Ontario Energy Board
RP 2004-0188
Exhibit ____

Cost Recovery for Conservation and Demand-Management for Ontario Electric-Distribution Utilities

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on behalf of
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I. Introduction

This evidence discusses the ratemaking context for the conservation and demand management (C&DM) activities of Ontario's electric distribution utilities, including recovery of direct costs, recovery of lost revenues, and incentives to promote energy efficiency. These are issues that remain outstanding as part of the Ontario Energy Board's 2006 Electric Distribution Rate Handbook stakeholder consultation exercise.

I describe and distinguish the issues that arise with C&DM on the customer's side of the meter and those that arise with efficiency improvements on the utility side.

Portions of this filing rely heavily on my evidence in RP-1999-0034.

This evidence applies to the utility C&DM efforts in 2006–2008. The same considerations would apply to C&DM in 2005. The panel hearing applications for approval of 2005 C&DM plans has approved a simple 5% of TRC incentive for customer-side spending and approved the concept of an LRAM, but left the details of the LRAM to this proceeding. Funding for C&DM in 2005 would come from the third installment of market-adjusted revenue requirement (the "third tranche"), so no special funding mechanism is required. The third tranche may fund C&DM plans over three years, and the approved plans have spread spending over all three years. Accordingly, the current proceeding should also consider the appropriate mechanism beyond 2005 for C&DM funded by the third tranche, as well as additional C&DM funded in rates.

Adoption of any approved mechanism for recovery of lost revenues or incentives should be voluntary. The same is true for a mechanism for reconciling C&DM spending, so long as C&DM costs have not been included in rates. Once C&DM costs are in rates, a reconciliation mechanism should be mandatory, at least with respect to utilities that spend less than the revenues they are provided for C&DM.

II. Distribution Utilities and Demand-Side Management

A. Market Barriers and the Opportunity to Provide Benefits

Experience suggests that the potential benefits of energy efficiency have primarily been achieved where utilities have intervened in the market to overcome a range of market barriers that have persisted despite the restructuring of the generation market. These barriers arise any time customers are faced with the choice of committing their time, effort and capital, compared to simply purchasing power from the utility or a marketer. They include the following:

- The cost to individual consumers of acquiring the specialized information needed to select energy-efficiency technologies, products, and vendors.
- Split incentives between energy users and the people who select equipment and designs (landlords, developers, architects, engineers, plumbers, contractors, and vendors).
- Access to capital
- Real and perceived non-diversified risks associated with committing capital for energy-efficiency investment, such as lack of liquidity in investments tied to particularly buildings.
- Transaction costs for customers and vendors, especially in locating, evaluating, and selecting unconventional equipment and services.
- Lack of market infrastructure, including unavailability of equipment (except perhaps as a more expensive special order) and services.
- Institutional constraints.
- The lack of market signals reflecting the externalities of energy production and transmission, principally environmental effects of building power plants and transmission lines, and the effects on air and water resources of burning fuels to generate electricity. For valuing gas DSM, the Board has used a value of $40/ton of CO_2, which is equivalent to about 1.5¢/kWh for a clean new gas combined-cycle unit. Other environmental effects (e.g., emissions of NOx, heating and consumption of surface water) would add to this value.[1]

B. Potential Benefits of C&DM

1. Experience with C&DM in Ontario

Demand-side management has a significant history in Ontario. Ontario Hydro formalized its C&DM efforts (which were then called DSM, or demand-side management) in the 1980s, culminating in a major 25-year plan filed as part of its Demand-Supply Plan (DSP) in 1990. Throughout the late 1980s and the early 1990s, the Ontario Energy Board reviewed Hydro's C&DM plans and in large measure endorsed the utility's direction. Hydro ultimately withdrew its DSP (in

[1]Other generation sources, such as Ontario's existing coal plants, have higher CO_2 and NOx emissions, and also release significant amounts of SO_2, fine particulates, and toxic metals.

part due to lower load forecasts) and was not subject to broad regulatory review by the OEB after the early 1990s. Accordingly, while I understand that Hydro continued to pursue C&DM at some level after 1995, the details are not a matter of public record.

