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Docket No. 90-261-A
Exhibit BGC-3

COMMONWEALTH OF MASSACHUSETTS
BEFORE THE
DEPARTMENT OF PUBLIC UTILITIES

DIRECT TESTIMONY OF

PAUL CHERNICK
Resource Insight, Inc.

ON BEHALF OF THE

BOSTON GAS COMPANY

April 17, 1991

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1. INTRODUCTION AND QUALIFICATIONS

1.1 Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received an S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options.

As a Research Associate at Analysis and Inference and in my current position, I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached to this testimony as Attachment PLC-1 to this testimony.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately eighty times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Energy Facilities Siting Council, the Maine Public Utilities Commission, the Vermont Public Service Board, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Illinois Commerce Commission, the Minnesota Public Utilities Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects on which I have testified include nuclear power plant construction costs and schedules, nuclear power plant operating costs, power plant phase-in procedures, the funding of nuclear decommissioning, cost allocation, rate design, long range energy and demand forecasts, utility supply planning decisions, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Have you testified previously before this Department?

A: Yes. I have testified before the DPU in approximately thirty cases since 1978.

Q: Have you been involved in least-cost utility resource planning?

A: Yes. I have been involved in utility planning issues since 1978, including load forecasting, the economic evaluation of proposed and existing power plants, and the establishment of rate for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to the Conservation Law Foundation's (CLF's) conservation design project in Jamaica; to CLF interventions in a number of New England rulemaking and adjudicatory proceedings; to the Boston Gas Company on avoided costs and conservation program design; to the City of Chicago on Commonwealth Edison's least-cost plan; to the Penobscot River Coalition on Bangor Hydro's DSM program and philosophy; to the Maryland Office of People's Counsel on Baltimore Gas and Electric's DSM program; and to several parties on least-cost-planning rulemakings and the incorporation of externalities in utility planning and resource acquisition.

Q: Have you authored any publications on utility planning and ratemaking issues?

A: Yes. I have authored a number of publications on rate design, cost allocations, power plant cost recovery, conservation program design and cost-benefit analysis, and other ratemaking issues. These publications are listed in my resume.

Q: Please describe your experience in analyzing the cost-effectiveness of fuel-switching.

A: I have worked on fuel-switching cost-effectiveness analyses for two CLF collaborative conservation program design efforts: Central Vermont Public Service and Citizens' Utilities. I prepared and filed an extensive analysis of the cost-effectiveness of fuel-switching in DPU 89-239, and assisted Providence Gas and Valley Gas in the review and correction of a Xenergy report on commercial chilling as part of the Rhode Island Fuel-Switching Task Force (under the sponsorship of the PUC and the Energy Office). I have written articles on fuel-switching for Gas Energy Review and the 1990 NARUC BRIC conference and made an invited presentation on the subject to the NARUC Conservation and Gas Committees.

1.2 Introduction

Q: What is the purpose of this testimony?

A: This testimony discusses the economics and role of fuel-switching in the demand-side management (DSM) program of the Massachusetts Electric Company (MECo).

Q: How do you address these issues in the remainder of your testimony?

A: In Section 2, I start by discussing the conceptual role of fuel-switching in electric utility DSM programs. Among other things, that section considers the market barriers to fuel-switching and the need for electric utilities to overcome those barriers. In Section 3, I explain how the avoided costs of MECo and Boston Gas Company (BGC) can be compared for social cost analysis. Section 4 updates some of the Department's estimates of the social values of externalities. Section 5 summarizes the relative social costs of using electricity and gas for various end uses. Section 6 provides recommendations on the incorporation of fuel-switching in MECo's DSM program.

Q: Does this testimony discuss all potential fuel-switching options?

A: No. I focus on electric-to-gas fuel-switching for four residential end uses -- space heating, water heating, cooking, and clothes drying -- and for commercial chilling. From the residential results and my analysis for DPU 89-239 (Chernick, Goodman, and Espenhorst, 1989), I would expect electric-to-gas fuel-switching of the four residential end uses also would be generally cost-effective in the analogous commercial applications. Gas-fired desiccant cooling, supplementing either electric or gas chilling, may be cost-effective, especially in large food stores, where humidity creates a range of fogging and frosting problems. In addition, I am aware that several end-uses -- including refrigeration and industrial compression -- usually operated by electric motors can be operated by gas engines, but have not determined the cost-effectiveness of these applications.

I have not assessed the cost-effectiveness of fuel-switching from MECo electricity to other fuels, such as wood, oil, and propane. CLF collaboratives in Vermont have found fuel-switching to these alternatives to be cost-effective, although not as much so as switching to gas.

Since this docket concerns MECo's DSM program, no extensive discussion of gas-to-electric fuel-switching is required. However, some electric technologies are much more efficient than the corresponding direct use of fossil fuel and may thus be cost-effective, despite the higher cost of electricity. These technologies (e.g., induction heating, freeze concentration, non-thermal paint curing) are applicable primarily in industrial processes that are not very common in BGC's service territory. BGC has committed to including gas-to-electric fuel-switching in its large C&I program where applications are identified. Additionally, several gas conservation measures BGC will promote will use electricity in fans, pumps, and controls to reduce gas use. These measures effectively constitute a form of gas-to-electric fuel-switching. BGC currently uses fuel-switching from gas to oil as a load management measure, as discussed in the testimony of Walter Flaherty.

2. THE ROLE OF FUEL-SWITCHING IN UTILITY DSM PROGRAMS

Q: Which subjects do you cover in this section?

A: I discuss the cost-benefit test applicable to fuel-switching, the relative importance of equity issues for fuel-switching and other DSM, and the nature of market barriers to cost-effective fuel-switching. I also respond to analogies MECo makes in this proceeding between fuel-switching and self-generation and fuel-switching and customer relocation.

2.1 The Cost-Benefit Test

Q: Which cost-benefit test is appropriate for fuel-switching?

A: The same cost-benefit test is appropriate for fuel-switching as for any other DSM program. The objective of least-cost planning is the utility's minimization of the social cost of providing the energy services desired by its current and traditional customers.

Q: In its 12/12/90 Memorandum on Scope in DPU 90-261-A, MECo asserts that in this case, "the Department should evaluate whether electric utilities should minimize their cost of service or encourage the efficient use of electricity by our customers." Is MECo's characterization of the issue correct?

A: No. Neither of the standards MECo proposes will minimize social costs. Actions that reduce the utility's "cost of service" may increase total social costs by encouraging customers to assume costs greater than the utility's savings or by increasing external costs more than internal costs are reduced. Actions that "encourage the efficient use of electricity" may be more expensive than the value of their avoided costs and may (in some isolated cases) increase externalities. The DPU need not consider the choice between MECo's proposals. The Department's social cost test is clearly the appropriate test for regulated utilities.

2.2 Equity Issues

Q: On page 2 of the 12/12/90 Memorandum on Scope in DPU 90-261-A, MECo claims that paying for fuel-switching creates equity problems that are fundamentally different from those resulting from paying for its existing DSM programs. Is this correct?

A: No. MECo's distinction between its existing DSM programs and fuel-switching programs is arbitrary. This is apparent even in its inconsistent terminology: MECo refers to incentives for fuel-switching as "subsidies," while the incentives it pays for DSM are "incentives." Emotionally-laden terms "subsidy" and "cross-subsidy" cannot replace substantive analysis. MECo has not shown that any equity problems resulting from fuel-switching differ materially in kind or degree from those resulting from its existing DSM programs.

Consider the breadth of customer eligibility, for example. MECo's assertion that "all customers will be able to participate over time" in the existing programs, but that "customers' ability to participate in fuel-switching depends directly on his or her [sic] proximity to the gas distribution system," is misleading in at least two significant respects.

First, MECo implies that all customers can participate in MECo DSM programs to the same extent. This is not true. Residential customers are not eligible for storage cooling programs. Commercial customers without sufficient room for cool storage cannot participate in the storage chilling program.[1] Residential customers without electric water heaters will never receive wraps, or rebates for efficient units, but they will pay for other customers' wraps and water heaters. Residential customers whose use is dominated by electric ranges and dryers are not eligible for any current or planned DSM services for those end uses.

If fuel-switching is part of a comprehensive DSM program, some customers can receive fuel-switching, some insulation, some lighting services, and so on. The ability to participate should be at least as widely spread as it is in MECo's existing DSM program.

Second, MECo's argument about gas availability is grossly overstated. Where gas is unavailable, MECo can investigate the cost-effectiveness of switching to other fuels, including oil, propane, solar, and wood. For commercial applications, including chilling, savings are apt to be large enough to warrant major gas-line extensions, so large MECo customers are unlikely to be beyond the economic reach of gas. The same may

[1]This is a very close analogy to proximity to gas lines.

be true where entire residential developments can be converted from electric space and water heating to gas. Hence, eligibility for fuel-switching may be no more restricted than for some of MECo's existing programs.

2.3 Market Barriers and the Role of the Utility

Q: Are there market barriers to fuel-switching?

A: Yes. The market barriers generally resemble the barriers to other DSM measures, such as increasing the efficiency of electricity usage.

Q: Why is utility intervention necessary to promote any type of DSM?

A: For choices between energy consumption and investments in energy cost reduction, price signals are weaker than economic theory expects. Customers routinely fail to invest in measures that would be cost-effective under the utility's investment rules. This is true even where rates are set so that the customers' costs for electricity are set equal to (or higher than) the utility's avoidable costs. A range of market barriers prevents customers from minimizing the total social costs of energy services.

As discussed in Plunkett and Chernick (1988), attached as Attachment PLC-2, substantial evidence shows a wide "payback gap" between customer and utility investment horizons. For example, commercial customers routinely require cost-reducing equipment to pay for itself in two years or less, while utilities routinely trade off costs and benefits on the supply side with a 10-year payback requirement. Customers act as if they place a high markup on the costs of energy efficiency, as discussed in the NARUC Least-Cost Planning Manual:

> According to extensive surveys of customer choices, consumers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years. Moreover, this behavior is not limited to residential customers. Commercial and industrial customers implicitly require as short or even shorter payback requirements, sometimes as little as a month. This phenomenon is not only independent of the customer sector, but also is found irrespective of the particular end uses and technologies involved. (NARUC, 1988, page II-9)

This behavior largely stems from substantial market barriers' impeding customer choice.

Q: What are those market barriers?

A: Many factors create market barriers. Some of these barriers, such as lack of simple information and lack of capital, may be overcome by third parties, such as vendors and installers. Yet even customers who know that a technology exists and possess sufficient capital may not invest in the technology. Uncertainty, inconvenience, aversion to risk (real or perceived), split incentives, lack of time for exploring options, limited retail availability, and aversion to dealing with contractors will not be overcome by simple information or financing. In general, only the utility providing the current service can be expected to overcome these barriers.

Market barriers can be separated into a number of categories, including:

- **Institutional constraints:** Corporations impose very rapid payback requirements on discretionary investments, especially for activities (such as DSM) outside their primary business area. In many organizations (corporations, government agencies, non-profits), managers may have much more difficulty obtaining funds for capital investments than for operating costs.

- **Access to conventional capital** for many individuals and organizations involves large administrative costs for the borrower and the lender. As long as a utility secures financing for supply without evaluating its customers' creditworthiness, but DSM investments must be funded through cumbersome retail channels, resources will tend to be biased toward supply.

- **Split incentives** dominate many DSM decisions. Developers and landlords select building and equipment designs, while buyers and tenants must pay the bills. The developer's concerns are apt to be dominated by construction budgets, short-term risk reduction, and the marketability of the building, rather than theoretical incremental effects of energy efficiency on sales prices or long-term rents. Architects and engineers are generally responsible for construction budgets and for adequacy of equipment operation; specifying non-standard high-efficiency equipment increases the architect's risk with little or no offsetting benefits. Building managers may be responsible for maintenance expenses, but not for energy expenses; they may incur major administrative difficulties in receiving authorization for capital investments.

- **The potential for regret** may be as important to many decision-makers as the expected value of NPV (the basic decision-making tool for utilities). Using standard technologies and procedures is unlikely to result in serious recriminations, even if technical or energy-market problems subsequently arise; using energy-efficient equipment may expose the decision-maker to a range of problems. Any plant manager, architect, or engineer who specifies unusual technology or an "unnecessary" change in equipment will face criticism if the investment does not appear to perform well or (worse yet) is blamed for adverse effects on sales or production.[2] Decisions to continue business as usual generally do not impose such risks.

- **Risk** affects many customer DSM decisions. Customers must consider the possibility that a normally effective measure will not work in their particular application. Customers also face the risk that they will move or go out of business before the measure pays for itself.[3]

- **Information, inconvenience, and hassle** considerations create significant barriers to DSM. Customers and managers face significant time requirements to select technologies and contractors, to monitor the quality of work, to determine whether the project was successful, and to pursue suppliers and contractors if problems arise.

Q: Can market-rate financing programs overcome the difference in payback requirements?

A: No. As discussed in Attachment PLC-2, even corporations with ample access to capital mostly do not invest in all conservation measures that would appear to be cost-effective because of the other market barriers. Residential consumers who are investing their own money (whether taken from savings, borrowed from a bank, or borrowed from the utility) face the inconvenience and risk considerations.

Q: Is the risk of a DSM program to the utility equivalent to the risk of the underlying measures to individual customers, if they pursued them on their own?

A: No. Suppose a measure saves 2000 kWh/year for 95% of installations, and has no effect for 5%. The average savings

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[2]Outside professionals, such as architects and engineers, are more vulnerable to malpractice suits if unusual technology fails than if standard approaches fail.

[3]They also face uncertainty regarding recoverability of their investment through the resale price of the home or building.

are thus 1900 kWh/year. If the measure costs $60/year, the savings cost only 3.2 cents/kWh on average. Individual customers face a 5% risk that they will commit to the $60 annual cost but achieve no savings, for an infinite cost of conserved energy. The utility may install thousands of these and other measures in an aggressive program, yet the utility's overall outcome will very closely approach the average savings. Hence, a real risk for individual customers becomes a negligible risk for the utility.

Similarly, increased efficiency will continue to benefit the utility, regardless of whether the customer relocates or whether the sale price of the building reflects the DSM investment.

Q: Do any differences between consuming electricity and investing in DSM affect the nature of rational consumer behavior?

A: Yes. In choosing to use electricity rather than make efficiency investments, consumers avoid many of the problems I listed above. They commit little or none of their own capital (or capital they are responsible for repaying), and need not be concerned about recovering an investment. Their risks are diversified since the electric utility sells them a package of supply sources. They face no choices, no regret, and no recriminations, and need not know the technical basis for MECo's investment decisions. They do not select MECo's contractors, monitor their work, or pursue those contractors for inadequate performance.

As long as the electric utility provides an integrated and diversified package of electrical services but requires its customers to assume most of the risk and hassles of efficiency investments, the utility does not afford supply-side and demand-side investments a level playing field.

Q: Can utilities eliminate these barriers?

A: By supplying some or all of the incremental funds required for efficiency investments, utilities can eliminate many of the inefficiencies produced by market barriers. For example:

Risk: While a customer can purchase only one chiller (for example), a utility program can influence the installation of thousands of chillers. The utility can substantially diversify the risk of poor performance of individual units.

Information: The utility can virtually eliminate the extensive information costs customers face. The utility and its contractors need to learn about the technology only once. As long as the utility undertakes the bulk of the costs and risks, individual customers need not repeat this effort.

Inconvenience and Hassle: The utility can also greatly reduce or eliminate the costs customers (especially small customers) incur in dealing with suppliers and installers. Locating, selecting, and supervising the suppliers, verifying the quality of work, and ensuring adequate follow-up will be much easier for a utility contracting for thousands of units or jobs than for a homeowner arranging just one.

Costs: The suppliers' costs may also be much lower in dealing with a utility than with a succession of individual customers. Ordering and stocking equipment may be less expensive with bulk orders and assured markets. The costs of marketing, providing estimates for work never performed, dealing with customers, and collecting on accounts should be dramatically reduced.

Q: Are these considerations the same for fuel-switching as for increased electric use efficiency?

A: Yes. Split incentives are clearly important in fuel choice. Developers are usually under strong pressure to minimize first costs, sale price, and their financial exposure. This tends to result in the use of electricity in applications for which gas would be less expensive in the long term, but would require greater developer investments for hookups and equipment. Similar concerns apply between landlords and tenants.

Technology-related information costs are particularly high for gas chilling, an exotic application for many building owners. Information and inconvenience costs may be high for any fuel-switching application involving the choice of supplier, manufacturer, and installer. For a commercial building manager considering gas chilling, these burdens must be at least roughly comparable to the information and inconvenience costs associated with selecting high-efficiency electric chilling. The information and inconvenience costs for a residential customer switching between electric and gas heat should also be roughly comparable to the burdens of arranging for additional attic insulation.

Institutional barriers that discourage investments in efficient electrical equipment will also tend to discourage investments in fuel-switching. The same is true for risk, regret, inadequate access to capital, and other barriers.

Q: On pages 3-4 of its 12/12/90 Memorandum on Scope in DPU 90-261-A, MECo provides specific arguments on the lack of market barriers to fuel-switching. Are these arguments valid?

A: No. MECo argues that electric DSM technologies are "new and untested" but that gas technologies are "known [and] tested." I do not believe ceiling insulation, weather-stripping, or caulking, which MECo offers its customers, are newer and less tested than gas conversion. The same is true for high-efficiency electric chillers versus gas chillers, or high-efficiency water heaters versus gas water heaters.

MECo states electric DSM equipment "is not available in stores," but that gas equipment is "available." Again, insulation, weatherstrip, and caulk are available in any home improvement or hardware store, and high-efficiency lighting is available from any lighting distributor. It is hard to believe commercial customers would have more difficulty locating an efficient electric chiller than they would a gas chiller.

MECo notes that electric DSM technologies can present "significant technological risk, particularly given the long payback period," but avers that "Customers, architects, and builders are familiar with the economic analysis necessary to make a reasonable fuel choice." MECo assumes the short payback requirement it identifies as a market barrier to electric DSM simply does not exist for fuel choice or fuel-switching.[4] I know of no evidence that payback requirements for cost-reducing investments differ with the fuel involved. MECo does not claim that the payback period is any shorter for gas technologies than for electric ones. The company does not even attempt to demonstrate that the perceived risks of gas chillers or water heaters are any smaller than those of high-efficiency electric chillers or water heaters.

MECo concedes that the institutional barriers and split incentives discourage cost-effective fuel-switching, and that "Customers may lack the capital to support . . .the higher first cost investments in gas equipment." These points in themselves demonstrate that inclusion of fuel-switching in electric utility DSM programs is necessary.

Q: Are these MECo's central arguments against including fuel-switching in its DSM programs?

A: All of the these points seem to be side issues to MECo. The crux of MECo's argument appears to be that fuel-switching to gas is different from improved efficiency of electricity because gas utilities are sophisticated enough and well-positioned to overcome any perceived institutional market barriers:

> [M]ost important, an active marketer is present to encourage cost effective gas use and to provide the necessary information to customers. . .
>
> [U]nlike [all-electric] C&LM investments, in the fuel switching context another entity is present

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[4]MECo completely ignores here the split incentives among architects, builders, and the ultimate customers.

that can finance the installation and assure that the customer's discount rate in fact matches a utility discount rate. That financing source is the gas utility.

Q: Do you agree that the existence of an active gas marketer such as Boston Gas eliminates the market barriers you have discussed?

A: No. Gas utility marketing is not a suitable substitute for inclusion of fuel-switching in electric utility DSM programs, for a number of reasons.

First, like any other supplier of DSM services, the gas utility can help a user convert from standard electrical technologies to lower-cost technologies. Also like any other supplier, the gas utility can justify such assistance only if it costs less than the margin between rates and marginal cost. I understand that BGC's rates are based on marginal costs and that the margin available to assist in fuel-switching from electric to gas end uses is quite limited.

While gas-utility marketing efforts can aid in overcoming information barriers, the provision of information is unlikely to overcome most barriers. MECo must agree that information programs are not sufficient to overcome most of the market barriers to electric energy efficiency, or else it would offer customers brochures instead of incentives equal to 100% of incremental costs.

It is important to recognize that vendors, suppliers, and installers already exist for all of MECo's existing DSM measures. If the massive marketing muscle of General Electric, GTE, Honeywell, Lennox, Trane, Carrier, Johnson Controls, and all the other manufacturers, distributors, vendors, and installers does not result in the sale of efficient equipment and appliances, it is difficult to see how BGC can overcome the barriers to fuel-switching. Table 2.1 compares the financial strength of BGC to that of several suppliers of electric DSM services. Clearly, it is unrealistic to expect BGC to achieve for gas chillers what Hitachi cannot, and to do for gas furnaces what GE cannot do for efficient lighting.

Q: Should the gas utility, in promoting socially cost-effective electric-to-gas fuel-switching, pay more than the margin between rates and marginal cost and collect the difference from its existing customers?

A: While this is certainly feasible, it would require a very different view of the social responsibility of utilities than the DPU has asserted to date. Like the electric utility, the gas utility's current obligation is to minimize the social cost of energy services to its customers.

Thus, in evaluating the cost-effectiveness of induced-draft fans for more efficient gas combustion in boilers, BGC must consider the cost of the electricity used by the fan. In determining whether the social cost of space heating by its existing customers is reduced by induced draft retrofits, BGC must include the incidental effects on electric usage. The same is true for effects on water use, O&M, labor, and so on. Within its charge to minimize the social cost of the services it now provides, BGC must consider all identifiable costs.

It is a great leap from requiring that BGC include all costs in minimizing the social cost of providing its services to requiring that BGC minimize all social costs. The DPU has not required that BGC or MECo, in conjunction with their DSM programs, conduct all socially cost-effective actions, even though many such possibilities exist. For example, no utility has been asked to perform blood tests for lead as they deliver conservation services to inner-city families, even though lead screening is highly cost-effective in reducing social costs. The same is true for any number of measures related to health, education, neighborhood beautification, and public safety.

The DPU has not asked (let alone required) utilities to invest in DSM in other utilities' territories. MECo has not been required to invest in DSM in the territories of Massachusetts municipal utilities or Public Service of New Hampshire, even though social costs would certainly be reduced by greater efficiency in both those areas. BGC is not expected to pay for conservation in the service territory of other Massachusetts gas companies, even if their programs are lagging behind BGC's. Indeed, when electric utilities were spending ratepayer funds primarily for reducing gas and oil usage, the DPU actively discouraged such activities beyond the basic social responsibility of the utility: reducing the social cost of the services it provides.

The wasteful use of electricity in situations for which gas would be less expensive, like all other wasteful uses of electricity, is a problem for the electric utilities. The total social cost of existing electric energy services will decline through electric-to-gas fuel-switching, but the cost of providing existing gas services will not change. Existing gas customers are not eligible for electric-to-gas fuel-switching and will benefit little from such switching. Only electric customers will benefit, through reductions in their total bills.[5]

In short, facilitating cost-effective electric-to-gas fuel-switching is the responsibility of the electric utility in furtherance of its social obligation. It is not the responsibility of the gas utility.[6]

Q: Should a utility ever invest in switching loads from other fuels to its product?

