designing programs which minimize the magnitude of financial and other incentives that are offered to customers to adopt DSM measures. Reducing program costs can minimize rate increases and adverse impacts on non-participating customers.

Following discussions with the authors about benefits and potential problems with implementing it, O&R decided to base its DSM incentive proposal approved by the NYPSC on the first approach. And, Niagara Mohawk decided to base its DSM incentive on a percentage of the net resource savings. Both are implemented on an aggregate program basis. (NYPSC Opinion and Order 89-29 1989)

CONCLUSIONS

The traditional ratemaking process used by New York utilities provides significant disincentives to implement DSM and significant incentives to market electricity use as a means of enhancing profitability. The latter is fundamentally inconsistent with the goals of least cost planning and the acquisition of cost-effective DSM resources which can help customers reduce energy costs and reduce adverse environmental impacts.

The Electric Rate Adjustment Mechanism (ERAM) used by the California Public Utilities Commission eliminates both the DSM disincentive and power marketing incentive problems and has other desirable properties, including incentives to reduce electricity supply costs.

The Fuel Revenue Accounting (MFRA) method used by Central Maine Power can be modified to have most of ERAM's advantages with the added benefit of providing limited coupling of profitability to customers electricity consumption characteristics.

A DSM incentive based on a sharing of the net resource savings determined through in-depth program evaluation provides an effective motivational basis for rewarding utilities for their implementation of DSM programs. This DSM incentive should be integrated with a set of complementary incentive mechanisms which reward utilities for performance in reducing the costs of meeting customer end-use energy needs.

A conceptually appealing alternative to separate performance measures would be to develop global measures of utility performance which inherently capture and give appropriate weight to these separate performance factors, but in a self-consistent manner. The Effective Resource Cost of Electricity (ERCE) developed by one of the authors appears to have many desirable attributes for assessing utility performance. However, more analysis of utility cost and customer billing data is needed to determine whether the ERCE index or the customer bill-based performance index approach recommended by David Moskovitz can provide a practical basis for coupling profitability to performance.

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