In its Report in HR 21 (at 24) the Board reported Hydro's estimates and forecast of demand reduction to be as follows:

1991 Actual..........250.4 MW

1992 Budget.........308.4 MW

1993 Forecast.......350.9 MW

The 1992 budget called for $97.1 million in OM&A and $149.8 million in capital for C&DM, all in 1992 dollars. (HR 21 at 25, Table 3-2). In 2004 dollars, total 1992 C&DM spending was $309 million.

The Board next reviewed Hydro's DSM plans in 1994 as part of its HR 22 hearing. In that proceeding, the Board considered Hydro's restructuring including its strategic direction for DSM. The Board continued to endorse DSM despite increasing excess generation capacity. In particular, the Board noted the need to focus on lost opportunities, which would otherwise be lost as cost-effective options.

Throughout the late 1980s and 1990s several municipal utilities co-operated with Ontario Hydro in the promotion and delivery of conservation (or conducted independent programs).

2. Externalities

Energy efficiency is generally environmentally benign, and much distributed generation is likely to be cleaner than the existing mix of fossil central generation in Ontario. Load reductions are likely to be vital in achieving the goal of shutting down Ontario's coal plants in 2007 and avoiding imports of US coal-fired power. In the near term, the most promising distributed-generation options are zero-emission photovoltaics and wind power, along with gas-fired cogeneration and some gas-fired turbines in specialized situations, such as support of the distribution system. The high net efficiency of cogeneration, along with the lack of line losses, generally results in lower CO_2 emissions than central-station power plants.

3. Risk Reduction

Under traditional regulation, energy-efficiency programs reduce risks to energy consumers in several ways.[2] All the reliability benefits of energy efficiency continue to benefit customers in the restructured industry.

- Most importantly, in the restructured market, lower loads will reduce market prices and save money for all Ontario electricity consumers.
- Once installed, energy-efficiency measures are not generally subject to cost risks. This effect directly reduces customer price risk.
- Energy efficiency, unlike conventional power supply, is not subject to major simultaneous interruption due to environmental restrictions, equipment failure, construction delays, or transmission failure. When energy-efficient equipment fails, its energy usage generally decreases, rather than rising. In any case, failures are spread fairly smoothly across thousands of installations, and no one failure is likely to have any significant effect on regional electric-system reliability or cost.
- The actual energy and demand savings resulting from previously-installed energy-efficiency measures will tend to be greatest in times of high load (e.g., extreme weather, strong retail activity), when costs would otherwise be highest and reliability would be lowest. This same effect also reduces the volatility of load and hence market prices between months and years, reducing expected prices, price volatility, and the costs of new supply.
- If the distribution utility—or some other authority—maintains the capability to deliver full-scale efficiency programs, it can respond to capacity-tight situations or bottlenecks in the market. The result would be a more-reliable supply of power and lower, more-stable capacity and energy prices.

C. Role of Distributors

Distribution utilities have a unique role in the restructured electricity market. Unlike most other participants in the new market, each utility has a long-term relationship to the customers, the service area, and to other local market actors, such as builders and appliance dealers. Ontario's decision to condition the utilities' collection of the third tranche on the expenditure of those funds for C&DM demonstrates that the provincial government accepts the importance of the utility's role in implementing C&DM.

[2] See, for example, VPSB Docket No. 5270 Order at (3)121–125.

The recent passage of Bill 100 establishes the Conservation Bureau within the Ontario Power Authority, to implement province-wide C&DM programs. It is not clear to what extent the Conservation Bureau will take on the various planning, design and implementation roles in C&DM, and for which types of programs: energy efficiency, distributed generation, pricing or load management; market transformation, replacement or retrofit. Even if the Conservation Bureau provides much of the leadership, the distribution utility's closer relationship to its service territory is likely to create opportunities for cost reductions in implementation, while the utility's understanding of the local distribution and transmission problems allows for focussing of programs to increase benefits. Properly located C&DM can reduce both distribution and transmission investments, while maintaining or enhancing reliability.