A: Yes, if two conditions are fulfilled. First, the fuel switch must be expected to reduce social costs. Second, the

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[5]There will also tend to be benefits to society at large because of reductions in externalities.

[6]The converse is true of gas-to-electric fuel switching, as BGC has recognized. Even though an induced-draft fan substitutes a small amount of electricity for a large amount of gas, BGC, not MECo, has the obligation to facilitate installation of that fan.

utility's existing customers should not pay higher rates due to the switch.[7]

Q: Returning to MECo's assertion about the role of the gas utility in fuel-switching, does the presence of the gas utility as a "financing source" eliminate significant market barriers?

A: Not really. First, it is not clear that BGC could offer significantly better financing terms for fuel-switching than can normal commercial lenders (e.g., banks, credit unions), without supporting the loans with funds from existing customers.[8] Second, access to capital is not a significant market barrier for many customers, and does not account for most short-payback requirements.[9] Third, MECo apparently does not believe loans will overcome market barriers, since it does not depend on loans for <u>any</u> of its programs. MECo pays full incremental costs of essentially all DSM measures, except for some inefficient lighting options it wishes to discourage. MECo does not believe loans will adequately promote efficient

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[7]Here, at last, is a valid application of the no-losers' test (also called the non-participants' test or the rate impact measure), which is totally irrelevant to determining the cost-effectiveness of DSM in the utility's own service, or fuel-switching from its service to other fuels.

[8]BGC might avoid some postage charges by combining the loan bill with the gas bill. Bad debt, customer service, cost of capital, and other costs should be roughly equivalent for BGC and other lenders.

[9]For example, my incremental cost to convert from electric to gas clothes drying was only about $200, comparable to the price spread between simple and sophisticated dryers, and certainly no major impediment for many households.

investments, and its suggestion that BGC loans would adequately promote fuel-switching is implausible.

2.4 MECo's Erroneous Analogies

Q: In its 12/12/90 Memorandum on Scope in DPU 90-261-A, MECo asserts that "a requirement to minimize the cost of service not only leads to arguments for subsidized fuel-switching, it will also produce calls for subsidizing self-generation or customer relocation to other areas" (pp. 2-3). Is this an important consideration for the Department?

A: I think not. MECo does not actually assert that there is any necessary connection between fuel-switching and self-generation or relocation.[10] MECo asserts only that adopting a least-cost standard will "produce calls for . . . self-generation or customer relocation." MECo does not formally argue that there is any regulatory linkage between fuel-switching and relocation. Instead, MECo seems to be arguing that, if the DPU orders fuel-switching, some other unspecified parties will assert a right to MECo support of activities that MECo views as undesirable. I doubt that MECo and the DPU would be any more receptive to pressures to pursue uneconomical policies following an order requiring cost-effective fuel-switching than they are today. The argument is really a non sequitur.

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[10] I assume that MECo means "business relocation," although maybe MECo means "moving residences to New Hampshire."

Q: Is fuel-switching comparable to self-generation?

A: In a sense. If by "self-generation" MECo means "on-site generation," and that on-site generation is cost-effective, MECo should be working to get that generation installed. In fact, MECo has a program that provides incentives to customers to provide their own peaking generation on-site. MECo is also obligated to purchase cogenerated power at avoided cost. If these incentives are not encouraging installation of all the cost-effective on-site generation, perhaps MECo should offer to build and operate the generation, and provide discounted thermal energy, more secure power supply, or other incentives to the customer who provides the site. In any case, MECo has an obligation to pursue a least-cost supply plan, and socially cost-effective on-site generation should be part of that plan.

Q: Is fuel-switching comparable to relocation?

A: No. I have difficulty believing that anyone would see them as comparable; certainly, MECo provides no basis for such a comparison. Some important distinctions are obvious.

First, relocations of businesses result in a range of economic externalities, including lost (created) jobs, community dislocations, need for additional social services, and the like. The effects, many of which are negative at both ends of the relocation, would be difficult to value. No such effects occur for fuel-switching.

Second, to the extent that there are transfers in welfare between the originating locality (e.g., Massachusetts) and the receiving locality (e.g., Alabama), it is not clear that these transfers should be considered to be cost-free by the originating locality. Transfers from Massachusetts to Alabama are costs to Massachusetts, although perhaps not to the U.S. as a whole.

Third, businesses select their locations for a number of reasons. Energy cost is part of the location calculation, but so are other operating costs, proximity to suppliers and markets, an appropriate labor force, and a desirable living environment for management and prized employees. Customers may well be indifferent between electric space heat and gas space heat, so long as comfort and convenience are equivalent. Customers are not indifferent between being in Gloucester and Alabama. Valuing and including these costs in the cost-benefit analysis would not be easy, and might not be feasible.

Fourth, long-run avoided electric supply costs should not vary overwhelmingly from one region of the country to another. Because of shorter transportation routes, gas and coal are somewhat cheaper in Alabama than in Massachusetts, but the technologies of new generation are usually similar.[11] If a Massachusetts firm moves to Alabama, and if MECo is actively discouraging the growth of new firms in its service territory, the transmission and especially distribution investment in the

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[11]In the short run, Massachusetts environmental externalities are lower than those of coal-fired utilities, but direct costs are higher. Total short-run supply costs are probably lower in Massachusetts than in most of the country.

customer's facility will become useless; new capacity will have to be added in Alabama. In contrast, T&D capacity freed up by normal conservation or fuel-switching will provide for growth of other loads by the same customer or by its neighbors.

3. ESTABLISHING COMPARABLE AVOIDED COSTS

3.1 Restating BGC Avoided Costs in MECo's Projected Future World

Q: How have you made comparable the avoided costs of BGC and of MECo?

A: I have restated the BGC avoided costs in terms of the economic future hypothesized by MECo. That is, I use the inflation rate and fuel costs MECo used in deriving the avoided costs filed with the Department. This computation is shown in Attachment PLC-3. The important inflation rates are 4.5% for non-fuel expenses and 1.2% real for gas.[12]

Q: Why did you use MECo assumptions?

A: I had three reasons. First, this proceeding involves MECo's DSM program; all other decisions in the case have relied on MECo's projected inflation rates. Second, it is fundamentally much easier to restate BGC's avoided costs for new fuel prices and inflation rates than to reoptimize the more complex and price-sensitive electric utility dispatch. Third, I have access to BGC's avoided-cost model, but not to MECo's, so adjusting BGC's avoided costs is particularly easy for me.

In the December 1989 report filed in DPU 89-239 (Chernick and Espenhorst, 1989), I determined that the cost-effectiveness of fuel-switching was not very sensitive to

[12]The MECo least-cost plan refers to a 5.5% inflation rate for O&M, but this rate does not seem to have been used in determining the avoided costs.

economic assumptions used, as long as those were mutually consistent for the two utilities.

Q: How have you discounted avoided costs for BGC and for MECo to determine present values?

A: BGC uses a discount rate of 11.04%, while MECo uses 9.53% (based on an 11.25% cost of capital).

Since this case concerns the adequacy of MECo's DSM program and since the DPU has accepted MECo's asserted discount rate in this proceeding, I have used MECo's 9.53% nominal discount rate for both utilities' costs.

Q: What would be the effect of discounting MECo's costs at its DPU-accepted discount rate of 9.53%, and BGC's at its higher DPU-accepted discount rate of 11.4%?

A: The present value of gas supply costs would be smaller, and fuel-switching would be even more attractive.

Q: Are MECo and BGC avoided costs presented in the same form?

A: No. MECo presents its avoided costs in constant dollars, and discounts them at a 4.81% real discount rate. BGC presents its avoided costs in nominal dollars and discounts them at a nominal discount rate. These two treatments are consistent as long as nominal costs are not mixed with real discount rates (or vice versa). The present value of a nominal cost or benefit stream at the nominal discount rate is equal to the present value of the same stream restated in constant dollars and discounted at the real discount rate.

3.2 MECo Avoided Costs

Q: Have you used MECo's avoided costs filed in this docket?

A: Even though I believe that MECo's avoided costs are understated, I have used the filed values with some minor updates. I have used the updated avoided costs MECo provided in BGC-88. Since I expect all of the applications I discuss to operate at secondary voltage, I use MECo's estimates for secondary losses and avoided distribution costs. If any of the commercial applications covered in this analysis operated at primary voltages, the avoided costs for those applications would be somewhat lower.

3.3 BGC Avoided Costs

Q: What avoided costs did you use for BGC?

A: I used the avoided costs filed in DPU 90-320, with the previously discussed modification of inflation and fuel escalation to be consistent with MECo assumptions. The computations and the resulting avoided costs are provided in Attachment PLC-3.

Q: Are these avoided costs correctly estimated, to the best of your knowledge?

A: Yes, with two exceptions. BGC overstates local capacity (T&D) costs, and losses. Hence, the BGC avoided costs are somewhat overstated.

Q: How are the T&D costs overstated?

A: BGC has computed load-related net additions by subtracting out retirements at original cost. In most cases, the retired equipment will be replaced with new equipment (included in the gross additions) that is more expensive than the retired equipment, even without any growth in capacity, simply because of inflation.[13] BGC has been particularly active in the last few years in replacing old cast iron pipe with steel and plastic pipe. The cost of replacing fully depreciated equipment is not load-related and should not be included in the demand-related capacity charge.

BGC has not yet determined a suitable method for inflating the costs of 80-year-old cast iron pipe to reflect the costs of new steel and plastic pipe. Hence, BGC has assumed no inflation in the replacement for retired equipment, and has thus overstated demand-related capacity costs.

Q: How are BGC's losses overstated?

A: BGC has assumed that its marginal capacity and commodity losses are equal to the percentage of total sendout which is "unaccounted for" gas. This overstates the marginal losses for several reasons.

First, a large portion of unaccounted-for gas is not lost at all, but is simply not metered. Small volumetric gas meters are generally calibrated for temperatures close to room

[13]This is particularly true for gas utilities, whose lines are longer-lived than those of electric utilities.

temperature.[14] However, most gas is delivered when the ambient temperature, and hence the temperature of the gas, is below the calibration temperature. The denser low-temperature gas is simply under-counted.

Second, some unaccounted-for gas is released by measuring instruments at a rate which is essentially independent of sendout.

Third, some losses come from line purging for repair and construction work, and other losses are due to accidental breach of lines by non-gas-related construction equipment. These losses do not vary with sendout.

Fourth, the leakage of gas from imperfectly sealed pipes will not vary directly with sendout. Leakage will vary with pressure in the line, which will not vary significantly with sendout at the end of lines. In lines close to supply sources, pressure and hence leakage will vary with sendout, but probably less than linearly.

While BGC recognizes this overstatement in marginal losses, it has not yet performed a detailed loss analysis and therefore uses the average unaccounted-for percentage as an estimate of loss factors.

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[14]Large meters, for large C&I customers, interruptibles, and utilities, are generally temperature-compensated.

4. UPDATED EXTERNALITY ESTIMATES

4.1 Emission Factors

4.1.1 General update

Q: Have you updated your estimates of air-pollutant emission factors for electric power generation and gas technologies?

A: Yes. Updated and revised emissions values for relevant technologies are provided in Attachment PLC-3, along with the resulting externalities valuations at the DPU's required externality values.

Q: Are MECo's estimates of electric generation externalities consistent with your values?

A: Yes. MECo does not document the type of generation it expects to be marginal on the NEPOOL system, but the estimated externality valuation it uses is reasonable.

4.1.2 Gas engine-driven chillers

Q: What are the externalities of gas engine-driven chillers?

A: I have not located any published source for emissions factors of engine chillers, so I relied on personal communication with staff at Tecogen, a manufacturer and supplier of these units. Uncontrolled emissions from these chillers are 3.5 lbs of NO_x per MMBtu, and 0.175 lbs of carbon monoxide (CO) per MMBtu.

According to our source, catalytic converters are not routinely installed on existing engine chillers. However, Tecogen indicated that, based on lab tests, it would provide a manufacturers' guarantee for NO_x emissions of 0.85 lbs/hr or

0.575 lbs/MMBtu, and 0.85 lbs/hr for CO. These emissions guarantees are not based on operating history, and may be conservatively high. For instance, there is no reason the CO emissions should increase with the installation of the catalytic converter; actual CO emissions may be much lower than the guaranteed level. In addition, the NO_x levels Tecogen cited are an order of magnitude higher than those achieved on passenger cars under more demanding conditions.

Muffler manufacturers indicated that adding a catalytic converter to an engine chiller would cost only about $260. To be conservative, and to allow for replacement of the converter, if necessary, we added $400 to the Xenergy-estimated cost of the engine chillers.

The total social costs of engine chillers appear to be lower with catalytic converters than without, so I have modelled the emissions and costs of engine chillers with catalytic converters.

4.2 Unit Values

4.2.1 NO_x

Q: Do you have any comment on the value for NO_x adopted by the DPU?

A: The value for NO_x calculated by the DOER and adopted by the DPU is lower than the marginal cost of abatement in Massachusetts. The marginal cost should be calculated as the incremental cost of the most expensive control measure over the incremental emissions reductions achieved by that measure over the next best measure. For NO_x, the most stringent measure required in Massachusetts is selective catalytic reduction (SCR), and the next most stringent measure is steam injection (SWI). Benson et. al. (1988) calculates the incremental cost of SCR and the incremental emission reduction due to adding SCR to SWI to determine the marginal cost per ton of emissions reduction. This is the proper approach. However, the incremental emissions reduction assumed in Benson, et al., is larger than the expected incremental reduction from SWI to SCR.[15] Therefore, the marginal cost of control appropriate for Massachusetts is higher than the cost estimated in Tellus (1990), which simply applied Benson's data. Our calculations (also provided to the DPU in DPU 89-239) show that the marginal cost of control is closer to \$7.50/lb NO_x for the smallest gas-fired cogenerators in Massachusetts.

4.2.2 Particulates

Q: Do you have any additional information on the value of reducing particulate emissions?

A: The value for particulates adopted by the DPU was based on our DPU 89-239 analysis of the marginal cost of improving ESP efficiency from 95% to 99%. I have not attempted to refine this estimate. However, Science News (1991) recently reported

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[15]The effectiveness of SWI is understated.

two studies which re-examined health and air quality data. The studies found a strong and unexpected correlation between levels of particulate matter smaller than 10 microns (PM10) and minor and serious health problems.[16] These results were presented at the annual conference of the society for Occupational and Environmental Health. If these results are correct, the marginal value of particulate emissions is higher than previously thought, and more stringent and more costly control measures will be justified for PM10.

4.2.3 Carbon Dioxide

Q: Have you updated your analysis of CO_2 abatement costs since the December, 1989 report?

A: Yes. Attachment PLC-6, entitled "Update of CO_2 Mitigation Costs," provides several alternative estimates of the costs of various CO_2 reduction measures. It discusses a revised estimate of the costs of domestic tree planting based on recently released Forestry Service data, lists several estimates of the costs of other CO_2 reduction measures, and provides a summary of the estimated costs of attaining various CO_2 reduction targets for various countries and regions. The results generally show that $22/ton CO_2 is a modest or understated estimate of the costs of greenhouse mitigation.

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[16]Raloff, J., "Air Pollution: A respiratory hue and cry," Science News. March 30, 1991, p. 203.

4.2.4 Air Toxics

Q: Have you updated your estimate of the value of reducing air toxics?

A: We have reviewed several studies on the costs of control measures to reduce toxic air emissions not yet considered in utility planning in Massachusetts, such as heavy metals emissions. Typical controls effective for some air toxics include particulate control measures such as fabric filters for some metals, carbon absorption for volatile organic gases, and scrubbers for mercury. We have some cost estimates for some of these measures for utility power plants.[17] However, the estimates tend to be highly aggregated and report only the average cost of a range of currently required control measures, not the marginal costs of the most expensive measures that will be required under the Clean Air Act Amendments.[18]

The EPA is currently writing regulations (on a tight schedule) to comply with the provisions of the air toxics provisions in the Clean Air Act Amendments of 1990. Since these provisions stipulate that the cost-effectiveness of specific control measures will be considered in determining the control measures required, these regulations should

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[17]For example, Denny Technical Services (1990) and Energy and Environmental Analysis (1990).

[18]These costs are much lower than the costs per pound of removing lead from painted surfaces. The applicability of the paint-removal estimates to air emissions is not totally clear.

provide enough information for a marginal cost analysis for some important air toxics.

Adding a value for air toxics into our analysis will generally serve to increase the cost-effectiveness of fuel-switching from electricity to gas at the end-use. We have not evaluated the magnitude of this impact.

5. ELECTRIC AND GAS SYSTEM COST COMPARISONS

Q: How have you structured this section of your testimony?

A: I have divided the analyses between residential and commercial applications, which are discussed in the next two subsections. The detailed analyses are contained in Attachments cited in the text, below.

5.1 Residential Applications

Q: What residential fuel-switching applications have you reviewed?

A: I analyzed four end uses: space heating, water heating, ranges, and clothes dryers. For space heating, I have considered new and existing single-family homes; in the existing applications, I have considered the distinction between homes with ductwork (for a heat pump or central air conditioner) and those that will require new distribution systems. Multi-family applications may be similar to small residential applications, or may use any of a number of centralized systems.[19] Multi-family applications should probably be analyzed on a case-by-case basis.

For both space heating and water heating, I consider small, medium, and large customers.

The residential examples evaluated are discussed in greater detail in Attachment PLC-4.

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[19]Other options may include direct through-the-wall heating systems without distribution.

5.1.1 Data Sources

Q: What data sources did you use in formulating the residential examples in Attachment PLC-4?

A: In general, I used data similar to that in the BGC filing in DPU 89-239. In the water heater analysis, I have included $450 for the cost of adding control to a water heater. This is less than the per-point capital cost of the MECo load control program and does not include the continuing O&M costs.

5.1.2 Results

Q: Please describe the results of the residential analyses.

A: Table 5.1 summarizes the cost-effectiveness of the residential measures I analyzed. The costs do not include service drops or line extensions, which are site-specific. All of the options reviewed are cost-effective.

For space heating, cost-benefit ratios are most favorable for large houses, in part because I did not vary the assumed conversion cost with the size of the house. For large homes, high-efficiency furnaces are more cost-effective than standard units; this appears to reverse for smaller homes. For existing houses, the absence of ductwork increases the ratios, but even for a small house without ductwork, the cost-benefit ratio is .62 and the net saving is over $2000.

For water heating, I examined only existing electric installations. Again, the net benefits and cost-benefit ratios are more attractive for large customers than small ones. The gas options have lower capital costs <u>and</u> lower operating costs than controlled electric water heaters. As a result, the cost-benefit ratios are negative (since the net cost is negative).

Range and dryer fuel-switching are also cost-effective. In most cases, the savings are not large enough to justify the cost of adding a service just for one of these end uses.

5.2 Commercial Applications

Q: What residential fuel-switching applications have you reviewed?

A: I examined only chilling examples for commercial fuel-switching. Based on the residential results and my analysis for DPU 89-239 (Chernick, Goodman, and Espenhorst, 1989), I would expect that electric-to-gas fuel-switching of the four residential end uses would also generally be cost-effective in commercial applications. I use a range of application sizes and load shapes, and compare several gas chilling technologies to several electric chilling technologies.

The commercial examples evaluated are discussed in greater detail in Attachment PLC-5.

5.2.1 Data Sources

Q: What data sources did you use for the commercial chilling analysis?

A: I used cost and performance data from the Xenergy Revised Draft Final Report to the Rhode Island Fuel Switching Task Force.

Q: Why did you use this source?

A: The Xenergy report has been reviewed by NEES representatives, including Dean White and Shannon Larson, and accepted without complaint on the technical inputs. Xenergy is also NEES's consultant on the Energy Initiative program, which should imply that its estimates are consistent with the derivation of the Energy Initiative incentives. Finally, the Xenergy report has the advantage of being a single source of estimates for a range of electric and gas chilling technologies.

Q: Do you have any reservations on the use of this source?

A: Yes. My principle reservations concern the analyses of the water-source heat pump. These heat pumps are used as part of a system that transfers heat between occupied space and a water loop. At some times, some heat pumps will be cooling space while others are warming space. At other times, net heat is added by a boiler or removed by a cooling tower. The comparison of this integrated system to a free-standing gas absorption chiller may be oversimplified. For example, Xenergy has assumed that the entire building would be served by a single large cooling with water-source heat pumps, but by several small (and expensive) towers with gas chilling. It is not clear that the comparisons Xenergy selected are similar to those likely to be encountered in the field.

Xenergy also notes that storage cooling is extremely site-specific and that the examples it examined may not be applicable to all applications. However, given the wide margin between the costs of gas cooling and storage cooling, it is unlikely that storage cooling will be cost-effective in any large number of cases.[20]

5.2.2 Results

Q: Please describe the results of the commercial chilling analyses.

A: Table 5.2 summarizes the cost-effectiveness of the commercial chilling options I analyzed. All of the options analyzed were cost-effective, although the cost of 5 Ton absorption units are essentially identical to that of a water-source heat pump. The full-storage electric system is more expensive to build and operate than the gas systems, so the cost-benefit ratios are negative.

[20]Indeed, the Xenergy study indicates that storage cooling is not generally cost-effective compared to conventional electrical cooling options.

6. FUEL-SWITCHING IN MECO'S DSM PROGRAM

6.1 Relative Cost-Effectiveness of Fuel-Switching and MECo Options

Q: Can you compare the cost-effectiveness of MECo's existing DSM programs and the fuel-switching measures you have analyzed?

A: Yes. Table 6.1 compares the cost-benefit ratios of the fuel-switching measures to those of MECo's programs. The C/I programs tend to have lower ratios than do the residential programs. The cost-benefit ratios of the fuel-switching measures do not include program overheads and thus can be thought of as representing the cost-effectiveness of adding incremental fuel-switching to existing programs. Many of the fuel-switching measures would increase the cost-effectiveness of the DSM programs in which they would be included. In fact, even if the cost-benefit ratios are increased by 20% to reflect the costs of free-standing programs, fuel-switching is still often more cost-effective than many of MECo's programs.[21]

Table 6.2 lists the cost-benefit ratios of the few MECo measures or sub-programs for which disaggregated cost/benefit ratios are available. Some of the components of Energy Initiative and Design 2000 have higher cost-benefit ratios than the average for those programs, while others are less expensive. The more expensive C/I components have C/B ratios

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[21]The cost-effectiveness of MECo's existing programs may be slightly understated by the lower losses and secondary distribution MECo assumed in the filing.

as high as residential programs; individual measures would be even more expensive. This is understandable, since MECo says that it accepts DSM incremental measures so long as costs are less than benefits.

Table 6.3 compares the kWh savings, capital costs, and net social benefits per customer for some of MECo's measures and for competitive gas technologies. No comparisons are possible for ranges and dryers since MECo has no conservation programs addressing these end uses. For most measures, MECo has failed to provide break-downs of costs and benefits.

The social benefits of fuel-switching will be smaller if major line extensions are necessary. For the major measures, and particularly for combinations of measures, considerable line extension investments will be cost-effective.

6.2 MECo DSM Program Design Philosophy

6.2.1 Options versus optimization

Q: How does MECo determine for what measures it will offer incentives and how large the incentives will be?

A: It appears that MECO has preferred to offer customers <u>options</u> rather than to <u>optimize</u> customer responses. MECo states that it offers incentives equal to 100% of incremental cost for all measures except some lighting.

MECo apparently offers to pay the incremental costs of all options that cost-effectively increase efficiency over standard practice. More expensive options are offered larger incentives, even if they save less energy. For example, MECo will pay $418 to convert a 1000W incandescent lamp to a 400W metal halide lamp, but only $222.80 to convert to a 250W metal halide lamp. As explained in DR-BGC-60, MECo does not decide which lamp is preferable; the participant will be paid the incremental cost of any cost-effective option, regardless of whether it achieves all cost-effective savings.

Q: Are you commenting on the appropriateness of this method for setting incentives?

A: No. I have described MECo's approach as a background for proposing the form of fuel-switching incentives.

Q: Which approach do you believe is most appropriate at this time for setting fuel-switching incentives in MECo's DSM program?

A; Since the bulk of MECo's DSM program (and all parts of the program for which fuel-switching would be appropriate) are based on an options approach, MECo should use that same approach in setting incentives for fuel-switching. If the DPU changes the methodology in the future, the incentive structure for both electric efficiency and fuel-switching should change in tandem.

Q: What would be the effect of incorporating optimization in MECo's DSM program design, in conjunction with fuel-switching?

A: Some of MECo's less efficient electric-only options would drop out of the program, receive lower incentives, or be limited to areas without feasible gas connections. The programs most likely to be dropped out by optimization are the load management programs, especially the water heater component of Home Energy Management and storage chilling.

6.3 Modifications in MECo's DSM Program to Accommodate Fuel-Switching

Q: How should MECo's DSM program be modified to accommodate fuel-switching?

A: I would suggest that the following modifications be made to the MECo conservation program.

- All prohibitions on the use of custom design or comprehensive design for fuel-switching should be eliminated.

- Incentives for gas chilling should be added to the Energy Initiatives and Design 2000 programs. As is true for other measures in these programs, the incentive should be 100% of incremental cost, capped at reasonable levels. Based on the Xenergy study, caps that would include 100% of incremental costs for typical installations would include:

  - $1,000/T for the first 20 Tons per chiller,

  - $500/T for the next 130 Tons per chiller, and

  - $200/T for tonnage in excess of 150 Tons per chiller.

- When the refrigeration and major HVAC phases of the small C&I program start up, fuel-switching analysis should be included, and customers should be offered the full incremental cost of cost-effective fuel-switching.

- The Residential New Construction program should pay as much or more for efficient fossil-heated houses as for efficient electrically-heated houses.

- The Residential Space Heat program should include fuel-switching in the audit and Tier II retrofits.

- The Water Heater Rebate program should offer rebates of about $400 for fuel-switching electric water heaters to gas.

- Similar rebates should be offered for converting electric to gas cooking and clothes drying.

- The water heater component of the Home Energy Management program should not be available in single-family homes with gas in the building or on the street.

Q: How does your proposed maximum incentive for commercial gas chilling compare to MECo's existing incentives?

A: The HVAC component of Energy Initiative and Design 2000 include full incremental cost for storage cooling, up to $700/kW. At the .58 kW/T MECo assumes to be standard for large centrifugal chillers, this is equivalent to $1200/ton. For a 200 Ton chiller, my proposal would offer a maximum incentive of $95,000, or $475/Ton.

Q: Why is the restriction on the Home Energy Management Program necessary?

A: Some customers are eligible for HEM at any time, since the control can be installed on large existing water heaters. Fuel-switching is unlikely except where water heaters have failed. Since fuel-switching produces larger benefits than control, even controlled water heaters are cost-effective for fuel-switching. It is wasteful to install controls on water heaters that are likely to be switched to alternative fuels in several years.

Q: Does this conclude your testimony?

A: Yes.

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Table 2.1: **Revenue and Income for Corporate Producers of Energy Efficient Technologies (in millions of dollars)**

Interest	Corporation	1989 Revenue	1989 Income	1988 Revenue	1988 Income	1987 Revenue	1987 Income	Source of Figures [a]
LIGHTING	General Electric	54,574	3,939	50,089	3,386	48,158	2,915	M
	GTE Products (Sylvania)	1,283	82	1,316	79	1,272	106	S+P
	Philips	942	46	692	43	593	33	M
APPLIANCES & EQUIPMENT	Raytheon (Amana)	8,796	529	8,192	490	7,659	445	M
	Brown-Forman (Lenox)	1,292	92	1,287	144	1,354	103	M
	Hitachi [b]	48496	1406					S+P
	United Technologies (Carrier)	19,756	702	18,518	659	17,436	592	M
CONTROLS	Johnson Controls	3,684	98	3,100	104	2,642	86	M
	Honeywell	6,059	604	5,857	435	5,590	254	M
Eastern Enterprises (Boston Gas)		840	57	672	51	677	45	VL

[a]: Sources are:

M: Moody's Industrial Manual 1990
S+P: Standard and Poor's Corporation Records
VL: Value Line

[b]: Converted at a rate of 132 yen/$.

TABLE 5.1 COST EFFECTIVESNESS OF RESIDENTIAL FUEL-SWITCHING MEASURES

Measure	Type of gas equipment	Type of electric equipment	Cost/benefit ratio	Net savings
Space heating for a new large home				
	80% standard efficiency	resistance	0.30	$8,265
	80% standard efficiency	heat pump	0.18	$5,277
	91% high efficiency	resistance	0.34	$8,800
	91% high efficiency	heat pump	0.25	$5,812
Space heating for a new medium home				
	80% standard efficiency	resistance	0.40	$6,171
	80% standard efficiency	heat pump	0.25	$3,873
	91% high efficiency	resistance	0.45	$6,582
	91% high efficiency	heat pump	0.34	$4,284
Space heating for a new small home				
	80% standard efficiency	resistance	0.61	$4,077
	80% standard efficiency	heat pump	0.39	$2,468
	91% high efficiency	resistance	0.68	$4,365
	91% high efficiency	heat pump	0.53	$2,756
Space heating for an existing large home with ductwork				
	80% standard efficiency	resistance	0.16	$10,533
	80% standard efficiency	heat pump	0.03	$6,799
	91% high efficiency	resistance	0.20	$11,202
	91% high efficiency	heat pump	0.09	$7,467
Space heating for an existing medium home with ductwork				
	80% standard efficiency	resistance	0.21	$7,916
	80% standard efficiency	heat pump	0.04	$5,043
	91% high efficiency	resistance	0.26	$8,430
	91% high efficiency	heat pump	0.13	$5,557
Space heating for an existing small home with ductwork				
	80% standard efficiency	resistance	0.32	$5,298
	80% standard efficiency	heat pump	0.06	$3,288
	91% high efficiency	resistance	0.39	$5,658
	91% high efficiency	heat pump	0.19	$3,648
Space heating for an existing large home without ductwork				
	80% standard efficiency	resistance	0.31	$10,533
	80% standard efficiency	heat pump	0.09	$6,799
	91% high efficiency	resistance	0.34	$11,202
	91% high efficiency	heat pump	0.15	$7,467
Space heating for an existing medium home without ductwork				
	80% standard efficiency	resistance	0.41	$7,916
	80% standard efficiency	heat pump	0.13	$5,043
	91% high efficiency	resistance	0.45	$8,430
	91% high efficiency	heat pump	0.20	$5,557
Space heating for an existing small home without ductwork				
	80% standard efficiency	resistance	0.62	$5,298
	80% standard efficiency	heat pump	0.19	$3,288
	91% high efficiency	resistance	0.67	$5,658
	91% high efficiency	heat pump	0.31	$3,648
Water heater: high usage				
	65% AFUE free-standing	94% AFUE uncontrolled	0.09	$4,525
	65% AFUE free-standing	94% AFUE controlled	-0.02	$1,366
	85% AFUE zone boiler	94% AFUE uncontrolled	0.07	$4,825
	85% AFUE zone boiler	94% AFUE controlled	-0.08	$1,666
Water heater: medium usage				
	65% AFUE free-standing	94% AFUE uncontrolled	0.12	$3,429
	65% AFUE free-standing	94% AFUE controlled	-0.03	$1,089
	85% AFUE zone boiler	94% AFUE uncontrolled	0.09	$3,660
	85% AFUE zone boiler	94% AFUE controlled	-0.10	$1,320
Water heater: low usage				
	65% AFUE free-standing	94% AFUE uncontrolled	0.18	$2,333
	65% AFUE free-standing	94% AFUE controlled	-0.05	$722
	85% AFUE zone boiler	94% AFUE uncontrolled	0.13	$2,495
	85% AFUE zone boiler	94% AFUE controlled	-0.15	$883
Range	natural gas	electricity	0.28	$363
Clothes dryer	natural gas	electricity	0.31	$638

TABLE 5.2 COST EFFECTIVESNESS OF FUEL-SWITCHING FOR COMMERCIAL CHILLERS

Measure	Type of gas equipment	Type of electric equipment	Cost/benefit ratio	Net savings
5 ton chillers				
	gas absorption	eff. electric (packaged)	0.67	$5,268
	gas absorption	elec. air source heat pump	0.44	$6,181
	gas absorption	elec. water source heat pump	0.94	$4,697
20 ton chillers				
	gas LiBr abosrption	eff. electric (packaged)	0.49	$37,966
	gas LiBr abosrption	elec. air source heat pump	0.37	$41,620
	gas LiBr abosrption	elec. water source heat pump	0.62	$35,682
	gas LiBr abosrption	elec. air-cooled recip.	0.28	$37,405
50 ton chillers				
	gas LiBr abosrption	elec. high eff. (packaged)	0.33	$98,715
	gas LiBr abosrption	elec. water-cooled recip.	0.47	$62,231
	gas LiBr abosrption	elec. air-cooled recip.	0.47	$96,488
125 ton chillers				
	gas LiBr abosrption	elec. water-cooled recip.	0.76	$153,915
	gas LiBr abosrption	centrifugal high eff.	0.75	$84,128
	gas LiBr abosrption	centrifugal high eff. VSD	0.58	$55,581
	TecoChill engine chiller	elec. water-cooled recip.	0.72	$146,041
	TecoChill engine chiller	centrifugal high eff.	0.66	$76,255
	TecoChill engine chiller	centrifugal high eff. VSD	0.41	$47,707
250 ton chillers				
	gas LiBr abosrption	centrifugal high eff.	0.74	$152,647
	gas LiBr abosrption	centrifugal high eff. VSD	0.84	$93,018
	TecoChill engine chiller	centrifugal high eff.	0.73	$169,287
	TecoChill engine chiller	centrifugal high eff. VSD	0.81	$109,658
250 ton storage chillers				
	gas LiBr abosrption	partial storage	0.17	$258,786
	gas LiBr abosrption	full storage	-0.58	$93,608
	TecoChill engine chiller	partial storage	0.20	$275,426
	TecoChill engine chiller	full storage	-0.39	$110,248
Dessicant cooling vs. electric				
	gas LiBr abosrption	electric	0.18	$551,794

Table 6.1: Cost effectiveness of MECo Programs and of Fuel Switching

Program	Cost/Benefit Ratio	Notes
Design 2000	0.26	Exh CLM–4, p.2, Compliance Filing
Energy Initiative	0.33	
Small C/I	0.33	
Water Heater Rebate	0.32	(.45 for 1990, RR–DPU–43)
Appliance Efficiency	0.25	
Energy–Crafted Home	0.45	
Energy Fitness	0.64	
Home Energy Management	0.67	
Residential Lighting	0.66	
Residential Space Heating	0.51	

Fuel Switching	Cost/Benefit Range		Cost/Benefit * 1.2		
Commercial Chilling					
<= 100 T	0.28	0.94	0.34	1.13	
> 100 T	–0.58	0.84	–0.70	1.01	
Dessicant		0.18		0.22	
Residential					
Space Heating	0.03	0.68	0.04	0.82	Some <0
Water Heating	–0.15	0.18	–0.18	0.22	
Cooking		0.28		0.34	
Clothes Drying		0.31		0.37	

sab cost_eff.wk1

Table 6.2: MECo Measure Cost-Effectiveness

Measure/Component	Cost/Benefit Ratio	Notes
Energy Initiative		
2 - F4OT12 (34 W) / EEMAG to 2 - F4OT12 (34 W) / ELIG	0.44	RR-DPU-2 (* .33/.43/1.15)
Lighting	0.23	DPU-CE2-5
Motors	0.47	DPU-CE2-5
Adjustable Speed Drives	0.66	DPU-CE2-5
Custom Measures	0.63	DPU-CE2-5
HVAC	0.27	DPU-CE2-5
Storage Cooling	0.48	DPU-CE2-5
Design 2000		
Storage Cooling	0.55	DPU-CE2-5
Other	0.31	DPU-CE2-5

sab cost_eff.wk1

Table 6.3: Comparison of MECo Measures and Fuel Switching

	1991 Budget, $1000 [1]	1991 Units [2]	Cost/ Unit [3]	kWh Savings [4]	Net PV of Benefit [5]		Comments:
Water Heater Rebate	$435.6	900	$484	517	$1,032		
vs. Fuel Switching			$415	4,000	$2,900		Medium size
Residential Space heat	$2,399.2	2,667	$900	1,327	$880		
vs. Fuel Switching			$2,165	10,500	$8,850	[a]	Medium size retrofit, with duct work, standard efficiency, replacing resistance.

Notes:
[1] From Compliance Filing.
[2] From Data Request
[3] [2]/[1], for MECo.
[a] Includes 187 kWh for lighting, 3,500 kWh for water heat, and 6817 kWh for space heat; costs include $50 for lighting, $415 for water heat, and $1,700 of space heat; net benefits of $50, $2,900, and $5,900, respectively.

esb cost_eff.wk1

ATTACHMENT PLC-3

BGC AVOIDED COSTS, MECO AVOIDED COSTS, AND EXTERNALITIES

The avoided costs for both BGC and MECo are from previous filings.[1] Monetized externalities are derived from the DPU decision in DPU 89-239. We also provide re-estimates of MECo costs and alternative calculations of externalities, for both BGC and MECo, based on more recent emissions data than DPU 89-239.

All costs are stated in constant 1991$, and compared on a present value (PV) basis. The cost streams are discounted over the life of the measure. In H-4, MECo discounts cost to year-end 1990.[2] We do not use this methodology, but the results are not sensitive to the difference.

We use MECo's after-tax discount rate throughout this analysis. We do this for consistency in the statement of avoided costs. MECo's costs are stated in real terms, and we use the real after-tax discount rate. BGC's costs are in nominal terms and we use the nominal discount rate. This treatment produces comparable results.

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[1]The MECo costs are from the 5/90 C&LM Annual Report and 10/90 testimony by Elizabeth Hicks, exhibits H-1, 2, 3, and 4. The BGC costs use the supply sources from the 9/21/90 IRM filing costed using the most recent NEEI fuel and inflation forecast. Thus, the avoided costs are stated using consistent fuel and inflation assumptions.

[2]The formula is

@npv(discount rate,stream of costs)*(1+discount rate/2).

Lotus discounts the stream to the year prior to the first year. For example, a stream of costs from 1991 to 2000 would be discounted to 1990. Multiplying by (1+discount rate/2) discounts costs to mid-year 1990.

I. Massachusetts Electric Avoided Costs

A. Direct Costs

Avoided costs include energy, distribution capacity, the NEPCo demand charge (covering generation and transmission), energy and demand losses, and externalities. We make two adjustments to MECo estimates: we use the newer distribution costs provided in DR-BGC-88, and we credit all measures with reducing capacity and losses to secondary voltage.

1. Marginal Energy Costs

MECo exhibit H-1 provides real-levelized marginal energy costs in $/kwh for on-peak and off-peak rating periods for 1991 to 2011. These costs, without externalities, are shown in Table 1, columns 1 and 2. MECo does not provide the annual costs that lead to the levelized figure.

MECo does not provide the months and hours that constitute the periods. Instead, MECo defines the percentage on-peak and off-peak energy usage for the measures that corresponds to the rating periods.[3] MECo values peak and off-peak period energy savings by multiplying the lifetime PV of the period energy by the period kWh saved by the loss factor. Total energy savings is avoided

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[3]For HVAC, we have slightly adjusted the MECo percentages. We have also added two residential end-uses MECO did not consider. These actions are discussed below in the measure characteristics section.

externalities, discussed below, plus the on- and off-peak energy value.

2. Marginal Distribution

MECo states marginal distribution costs in $/kw-yr at the primary and secondary voltage levels as well as at the mix MECo's commercial customers take power: 47% at primary, 53% at secondary. The marginal distribution cost at the secondary voltage is shown in Table 1, column 6. The marginal distribution cost at MECo's commercial mix used is shown in column 9.

We include two recent estimates of MECo marginal secondary distribution cost. Table 1, column 7 shows the costs provided by MECo in response to DR BGC 88, DPU 90-261. This calculation still omits some "reliability-related" spending. In column 8, we show corrected secondary distribution costs based on our earlier work in Chernick and Espenhorst, 1989.

MECo values distribution savings by multiplying distribution capacity cost in $/kW-yr by kW saved at the customer level. This implies that losses are included in the distribution costs, but it is not clear that all such losses are included. The workpapers provided in DR-BGC-88 provide the primary and secondary distribution cost per kW of coincident demand per year. We include losses specific for each measure. Distribution costs are unitized per kW of coincident demand in order to be consistent with the valuation of the NEPCo demand charge.

3. NEPCo Demand Charge for Generation and Transmission

MECo values generation, including a reserve margin, and transmission capacity at the NEPCo demand charge. These values appear in Table 2. The months of January, February, June, July, August, September, and December are valued at $15.53/kw-month. March, April, May, October, and November are valued at $2.52/kw-month. The annual NEPCo demand charge, the sum of these months, is $121.31/kw-yr.

Measures are credited with reducing monthly peak by some percentage from 0 to 100% depending on the measure characteristics. For example, domestic hot water heaters are given 100% credit in each month, while storage cooling reduces demand in the summer months only. The capacity value for each month is calculated as the percent of peak reduction times the monthly NEPCo demand charge. The values for each month are summed to provide the annual NEPCo demand charge savings.

In the cases of distribution and the NEPCo demand charge, MECo exhibit H-4 assumes no real increase in these costs. To calculate the present value over the life of a measure, we multiply the cost by the present value of $1 at MECo's discount rate over the measure life.[4]

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[4]This produces the same result as calculating the present value of base cost each year over the measure life.

In Volumes 1 and 2 of the 1990 Load Forecast, pages 12 and 17 respectively, MECo indicates it uses a 1.0% per year real inflation rate for generation, transmission, and fixed o&m costs. This is

4. Capacity and Energy Losses

Losses appear on Table 3, and are taken from H-4 and the 5/90 Annual Report.[5] This report asserts that losses decline over time because of reduced strain on existing equipment and concerted loss reduction projects.[6] Both the projected energy and capacity losses are significantly lower than the company's current losses shown in the May 1990 Annual Report, page 28. MECo does not provide sufficient documentation to allow us to assess the accuracy of the new loss calculations. Additionally, the company does not seem to believe the loss reduction spending is avoidable by DSM, and so does not include it in marginal distribution costs.

Because of the combined effect of reduced demand resulting from DSM's reducing system strain and loss reduction projects, losses decline from 1995 to 2000. This explains the phenomenon in Exhibit H-4 of longer lived measures having lower losses than

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inconsistent with how these costs are used in H-4 and it is not clear where this 1.0% real increase is used elsewhere in NEES/MECo planning.

[5]MECo exhibit H-4 provides both energy and capacity losses at primary and secondary voltage levels as well as at the commercial customer mix. The Annual Report provides energy and capacity losses at the C/I mix and secondary winter and summer, and peak and off-peak. The Annual Report also shows the annual losses each year from 1990 to 2009, which indicates the decline in the losses. Losses in the Annual Report are reported as a percentage of customer meter-level savings, while losses in H-4 are a loss multiplier to coincident peak reductions.

[6]May, 1990 C&LM Annual Report, p 25-30.

shorter lived measures. As seen in Table 3, domestic hot water (DHW) has an expected life of 12 years, so an installation made in 1991 has higher losses than space heat with an expected life of 20 years. Over the space heat measures life, system losses have declined more than for the DHW, so marginal losses are lower for the space heat than DHW.

In our analysis, we use MECo's projected loss estimates. All measures are screened at secondary voltage.

B. Externalities

From 1991 to 1996 inclusive, MECo values avoided externalities at 5 ¢/kwh, which are the composite of two NEPOOL oil-fired steam plants. In 1997, New England Electric System, MECO's parent company, plans to build a combined-cycle plant. After 1997, MECo values externalities as those of a combined-cycle plant operating on gas 12 months per year: 1.2 ¢/kwh. These costs appear in Table 1, column 4. The levelized figure that MECo uses is in column 3. In the measure analysis, we use the present value of the annual, rather than levelized, costs.

C. Financial Assumptions

MECo uses a 4.5% GNP inflation rate and a 4.81% real discount rate.[7] MECo's nominal discount rate is 9.53%, as shown in the 1990 Load Forecast, Vol 2, p 11. MECo refers to a 1.0% real generation,

[7]Real discount rate = (1+nominal discount rate)/(1+GNP)-1.

transmission, and fixed O&M inflator, but does not appear to use the adder.

II. Boston Gas Avoided Costs and Externalities

A. BGC Direct Costs

The Boston Gas avoided costs and discount rate used in this analysis are based on the BGC supply mix in the 9/21/90 IRM filing. In that filing, the costs and discount rate are stated in nominal dollars. We use the MECo discount rate for all costs. BGC's avoided costs are in Appendix C of the IRM filing. The revised avoided costs, based on NEEI fuel prices, are attached in Table 5.[8]

B. Externalities of Gas at the End-Use

Table 5A provides our estimates of the emissions of the technologies we review: engine chillers, absorption chillers, space heat, domestic hot water, ranges, and clothes dryers. The high and low SO2 emissions are related to assumptions about natural gas sulfur content, rather than end-use equipment. The very low sulfur levels do not effect the externality adder. The high and low emissions of NOx and VOCs for engine chiller are due to the absence or presence of a catalytic converter. If a catalytic converter is included, NOx and VOC emissions are reduced substantially, at a cost of $400. We include this cost in the engine chillers, and use the lower emissions.

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[8]For a more comprehensive review of stating utility costs on a consistent basis, see Chernick and Espenhorst, 1989.