The evolving role of the distribution utilities in C&DM planning, design, and implementation will have important effects on the magnitude of costs to be recovered, the attribution of lost revenues, and the design of shareholder incentives. Any determinations made in this proceeding should be subject to reassessment as those roles become clearer.

D. Need to Supplement the Private Market

Prior to the restructuring of electric-power markets across North America, it appeared possible that marketers would bundle energy efficiency and distributed generation with power supply to create a more attractive overall product, providing opportunities for development of a competitive energy-services market. Marketers have not stepped into this role, and the potential for competitive C&DM services will continue to be constrained by the persistence of market barriers, including the following:

- The high transaction costs (which can result in quick payback requirements) for measuring and billing energy efficiency savings.
- The risks to one or both parties if the customer moves, changes supplier, or goes out of business.
- The inability of building owners and developers (who would sign up for the efficiency services) to obligate tenants and purchasers to purchase energy from particular marketers.
- The information and other transaction costs for customers to understand and evaluate complex contractual offerings blending energy-efficiency technologies, power supply, and payment schemes.

- The complexity of administering market-driven programs (e.g., selecting a more efficient refrigerator) through multiple marketers serving each community.

Non-utility companies may not have sufficient financial incentive to serve many types of customers (e.g., low-volume and low-income customers), and their efficiency measures may be limited to those with the shortest payback period. Of course, the competitive market is not likely to take into account costs and benefits that affect anyone other than the parties to the transaction. It will thus ignore environmental and other externalities, avoided T&D costs in excess of rates, and benefits to tenants, subsequent owners, and other affected parties.

Competitive markets do deliver some efficiency services to consumers. Where utilities have not been active in promoting energy efficiency, ESCos have achieved some success in selling efficiency, through such mechanisms as shared-savings programs. These efforts have tended to emphasize actions that are low in risk, pay back their investment quickly, and are easily measured. They have also generally been restricted to large energy consumers.[3]

Where utilities have provided energy efficiency services, participation and savings have often increased remarkably, and have reached new markets, including new construction and residential and small-business customers. These benefits may also be achieved, in part, by the Conservation Bureau of the Ontario Power Authority.

III. Ratemaking for Conservation and Demand Management

Care should be taken to ensure that ratemaking supports, rather than undermines, conservation and demand-management initiatives by distribution utilities. The current ratemaking system has the following two adverse effects on utility C&DM efforts:

- Utility rates are capped. Increased utility spending on C&DM does not result in any increase in revenues. A utility that chooses to reduce customer costs by investing in energy efficiency would have no way to recover those investments.

[3] Savings are typically shared between the ESCo and the customer. Consequently, the ESCo has no incentive to pursue any measure whose cost is not covered by the ESCo’s share of the savings, over the limited term of the contract, and heavily discounted to reflect the costs and risks to demonstrating the persistence of savings in any particular installation.

- The rate cap does not reflect changes in usage; a utility that reduces customer costs with C&DM would also reduce its sales, and hence the revenues available to cover distribution costs.

The recent 2005–2007 third-tranche Conservation and Demand Management Plan filing by Veridian Connections in RP-2004-0203 docket illustrates the sort of reaction that can be expected from utilities in the current situation. Of Veridian's $3.5 million share of the third installment of market-adjusted revenue requirement, 80% would be spent on enhancement of normal utility functions of installing meters and capacitors and reconfiguring the distribution system, none of which result in any lost revenues. Another 3% would be spent on arrangements for the use of emergency generators for system support, which also involves no lost revenues. And 80% of the spending on these categories would be for capital, which the utility would be able to recover after the end of the current rate freeze.

Only 10% of the expenditures would be related to energy efficiency, and that would be for a "Co-branded Mass Market Program," which appears to be mostly education and marketing. It is not clear that this program would have any effects on Veridian's sales; even if it gradually changed customer attitudes, most of the effects would likely occur after the next rebasing of rates.

The final 7% of expenditures would be spent in connection with load-displacement generation on the customer's side of the meter. The Veridian filing is vague about how those funds would be spent, but the "training and education programs in conjunction with colleges and universities" that Veridian "may consider" would not be likely to have much short-term effect without the "financial incentives [that] will be considered." Since Veridian proposes that 70% of the spending for this program be for capital investments, presumably for distribution upgrades on the utility side of the meter, incentives would appear to represent a small portion of program spending.