Table H.1 GAS COST ANALYSIS

	|——— 1990 ———			|
SUPPLY	Demand Cost (000's)	Well-Head Cost ($/MMbtu)	Other Commodity ($/MMbtu)	Total Commodity ($/MMbtu)
F1	$23,505.00	$2.330	$0.338	$2.668
F2	$5,665.00	$2.330	$0.593	$2.923
F3	$1,677.00	$2.330	$0.593	$2.923
F4	$0.00	$0.000	$0.000	$0.000
CD/NOREX	$16,283.00	$2.330	$0.691	$3.021
BOUNDARY	$4,895.00	$1.887	$0.423	$2.310
TGT	$4,601.00	$1.750	$0.577	$2.327
STB	$7,434.00	$1.750	$0.457	$2.207
SIS	$617.00	$1.750	$0.457	$2.207
WS	$4,518.00	$1.750	$0.457	$2.207
LNG	$1,588.00	$2.330	$1.595	$3.925
PROPANE	$2,683.00	$4.000	$0.500	$4.500
DGAS	$1,920.00	$2.330	$0.758	$3.088
DGBO	$0.00	$2.330	$0.338	$2.668
SPOT	$0.00	$1.400	$0.500	$1.900
CDS	$6,877.00	$2.330	$0.220	$2.550
STEUB	$1,507.00	$1.433	$0.645	$2.078
ESSO	$18,731.00	$1.950	$0.240	$2.190
ANE	$9,518.00	$1.863	$0.257	$2.120

SUPPLY	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
F1	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
F2	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
F3	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
F4											
CD/NOREX	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
BOUNDARY											
TGT	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
STB	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
SIS	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
WS	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
LNG	62%	64%	65%	65%	65%	64%	65%	66%	67%	67%	67%
PROPANE	128%	128%	128%	128%	128%	128%	128%	128%	128%	128%	128%
DGAS	62%	64%	65%	65%	65%	64%	65%	66%	67%	84%	85%
DGBO	62%	64%	65%	65%	65%	64%	65%	66%	67%	84%	85%
SPOT	62%	64%	65%	65%	65%	64%	65%	66%	67%	78%	79%
CDS	62%	64%	65%	65%	65%	64%	65%	66%	67%	84%	85%
STEUB	62%	64%	65%	65%	65%	64%	65%	66%	67%	80%	81%
ESSO											
ANE											

SUPPLY	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
F2	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
F3	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
F4											
CD/NOREX	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
BOUNDARY											
TGT	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
STB	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
SIS	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
WS	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
LNG	68%	69%	69%	69%	69%	69%	69%	69%	69%	69%	69%
PROPANE	128%	128%	128%	128%	128%	128%	128%	128%	128%	128%	128%
DGAS	86%	87%	88%	89%	89%	89%	89%	89%	89%	89%	89%
DGBO	86%	87%	88%	89%	89%	89%	89%	89%	89%	89%	89%
SPOT	80%	81%	82%	83%	84%	84%	84%	84%	84%	84%	84%
CDS	86%	87%	88%	89%	89%	89%	89%	89%	89%	89%	89%
STEUB	82%	83%	84%	85%	86%	86%	86%	86%	86%	86%	86%
ESSO											
ANE											

OIL PRICES	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
RACC																						
INF $'S	3.13	3.27	3.49	3.72	3.96	4.24	4.47	4.71	4.98	5.25	5.53	5.78	6.04	6.31	6.59	6.89	7.20	7.52	7.86	8.22	8.59	8.97
1990 $'S	$3.13	$3.13	$3.20	$3.26	$3.32	$3.40	$3.43	$3.46	$3.50	$3.53	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56	$3.56
% Diff																						
INF $'S	–	4.5%	6.8%	6.5%	6.4%	7.0%	5.4%	5.4%	5.7%	5.4%	5.4%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
1990 $'S	–	0.0%	2.2%	1.9%	1.8%	2.4%	0.9%	0.9%	1.2%	0.9%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NEEI Wellhead Gas	1.95	2.01	2.07	2.11	2.15	2.19	2.24	2.29	2.33	2.37	2.4	2.42	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45

Table H.2

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
FACTORS–90$																						
#6 Oil	$2.68	$2.68	$2.77	$2.82	$2.86	$3.00	$3.03	$3.05	$3.08	$3.10	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13	$3.13
#2 Oil	$4.05	$4.05	$4.14	$4.22	$4.31	$4.39	$4.43	$4.47	$4.52	$4.57	$4.61	$4.61	$4.61	$4.61	$4.61	$4.61	$4.61	$4.61	$4.61	$4.61	$4.61	$4.61
Avg Pipe																						
CD6	$3.34	$3.40	$3.42	$3.41	$3.41	$3.40	$3.41	$3.42	$3.43	$3.45	$3.44	$3.43	$3.42	$3.38	$3.35	$3.32	$3.30	$3.27	$3.24	$3.23	$3.22	$3.21
F1	$3.10	$3.20	$3.24	$3.28	$3.27	$3.27	$3.28	$3.29	$3.30	$3.32	$3.32	$3.31	$3.31	$3.27	$3.25	$3.22	$3.20	$3.18	$3.15	$3.14	$3.13	$3.13
Avg	$3.22	$3.30	$3.33	$3.34	$3.34	$3.33	$3.34	$3.36	$3.37	$3.38	$3.38	$3.37	$3.36	$3.33	$3.30	$3.27	$3.25	$3.22	$3.20	$3.19	$3.18	$3.17
Weighted Avg	$3.34	$3.37	$3.43	$3.48	$3.52	$3.58	$3.60	$3.63	$3.66	$3.68	$3.70	$3.70	$3.70	$3.68	$3.67	$3.66	$3.65	$3.64	$3.63	$3.63	$3.62	$3.62
% Increase	–	0.9%	2.0%	1.3%	1.1%	1.7%	0.7%	0.7%	0.8%	0.8%	0.5%	–0.1%	0.0%	–0.4%	–0.3%	–0.3%	–0.2%	–0.3%	–0.3%	–0.1%	–0.1%	–0.1%
INFLATION FACTOR	1.00	1.05	1.09	1.14	1.19	1.25	1.30	1.36	1.42	1.49	1.55	1.62	1.70	1.77	1.85	1.94	2.02	2.11	2.21	2.31	2.41	2.52
FACTORS–INF																						
#6 Oil	$2.68	$2.80	$3.02	$3.22	$3.41	$3.74	$3.95	$4.15	$4.38	$4.61	$4.86	$5.08	$5.31	$5.55	$5.80	$6.06	$6.33	$6.61	$6.91	$7.22	$7.55	$7.89
#2 Oil	$4.05	$4.23	$4.52	$4.82	$5.14	$5.47	$5.77	$6.08	$6.43	$6.79	$7.16	$7.48	$7.82	$8.17	$8.54	$8.92	$9.32	$9.74	$10.18	$10.64	$11.12	$11.62
Avg Pipe																						
CD6	$3.34	$3.55	$3.73	$3.89	$4.07	$4.24	$4.44	$4.66	$4.88	$5.12	$5.34	$5.56	$5.80	$5.99	$6.21	$6.43	$6.67	$6.91	$7.16	$7.46	$7.77	$8.10
F1	$3.10	$3.34	$3.54	$3.74	$3.90	$4.07	$4.27	$4.48	$4.70	$4.94	$5.15	$5.37	$5.61	$5.80	$6.02	$6.23	$6.47	$6.71	$6.96	$7.25	$7.56	$7.88
Avg	$3.22	$3.45	$3.64	$3.82	$3.99	$4.16	$4.36	$4.57	$4.79	$5.03	$5.25	$5.47	$5.71	$5.90	$6.12	$6.33	$6.57	$6.81	$7.06	$7.36	$7.67	$7.99
Weighted Avg	$3.34	$3.52	$3.75	$3.97	$4.19	$4.46	$4.69	$4.94	$5.20	$5.47	$5.75	$6.00	$6.27	$6.52	$6.80	$7.08	$7.38	$7.69	$8.02	$8.37	$8.73	$9.12
% Increase	–	5.5%	6.6%	5.9%	5.7%	6.3%	5.2%	5.2%	5.3%	5.3%	5.0%	4.4%	4.5%	4.1%	4.2%	4.1%	4.2%	4.2%	4.2%	4.4%	4.4%	4.4%
CANADIAN PRICES–90$																						
Boundary																						
Border Demand	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587	$3,587
Max Sendout	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
Avg Demand	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960	0.960
Avg Gas	1.887	1.913	1.970	2.009	2.042	2.095	2.116	2.137	2.161	2.185	2.200	2.197	2.196	2.183	2.174	2.164	2.156	2.147	2.138	2.135	2.132	2.129
	2.847	2.874	2.931	2.969	3.003	3.055	3.077	3.097	3.121	3.145	3.161	3.157	3.156	3.143	3.135	3.124	3.116	3.107	3.098	3.095	3.092	3.089
ANE																						
Border Demand	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745	$5,745
Max Sendout	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099
Avg Demand	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942
Avg Gas	1.863	1.889	1.945	1.983	2.016	2.068	2.089	2.109	2.133	2.156	2.172	2.168	2.167	2.154	2.146	2.136	2.128	2.119	2.110	2.107	2.104	2.101
	2.805	2.831	2.887	2.925	2.958	3.010	3.031	3.051	3.075	3.098	3.114	3.110	3.109	3.096	3.088	3.077	3.070	3.061	3.052	3.049	3.046	3.043
ESSO																						
Avg Cost	1.950	1.968	2.007	2.034	2.057	2.092	2.107	2.121	2.138	2.154	2.165	2.162	2.162	2.153	2.147	2.140	2.134	2.128	2.122	2.120	2.118	2.116
Avg Cost(ESSO/ANE)	1.907	1.929	1.976	2.008	2.036	2.060	2.098	2.115	2.135	2.155	2.168	2.165	2.164	2.154	2.147	2.138	2.131	2.124	2.116	2.113	2.111	2.109

Table H.3

CANADIAN PRICES–INF$	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Boundary–Market Basket																						
Border Demand	$3,587	$3,748	$3,917	$4,093	$4,278	$4,470	$4,671	$4,881	$5,101	$5,331	$5,571	$5,821	$6,083	$6,357	$6,643	$6,942	$7,254	$7,581	$7,922	$8,278	$8,651	$9,040
Max Sendout	3,735	3,735	3,735	3,735	3,735	3,735	3,73?	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
Avg Demand	0.960	1.004	1.049	1.096	1.145	1.197	1.251	1.307	1.366	1.427	1.491	1.559	1.629	1.702	1.779	1.859	1.942	2.030	2.121	2.216	2.316	2.420
Avg Gas	1.887	2.000	2.152	2.292	2.436	2.610	2.756	2.908	3.073	3.247	3.417	3.565	3.724	3.868	4.027	4.187	4.360	4.537	4.722	4.927	5.141	5.366
	2.847	3.003	3.200	3.388	3.581	3.807	4.006	4.215	4.439	4.674	4.909	5.124	5.352	5.570	5.805	6.046	6.302	6.567	6.843	7.143	7.457	7.786
ANE–Market Basket																						
Border Demand	$5,745	$6,004	$6,274	$6,556	$6,851	$7,159	$7,481	$7,818	$8,170	$8,538	$8,922	$9,323	$9,743	$10,181	$10,639	$11,118	$11,619	$12,141	$12,688	$13,259	$13,855	$14,479
Max Sendout	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099
Avg Demand	0.942	0.984	1.029	1.075	1.123	1.174	1.227	1.282	1.340	1.400	1.463	1.529	1.597	1.669	1.744	1.823	1.905	1.991	2.080	2.174	2.272	2.374
Avg Gas	1.863	1.974	2.124	2.263	2.404	2.577	2.720	2.870	3.033	3.205	3.373	3.519	3.675	3.818	3.974	4.133	4.304	4.478	4.661	4.863	5.074	5.296
	2.805	2.958	3.153	3.338	3.527	3.751	3.947	4.152	4.373	4.605	4.835	5.048	5.273	5.487	5.719	5.956	6.209	6.469	6.741	7.037	7.346	7.670
ESSO–Market Basket																						
Avg Cost	1.950	2.057	2.192	2.321	2.452	2.608	2.744	2.887	3.040	3.201	3.362	3.509	3.666	3.815	3.976	4.141	4.316	4.498	4.687	4.892	5.107	5.333
Avg Cost(ESSO/ANE)	1.907	2.015	2.158	2.292	2.428	2.592	2.732	2.878	3.036	3.203	3.367	3.514	3.671	3.816	3.975	4.137	4.310	4.488	4.674	4.877	5.091	5.314
F1 Commodity	2.668	2.454	2.630	2.794	2.967	3.151	3.358	3.577	3.795	4.025	4.253	4.476	4.729	4.942	5.164	5.396	5.639	5.893	6.158	6.435	6.725	7.027
CD6 Commodity	3.021	2.823	3.015	3.197	3.388	3.591	3.817	4.057	4.297	4.549	4.801	5.049	5.327	5.567	5.818	6.079	6.353	6.639	6.937	7.250	7.576	7.917
Average	2.845	2.638	2.823	2.995	3.178	3.371	3.588	3.817	4.046	4.287	4.527	4.763	5.028	5.254	5.491	5.738	5.996	6.266	6.548	6.842	7.150	7.472
Border ANE	2.805	2.958	3.153	3.338	3.527	3.751	3.947	4.152	4.373	4.605	4.835	5.048	5.273	5.487	5.719	5.956	6.209	6.469	6.741	7.037	7.346	7.670
Border ESSO	2.810	3.104	3.286	3.464	3.647	3.856	4.049	4.250	4.465	4.690	4.918	5.135	5.365	5.591	5.832	6.080	6.343	6.615	6.899	7.205	7.524	7.858
Border Boundary	2.847	3.003	3.200	3.388	3.581	3.807	4.006	4.215	4.439	4.674	4.909	5.124	5.352	5.570	5.805	6.046	6.302	6.567	6.843	7.143	7.457	7.786
Percentage Average																						
Border ANE	98.6%		98.6%			98.6%			98.6%			98.6%			98.6%			98.6%			98.6%	
Border ESSO	98.8%		98.8%			98.8%			98.8%			98.8%			98.8%			98.8%			98.8%	
Border Boundary	100.1%		100.1%			100.1%			100.1%			100.1%			100.1%			100.1%			100.1%	
Expected Border																						
Border ANE			2.783			3.323			3.989			4.696			5.414			6.178			7.050	
Border ESSO			2.789			3.330			3.997			4.705			5.424			6.190			7.064	
Border Boundary			2.825			3.374			4.049			4.767			5.496			6.271			7.157	
ANE–Adjusted																						
Border Demand	$5,745	$6,004	$6,274	$6,556	$6,851	$7,159	$7,481	$7,818	$8,170	$8,538	$8,922	$9,323	$9,743	$10,181	$10,639	$11,118	$11,619	$12,141	$12,688	$13,259	$13,855	$14,479
Max Sendout	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099	6,099
Avg Demand	0.942	0.984	1.029	1.075	1.123	1.174	1.227	1.282	1.340	1.400	1.463	1.529	1.597	1.669	1.744	1.823	1.905	1.991	2.080	2.174	2.272	2.374
Avg Gas	1.863	1.974	1.754	1.872	1.991	2.150	2.271	2.397	2.649	2.801	2.948	3.167	3.308	3.436	3.669	3.815	3.972	4.187	4.357	4.546	4.778	4.987
	2.805	2.958	2.783	2.947	3.114	3.323	3.497	3.679	3.989	4.201	4.411	4.696	4.905	5.105	5.414	5.638	5.877	6.178	6.438	6.720	7.050	7.361
ESSO–Adjusted																						
Border Demand	$10,803	$11,289	$11,797	$12,328	$12,883	$13,463	$14,068	$14,701	$15,363	$16,054	$16,777	$17,532	$18,321	$19,145	$20,007	$20,907	$21,848	$22,831	$23,858	$24,932	$26,054	$27,226
Max Sendout	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558
Avg Demand	0.860	0.899	0.939	0.982	1.026	1.072	1.120	1.171	1.223	1.278	1.336	1.396	1.459	1.525	1.593	1.665	1.740	1.818	1.900	1.985	2.075	2.168
Avg Gas	1.950	2.057	1.849	1.958	2.069	2.258	2.376	2.499	2.773	2.920	3.067	3.309	3.457	3.597	3.831	3.990	4.159	4.372	4.556	4.755	4.989	5.209
	2.810	2.956	2.789	2.939	3.095	3.330	3.496	3.670	3.997	4.199	4.403	4.705	4.916	5.122	5.424	5.655	5.899	6.190	6.456	6.741	7.064	7.377
Boundary–Adjusted																						
Border Demand	$3,587	$3,748	$3,917	$4,093	$4,278	$4,470	$4,671	$4,881	$5,101	$5,331	$5,571	$5,821	$6,083	$6,357	$6,643	$6,942	$7,254	$7,581	$7,922	$8,278	$8,651	$9,040
Max Sendout	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
Avg Demand	0.960	1.004	1.049	1.096	1.145	1.197	1.251	1.307	1.366	1.427	1.491	1.559	1.629	1.702	1.779	1.859	1.942	2.030	2.121	2.216	2.316	2.420
Avg Gas	1.887	1.999	1.776	1.895	2.016	2.177	2.300	2.428	2.684	2.837	2.986	3.209	3.351	3.480	3.717	3.865	4.024	4.242	4.414	4.605	4.841	5.052
	2.847	3.003	2.825	2.991	3.161	3.374	3.550	3.735	4.049	4.264	4.478	4.767	4.980	5.182	5.496	5.723	5.966	6.271	6.535	6.822	7.157	7.472

Table H.4

Commodity Charges	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	2.67	2.45	2.63	2.79	2.97	3.15	3.36	3.58	3.79	4.02	4.25	4.48	4.73	4.94	5.16	5.40	5.64	5.89	6.16	6.44	6.72	7.03
F2	2.92	2.72	2.91	3.08	3.27	3.47	3.69	3.92	4.16	4.40	4.65	4.89	5.16	5.39	5.64	5.89	6.15	6.43	6.72	7.02	7.34	7.67
F3	2.92	2.72	2.91	3.08	3.27	3.47	3.69	3.92	4.16	4.40	4.65	4.89	5.16	5.39	5.64	5.89	6.15	6.43	6.72	7.02	7.34	7.67
F4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CD/NOREX	3.02	2.82	3.02	3.20	3.39	3.59	3.82	4.06	4.30	4.55	4.80	5.05	5.33	5.57	5.82	6.08	6.35	6.64	6.94	7.25	7.58	7.92
BOUNDARY	2.31	2.44	2.24	2.38	2.52	2.70	2.85	3.00	3.29	3.47	3.64	3.90	4.07	4.23	4.50	4.68	4.88	5.14	5.35	5.58	5.86	6.12
TGT	2.33	2.70	2.89	3.07	3.25	3.45	3.67	3.90	4.13	4.38	4.62	4.86	5.13	5.36	5.61	5.86	6.12	6.40	6.69	6.99	7.30	7.63
STB	2.21	2.58	2.76	2.93	3.11	3.30	3.51	3.74	3.96	4.20	4.44	4.67	4.93	5.15	5.38	5.63	5.88	6.14	6.42	6.71	7.01	7.33
SIS	2.21	2.58	2.76	2.93	3.11	3.30	3.51	3.74	3.96	4.20	4.44	4.67	4.93	5.15	5.38	5.63	5.88	6.14	6.42	6.71	7.01	7.33
WS	2.21	2.58	2.76	2.93	3.11	3.30	3.51	3.74	3.96	4.20	4.44	4.67	4.93	5.15	5.38	5.63	5.88	6.14	6.42	6.71	7.01	7.33
LNG	3.93	3.77	4.00	4.23	4.47	4.72	4.99	5.29	5.58	5.89	6.20	6.52	6.86	7.17	7.49	7.83	8.18	8.55	8.93	9.34	9.76	10.19
PROPANE	4.50	4.70	5.01	5.32	5.66	6.04	6.36	6.70	7.07	7.45	7.84	8.19	8.56	8.95	9.35	9.77	10.21	10.67	11.15	11.65	12.18	12.73
DGAS	3.09	2.89	3.09	3.27	3.47	3.67	3.90	4.15	4.39	5.52	5.87	6.19	6.52	6.87	7.25	7.63	7.97	8.33	8.70	9.10	9.50	9.93
DGBO	2.67	2.45	2.63	2.79	2.97	3.15	3.36	3.58	3.79	4.90	5.21	5.51	5.81	6.13	6.47	6.81	7.12	7.44	7.78	8.13	8.49	8.87
SPOT	1.90	2.62	2.81	2.98	3.16	3.35	3.57	3.80	4.02	4.84	5.16	5.44	5.74	6.06	6.40	6.75	7.05	7.37	7.70	8.05	8.41	8.79
CDS	2.55	2.33	2.50	2.66	2.83	3.00	3.20	3.42	3.63	4.72	5.03	5.31	5.61	5.92	6.25	6.59	6.88	7.19	7.51	7.85	8.21	8.58
STEUB	2.08	2.77	2.96	3.14	3.33	3.53	3.76	3.99	4.23	5.15	5.48	5.79	6.10	6.44	6.79	7.16	7.49	7.82	8.17	8.54	8.93	9.33
ESSO	2.19	2.31	2.11	2.23	2.36	2.56	2.69	2.83	3.11	3.28	3.44	3.70	3.86	4.02	4.28	4.45	4.64	4.88	5.09	5.31	5.57	5.81
ANE	2.12	2.24	2.03	2.16	2.30	2.47	2.61	2.75	3.01	3.18	3.35	3.58	3.74	3.89	4.14	4.31	4.49	4.73	4.92	5.14	5.40	5.63

B.1. Summary of Avoided Cost

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
I. Energy Cost											
A. Heating Season Conservation											
1. Proportional	3.09	3.37	5.07	5.17	5.63	5.89	2.53	3.05	2.70	2.77	3.08
2. Insulation	3.09	3.37	5.07	5.17	5.63	5.89	2.53	3.05	2.70	2.77	3.08
B. Baseload Conservation											
1. Annual	2.91	3.13	4.29	4.52	4.80	5.04	3.87	4.20	4.42	4.65	4.95
2. Summer	2.77	2.96	3.11	3.42	3.62	3.85	4.08	4.33	4.85	5.13	5.40
3. Winter	2.94	3.20	5.78	5.89	6.27	6.52	3.49	3.93	3.73	3.86	4.19
II. Capacity Cost											
A. Heating Season Conservation											
1. Proportional	1.83	1.92	2.00	2.09	2.19	2.29	6.42	6.70	7.01	7.32	7.65
2. Insulation	1.25	1.30	1.36	1.42	1.49	1.55	5.25	5.49	5.73	5.99	6.26
B. Baseload Conservation											
1. Annual	0.37	0.39	0.41	0.42	0.44	0.46	1.90	1.99	2.08	2.17	2.27
2. Summer	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. Winter	0.87	0.90	0.95	0.99	1.03	1.08	4.42	4.62	4.83	5.05	5.28
III. Total Avoided Cost											
A. Heating Season Conservation											
1. Proportional	4.93	5.29	7.07	7.26	7.81	8.18	8.95	9.76	9.71	10.09	10.73
2. Insulation	4.34	4.68	6.43	6.59	7.11	7.45	7.78	8.54	8.43	8.76	9.34
B. Baseload Conservation											
1. Annual	3.28	3.52	4.70	4.95	5.24	5.50	5.78	6.19	6.50	6.82	7.22
2. Summer	2.77	2.96	3.11	3.42	3.62	3.85	4.08	4.33	4.85	5.13	5.40
3. Winter	3.80	4.10	6.73	6.87	7.30	7.60	7.91	8.55	8.56	8.91	9.47