With appropriate C&DM ratemaking, utilities would be more willing to spend money on expenses, such as rebates and direct installations, and to spend more on programs that would actually reduce energy use. Such reductions in energy use are critical to achieving environmental goals, such as reductions in carbon emissions, and in controlling upward pressure on market energy prices, allowing the eventual creation of a balanced and efficient electric-power market in Ontario.

In order to encourage distribution utilities to implement energy-efficiency programs, the ratemaking mechanism should at least remove financial disincentives, and provide the opportunity for some additional incentive to encourage the use of less-traditional resources. Some mechanisms that would help in achieving these goals are recovery of direct costs, recovery of lost revenues, and an explicit incentive mechanism.

A. Recovery of Direct Costs

It is important for utilities to be assured that funds prudently expended to serve their customers, including C&DM funding, will be recovered in rates. In the present environment of a rate freeze and considerable regulatory uncertainty, the Board should also strive to reduce utilities' concerns with cash flow and accrual of deferred assets, by allowing adjustment of rates to accommodate C&DM, and clearance of accounts, as frequently as any other rate adjustments are allowed.

1. Recovery Mechanism

Distribution utilities should be allowed to recover their investments in C&DM programs. The Conservation Working Group has proposed that each utility establish a Conservation Expenditures Variance Account, which would allow for deferral of "the variance between a utility's budgeted annual conservation revenues and expenditures" and associated carrying charges. This Conservation Expenditures Variance Account should actually include only the expenditures that are expensed and the carrying charges on capital investments. Most of the costs of capitalized expenditures will be recovered after the next rate rebalancing, when they will be reflected in the utility's rate base.

Compliance would be straightforward, since the utility's spending on C&DM can be determined from accounting records. Explicit incremental C&DM expenditures (rebates, equipment purchases, hiring dedicated staff and contractors) should be easily tracked.

2. Cost-Effectiveness

As part of the cost-recovery process, utilities should be required to demonstrate that their programs are reasonably expected to be cost-effective under the societal cost test.[4] Each large utility may wish to demonstrate the cost-effectiveness of its particular package of C&DM measures and programs. Smaller utilities should be encouraged to make this demonstration by such low-cost approaches as follows:

- adopting programs in use by other Ontario utilities and previously reviewed by the Board,
- adopting programs in use by utilities in other jurisdictions, and subject to cost-effectiveness review in those jurisdictions,

[4]Programs that pass the TRC would also pass the SCT test.

- filing joint proposals with similar or identical programs across a number of small utilities.

A consultative effort, such as the stakeholder advisory group proposed by the CWG to assist the Board's auditor and staff with pre-approval of inputs and with audits of utility revenue claims, should be encouraged to develop avoided costs, design standard programs, and demonstrate the cost-effectiveness of those programs. A single effort of the most-knowledgeable parties, with province-wide effect, would reduce costs, Board Staff time commitments, and redundant efforts by many utilities. I understand that a first cut at avoided costs will be filed by a group of large electric and gas utilities in January 2005. Based on my previous experience with avoided-cost estimates, these values are likely to be controversial; reaching agreement on avoided costs should be one of the first goals of the auditor and advisory group.

3. Spending Levels

Since most Ontario utilities have little experience with operating C&DM programs, they may lack a sense of an appropriate scale for customer-side program spending. Two related questions may arise for a utility manager, in terms of a potential level of customer-side C&DM spending:

1. Would this magnitude of spending represent an excessive rate effect?
2. Is it likely that my utility could prudently spend this much on C&DM?

To reduce these uncertainties, the Board should establish an expenditure level for C&DM that is primae facia reasonable. The following table shows the spending in dollars per MWh on energy efficiency and renewable energy for a number of utilities.