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
I. Energy Cost										
A. Heating Season Conservation										
1. Proportional	3.11	3.15	3.50	3.57	3.68	3.96	4.08	4.24	4.52	4.70
2. Insulation	3.11	3.15	3.50	3.57	3.68	3.96	4.08	4.24	4.52	4.70
B. Baseload Conservation										
1. Annual	5.17	5.38	5.70	5.94	6.19	6.51	6.78	7.08	7.43	7.75
2. Summer	5.70	5.98	6.27	6.57	6.86	7.17	7.49	7.83	8.18	8.55
3. Winter	4.30	4.41	4.78	4.92	5.11	5.43	5.63	5.86	6.20	6.46
II. Capacity Cost										
A. Heating Season Conservation										
1. Proportional	8.00	8.36	8.73	9.12	9.54	9.96	10.41	10.88	11.37	11.88
2. Insulation	6.54	6.84	7.14	7.46	7.80	8.15	8.52	8.90	9.30	9.72
B. Baseload Conservation										
1. Annual	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.37	3.52
2. Summer	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. Winter	5.51	5.76	6.02	6.29	6.58	6.87	7.18	7.50	7.84	8.19
III. Total Avoided Cost										
A. Heating Season Conservation										
1. Proportional	11.10	11.50	12.23	12.69	13.22	13.93	14.50	15.12	15.89	16.59
2. Insulation	9.65	9.98	10.65	11.03	11.48	12.11	12.60	13.14	13.82	14.43
B. Baseload Conservation										
1. Annual	7.54	7.86	8.29	8.65	9.02	9.46	9.87	10.31	10.80	11.28
2. Summer	5.70	5.98	6.27	6.57	6.86	7.17	7.49	7.83	8.18	8.55
3. Winter	9.81	10.17	10.80	11.22	11.68	12.30	12.81	13.37	14.04	14.65

C.1.A. Summary of Avoided Energy Cost

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
I. Commodity Cost																					
A. Heating Season Conservation	3.09	3.37	−0.09	−0.23	−0.01	0.00	0.02	0.43	−0.04	−0.10	0.09	−0.02	−0.12	0.06	0.00	−0.05	0.06	0.01	−0.02	0.07	0.05
B. Baseload Conservation																					
1. Annual	2.91	3.13	2.28	2.42	2.60	2.75	2.90	3.18	3.36	3.53	3.78	3.95	4.10	4.37	4.55	4.74	4.99	5.19	5.42	5.69	5.94
2. Summer	2.77	2.96	3.11	3.42	3.62	3.85	4.08	4.33	4.65	5.13	5.40	5.70	5.98	6.27	6.57	6.86	7.17	7.49	7.83	8.18	8.55
3. Winter	2.94	3.20	1.11	1.00	1.17	1.19	1.21	1.55	1.24	1.26	1.48	1.46	1.45	1.69	1.69	1.73	1.90	1.94	2.01	2.17	2.25
II. Capitalized Energy Cost																					
A. Heating Season Conservation																					
1. Proportional	0.00	0.00	5.16	5.39	5.63	5.89	2.51	2.62	2.74	2.87	2.99	3.13	3.27	3.42	3.57	3.73	3.90	4.08	4.26	4.45	4.65
2. Insulation	0.00	0.00	5.16	5.39	5.63	5.89	2.51	2.62	2.74	2.87	2.99	3.13	3.27	3.42	3.57	3.73	3.90	4.08	4.26	4.45	4.65
B. Baseload Conservation																					
1. Annual	0.00	0.00	2.01	2.10	2.19	2.29	0.98	1.02	1.07	1.12	1.17	1.22	1.27	1.33	1.39	1.45	1.52	1.59	1.66	1.73	1.81
2. Summer	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. Winter	0.00	0.00	4.67	4.88	5.10	5.33	2.27	2.38	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.38	3.53	3.69	3.86	4.03	4.21
III. Total Avoided Energy Cost																					
A. Heating Season Conservation																					
1. Proportional	3.09	3.37	5.07	5.17	5.63	5.89	2.53	3.05	2.70	2.77	3.08	3.11	3.15	3.50	3.57	3.68	3.96	4.08	4.24	4.52	4.70
2. Insulation	3.09	3.37	5.07	5.17	5.63	5.89	2.53	3.05	2.70	2.77	3.08	3.11	3.15	3.50	3.57	3.68	3.96	4.08	4.24	4.52	4.70
B. Baseload Conservation																					
1. Annual	2.91	3.13	4.29	4.52	4.80	5.04	3.87	4.20	4.42	4.65	4.95	5.17	5.38	5.70	5.94	6.19	6.51	6.78	7.08	7.43	7.75
2. Summer	2.77	2.96	3.11	3.42	3.62	3.85	4.08	4.33	4.65	5.13	5.40	5.70	5.98	6.27	6.57	6.86	7.17	7.49	7.83	8.18	8.55
3. Winter	2.94	3.20	5.78	5.89	6.27	6.52	3.49	3.93	3.73	3.86	4.19	4.30	4.41	4.78	4.92	5.11	5.43	5.63	5.86	6.20	6.46

B.1.A. *Summary of Avoided Cost*

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
I. Energy Cost																					
A. *Heating Season Conservation*																					
1. Proportional	3.09	3.37	5.07	5.17	5.63	5.89	2.53	3.05	2.70	2.77	3.08	3.11	3.15	3.50	3.57	3.68	3.96	4.08	4.24	4.52	4.70
2. Insulation	3.09	3.37	5.07	5.17	5.63	5.89	2.53	3.05	2.70	2.77	3.08	3.11	3.15	3.50	3.57	3.68	3.96	4.08	4.24	4.52	4.70
B. Baseload Conservation																					
1. *Annual*	2.91	3.13	4.29	4.52	4.80	5.04	3.87	4.20	4.42	4.65	4.95	5.17	5.38	5.70	5.94	6.19	6.51	6.78	7.08	7.43	7.75
2. Summer	2.77	2.96	3.11	3.42	3.62	3.85	4.08	4.33	4.65	5.13	5.40	5.70	5.98	6.27	6.57	6.86	7.17	7.49	7.83	8.18	8.55
3. Winter	2.94	3.20	5.78	5.89	6.27	6.52	3.49	3.93	3.73	3.86	4.19	4.30	4.41	4.78	4.92	5.11	5.43	5.63	5.86	6.20	6.46
II. Capacity Cost																					
A. Heating Season Conservation																					
1. Proportional	1.63	1.92	2.00	2.09	2.19	2.29	6.42	6.70	7.01	7.32	7.65	8.00	8.36	8.73	9.12	9.54	9.96	10.41	10.88	11.37	11.88
2. Insulation	1.25	1.30	1.36	1.42	1.49	1.55	5.25	5.49	5.73	5.99	6.26	6.54	6.84	7.14	7.46	7.80	8.15	8.52	8.90	9.30	9.72
B. Baseload Conservation																					
1. Annual	0.37	0.39	0.41	0.42	0.44	0.46	1.90	1.99	2.08	2.17	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.37	3.52
2. Summer	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. Winter	0.87	0.90	0.95	0.99	1.03	1.08	4.42	4.62	4.83	5.05	5.28	5.51	5.76	6.02	6.29	6.58	6.87	7.18	7.50	7.84	8.19
III. Total Avoided Cost																					
A. Heating Season Conservation																					
1. Proportional	4.93	5.29	7.07	7.26	7.81	8.18	8.95	9.76	9.71	10.09	10.73	11.10	11.50	12.23	12.69	13.22	13.93	14.50	15.12	15.89	16.59
2. Insulation	4.34	4.68	6.43	6.59	7.11	7.45	7.78	8.54	8.43	8.76	9.34	9.65	9.98	10.65	11.03	11.48	12.11	12.60	13.14	13.82	14.43
B. Baseload Conservation																					
1. Annual	3.28	3.52	4.70	4.95	5.24	5.50	5.78	6.19	6.50	6.82	7.22	7.54	7.86	8.29	8.65	9.02	9.46	9.87	10.31	10.80	11.28
2. Summer	2.77	2.96	3.11	3.42	3.62	3.85	4.08	4.33	4.85	5.13	5.40	5.70	5.98	6.27	6.57	6.86	7.17	7.49	7.83	8.18	8.55
3. Winter	3.80	4.10	6.73	6.87	7.30	7.60	7.91	8.55	8.56	8.91	9.47	9.81	10.17	10.80	11.22	11.68	12.30	12.81	13.37	14.04	14.65

C.2.A. Summary of Avoided Commodity Costs

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
I. Heating Season Conservation																					
A. With Interruptible																					
1. Unit Cost of Avoided Commodity	2.93	3.20	–0.09	–0.21	–0.01	0.00	0.02	0.41	–0.04	–0.09	0.08	–0.02	–0.12	0.08	0.00	–0.05	0.06	0.01	–0.01	0.07	0.05
2. Non–Gas Production O&M Loading Factor	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G Non–Plant Loading Factor	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. Other Production O&M	0.002	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5. Total Variable Avoided Commodity Cost	2.93	3.20	–0.09	–0.21	–0.01	0.00	0.02	0.41	–0.04	–0.09	0.08	–0.02	–0.12	0.08	0.00	–0.05	0.06	0.01	–0.01	0.07	0.05
6. Working Cash Allowance	0.15	0.16	0.00	–0.01	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	–0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7. Working Capital Revenue Requirement	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8. Loss Factor	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%
9. Heating Season Avoided Commodity Cost	3.09	3.37	–0.09	–0.23	–0.01	0.00	0.02	0.43	–0.04	–0.10	0.09	–0.02	–0.12	0.08	0.00	–0.05	0.06	0.01	–0.02	0.07	0.05
II. Baseload Conservation																					
A. Annual Baseload																					
1. Unit Cost of Avoided Commodity	2.75	2.97	2.16	2.30	2.47	2.61	2.75	3.01	3.18	3.35	3.58	3.74	3.89	4.14	4.31	4.49	4.73	4.92	5.14	5.40	5.63
2. Non–Gas Production O&M Loading Factor	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G Non–Plant Loading Factor	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. Other Production O&M	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004	0.004	0.004	0.005	0.005
5. Total Variable Avoided Commodity Cost	2.76	2.97	2.17	2.30	2.47	2.61	2.75	3.02	3.19	3.35	3.59	3.75	3.89	4.15	4.32	4.50	4.73	4.93	5.14	5.40	5.64
6. Working Cash Allowance	0.14	0.15	0.11	0.11	0.12	0.13	0.14	0.15	0.16	0.17	0.18	0.19	0.19	0.21	0.21	0.22	0.24	0.24	0.26	0.27	0.28
7. Working Capital Revenue Requirement	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
8. Loss Factor	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%
9. Annual Baseload Avoided Com. Cost	2.91	3.13	2.28	2.42	2.60	2.75	2.90	3.18	3.36	3.53	3.78	3.95	4.10	4.37	4.55	4.74	4.99	5.19	5.42	5.69	5.94
B. Summer Baseload Avoided Cost																					
1. Unit Cost of Avoided Commodity	2.62	2.81	2.95	3.25	3.43	3.65	3.87	4.10	4.60	4.86	5.12	5.41	5.67	5.94	6.22	6.51	6.80	7.10	7.42	7.76	8.11
2. Non–Gas Production O&M Loading Factor	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G Non–Plant Loading Factor	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. Other Production O&M	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004	0.005	0.005	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.007
5. Total Variable Avoided Commodity Cost	2.63	2.81	2.95	3.25	3.43	3.65	3.88	4.11	4.60	4.87	5.13	5.41	5.67	5.95	6.23	6.51	6.80	7.11	7.43	7.76	8.11
6. Working Cash Allowance	0.13	0.14	0.15	0.16	0.17	0.18	0.19	0.20	0.23	0.24	0.25	0.27	0.28	0.30	0.31	0.32	0.34	0.35	0.37	0.39	0.40
7. Working Capital Revenue Requirement	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06
8. Loss Factor	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%
9. Summer Baseload Avoided Com. Cost	2.77	2.96	3.11	3.42	3.62	3.85	4.08	4.33	4.85	5.13	5.40	5.70	5.98	6.27	6.57	6.86	7.17	7.49	7.83	8.18	8.55
C. Winter Baseload Avoided Cost																					
1. Unit Cost of Avoided Commodity	2.79	3.03	1.05	0.95	1.11	1.13	1.15	1.47	1.18	1.20	1.40	1.39	1.38	1.60	1.60	1.64	1.80	1.84	1.90	2.05	2.13
2. Non–Gas Production O&M Loading Factor	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
3. A&G Non–Plant Loading Factor	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
4. Other Production O&M	0.002	0.003	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002	0.002
5. Total Variable Avoided Commodity Cost	2.79	3.04	1.06	0.95	1.11	1.13	1.15	1.47	1.18	1.20	1.40	1.39	1.38	1.60	1.60	1.64	1.80	1.84	1.90	2.06	2.13
6. Working Cash Allowance	0.14	0.15	0.05	0.05	0.06	0.06	0.06	0.07	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.11
7. Working Capital Revenue Requirement	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02
8. Loss Factor	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%
9. Winter Baseload Avoided Com. Cost	2.94	3.20	1.11	1.00	1.17	1.19	1.21	1.55	1.24	1.26	1.48	1.46	1.45	1.69	1.69	1.73	1.90	1.94	2.01	2.17	2.25

C.3.A. Capitalized Energy and Pure Peaking Cost

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1. Avoided Demand Cost																					
A. $/year	0.00	0.00	659.78	689.47	720.50	752.92	786.80	822.21	859.21	897.87	938.27	980.50	1024.62	1070.73	1118.91	1169.26	1221.88	1276.86	1334.32	1394.36	1457.11
1. Adj. for Losses & W/Cap.	0.00	0.00	695.27	726.55	759.25	793.41	829.12	866.43	905.42	946.16	988.74	1033.23	1079.73	1128.31	1179.09	1232.15	1287.59	1345.53	1406.08	1469.36	1535.48
II. Pure Peaking Cost																					
A. $/year	0.00	0.00	0.00	0.00	0.00	0.00	465.71	486.67	508.57	531.45	555.37	580.36	606.48	633.77	662.29	692.09	723.23	755.78	789.79	825.33	862.47
1. Adj. for Losses & W/Cap.	0.00	0.00	0.00	0.00	0.00	0.00	490.76	512.84	535.92	560.04	585.24	611.57	639.09	667.85	697.91	729.31	762.13	796.43	832.27	869.72	908.86
B. Peak Period MMBtu	0.00	0.00	0.00	0.00	0.00	0.00	7.22	7.54	7.88	8.24	8.61	8.99	9.40	9.82	10.26	10.73	11.21	11.71	12.24	12.79	13.37
C. $/Heating Season MMBtu																					
1. Proportional	0.00	0.00	0.00	0.00	0.00	0.00	4.03	4.21	4.40	4.60	4.80	5.02	5.24	5.48	5.73	5.98	6.25	6.54	6.83	7.14	7.46
2. Insulation	0.00	0.00	0.00	0.00	0.00	0.00	3.62	3.79	3.96	4.14	4.32	4.52	4.72	4.93	5.15	5.39	5.63	5.88	6.15	6.42	6.71
D. $/Annual Baseload MMBtu	0.00	0.00	0.00	0.00	0.00	0.00	1.42	1.48	1.55	1.62	1.69	1.77	1.85	1.93	2.02	2.11	2.20	2.30	2.41	2.51	2.63
E. $/Winter Baseload MMBtu	0.00	0.00	0.00	0.00	0.00	0.00	3.30	3.45	3.60	3.76	3.93	4.11	4.29	4.49	4.69	4.90	5.12	5.35	5.59	5.84	6.11
III. Avoided Capitalized Cost																					
A. $/year	0.00	0.00	695.27	726.55	759.25	793.41	338.36	353.59	369.50	386.12	403.50	421.66	440.63	460.46	481.18	502.83	525.46	549.11	573.82	599.64	626.62
1. Proportional	0.00	0.00	5.16	5.39	5.63	5.89	2.51	2.62	2.74	2.87	2.99	3.13	3.27	3.42	3.57	3.73	3.90	4.08	4.26	4.45	4.65
2. Insulation	0.00	0.00	5.16	5.39	5.63	5.89	2.51	2.62	2.74	2.87	2.99	3.13	3.27	3.42	3.57	3.73	3.90	4.08	4.26	4.45	4.65
B. $/Annual Baseload MMBtu	0.00	0.00	2.01	2.10	2.19	2.29	0.98	1.02	1.07	1.12	1.17	1.22	1.27	1.33	1.39	1.45	1.52	1.59	1.66	1.73	1.81
C. $/Winter Baseload MMBtu	0.00	0.00	4.67	4.88	5.10	5.33	2.27	2.38	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.38	3.53	3.69	3.86	4.03	4.21

C.4.A. Summary of Capacity Cost

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1. Avoided local Cost																					
A. $/year	128.81	134.61	140.67	147.00	153.61	160.52	167.75	175.30	183.18	191.43	200.04	209.04	218.45	228.26	238.55	249.29	260.51	272.23	284.48	297.28	310.66
B. $/Heating Season MMBtu																					
1. Proportional	1.83	1.92	2.00	2.09	2.19	2.29	2.39	2.50	2.61	2.73	2.85	2.98	3.11	3.25	3.40	3.55	3.71	3.88	4.05	4.23	4.42
2. Insulation	1.25	1.30	1.36	1.42	1.49	1.55	1.62	1.70	1.77	1.85	1.94	2.02	2.12	2.21	2.31	2.41	2.52	2.64	2.76	2.88	3.01
C. $/Annual Baseload MMBtu	0.37	0.39	0.41	0.42	0.44	0.46	0.48	0.51	0.53	0.55	0.58	0.60	0.63	0.66	0.69	0.72	0.75	0.79	0.82	0.86	0.90
D. $/Winter Baseload MMBtu	0.87	0.90	0.95	0.99	1.03	1.08	1.13	1.18	1.23	1.29	1.34	1.40	1.47	1.53	1.60	1.66	1.75	1.83	1.91	2.00	2.09
II. Pure Peaking Cost																					
A. $/year	0.00	0.00	0.00	0.00	0.00	0.00	465.71	486.67	508.57	531.45	555.37	580.36	606.48	633.77	662.29	692.09	723.23	755.78	789.79	825.33	862.47
1. Adj. for Losses & W/Cap.	0.00	0.00	0.00	0.00	0.00	0.00	490.76	512.84	535.92	560.04	585.24	611.57	639.09	667.85	697.91	729.31	762.13	796.43	832.27	869.72	908.86
B. $/Heating Season MMBtu																					
1. Proportional	0.00	0.00	0.00	0.00	0.00	0.00	4.03	4.21	4.40	4.60	4.80	5.02	5.24	5.48	5.73	5.98	6.25	6.54	6.83	7.14	7.46
2. Insulation	0.00	0.00	0.00	0.00	0.00	0.00	3.62	3.79	3.96	4.14	4.32	4.52	4.72	4.93	5.15	5.39	5.63	5.88	6.15	6.42	6.71
C. $/Annual Baseload MMBtu	0.00	0.00	0.00	0.00	0.00	0.00	1.42	1.48	1.55	1.62	1.69	1.77	1.85	1.93	2.02	2.11	2.20	2.30	2.41	2.51	2.63
D. $/Winter Baseload MMBtu	0.00	0.00	0.00	0.00	0.00	0.00	3.30	3.45	3.60	3.76	3.93	4.11	4.29	4.49	4.69	4.90	5.12	5.35	5.59	5.84	6.11
III. Total Avoided Capacity Cost																					
A. $/Heating Season MMBtu																					
1. Proportional	1.83	1.92	2.00	2.09	2.19	2.29	6.42	6.70	7.01	7.32	7.65	8.00	8.36	8.73	9.12	9.54	9.96	10.41	10.88	11.37	11.88
2. Insulation	1.25	1.30	1.36	1.42	1.49	1.55	5.25	5.49	5.73	5.99	6.26	6.54	6.84	7.14	7.46	7.80	8.15	8.52	8.90	9.30	9.72
B. $/Annual Baseload MMBtu	0.37	0.39	0.41	0.42	0.44	0.46	1.90	1.99	2.08	2.17	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.37	3.52
C. $/Winter Baseload MMBtu	0.87	0.90	0.95	0.99	1.03	1.08	4.42	4.62	4.83	5.05	5.28	5.51	5.76	6.02	6.29	6.58	6.87	7.18	7.50	7.84	8.19

C.6. Peak Period Analysis

	1997/1998 Design	1997/1998 Normal
Peak Days	68	39
Total Sendout, BBtu	90,847.8	83,477.6
Total Sendout (Peak Period), BBtu	36,186.8	19,462.9
Peak Day Sendout, BBtu	962.6	746.5
Peak Volumes, BBtu	4,252.2	1,250.4
Total Sendout (Design Days)	36,186.8	32,479.7
Average Daily Sendout, BBtu	532.2	499.0
Daily Baseload Sendout, BBtu		
Winter	83.1	81.9
Summer	77.8	76.6
Total Baseload, BBtu	29,199.4	28,750.7
Heat Load, BBtu	61,448.4	54,727.1
Daily Net Average Heat, BBtu	449.1	417.1

Coefficients

Proportional Heat Capacity	121.9
Proportional Heat Capitalized Energy	
Design Peak Method	138.3
Normal Peak Method	131.2
Average	134.7
Baseload (annual)	346.0
Baseload (winter)	148.8
Heating (local cap.)	70.2

Heating Decrement

ANE Only	
MDQ, BBtu	16.7
Daily Heat, BBtu	449.1
Decrement, %	3.72%
ANE/ESSO	
MDQ, BBtu	51.1
Daily Heat, BBtu	449.1
Decrement, %	11.38%

::

C.5. Avoided Local Cost, 1989 Dollars

A. Plant Investment $/PeakDay MMBtu	
1. Long Run Unit Cost	503.72
2. General Plant Loading Factor	3.29%
3. Unit Cost + Loading Factor	520.29
4. Fixed Carge Rate	10.45%
5. A&G Expense Plant-Related Loading Factor	1.01%
6. Total Rate	11.46%
7. Annualized Cost	59.63
B. Operating Expenses $/PeakDay MMBtu	
1. Production Capacity Cost	5.28
2. Distribution Capacity Cost	31.9
3. A&G Expense Non_Plant Related Loading Factor	39.56%
4. Loading	51.90
5. Total Capacity Expenses	51.90
C. Working Capital $/PeakDay MMBtu	
1. M&S Prepayments Rate	1.07%
2. M&S Cost	5.57
3. Working Cash O&M	6.40
4. Total Working Capital	11.97
D. Working Capital Revenue Required	1.79
Revenue Required	14.94%
E. System Seasonal Capacity Related Cost	113.31
F. Loss Factor	0.956
G. Total Avoded Local Cost	118.52