Table 1: Leading Utility Spending on C&DM

	US $/MWh			
State or Utility	Energy Efficiency	Renewable Energy	Total	**CAN $/MWh**
New Hampshire	$1.8/MWh	—	$1.8/MWh	$2.2/MWh
Rhode Island[a]	$2.3/MWh		$2.3/MWh	$2.8/MWh
Massachusetts	$2.5/MWh	$0.5/MWh	$3.0/MWh	$3.7/MWh
Vermont	$2.9/MWh	—	$2.9/MWh	$3.5/MWh
Connecticut	$3.0/MWh	$0.75/MWh	$3.8/MWh	$4.6/MWh
New Jersey	$1.26/MWh	$0.31/MWh	$1.6/MWh	$1.9/MWh
New Jersey	$1.3/MWh	$0.43/MWh	$1.7/MWh	$2.1/MWh
ConEd	$1.6/MWh	—	$1.6/MWh	$2.0/MWh

NOTES: Assumes $0.82 U.S. per Canadian dollar.
[a]Renewables included in efficiency

In addition, many of these utilities make other expenditures on load management, advanced metering, demand response, utility-side loss reduction, distributed non-renewable generation, and other programs that may be included in C&DM spending.

All these utility programs are subject to extensive oversight and/or public participation in program design and resource allocation. The programs have been found to be cost-effective, and the spending has not resulted in excessive customer rates. In many cases, additional funding could have been used productively.

Many of these areas (e.g., New York, New Jersey, Massachusetts) have experienced high electricity prices for many years, and customers have adapted their energy use to those prices. Hence, equipment and buildings in those areas probably tend to be more efficient than corresponding uses in Ontario. If anything, the Ontario utilities could probably productively spend even more than the utilities in Table 1. Most Ontario utilities could probably productively spend $5/MWh of sales on customer-side C&DM.

Since most of the Ontario distribution companies will be ramping up their C&DM capability over the next few years, and the scope of spending by the Conservation Bureau is not yet known, I recommend that the Board at this time declare that annual C&DM expenditures (including funding from the third tranche) of less than $2.5/MWh of sales are not unreasonable in magnitude. Utilities that wish to spend more than that level on customer-side C&DM should be encouraged to seek review of their plans by the Board or its designee.

B. Recovery of Lost Revenues

1. LRAM Mechanism

The decision on 2005 C&DM approves removing the penalty on utilities that voluntarily reduce their sales by allowing them to book and defer the lost revenues through a lost-revenue adjustment mechanism (LRAM). This practice should be extended to 2006 and beyond.

Compliance would require an audit or review by independent auditor, an individual or firm qualified and hired by the Board to estimate the sales reductions from the types of programs the utility has operated. To facilitate this process, the Board auditor and the advisory group should develop standardized methods for estimating the sales reductions of the programs implemented by the utilities. For some generic programs, estimating energy saved may be as simple as counting participants.

The CWG has proposed pre-approval of inputs as a means of reducing regulatory risk and allowing utilities to share data and analysis and avoid duplicated effort. In the longer term, LRAM recovery should be based on the best available estimate of the actual load reductions, based on information at the time of account clearance, which may differ from prior estimates. In the short term, this objective is eclipsed by the need to assure utilities of a simple and predictable mechanism for lost revenues. I therefore support the simplified approach proposed by the CWG, in the short term.

2. *Alternatives to LRAM*

Instead of an LRAM, some jurisdictions have implemented broader adjustment mechanisms, such as a true-up of revenues to the level projected in the ratesetting process, capturing changes in sales due to C&DM, economic fluctuations, weather, and all other factors, unless some explicit adjustment is made. This approach would require extensive revisions to the existing PBR system, which is fairly new and still in flux. A full revenue true-up seems too complex for the electric utilities, at this time.

In RP-2004-0203, Woodstock Hydro has proposed what it describes as "a more simplistic approach to address the LRAM" in which "LDC distribution charges move to a full 100% fixed charge." Woodstock Hydro asserts that "a full fixed charge is based on cost causality principles" because "The cost to support demand or usage is determined at the time of construction and is essentially a fixed cost."[5] Wodstock Hydro's position is summarized in its paragraph 24:

> When a new customer is connected to the distribution system, a distribution engineer will determine the maximum demand they expect the customer to use. Generally, this is called the design demand. Once the design demand is know, the distribution system will be constructed or upgraded to handle the additional design demand. The cost to construct or upgrade will be incurred before the customer starts taking power and will be a fixed costs. When the new customer starts taking power their usage pattern will have very little impact on the cost of the distribution system.