D.1. Avoided Annual Commodity Cost of Baseload Conservation

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1. BBtu's of Conservation	6,100	6,099	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100
2. Total Commodity Savings	$15,890	$17,161	$13,205	$14,011	$15,064	$15,891	$16,754	$18,388	$19,411	$20,416	$21,862
3. Avoided Commodity Cost $/BBtu	$2.60	$2.81	$2.16	$2.30	$2.47	$2.61	$2.75	$3.01	$3.18	$3.35	$3.58
4. Base Case Interruptible Sales	27,539	25,892	42,189	25,129	23,865	22,685	21,507	20,347	20,347	20,347	20,347
Case 2 Interruptible Sales	33,321	31,512	42,189	25,129	23,865	22,685	21,507	20,347	20,347	20,347	20,347
Change	5,782	5,620	0	0	0	0	0	0	0	0	0
5. Interruptible Sales Margin											
Cogeneration	$0.000	$0.000	$0.746	$0.802	$0.836	$0.872	$0.909	$0.948	$0.988	$1.031	$1.075
C/I	$0.220	$0.230	$0.240	$0.251	$0.262	$0.274	$0.286	$0.299	$0.313	$0.327	$0.342
Utility Power	$0.158	$0.165	$0.173	$0.180	$0.188	$0.197	$0.206	$0.215	$0.225	$0.235	$0.245
6. Change Interruptible To:											
Cogeneration	0	0	0	0	0	0	0	0	0	0	0
C/I	0	0	0	0	0	0	0	0	0	0	0
Utility Power	5,782	5,620	0	0	0	0	0	0	0	0	0
7. Change in Interruptible Margin	$0.150	$0.152	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8. Total Avoided Commodity Costs	$2.75	$2.97	$2.16	$2.30	$2.47	$2.61	$2.75	$3.01	$3.18	$3.35	$3.58

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1. BBtu's of Conservation	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100	6,100
2. Total Commodity Savings	$22,834	$23,733	$25,282	$26,302	$27,398	$28,851	$30,038	$31,345	$32,924	$34,366
3. Avoided Commodity Cost $/BBtu	$3.74	$3.89	$4.14	$4.31	$4.49	$4.73	$4.92	$5.14	$5.40	$5.63
4. Base Case Interruptible Sales	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347
Case 2 Interruptible Sales	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347
Change	0	0	0	0	0	0	0	0	0	0
5. Interruptible Sales Margin										
Cogeneration	$1.121	$1.168	$1.218	$1.270	$1.325	$1.381	$1.440	$1.502	$1.566	$1.633
C/I	$0.357	$0.373	$0.390	$0.407	$0.426	$0.445	$0.465	$0.486	$0.508	$0.531
Utility Power	$0.256	$0.268	$0.280	$0.293	$0.306	$0.320	$0.334	$0.349	$0.365	$0.381
6. Change Interruptible To:										
Cogeneration	0	0	0	0	0	0	0	0	0	0
C/I	0	0	0	0	0	0	0	0	0	0
Utility Power	0	0	0	0	0	0	0	0	0	0
7. Change in Interruptible Margin	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8. Total Avoided Commodity Costs	$3.74	$3.89	$4.14	$4.31	$4.49	$4.73	$4.92	$5.14	$5.40	$5.63

D.2.A. Avoided Commodity Costs of Heating Season Conservation

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1. BBtu's of Conservation	1,762	1,804	1,844	1,887	1,922	1,959	2,000	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037
2. Total Commodity Savings	$4,932	$5,549	$571	$324	$735	$784	$857	$1,665	$792	$719	$1,120	$950	$803	$1,249	$1,127	$1,090	$1,360	$1,309	$1,324	$1,552	$1,582
3. Avoided Commodity Cost $/BBtu	$2.80	$3.08	$0.31	$0.17	$0.38	$0.40	$0.43	$0.82	$0.39	$0.35	$0.55	$0.47	$0.39	$0.61	$0.55	$0.54	$0.67	$0.64	$0.65	$0.76	$0.78
4. Base Case Interruptible Sales	27,539	25,892	42,189	25,129	23,865	22,685	21,507	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347
Case 3 Interruptible Sales	29,021	27,251	37,954	21,085	19,871	18,720	17,558	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470
Change	1,482	1,359	(4,235)	(4,044)	(3,994)	(3,965)	(3,949)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)
5. Interruptible Sales Margin																					
Cogeneration	$0.000	$0.000	$0.746	$0.802	$0.836	$0.872	$0.909	$0.948	$0.986	$1.031	$1.075	$1.121	$1.168	$1.218	$1.270	$1.325	$1.381	$1.440	$1.502	$1.566	$1.633
C/I	$0.220	$0.230	$0.240	$0.251	$0.262	$0.274	$0.286	$0.299	$0.313	$0.327	$0.342	$0.357	$0.373	$0.390	$0.407	$0.426	$0.445	$0.465	$0.486	$0.508	$0.531
Utility Power	$0.158	$0.165	$0.173	$0.180	$0.188	$0.197	$0.206	$0.215	$0.225	$0.235	$0.245	$0.256	$0.268	$0.280	$0.293	$0.306	$0.320	$0.334	$0.349	$0.365	$0.381
6. Change Interruptible To:																					
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C/I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Utility Power	1,482	1,359	(4,235)	(4,044)	(3,994)	(3,965)	(3,949)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)	(3,877)
7. Change in Interruptible Margin	$0.133	$0.124	($0.396)	($0.386)	($0.392)	($0.398)	($0.406)	($0.409)	($0.428)	($0.447)	($0.467)	($0.488)	($0.510)	($0.533)	($0.557)	($0.582)	($0.606)	($0.636)	($0.664)	($0.694)	($0.725)
8. Total Heat Sensitive Avoided Costs	$2.93	$3.20	($0.09)	($0.21)	($0.01)	$0.00	$0.02	$0.41	($0.04)	($0.09)	$0.08	($0.02)	($0.12)	$0.08	($0.00)	($0.05)	$0.06	$0.01	($0.01)	$0.07	$0.05

D.3. Avoided Commodity Costs Due To Winter Baseload Conservation

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1. BBtu's of Conservation	2523.4	2522.9	2523.4	2523.8	2523.6	2523.4	2524.4	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5	2523.5
2. Total Commodity Savings	$7,007	$7,630	$2,660	$2,401	$2,795	$2,844	$2,907	$3,709	$2,975	$3,023	$3,542	$3,504	$3,472	$4,039	$4,042	$4,136	$4,542	$4,635	$4,799	$5,183	$5,377
3. Avoided Commodity Cost $/BBtu	$2.78	$3.02	$1.05	$0.95	$1.11	$1.13	$1.15	$1.47	$1.18	$1.20	$1.40	$1.39	$1.38	$1.60	$1.60	$1.64	$1.80	$1.84	$1.90	$2.05	$2.13
4. Annual Change in Interruptible Margin	$0.150	$0.152	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
5. 6.36% of Annual Change	$0.009	$0.010	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6. Total Winter Avoided Costs	$2.79	$3.03	$1.05	$0.95	$1.11	$1.13	$1.15	$1.47	$1.18	$1.20	$1.40	$1.39	$1.38	$1.60	$1.60	$1.64	$1.80	$1.84	$1.90	$2.05	$2.13

D.4. Avoided Commodity Costs Due To Summer Baseload Conservation

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
1. BBtu's of Conservation	3576.8	3576.1	3576.1	3575.7	3575.9	3576.1	3575.1	3576	3576	3576	3576	3576	3576	3576	3576	3576	3576	3576	3576	3576	3576
2. Total Commodity Savings	$8,883	$9,531	$10,544	$11,610	$12,269	$13,047	$13,847	$14,679	$16,436	$17,394	$18,320	$19,330	$20,261	$21,244	$22,260	$23,262	$24,309	$25,403	$26,546	$27,741	$28,989
3. Avoided Commodity Cost $/BBtu	$2.48	$2.67	$2.95	$3.25	$3.43	$3.65	$3.87	$4.10	$4.60	$4.86	$5.12	$5.41	$5.67	$5.94	$6.22	$6.51	$6.80	$7.10	$7.42	$7.76	$8.11
4. Annual Change in Interruptible Margin	$0.150	$0.152	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
5. 93.64% of Annual Change	$0.140	$0.142	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6. Total Summer Avoided Costs	$2.62	$2.81	$2.95	$3.25	$3.43	$3.65	$3.87	$4.10	$4.60	$4.86	$5.12	$5.41	$5.67	$5.94	$6.22	$6.51	$6.80	$7.10	$7.42	$7.76	$8.11

E.1 Change in Commodity Cost (case 1 – case 2)

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$7,912	$8,257	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
F2/F3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CD/NOREX	$5,209	$5,384	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOUN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$142	$171	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WS	$752	$946	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LNG	$626	$1,543	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PROP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPOT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CDS	$765	$902	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANE	$0	$0	$13,205	$14,011	$15,064	$15,891	$16,754	$18,388	$19,411	$20,416	$21,862	$22,834	$23,733	$25,282	$26,302	$27,398	$28,851	$30,036	$31,345	$32,924	$34,366
ESSO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGAS	$548	$71	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGASBOIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage																					
A. LNG	($27)	($66)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
B. STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. SIS	($6)	($7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
D. TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. WS	($32)	($40)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
F. STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$15,890	$17,161	$13,205	$14,011	$15,064	$15,891	$16,754	$18,388	$19,411	$20,416	$21,862	$22,834	$23,733	$25,282	$26,302	$27,398	$28,851	$30,036	$31,345	$32,924	$34,366

E.2.A. *Change in Commodity Cost (case 1 – case 3)*

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$312	$276	($4,370)	($210)	($251)	($209)	($254)	($243)	($258)	($272)	($286)	($303)	($316)	($330)	($345)	($361)	($377)	($394)	($412)	($430)	($450)
F2/F3	$0	$0	($5,347)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CD/NOREX	$2,633	$2,698	($2,215)	($10,362)	($10,462)	($11,034)	($11,365)	($11,773)	($12,465)	($13,154)	($13,835)	($14,597)	($15,254)	($15,940)	($16,657)	($17,407)	($18,190)	($19,009)	($19,864)	($20,758)	($21,692)
BOUN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$130	$124	($41)	($7)	($38)	($95)	($81)	($159)	($168)	($177)	($187)	($197)	($206)	($215)	($225)	($235)	($246)	($257)	($268)	($280)	($293)
WS	$577	$731	($87)	($269)	($323)	($376)	($484)	($527)	($559)	($590)	($621)	($656)	($685)	($716)	($748)	($782)	($817)	($854)	($892)	($932)	($974)
LNG	$654	$1,558	$33	$50	$58	$48	$50	$89	$94	$99	$104	$110	$115	$120	$125	$131	$137	$143	$149	$156	$163
PROP	$0	$0	$0	$0	$0	$0	($65)	($184)	($194)	($204)	($213)	($223)	($233)	($243)	($254)	($266)	($277)	($290)	($303)	($317)	($331)
SPOT	$0	$0	$0	($462)	($554)	($515)	($457)	($507)	($610)	($650)	($686)	($724)	($763)	($806)	($850)	($889)	($928)	($970)	($1,014)	($1,060)	($1,107)
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CDS	$216	$263	($601)	($2,405)	($2,750)	($2,943)	($3,262)	($3,445)	($4,487)	($4,778)	($5,048)	($5,327)	($5,621)	($5,936)	($6,256)	($6,537)	($6,832)	($7,139)	($7,460)	($7,796)	($8,147)
ANE	$0	$0	$13,205	$14,011	$15,064	$15,891	$16,754	$18,388	$19,411	$20,416	$21,862	$22,834	$23,733	$25,282	$26,302	$27,398	$28,651	$30,038	$31,345	$32,924	$34,366
ESSO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGAS	$468	$1	($8)	($32)	($21)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGASBOIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
A. LNG	($28)	($66)	($1)	($2)	($2)	($2)	($2)	($4)	($4)	($4)	($4)	($5)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($7)	($7)
B. STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. SIS	($6)	($5)	$2	$0	$2	$4	$3	$7	$7	$8	$8	$8	$9	$9	$10	$10	$10	$11	$11	$12	$12
D. TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. WS	($25)	($31)	$4	$11	$14	$16	$21	$22	$24	$25	$26	$28	$29	$30	$32	$33	$35	$36	$38	$40	$41
F. STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$4,932	$5,549	$571	$324	$735	$784	$857	$1,665	$792	$719	$1,120	$950	$803	$1,249	$1,127	$1,090	$1,360	$1,309	$1,324	$1,552	$1,582

E.3. Change In Commodity Cost (Remainder)

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
F2/F3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CD/NOREX	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOUN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PROP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPOT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CDS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGASBOIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
A. LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
B. STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
D. TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. WS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
F. STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

E.3. Change in Commodity Cost (case 1 – case 4a)

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
F1	$544	$491	($4,133)	($194)	($235)	($262)	($280)	($273)	($290)	($306)	($322)
F2/F3	$0	$0	($5,291)	$0	$0	$0	$0	$0	$0	$0	$0
CD/NOREX	$4,200	$4,178	($626)	($8,611)	($8,614)	($9,356)	($9,822)	($10,381)	($10,991)	($11,598)	($12,199)
BOUN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$142	$171	$0	$0	$0	$0	$0	$0	$0	$0	$0
WS	$752	$946	$0	$0	$0	$0	($9)	($40)	($42)	($44)	($47)
LNG	$626	$1,543	$0	$0	$0	$0	$0	$0	$0	$0	$0
PROP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPOT	$0	$0	$0	($629)	($734)	($724)	($694)	($785)	($944)	($1,005)	($1,062)
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CDS	$260	$343	($494)	($2,176)	($2,485)	($2,704)	($3,042)	($3,202)	($4,170)	($4,441)	($4,692)
ANE	$0	$0	$13,205	$14,011	$15,064	$15,891	$16,754	$18,388	$19,411	$20,416	$21,862
ESSO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGAS	$548	$71	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGASBOIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage											
A. LNG	($27)	($66)	$0	$0	$0	$0	$0	$0	$0	$0	$0
B. STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. SIS	($6)	($7)	$0	$0	$0	$0	$0	$0	$0	$0	$0
D. TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. WS	($32)	($40)	$0	$0	$0	$0	$0	$2	$2	$2	$2
F. STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$7,007	$7,630	$2,660	$2,401	$2,795	$2,844	$2,907	$3,709	$2,975	$3,023	$3,542

Supply	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	($340)	($356)	($372)	($389)	($406)	($424)	($443)	($463)	($484)	($506)
F2/F3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CD/NOREX	($12,871)	($13,450)	($14,055)	($14,688)	($15,349)	($16,039)	($16,761)	($17,515)	($18,303)	($19,127)
BOUN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WS	($49)	($52)	($54)	($56)	($59)	($61)	($64)	($67)	($70)	($73)
LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PROP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPOT	($1,120)	($1,182)	($1,248)	($1,316)	($1,375)	($1,437)	($1,502)	($1,569)	($1,640)	($1,714)
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CDS	($4,951)	($5,224)	($5,516)	($5,815)	($6,076)	($6,350)	($6,635)	($6,934)	($7,246)	($7,572)
ANE	$22,834	$23,733	$25,282	$26,302	$27,398	$28,851	$30,038	$31,345	$32,924	$34,366
ESSO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGASBOIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage										
A. LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
B. STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
D. TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. WS	$2	$2	$2	$2	$2	$3	$3	$3	$3	$3
F. STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$3,504	$3,472	$4,039	$4,042	$4,136	$4,542	$4,635	$4,799	$5,183	$5,377

E.4. Change in Commodity Cost (case 4a – case 2)

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
F1	$7,368	$7,766	$4,133	$194	$235	$262	$280	$273	$290	$306
F2/F3	$0	$0	$5,291	$0	$0	$0	$0	$0	$0	$0
CD/NOREX	$1,009	$1,206	$626	$8,611	$8,814	$9,356	$9,822	$10,381	$10,991	$11,598
BOUN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WS	$0	$0	$0	$0	$0	$0	$9	$40	$42	$44
LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PROP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPOT	$0	$0	$0	$629	$734	$724	$694	$785	$944	$1,005
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CDS	$505	$558	$494	$2,176	$2,485	$2,704	$3,042	$3,202	$4,170	$4,441
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGASBOIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
A. LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
B. STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
D. TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. WS	$0	$0	$0	$0	$0	$0	($0)	($2)	($2)	($2)
F. STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$8,883	$9,531	$10,544	$11,610	$12,269	$13,047	$13,847	$14,679	$16,436	$17,394

Supply	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$322	$340	$356	$372	$389	$406	$424	$443	$463	$484	$506
F2/F3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CD/NOREX	$12,199	$12,871	$13,450	$14,055	$14,688	$15,349	$16,039	$16,761	$17,515	$18,303	$19,127
BOUN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WS	$47	$49	$52	$54	$56	$59	$61	$64	$67	$70	$73
LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PROP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPOT	$1,062	$1,120	$1,182	$1,248	$1,316	$1,375	$1,437	$1,502	$1,569	$1,640	$1,714
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CDS	$4,692	$4,951	$5,224	$5,518	$5,815	$6,076	$6,350	$6,635	$6,934	$7,246	$7,572
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DGASBOIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
A. LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
B. STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
D. TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. WS	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($3)
F. STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$18,320	$19,330	$20,261	$21,244	$22,260	$23,262	$24,309	$25,403	$26,546	$27,741	$28,989

F.1. **Base Case: Total Commodity Cost**

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
F1	$78,437	$85,235	$67,703	$96,417	$102,322	$109,055	$116,127	$123,200	$130,674	$138,067	$145,333
F2/F3	$27,534	$29,436	$25,875	$33,111	$35,105	$37,344	$39,713	$42,076	$44,571	$47,048	$49,494
CD/NOREX	$38,089	$43,248	$30,951	$51,980	$58,500	$65,606	$73,422	$81,163	$85,938	$90,685	$95,379
BOUN	$9,118	$8,361	$8,882	$9,414	$10,100	$10,647	$11,218	$12,270	$12,944	$13,608	$14,548
TGT	$5,182	$5,541	$5,878	$6,234	$6,610	$7,032	$7,479	$7,924	$8,395	$8,862	$9,323
STB	$8,814	$9,435	$10,016	$10,629	$11,278	$12,008	$12,781	$13,551	$14,364	$15,170	$15,963
SIS	$723	$872	$508	$728	$821	$1,027	$1,271	$1,446	$1,533	$1,619	$1,704
WS	$3,457	$4,337	$2,601	$3,462	$4,293	$5,312	$6,575	$7,886	$8,359	$8,828	$9,290
LNG	$4,636	$6,208	$4,428	$4,870	$5,495	$6,778	$8,311	$10,293	$10,866	$11,440	$12,015
PROP	$0	$0	$0	$0	$0	$0	$737	$2,511	$2,644	$2,784	$2,909
SPOT	$0	$0	$0	$543	$632	$857	$1,150	$1,384	$1,665	$1,773	$1,873
STEUB	$0	$0	$0	$3,341	$3,541	$3,766	$4,004	$4,241	$5,164	$5,496	$5,803
CDS	$11,366	$12,527	$10,814	$14,742	$15,918	$17,227	$18,636	$20,351	$26,506	$28,228	$29,822
ANE	$0	$0	$13,205	$14,011	$15,064	$15,891	$16,754	$18,388	$19,411	$20,416	$21,862
ESSO	$0	$0	$28,023	$29,574	$32,108	$33,760	$35,487	$39,110	$41,150	$43,191	$46,443
DGAS	$2,893	$3,089	$2,159	$2,872	$3,532	$3,905	$4,148	$4,392	$5,523	$5,866	$6,188
DGASBOIL	$2,956	$3,168	$3,365	$3,574	$3,795	$4,044	$4,308	$4,571	$5,901	$6,280	$6,632
Storage											
A. LNG	$1,257	$1,281	$1,443	$1,516	$1,587	$1,639	$1,687	$1,717	$1,812	$1,908	$2,004
B. STB	$392	$420	$446	$473	$502	$534	$569	$603	$639	$675	$710
C. SIS	$202	$212	$243	$250	$263	$274	$284	$297	$315	$332	$350
D. TGT	$225	$240	$255	$270	$287	$305	$324	$344	$364	$384	$404
E. WS	$415	$417	$528	$530	$536	$539	$535	$528	$560	$591	$622
F. STEUB	$236	$253	$268	$142	$151	$160	$170	$180	$219	$234	$247
TOTAL	$195,933	$214,280	$217,591	$288,684	$312,438	$337,712	$365,691	$398,425	$429,516	$453,486	$478,919

Supply	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$153,525	$160,434	$167,653	$175,198	$183,082	$191,320	$199,930	$208,926	$218,328	$228,153
F2/F3	$52,236	$54,586	$57,043	$59,610	$62,292	$65,095	$68,025	$71,086	$74,285	$77,627
CD/NOREX	$100,632	$105,161	$109,893	$114,838	$120,006	$125,406	$131,049	$136,946	$143,109	$149,549
BOUN	$15,196	$15,800	$16,810	$17,493	$18,225	$19,183	$19,977	$20,848	$21,891	$22,851
TGT	$9,840	$10,283	$10,745	$11,229	$11,734	$12,262	$12,814	$13,391	$13,993	$14,623
STB	$16,856	$17,614	$18,407	$19,235	$20,101	$21,005	$21,951	$22,938	$23,971	$25,049
SIS	$1,799	$1,880	$1,965	$2,053	$2,146	$2,242	$2,343	$2,448	$2,559	$2,674
WS	$9,809	$10,251	$10,712	$11,194	$11,698	$12,224	$12,774	$13,349	$13,950	$14,578
LNG	$12,650	$13,219	$13,814	$14,435	$15,085	$15,764	$16,473	$17,214	$17,989	$18,798
PROP	$3,040	$3,177	$3,320	$3,469	$3,625	$3,788	$3,959	$4,137	$4,323	$4,518
SPOT	$1,976	$2,084	$2,201	$2,321	$2,426	$2,535	$2,649	$2,768	$2,893	$3,023
STEUB	$6,120	$6,453	$6,811	$7,182	$7,505	$7,842	$8,195	$8,564	$8,950	$9,352
CDS	$31,469	$33,204	$35,068	$36,955	$38,618	$40,356	$42,172	$44,070	$46,053	$48,126
ANE	$22,834	$23,733	$25,282	$26,302	$27,398	$28,651	$30,038	$31,345	$32,924	$34,366
ESSO	$48,516	$50,513	$53,688	$55,933	$58,321	$61,267	$63,862	$66,670	$69,916	$73,005
DGAS	$6,521	$6,871	$7,246	$7,627	$7,970	$8,329	$8,704	$9,095	$9,505	$9,932
DGASBOIL	$6,996	$7,379	$7,791	$8,208	$8,577	$8,963	$9,366	$9,788	$10,228	$10,689
Storage										
A. LNG	$2,110	$2,205	$2,304	$2,407	$2,516	$2,629	$2,747	$2,871	$3,000	$3,135
B. STB	$750	$784	$819	$856	$895	$935	$977	$1,021	$1,067	$1,115
C. SIS	$369	$386	$403	$421	$440	$460	$481	$503	$525	$549
D. TGT	$427	$446	$466	$487	$509	$532	$556	$581	$607	$634
E. WS	$657	$687	$717	$750	$783	$819	$856	$894	$934	$976
F. STEUB	$260	$274	$289	$305	$319	$333	$348	$364	$380	$397
TOTAL	$504,587	$527,423	$553,448	$578,508	$604,271	$632,142	$660,245	$689,818	$721,379	$753,719

F.2. Case 2: Total Commodity Cost

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$70,525	$76,978	$67,703	$96,417	$102,322	$109,055	$116,127	$123,200	$130,674	$138,067	$145,333	$153,525	$160,434	$167,653	$175,198	$183,082	$191,320	$199,930	$208,926	$218,328	$228,153
F2/F3	$27,534	$29,436	$25,875	$33,111	$35,105	$37,344	$39,713	$42,076	$44,571	$47,048	$49,494	$52,236	$54,586	$57,043	$59,610	$62,292	$65,095	$68,025	$71,086	$74,285	$77,627
CD/NOREX	$32,880	$37,864	$30,951	$51,980	$58,500	$65,606	$73,422	$81,163	$85,938	$90,685	$95,379	$100,632	$105,161	$109,893	$114,838	$120,006	$125,406	$131,049	$136,946	$143,109	$149,549
BOUN	$9,118	$8,361	$8,882	$9,414	$10,100	$10,647	$11,218	$12,270	$12,944	$13,608	$14,548	$15,196	$15,800	$16,810	$17,493	$18,225	$19,183	$19,977	$20,848	$21,891	$22,851
TGT	$5,182	$5,541	$5,878	$6,234	$6,610	$7,032	$7,479	$7,924	$8,395	$8,862	$9,323	$9,840	$10,283	$10,745	$11,229	$11,734	$12,262	$12,814	$13,391	$13,993	$14,623
STB	$8,814	$9,435	$10,016	$10,629	$11,278	$12,008	$12,781	$13,551	$14,364	$15,170	$15,963	$16,856	$17,614	$18,407	$19,235	$20,101	$21,005	$21,951	$22,938	$23,971	$25,049
SIS	$581	$701	$508	$728	$821	$1,027	$1,271	$1,446	$1,533	$1,619	$1,704	$1,799	$1,880	$1,965	$2,053	$2,146	$2,242	$2,343	$2,448	$2,559	$2,674
WS	$2,706	$3,391	$2,601	$3,462	$4,293	$5,312	$6,575	$7,886	$8,359	$8,828	$9,290	$9,809	$10,251	$10,712	$11,194	$11,698	$12,224	$12,774	$13,349	$13,950	$14,578
LNG	$4,009	$4,665	$4,428	$4,870	$5,495	$6,778	$8,311	$10,293	$10,866	$11,440	$12,015	$12,650	$13,219	$13,814	$14,435	$15,085	$15,764	$16,473	$17,214	$17,989	$18,798
PROP	$0	$0	$0	$0	$0	$0	$737	$2,511	$2,644	$2,784	$2,909	$3,040	$3,177	$3,320	$3,469	$3,625	$3,788	$3,959	$4,137	$4,323	$4,518
SPOT	$0	$0	$0	$543	$632	$857	$1,150	$1,384	$1,665	$1,773	$1,873	$1,976	$2,084	$2,201	$2,321	$2,426	$2,535	$2,649	$2,768	$2,893	$3,023
STEUB	$0	$0	$0	$3,341	$3,541	$3,766	$4,004	$4,241	$5,164	$5,496	$5,803	$6,120	$6,453	$6,811	$7,182	$7,505	$7,842	$8,195	$8,564	$8,950	$9,352
CDS	$10,601	$11,626	$10,814	$14,742	$15,918	$17,227	$18,636	$20,351	$26,506	$28,228	$29,822	$31,469	$33,204	$35,068	$36,955	$38,618	$40,356	$42,172	$44,070	$46,053	$48,126
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$0	$0	$28,023	$29,574	$32,108	$33,760	$35,487	$39,110	$41,150	$43,191	$46,443	$48,516	$50,513	$53,688	$55,933	$58,321	$61,267	$63,862	$66,670	$69,916	$73,005
DGAS	$2,345	$3,017	$2,159	$2,872	$3,532	$3,905	$4,148	$4,392	$5,523	$5,866	$6,188	$6,521	$6,871	$7,246	$7,627	$7,970	$8,329	$8,704	$9,095	$9,505	$9,932
DGASBOIL	$2,956	$3,168	$3,365	$3,574	$3,795	$4,044	$4,308	$4,571	$5,901	$6,280	$6,632	$6,996	$7,379	$7,791	$8,208	$8,577	$8,963	$9,366	$9,788	$10,228	$10,689
Storage																					
A. LNG	$1,283	$1,346	$1,443	$1,516	$1,587	$1,639	$1,687	$1,717	$1,812	$1,908	$2,004	$2,110	$2,205	$2,304	$2,407	$2,516	$2,629	$2,747	$2,871	$3,000	$3,135
B. STB	$392	$420	$446	$473	$502	$534	$569	$603	$639	$675	$710	$750	$784	$819	$856	$895	$935	$977	$1,021	$1,067	$1,115
C. SIS	$208	$220	$243	$250	$263	$274	$284	$297	$315	$332	$350	$369	$386	$403	$421	$440	$460	$481	$503	$525	$549
D. TGT	$225	$240	$255	$270	$287	$305	$324	$344	$364	$384	$404	$427	$446	$466	$487	$509	$532	$556	$581	$607	$634
E. WS	$447	$457	$528	$530	$536	$539	$535	$528	$560	$591	$622	$657	$687	$717	$750	$783	$819	$856	$894	$934	$976
F. STEUB	$236	$253	$268	$142	$151	$160	$170	$180	$219	$234	$247	$260	$274	$289	$305	$319	$333	$348	$364	$380	$397
TOTAL	$180,043	$197,119	$204,386	$274,673	$297,374	$321,821	$348,938	$380,037	$410,105	$433,070	$457,057	$481,753	$503,690	$526,165	$552,206	$576,873	$603,291	$630,207	$658,473	$688,455	$719,353

F.3.A. Case 3: Total Commodity Cost

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
F1	$78,126	$84,960	$72,074	$96,627	$102,574	$109,264	$116,381	$123,443	$130,931	$138,339	$145,620
F2/F3	$27,534	$29,436	$31,223	$33,111	$35,105	$37,344	$39,713	$42,076	$44,571	$47,048	$49,494
CD/NOREX	$35,456	$40,550	$33,166	$62,342	$68,962	$76,641	$84,787	$92,935	$98,403	$103,839	$109,214
BOUN	$9,118	$8,361	$8,882	$9,414	$10,100	$10,647	$11,218	$12,270	$12,944	$13,608	$14,548
TGT	$5,182	$5,541	$5,878	$6,234	$6,610	$7,032	$7,479	$7,924	$8,395	$8,862	$9,323
STB	$8,814	$9,435	$10,016	$10,629	$11,278	$12,008	$12,781	$13,551	$14,364	$15,170	$15,963
SIS	$593	$747	$549	$735	$859	$1,122	$1,352	$1,605	$1,701	$1,797	$1,891
WS	$2,881	$3,606	$2,688	$3,731	$4,615	$5,669	$7,059	$8,413	$8,918	$9,418	$9,911
LNG	$3,982	$4,650	$4,395	$4,820	$5,437	$6,730	$8,261	$10,203	$10,771	$11,341	$11,911
PROP	$0	$0	$0	$0	$0	$0	$802	$2,694	$2,837	$2,988	$3,122
SPOT	$0	$0	$0	$1,005	$1,186	$1,372	$1,608	$1,892	$2,275	$2,423	$2,559
STEUB	$0	$0	$0	$3,341	$3,541	$3,766	$4,004	$4,241	$5,164	$5,496	$5,803
CDS	$11,149	$12,265	$11,416	$17,147	$18,668	$20,170	$21,899	$23,796	$30,992	$33,006	$34,870
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$0	$0	$28,023	$29,574	$32,108	$33,760	$35,487	$39,110	$41,150	$43,191	$46,443
DGAS	$2,425	$3,087	$2,168	$2,904	$3,553	$3,905	$4,148	$4,392	$5,523	$5,866	$6,188
DGASBOIL	$2,956	$3,168	$3,365	$3,574	$3,795	$4,044	$4,308	$4,571	$5,901	$6,280	$6,632
Storage											
A. LNG	$1,285	$1,347	$1,445	$1,519	$1,589	$1,641	$1,689	$1,720	$1,816	$1,912	$2,008
B. STB	$392	$420	$446	$473	$502	$534	$569	$603	$639	$675	$710
C. SIS	$208	$218	$242	$250	$262	$270	$281	$290	$308	$325	$342
D. TGT	$225	$240	$255	$270	$287	$305	$324	$344	$364	$384	$404
E. WS	$439	$448	$524	$519	$522	$523	$514	$506	$536	$566	$596
F. STEUB	$236	$253	$268	$142	$151	$160	$170	$180	$219	$234	$247
TOTAL	$191,001	$208,731	$217,020	$288,360	$311,703	$336,927	$364,835	$396,760	$428,724	$452,767	$477,799

Supply	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$153,828	$160,750	$167,984	$175,543	$183,442	$191,697	$200,324	$209,338	$218,759	$228,603
F2/F3	$52,236	$54,586	$57,043	$59,610	$62,292	$65,095	$68,025	$71,086	$74,285	$77,627
CD/NOREX	$115,229	$120,414	$125,833	$131,495	$137,413	$143,596	$150,058	$156,811	$163,867	$171,241
BOUN	$15,196	$15,800	$16,810	$17,493	$18,225	$19,183	$19,977	$20,848	$21,891	$22,851
TGT	$9,840	$10,283	$10,745	$11,229	$11,734	$12,262	$12,814	$13,391	$13,993	$14,623
STB	$16,856	$17,614	$18,407	$19,235	$20,101	$21,005	$21,951	$22,938	$23,971	$25,049
SIS	$1,996	$2,086	$2,180	$2,278	$2,381	$2,488	$2,600	$2,717	$2,839	$2,967
WS	$10,465	$10,936	$11,428	$11,942	$12,480	$13,041	$13,628	$14,241	$14,882	$15,552
LNG	$12,540	$13,104	$13,694	$14,310	$14,954	$15,627	$16,330	$17,065	$17,833	$18,635
PROP	$3,263	$3,409	$3,563	$3,723	$3,891	$4,066	$4,249	$4,440	$4,640	$4,849
SPOT	$2,700	$2,848	$3,007	$3,172	$3,314	$3,463	$3,619	$3,782	$3,952	$4,130
STEUB	$6,120	$6,453	$6,811	$7,182	$7,505	$7,842	$8,195	$8,564	$8,950	$9,352
CDS	$36,796	$38,825	$41,004	$43,211	$45,156	$47,188	$49,311	$51,530	$53,849	$56,272
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$48,516	$50,513	$53,688	$55,933	$58,321	$61,267	$63,862	$66,670	$69,916	$73,005
DGAS	$6,521	$6,871	$7,246	$7,627	$7,970	$8,329	$8,704	$9,095	$9,505	$9,932
DGASBOIL	$6,996	$7,379	$7,791	$8,208	$8,577	$8,963	$9,366	$9,788	$10,228	$10,689
Storage										
A. LNG	$2,114	$2,209	$2,309	$2,413	$2,521	$2,635	$2,753	$2,877	$3,007	$3,142
B. STB	$750	$784	$819	$856	$895	$935	$977	$1,021	$1,067	$1,115
C. SIS	$361	$377	$394	$412	$430	$450	$470	$491	$513	$536
D. TGT	$427	$446	$466	$487	$509	$532	$556	$581	$607	$634
E. WS	$629	$657	$687	$718	$750	$784	$819	$856	$895	$935
F. STEUB	$260	$274	$289	$305	$319	$333	$348	$364	$380	$397
TOTAL	$503,637	$526,620	$552,198	$577,381	$603,180	$630,782	$658,935	$688,494	$719,827	$752,137

F.4. Case 4a: Total Commodity Cost

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
F1	$77,894	$84,744	$71,837	$96,612	$102,558	$109,317	$116,408	$123,473	$130,964	$138,373	$145,656
F2/F3	$27,534	$29,436	$31,166	$33,111	$35,105	$37,344	$39,713	$42,076	$44,571	$47,048	$49,494
CD/NOREX	$33,889	$39,071	$31,577	$60,591	$67,314	$74,962	$83,244	$91,543	$96,929	$102,284	$107,578
BOUN	$9,118	$8,361	$8,882	$9,414	$10,100	$10,647	$11,218	$12,270	$12,944	$13,608	$14,548
TGT	$5,182	$5,541	$5,878	$6,234	$6,610	$7,032	$7,479	$7,924	$8,395	$8,862	$9,323
STB	$8,814	$9,435	$10,016	$10,629	$11,278	$12,008	$12,781	$13,551	$14,364	$15,170	$15,963
SIS	$581	$701	$508	$728	$821	$1,027	$1,271	$1,446	$1,533	$1,619	$1,704
WS	$2,706	$3,391	$2,601	$3,462	$4,293	$5,312	$6,583	$7,926	$8,401	$8,873	$9,337
LNG	$4,009	$4,665	$4,428	$4,870	$5,495	$6,778	$8,311	$10,293	$10,866	$11,440	$12,015
PROP	$0	$0	$0	$0	$0	$0	$737	$2,511	$2,644	$2,784	$2,909
SPOT	$0	$0	$0	$1,172	$1,366	$1,581	$1,845	$2,169	$2,609	$2,779	$2,935
STEUB	$0	$0	$0	$3,341	$3,541	$3,766	$4,004	$4,241	$5,164	$5,496	$5,803
CDS	$11,106	$12,184	$11,308	$16,918	$18,403	$19,932	$21,678	$23,553	$30,676	$32,669	$34,514
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$0	$0	$28,023	$29,574	$32,108	$33,760	$35,487	$39,110	$41,150	$43,191	$46,443
DGAS	$2,345	$3,017	$2,159	$2,872	$3,532	$3,905	$4,148	$4,392	$5,523	$5,866	$6,188
DGASBOIL	$2,956	$3,168	$3,365	$3,574	$3,795	$4,044	$4,308	$4,571	$5,901	$6,280	$6,632
Storage											
A. LNG	$1,283	$1,346	$1,443	$1,516	$1,587	$1,639	$1,687	$1,717	$1,812	$1,908	$2,004
B. STB	$392	$420	$446	$473	$502	$534	$569	$603	$639	$675	$710
C. SIS	$208	$220	$243	$250	$263	$274	$284	$297	$315	$332	$350
D. TGT	$225	$240	$255	$270	$287	$305	$324	$344	$364	$384	$404
E. WS	$447	$457	$528	$530	$536	$539	$535	$526	$558	$589	$620
F. STEUB	$236	$253	$268	$142	$151	$160	$170	$180	$219	$234	$247
TOTAL	$188,926	$206,650	$214,931	$286,283	$309,643	$334,868	$362,785	$394,716	$426,541	$450,463	$475,376

Supply	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$153,866	$160,790	$168,025	$175,586	$183,488	$191,744	$200,373	$209,390	$218,812	$228,659
F2/F3	$52,236	$54,586	$57,043	$59,610	$62,292	$65,095	$68,025	$71,086	$74,285	$77,627
CD/NOREX	$113,503	$118,610	$123,948	$129,526	$135,354	$141,445	$147,810	$154,462	$161,412	$168,676
BOUN	$15,196	$15,800	$16,810	$17,493	$18,225	$19,183	$19,977	$20,848	$21,891	$22,851
TGT	$9,840	$10,283	$10,745	$11,229	$11,734	$12,262	$12,814	$13,391	$13,993	$14,623
STB	$16,856	$17,614	$18,407	$19,235	$20,101	$21,005	$21,951	$22,938	$23,971	$25,049
SIS	$1,799	$1,880	$1,965	$2,053	$2,146	$2,242	$2,343	$2,448	$2,559	$2,674
WS	$9,859	$10,302	$10,766	$11,250	$11,757	$12,286	$12,838	$13,416	$14,020	$14,651
LNG	$12,650	$13,219	$13,814	$14,435	$15,085	$15,764	$16,473	$17,214	$17,989	$18,798
PROP	$3,040	$3,177	$3,320	$3,469	$3,625	$3,788	$3,959	$4,137	$4,323	$4,518
SPOT	$3,096	$3,266	$3,449	$3,637	$3,801	$3,972	$4,151	$4,337	$4,533	$4,737
STEUB	$6,120	$6,453	$6,811	$7,182	$7,505	$7,842	$8,195	$8,564	$8,950	$9,352
CDS	$36,420	$38,428	$40,586	$42,770	$44,695	$46,706	$48,808	$51,004	$53,299	$55,698
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$48,516	$50,513	$53,688	$55,933	$58,321	$61,267	$63,862	$66,670	$69,916	$73,005
DGAS	$6,521	$6,871	$7,246	$7,627	$7,970	$8,329	$8,704	$9,095	$9,505	$9,932
DGASBOIL	$6,996	$7,379	$7,791	$8,208	$8,577	$8,963	$9,366	$9,788	$10,228	$10,689
Storage										
A. LNG	$2,110	$2,205	$2,304	$2,407	$2,516	$2,629	$2,747	$2,871	$3,000	$3,135
B. STB	$750	$784	$819	$856	$895	$935	$977	$1,021	$1,067	$1,115
C. SIS	$369	$386	$403	$421	$440	$460	$481	$503	$525	$549
D. TGT	$427	$446	$466	$487	$509	$532	$556	$581	$607	$634
E. WS	$655	$684	$715	$747	$781	$816	$853	$891	$931	$973
F. STEUB	$260	$274	$289	$305	$319	$333	$348	$364	$380	$397
TOTAL	$501,083	$523,951	$549,409	$574,467	$600,135	$627,600	$655,610	$685,019	$716,195	$748,342

Interest	0.085

STORAGE CAPACITY	BBtu
LNG	4,540
STB	3,500
SIS	1,064
TGT	1,936
WS	2,563
STEUB	1,003

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DEMAND CARGES FOR STORAGE GAS

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
LNG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SIS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TGT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STEUB	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INFLATOR	1.05																					

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F.5. Case 4b: Total Commodity Cost

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
F1	$71,077	$77,514	$68,560	$96,354	$102,251	$108,962	$116,054	$122,484	$129,914	$137,264
F2/F3	$27,534	$29,436	$25,932	$33,111	$35,105	$37,344	$39,713	$42,076	$44,571	$47,048
CD/NOREX	$37,064	$42,063	$35,707	$57,429	$63,723	$70,471	$77,605	$85,603	$90,639	$95,646
BOUN	$9,118	$8,361	$8,882	$9,414	$10,100	$10,647	$11,218	$12,270	$12,944	$13,608
TGT	$5,182	$5,541	$5,878	$6,234	$6,610	$7,032	$7,479	$7,924	$8,395	$8,862
STB	$8,814	$9,435	$10,016	$10,629	$11,278	$12,008	$12,781	$13,551	$14,364	$15,170
SIS	$723	$872	$678	$908	$1,140	$1,312	$1,582	$1,947	$2,064	$2,180
WS	$3,457	$4,337	$3,187	$4,736	$5,786	$6,975	$8,254	$9,661	$10,240	$10,815
LNG	$4,636	$6,208	$4,634	$5,667	$6,947	$8,287	$10,328	$12,549	$13,247	$13,948
PROP	$0	$0	$0	$0	$280	$1,751	$3,758	$6,225	$6,556	$6,903
SPOT	$0	$0	$0	$543	$714	$914	$1,231	$1,454	$1,749	$1,863
STEUB	$0	$0	$0	$3,341	$3,541	$3,766	$4,004	$4,241	$5,164	$5,496
CDS	$10,867	$11,910	$11,236	$15,076	$16,291	$17,639	$19,065	$20,926	$27,255	$29,025
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$0	$0	$28,023	$29,574	$32,108	$33,760	$35,487	$39,110	$41,150	$43,191
DGAS	$2,893	$3,089	$2,962	$3,468	$3,674	$3,905	$4,148	$4,392	$5,523	$5,866
DGASBOIL	$2,956	$3,168	$3,365	$3,574	$3,795	$4,044	$4,308	$4,571	$5,901	$6,280
Storage										
A. LNG	$1,257	$1,281	$1,435	$1,483	$1,525	$1,575	$1,601	$1,621	$1,711	$1,801
B. STB	$392	$420	$446	$473	$502	$534	$569	$603	$639	$675
C. SIS	$202	$212	$236	$243	$250	$262	$271	$276	$292	$309
D. TGT	$225	$240	$255	$270	$287	$305	$324	$344	$364	$384
E. WS	$415	$417	$503	$476	$473	$469	$464	$453	$480	$507
F. STEUB	$236	$253	$268	$142	$151	$160	$170	$180	$219	$234
TOTAL	$187,049	$204,756	$212,201	$283,145	$306,528	$332,122	$360,414	$392,460	$423,382	$447,075

Supply	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	$144,489	$152,633	$159,501	$166,679	$174,179	$182,017	$190,208	$198,768	$207,712	$217,059	$226,827
F2/F3	$49,494	$52,236	$54,586	$57,043	$59,610	$62,292	$65,095	$68,025	$71,086	$74,285	$77,627
CD/NOREX	$100,597	$106,137	$110,914	$115,905	$121,120	$126,571	$132,266	$138,218	$144,438	$150,938	$157,730
BOUN	$14,548	$15,196	$15,800	$16,810	$17,493	$18,225	$19,183	$19,977	$20,848	$21,891	$22,851
TGT	$9,323	$9,840	$10,283	$10,745	$11,229	$11,734	$12,262	$12,814	$13,391	$13,993	$14,623
STB	$15,963	$16,856	$17,614	$18,407	$19,235	$20,101	$21,005	$21,951	$22,938	$23,971	$25,049
SIS	$2,294	$2,422	$2,531	$2,645	$2,764	$2,888	$3,018	$3,154	$3,296	$3,444	$3,599
WS	$11,381	$12,017	$12,557	$13,123	$13,713	$14,330	$14,975	$15,649	$16,353	$17,089	$17,858
LNG	$14,649	$15,422	$16,116	$16,842	$17,599	$18,391	$19,219	$20,084	$20,988	$21,932	$22,919
PROP	$7,214	$7,538	$7,878	$8,232	$8,603	$8,990	$9,394	$9,817	$10,259	$10,720	$11,203
SPOT	$1,968	$2,076	$2,190	$2,312	$2,439	$2,548	$2,663	$2,783	$2,908	$3,039	$3,176
STEUB	$5,803	$6,120	$6,453	$6,811	$7,162	$7,505	$7,842	$8,195	$8,564	$8,950	$9,352
CDS	$30,665	$32,358	$34,142	$36,059	$38,000	$39,710	$41,497	$43,364	$45,315	$47,355	$49,486
ANE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ESSO	$46,443	$48,516	$50,513	$53,688	$55,933	$58,321	$61,267	$63,862	$66,670	$69,916	$73,005
DGAS	$6,188	$6,521	$6,871	$7,246	$7,627	$7,970	$8,329	$8,704	$9,095	$9,505	$9,932
DGASBOIL	$6,632	$6,996	$7,379	$7,791	$8,208	$8,577	$8,963	$9,366	$9,788	$10,228	$10,689
Storage											
A. LNG	$1,892	$1,992	$2,081	$2,175	$2,273	$2,375	$2,482	$2,594	$2,711	$2,832	$2,960
B. STB	$710	$750	$784	$819	$856	$895	$935	$977	$1,021	$1,067	$1,115
C. SIS	$325	$343	$358	$374	$391	$409	$427	$447	$467	$488	$510
D. TGT	$404	$427	$446	$466	$487	$509	$532	$556	$581	$607	$634
E. WS	$533	$563	$589	$615	$643	$672	$702	$733	$766	$801	$837
F. STEUB	$247	$260	$274	$289	$305	$319	$333	$348	$364	$380	$397
TOTAL	$471,760	$497,218	$519,861	$545,076	$569,887	$595,350	$622,599	$650,384	$679,558	$710,489	$742,378