This statement is only true for equipment that serves only one customer, such as a service drop for a single-family home. For all other equipment, sizing is determined by the sums of the loads sharing it, reflecting the diversity of those loads, and the point at which the equipment must be expanded or replaced is determined by that total load. That is true for line transformers, distribution feeders and distribution substations (often at multiple voltage levels), as well as for such supplementary equipment as capacitors. The lifetime of equipment is reduced as the frequency and magnitude of loads exceeding design rating increases.

[5] All Woodstock Hydro quotes are from Woodstock Hydro, 2004.

The Woodstock Hydro proposal thus is based on a misconception. If customer loads grow, distribution investments and costs will also grow. The Woodstock Hydro proposal would encourage wasteful increases in load and in distribution costs, by exempting the customers imposing those costs from responsibility for their costs.[6]

C. Shared-Savings Mechanism

As discussed in Appendix A, within each utility, customer-side C&DM faces competition for capital from more traditional utility operations, and resistance from the traditional utility culture of building plant and selling energy. To overcome these impediments, the Board has allowed utilities to request a shared-savings mechanism (SSM) for their 2005 C&DM performance. For 2005, the Board has adopted an incentive of 5% of net total-resource-cost (TRC) benefits.

The 5% incentive is a reasonable starting point. Once the Board accepts projections of avoided costs and has some idea of how much net TRC benefit various utilities can generate with various levels of effort, it will be able to establish an incentive that rewards insipid efforts less and aggressive efforts more. For example, the Board might allow an SSM of 2% of net TRC benefits up to a turning point, and 8% above that point. The turning point may be defined as a fraction of utility annual revenues, or as a mill rate times the utility's distribution deliveries. Those turning points should be influenced by the avoided costs selected, since higher avoided-cost estimates will produce higher estimates of TRC benefits.

The auditor and advisory group may be able to make recommendations to the Board on the design of a progressive SSM sometime in 2006 or 2007.

The Board will also need to monitor the development of the Federal and provincial C&DM programs, as well as cooperative programs between electric and gas companies, to determine whether the distribution utilities have a major role in delivering or facilitating those programs. A utility should only be allowed to claim an incentive for the incremental benefits of its participation in such programs. As specific situations arise, the Board should develop pre-approved inputs and methods for appropriately determining the electric utility's share of the benefits and its eligibility for SSM rewards.

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[6]Indeed, in RP-1999-0034, I presented evidence that the variable distribution cost was much higher than the value adopted by the Board. The $0.0062/kWh value in the Rate Handbook is in 1987 dollars, excludes capitalized overheads, and is computed for average load, not for customers served by the full distribution system. I estimated a corrected value of $0.0142/kWh.

As explained in the next section, the SSM should reflect only customer-side C&DM.

D. Ratemaking for Utility-Side Expenditures

Expenditures on the utility side of the meter are likely to be mostly capital, such as for installation of low-loss transformers. Little or no special ratemaking should be necessary for these investments, so long as the costs are included in rate rebasing every few years. Most of the capitalized costs will be recovered after the rebasing, so no variance account should be necessary. No net revenues are lost. And these are the types of expenditures familiar to utilities, and involve no cultural conflict, so no lifecycle TRC incentive should be necessary.

If rates remain frozen for more than three or four years, the Board should consider allowing utilities to defer some carrying costs from utility-side C&DM. In any case, if the utility incurs large operating expenses for utility-side C&DM, such as reconfiguring distribution feeders, the Board might allow the utility to defer those expenses in a variance account. Alternatively, the utility could be allowed to keep the loss savings from the projects until rates are reset

Appendix A: The Rationale for C&DM Incentives

Negative perceptions about energy efficiency are common and deeply rooted in the culture of energy-utility staff. As Union Gas has pointed out, energy utilities have long been oriented “to increase energy sales and thereby increase net revenues and returns to the shareholder” (Application in EBRO 499, Exhibit D1, Appendix E, at E4). Pursuing energy efficiency is clearly a substantial change from this traditional approach. Lost revenues from energy efficiency are inherently inconsistent with increasing sales, revenues and returns. But even when the major conflicts between efficiency and profit-maximization are resolved with an LRAM, utility managers may have a number of concerns with promoting energy efficiency:

- C&DM must compete for management attention, talented staff, and other scarce resources with other activities, including many that increase sales, reduce costs, or otherwise increase profitability between rate cases. If C&DM is simply earning-neutral, management will quite sensibly direct their efforts to those activities that can increase profits.
- Utility promotion of energy-efficiency measures may encourage others to adopt similar measures, resulting in lost revenues beyond those covered by systems that account only for the direct effects of utility programs.

- Utility endorsement of energy efficiency may undermine the culture of energy consumption, making the use of less energy (and specifically less electricity) more socially acceptable.
- The moral status of the utility's sales efforts will be undermined by the utility's efforts to reduce energy consumption. How can our product be good, if we are encouraging our customers to use less of it?
- Increased investment, and hence sales growth, increases the future profitability of investor-owned utilities if allowed return on equity is above the cost of attracting new capital. In this situation, C&DM will make existing shareholders slightly worse off, by reducing the growth in rate base.
- Utility employees are used to seeing corporate profitability varying directly and dramatically with short-term fluctuations in sales (due to weather, for example). While an LRAM would eliminate the potential short-term effect of C&DM on profitability, the idea that reduced sales may be earnings-neutral will not be accepted immediately.
- Financial analysts customarily associate rising sales and low rates with profitability. Even if utility managers understand concepts, C&DM is harder to explain to the financial community than sales promotion.

Managers may also have more personal concerns about C&DM.

- Employee incentive programs for executives and top managers often include incentives based on profits and sales growth. This incentive structure will make managers resistant to C&DM.
- Most utility staff have seen peers and superiors advance in a variety of activities—engineering, sales, finance—but not in C&DM. Until C&DM is established as a profitable utility activity, talented staff may resist assignment to an activity that has not been demonstrated to enhance career potential.
- Utility management may prefer higher sales, since a larger and faster-growing company is more exciting to manage. The growing company will present more opportunities for hiring and promoting staff, making dramatic decisions about expansion projects, and being feted by investment banks and equipment suppliers.

This combination of exaggerated concerns about shareholders and the very real self-interest of utility management creates the need for some incentive to overcome internal resistance to energy efficiency. Even were the ratemaking mechanism to create a level playing field in objective financial terms, an explicit incentive would also be necessary to balance the inertia of history and managerial psychology.

Appendix B: Resume of Paul L. Chernick

Paul Chernick, President of Resource Insight, has 27 years of experience in the electric and gas utility field. He has consulted and testified extensively on utility and insurance economics. His recent and current responsibilities include quantifying stranded investment, assessing prudence of power-planning investment decisions, reviewing electric utility rate design, assessing energy-conservation and renewable-energy opportunities, estimating the magnitude and cost of future load growth, evaluating proposed utility mergers, reviewing and designing utility performance incentives, and assessing and designing systems for distributed-utility planning. He has been a leader in designing and evaluating electric, natural gas, and water utility conservation programs, including hook-up charges and conservation cost-recovery mechanisms, and advising regulatory commissions in least-cost planning, rate design, and cost allocation.

Mr. Chernick's experience includes three years on the staff of the Massachusetts Attorney General's utility division and eighteen years as principal and president of his own consulting firm.

Mr. Chernick has testified in more than two hundred regulatory and court proceedings and has performed a wide variety of studies for public agencies, non-profit organizations, and corporations. His clients are regulators, public advocates, energy utilities, non-utility power producers, environmental advocates, and municipal governments. He is author of more than 35 published papers and has provided training to public advocates and regulatory staffs.

Mr. Chernick holds an SM from the Technology and Policy Program and an SB from the Civil Engineering Department of the Massachusetts Institute of Technology. He is a member of Chi Epsilon, Tau Beta Pi, and Sigma Xi honorary societies, and received an Institute of Public Utilities Award.

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