F.6. Commodity Cost $/MMBtu

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	2.45	2.63	2.79	2.97	3.15	3.36	3.58	3.79	4.02	4.25	4.48	4.73	4.94	5.16	5.40	5.64	5.89	6.16	6.44	6.72	7.03
F2/F3	2.72	2.91	3.08	3.27	3.47	3.69	3.92	4.16	4.40	4.65	4.89	5.16	5.39	5.64	5.89	6.15	6.43	6.72	7.02	7.34	7.67
CD/NOREX	2.82	3.02	3.20	3.39	3.59	3.82	4.06	4.30	4.55	4.80	5.05	5.33	5.57	5.82	6.08	6.35	6.64	6.94	7.25	7.58	7.92
BOUN	2.44	2.24	2.38	2.52	2.70	2.85	3.00	3.29	3.47	3.64	3.90	4.07	4.23	4.50	4.68	4.88	5.14	5.35	5.58	5.86	6.12
TGT	2.70	2.89	3.07	3.25	3.45	3.67	3.90	4.13	4.38	4.62	4.86	5.13	5.36	5.61	5.86	6.12	6.40	6.69	6.99	7.30	7.63
STB	2.58	2.76	2.93	3.11	3.30	3.51	3.74	3.96	4.20	4.44	4.67	4.93	5.15	5.38	5.63	5.88	6.14	6.42	6.71	7.01	7.33
SIS	2.58	2.76	2.93	3.11	3.30	3.51	3.74	3.96	4.20	4.44	4.67	4.93	5.15	5.38	5.63	5.88	6.14	6.42	6.71	7.01	7.33
WS	2.58	2.76	2.93	3.11	3.30	3.51	3.74	3.96	4.20	4.44	4.67	4.93	5.15	5.38	5.63	5.88	6.14	6.42	6.71	7.01	7.33
LNG	3.77	4.00	4.23	4.47	4.72	4.99	5.29	5.58	5.89	6.20	6.52	6.86	7.17	7.49	7.83	8.18	8.55	8.93	9.34	9.76	10.19
PROP	4.70	5.01	5.32	5.66	6.04	6.36	6.70	7.07	7.45	7.84	8.19	8.56	8.95	9.35	9.77	10.21	10.67	11.15	11.65	12.18	12.73
SPOT	2.62	2.81	2.98	3.16	3.35	3.57	3.80	4.02	4.84	5.16	5.44	5.74	6.06	6.40	6.75	7.05	7.37	7.70	8.05	8.41	8.79
STEUB	2.77	2.96	3.14	3.33	3.53	3.76	3.99	4.23	5.15	5.48	5.79	6.10	6.44	6.79	7.16	7.49	7.82	8.17	8.54	8.93	9.33
CDS	2.33	2.50	2.66	2.83	3.00	3.20	3.42	3.63	4.72	5.03	5.31	5.61	5.92	6.25	6.59	6.88	7.19	7.51	7.85	8.21	8.58
ANE	2.24	2.03	2.16	2.30	2.47	2.61	2.75	3.01	3.18	3.35	3.58	3.74	3.89	4.14	4.31	4.49	4.73	4.92	5.14	5.40	5.63
ESSO	2.31	2.11	2.23	2.36	2.56	2.69	2.83	3.11	3.28	3.44	3.70	3.86	4.02	4.28	4.45	4.64	4.88	5.09	5.31	5.57	5.81
DGAS	2.89	3.09	3.27	3.47	3.67	3.90	4.15	4.39	5.52	5.87	6.19	6.52	6.87	7.25	7.63	7.97	8.33	8.70	9.10	9.50	9.93
DGASBOIL	2.45	2.63	2.79	2.97	3.15	3.36	3.58	3.79	4.90	5.21	5.51	5.81	6.13	6.47	6.81	7.12	7.44	7.78	8.13	8.49	8.87

gnp 0.045

G.3.A. Case 3a Sendout: without ANE, Heating Decrement of 3.72%

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
F1	31,835	32,304	25,796	32,562	32,554	32,541	32,537	32,530	32,530	32,530	32,530
F2/F3	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121
CD/NOREX	12,560	13,448	10,375	18,399	19,206	20,077	20,898	21,630	21,630	21,630	21,630
BOUN	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
TGT	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
STB	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420
SIS	230	271	188	236	260	320	362	405	405	405	405
WS	1,118	1,307	918	1,200	1,399	1,620	1,869	2,123	2,123	2,123	2,123
LNG	1,057	1,162	1,039	1,079	1,153	1,348	1,563	1,828	1,828	1,828	1,828
PROP	0	0	0	0	0	0	120	381	381	381	381
SPOT	0	0	0	318	354	384	423	470	470	470	470
STEUB	0	0	0	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003
CDS	4,784	4,904	4,293	6,067	6,216	6,296	6,411	6,562	6,562	6,562	6,562
ANE	0	0	0	0	0	0	0	0	0	0	0
ESSO	0	0	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558
DGAS	838	1,000	662	837	967	1,000	1,000	1,000	1,000	1,000	1,000
DGASBOIL	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
TOTAL	72,819	74,792	76,225	94,657	96,066	97,542	99,159	100,886	100,886	100,886	100,886
INTERRUPTIBLE	29,021	27,251	37,954	21,085	19,871	18,720	17,558	16,470	16,470	16,470	16,470

Supply	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530
F2/F3	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121
CD/NOREX	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630
BOUN	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
TGT	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
STB	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420
SIS	405	405	405	405	405	405	405	405	405	405
WS	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123
LNG	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828
PROP	381	381	381	381	381	381	381	381	381	381
SPOT	470	470	470	470	470	470	470	470	470	470
STEUB	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003
CDS	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562
ANE	0	0	0	0	0	0	0	0	0	0
ESSO	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558
DGAS	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
DGASBOIL	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
TOTAL	100,886	100,886	100,886	100,886	100,886	100,886	100,886	100,886	100,886	100,886
INTERRUPTIBLE	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470

G.3.B. Case 3b Sendout: without ANE, ESSO, Heating Decrement of 11.38%

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
F1	31,508	32,019	32,261	32,677	32,651	32,634	32,621	32,618	32,618	32,618
F2/F3	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121
CD/NOREX	10,442	11,378	12,105	24,496	25,260	26,000	26,697	27,313	27,313	27,313
BOUN	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
TGT	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
STB	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420
SIS	122	163	207	261	317	376	445	475	475	475
WS	742	884	995	1,426	1,658	1,933	2,211	2,446	2,446	2,446
LNG	999	1,014	1,027	1,056	1,129	1,348	1,529	1,808	1,808	1,808
PROP	0	0	0	0	0	0	189	501	501	501
SPOT	0	0	0	607	654	696	756	839	839	839
STEUB	0	0	0	1,003	1,003	1,003	1,003	1,003	1,003	1,003
CDS	4,576	4,687	4,767	7,992	8,064	8,123	8,196	8,289	8,289	8,289
ANE	0	0	0	0	0	0	0	0	0	0
ESSO	0	0	0	0	0	0	0	0	0	0
DGAS	405	535	669	858	980	1,000	1,000	1,000	1,000	1,000
DGASBOIL	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
TOTAL	69,191	71,076	72,427	90,771	92,109	93,509	95,043	96,686	96,686	96,686
INTERRUPTIBLE	32,133	30,405	29,217	12,764	11,655	10,603	9,561	8,613	8,613	8,613

Supply	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	32,618	32,618	32,618	32,618	32,618	32,618	32,618	32,618	32,618	32,618	32,618
F2/F3	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121
CD/NOREX	27,313	27,313	27,313	27,313	27,313	27,313	27,313	27,313	27,313	27,313	27,313
BOUN	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
TGT	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
STB	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420
SIS	475	475	475	475	475	475	475	475	475	475	475
WS	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446
LNG	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808	1,808
PROP	501	501	501	501	501	501	501	501	501	501	501
SPOT	839	839	839	839	839	839	839	839	839	839	839
STEUB	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003
CDS	8,289	8,289	8,289	8,289	8,289	8,289	8,289	8,289	8,289	8,289	8,289
ANE	0	0	0	0	0	0	0	0	0	0	0
ESSO	0	0	0	0	0	0	0	0	0	0	0
DGAS	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
DGASBOIL	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
TOTAL	96,686	96,686	96,686	96,686	96,686	96,686	96,686	96,686	96,686	96,686	96,686
INTERRUPTIBLE	8,613	8,613	8,613	8,613	8,613	8,613	8,613	8,613	8,613	8,613	8,613

G.1. Case 1 (Base Case) Sendout: No Decrement

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
F1	31962	32409	24231	32492	32475	32479	32466	32466	32466	32466	32466
F2/F3	10121	10121	8388	10121	10121	10121	10121	10121	10121	10121	10121
CD/NOREX	13493	14342	9682	15341	16292	17187	18097	18890	18890	18890	18890
BOUN	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735
TGT	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917
STB	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420
SIS	281	316	174	234	249	292	340	365	365	365	365
WS	1341	1572	888	1114	1302	1513	1759	1990	1990	1990	1990
LNG	1231	1551	1047	1091	1165	1357	1572	1844	1844	1844	1844
PROP	0	0	0	0	0	0	110	355	355	355	355
SPOT	0	0	0	172	188	240	303	344	344	344	344
STEUB	0	0	0	1003	1003	1003	1003	1003	1003	1003	1003
CDS	4877	5010	4067	5216	5300	5378	5456	5612	5612	5612	5612
ANE	0	0	6100	6100	6100	6100	6100	6100	6100	6100	6100
ESSO	0	0	12558	12558	12558	12558	12558	12558	12558	12558	12558
DGAS	1000	1000	660	828	961	1000	1000	1000	1000	1000	1000
DGASBOIL	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205
TOTAL	74581	76596	78070	96543	97989	99502	101159	102922	102922	102922	102922
INTERRUPTIBLE	27,539	25,892	42,189	25,129	23,865	22,685	21,507	20,347	20,347	20,347	20,347

Supply	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	32466	32466	32466	32466	32466	32466	32466	32466	32466	32466
F2/F3	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121
CD/NOREX	18890	18890	18890	18890	18890	18890	18890	18890	18890	18890
BOUN	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735
TGT	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917
STB	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420
SIS	365	365	365	365	365	365	365	365	365	365
WS	1990	1990	1990	1990	1990	1990	1990	1990	1990	1990
LNG	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844
PROP	355	355	355	355	355	355	355	355	355	355
SPOT	344	344	344	344	344	344	344	344	344	344
STEUB	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003
CDS	5612	5612	5612	5612	5612	5612	5612	5612	5612	5612
ANE	6100	6100	6100	6100	6100	6100	6100	6100	6100	6100
ESSO	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558
DGAS	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
DGASBOIL	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205
TOTAL	102922	102922	102922	102922	102922	102922	102922	102922	102922	102922
INTERRUPTIBLE	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347

G.3. Case 3 Sendout: Heating Decrement

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	31,835	32,304	25,796	32,562	32,554	32,541	32,537	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530	32,530
F2/F3	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121	10,121
CD/NOREX	12,560	13,448	10,375	18,399	19,206	20,077	20,898	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630	21,630
BOUN	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
TGT	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
STB	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420
SIS	230	271	188	236	260	320	362	405	405	405	405	405	405	405	405	405	405	405	405	405	405
WS	1,118	1,307	918	1,200	1,399	1,620	1,889	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123
LNG	1,057	1,162	1,039	1,079	1,153	1,348	1,563	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828
PROP	0	0	0	0	0	0	120	381	381	381	381	381	381	381	381	381	381	381	381	381	381
SPOT	0	0	0	318	354	384	423	470	470	470	470	470	470	470	470	470	470	470	470	470	470
STEUB	0	0	0	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003	1,003
CDS	4,784	4,904	4,293	6,067	6,216	6,296	6,411	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562	6,562
ANE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESSO	0	0	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558	12,558
DGAS	838	1,000	662	837	967	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
DGASBOIL	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
TOTAL	72819.2	74791.7	76225.1	94656.6	96066.3	97542.4	99159.2	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9	100885.9
INTERRUPTIBLE	29,021	27,251	37,954	21,085	19,871	18,720	17,558	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470	16,470

G.2. Case 2 Sendout: Without ANE, Decrement of 16.7/day

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	28738	29269	24231	32492	32475	32479	32466	32466	32466	32466	32466	32466	32466	32466	32466	32466	32466	32466	32466	32466	32466
F2/F3	10121	10121	8388	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121
CD/NOREX	11648	12557	9682	15341	16292	17187	18097	18890	18890	18890	18890	18890	18890	18890	18890	18890	18890	18890	18890	18890	18890
BOUN	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735
TGT	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917
STB	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420
SIS	225	254	174	234	249	292	340	365	365	365	365	365	365	365	365	365	365	365	365	365	365
WS	1050	1229	888	1114	1302	1513	1759	1990	1990	1990	1990	1990	1990	1990	1990	1990	1990	1990	1990	1990	1990
LNG	1064	1166	1047	1091	1165	1357	1572	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844
PROP	0	0	0	0	0	0	110	355	355	355	355	355	355	355	355	355	355	355	355	355	355
SPOT	0	0	0	172	188	240	303	344	344	344	344	344	344	344	344	344	344	344	344	344	344
STEUB	0	0	0	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003
CDS	4549	4649	4067	5216	5300	5378	5456	5612	5612	5612	5612	5612	5612	5612	5612	5612	5612	5612	5612	5612	5612
ANE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESSO	0	0	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558
DGAS	811	977	660	828	961	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
DGASBOIL	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205
TOTAL	68481	70497	71970	90444	91889	93402	95060	96823	96823	96823	96823	96823	96823	96823	96823	96823	96823	96823	96823	96823	96823
INTERRUPTIBLE	33,321	31,512	42,189	25,129	23,865	22,685	21,507	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347	20,347

G.5. Case 4b Sendout: without ANE, Summer Baseload Decrement of 16.7/day

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	28963	29473	24538	32470	32452	32451	32446	32277	32277	32277	32277	32277	32277	32277	32277	32277	32277	32277	32277	32277	32277
F2/F3	10121	10121	8406	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121
CD/NOREX	13130	13949	11170	16949	17747	18461	19128	19923	19923	19923	19923	19923	19923	19923	19923	19923	19923	19923	19923	19923	19923
BOUN	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735
TGT	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917
STB	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420
SIS	281	316	231	292	346	374	423	491	491	491	491	491	491	491	491	491	491	491	491	491	491
WS	1341	1572	1088	1524	1754	1986	2208	2438	2438	2438	2438	2438	2438	2438	2438	2438	2438	2438	2438	2438	2438
LNG	1231	1551	1096	1269	1473	1659	1954	2248	2248	2248	2248	2248	2248	2248	2248	2248	2248	2248	2248	2248	2248
PROP	0	0	0	0	46	275	561	880	880	880	880	880	880	880	880	880	880	880	880	880	880
SPOT	0	0	0	172	213	256	324	361	361	361	361	361	361	361	361	361	361	361	361	361	361
STEUB	0	0	0	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003
CDS	4663	4763	4226	5334	5424	5506	5581	5771	5771	5771	5771	5771	5771	5771	5771	5771	5771	5771	5771	5771	5771
ANE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESSO	0	0	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558
DGAS	1000	1000	905	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
DGASBOIL	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205
TOTAL	71005	73020	74493	92967	94412	95925	97582	99347	99347	99347	99347	99347	99347	99347	99347	99347	99347	99347	99347	99347	99347

G.4. Case 4a Sendout: without ANE, Winter Baseload Decrement of 16.7/day

Supply	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
F1	31741	32222	25711	32557	32549	32557	32544	32538	32538	32538	32538	32538	32538	32538	32538	32538	32538	32538	32538	32538	32538
F2/F3	10121	10121	10103	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121	10121
CD/NOREX	12005	12957	9878	17882	18747	19637	20518	21306	21306	21306	21306	21306	21306	21306	21306	21306	21306	21306	21306	21306	21306
BOUN	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735	3735
TGT	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917	1917
STB	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420	3420
SIS	225	254	174	234	249	292	340	365	365	365	365	365	365	365	365	365	365	365	365	365	365
WS	1050	1229	888	1114	1302	1513	1761	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
LNG	1064	1166	1047	1091	1165	1357	1572	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844	1844
PROP	0	0	0	0	0	0	110	355	355	355	355	355	355	355	355	355	355	355	355	355	355
SPOT	0	0	0	371	408	443	486	539	539	539	539	539	539	539	539	539	539	539	539	539	539
STEUB	0	0	0	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003	1003
CDS	4766	4872	4253	5986	6128	6222	6347	6495	6495	6495	6495	6495	6495	6495	6495	6495	6495	6495	6495	6495	6495
ANE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESSO	0	0	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558	12558
DGAS	811	977	660	828	961	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
DGASBOIL	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205	1205
TOTAL	72058	74073	75546	94020	95465	96978	98635	100399	100399	100399	100399	100399	100399	100399	100399	100399	100399	100399	100399	100399	100399

Table 1: Annual Mass Electric Marginal Energy and Distribution Costs (1991$) 16-Apr-91

	Marginal Energy Costs		Externalities $/kWh		Secondary Distribution Costs ($/kW)			
	Peak ($/kWh) [1]	Off-Peak ($/kWh) [2]	MECo Levelized [3]	Annual [4]	Oct 1990 Filing [5]	March 1991 Workpapers [6]	Corrected 12/89 [7]	MECo Mix Commercial [8]
1991	0.04928	0.03678	0.02624	0.050	38.03	55.06	95.43	28.89
1992	0.04928	0.03678	0.02624	0.050	38.03	55.06	95.43	28.89
1993	0.04928	0.03678	0.02624	0.050	38.03	55.06	95.43	28.89
1994	0.04928	0.03678	0.02624	0.050	38.03	55.06	95.43	28.89
1995	0.04928	0.03678	0.02624	0.050	38.03	55.06	95.43	28.89
1996	0.04928	0.03678	0.02624	0.050	38.03	55.06	95.43	28.89
1997	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
1998	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
1999	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2000	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2001	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2002	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2003	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2004	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2005	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2006	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2007	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2008	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2009	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2010	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
2011	0.04928	0.03678	0.02624	0.012	38.03	55.06	95.43	28.89
PV over lifetime								
12	$0.44	$0.33	$0.24	$0.30	$341	$493	$855	$259
15	$0.52	$0.39	$0.28	$0.32	$400	$579	$1,003	$304
20	$0.62	$0.47	$0.33	$0.35	$482	$697	$1,209	$366

MECo Real Discount Rate 4.81%

Notes:
[1], [2], [3], [4]: October, 1990 C&LM Filing, Book II, Witness Hicks, Exhibit H-1.
[5], [8]: October, 1990 C&LM Filing, Witness Hicks, Exhibit H-4, p. 17.
[7]: March, 1991 distribution capacity cost, DR BGC-88.
[8]: See Chernick and Espenhorst, 1989.
[9]: MECo assumes a 47/53 primary/secondary split for commercial customers, and omits secondary costs for 47% of Mass Electric commercial customers.

Table 2: NEP Demand Charge Benefit, Percent of Maximum Impact on Peak

16-Apr-91

	NEP Demand Charge	Commercial Chilling		Residential Applications					
				Domestic Hot Water & Clothes Dryer		Range		Space Heat	
	Charge	% on-peak	Savings	% on-peak	Savings	% on-peak	Savings	% on-peak	Savings
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Jan	$15.53	0%	$0.00	100%	$15.53	100%	$15.53	100%	$15.53
Feb	$15.53	0%	$0.00	100%	$15.53	100%	$15.53	100%	$15.53
Mar	$2.52	0%	$0.00	100%	$2.52	100%	$2.52	100%	$2.52
Apr	$2.52	50%	$1.26	100%	$2.52	100%	$2.52	50%	$1.26
May	$2.52	100%	$2.52	100%	$2.52	100%	$2.52	0%	$0.00
Jun	$15.53	100%	$15.53	100%	$15.53	100%	$15.53	0%	$0.00
Jul	$15.53	100%	$15.53	100%	$15.53	100%	$15.53	0%	$0.00
Aug	$15.53	100%	$15.53	100%	$15.53	100%	$15.53	0%	$0.00
Sep	$15.53	100%	$15.53	100%	$15.53	100%	$15.53	0%	$0.00
Oct	$2.52	50%	$1.26	100%	$2.52	100%	$2.52	50%	$1.26
Nov	$2.52	0%	$0.00	100%	$2.52	100%	$2.52	100%	$2.52
Dec	$15.53	0%	$0.00	100%	$15.53	100%	$15.53	100%	$15.53
Lifetime (years)			20		12		15		20
Annual Total	$121.31		$67.16		$121.31		$121.31		$54.15
PV Multiplier [10]			12.67		8.96		10.51		12.67
NEP Demand Charge Savings [11]			$851		$1,087		$1,275		$686

Source: October 1990 C&LM filing, Witness Hicks, Exhibit H-4.

Notes:
- [1]: Exhibit H-4, p4.
- [2]: Exhibit H-4, p4. Commercial chilling is valued using the monthly savings for storage cooling.
- [3]: [1] * [2].
- [3], [5], [7] , [9]: Monthly on-peak reduction times monthly NEP Demand Charge.
- [4]: Exhibit H-4, p 30.
- [5]: [1] * [4].
- [6]: Exhibit H-4, p 30. Assumes ranges and dryers effect monthly peak similarly.
- [4], [6]: Monthly peak impact of residential programs includes new water heaters and we include clothes dryers and ranges.
- [7]: [1] * [6].
- [8]: Exhibit H-4, p 53. We calculate heating season savings only.
- [9]: [1] * [8].
- [10]: Present value of $1, at 4.81% over lifetime.
- [11]: Annual Total * [10].

Table 3: Marginal Energy and Capacity Loss Data 16-Apr-91

			Commercial Chilling	Residential Applications: Domestic Hot Water	Clothes Dryer	Range	Space Heat
			[a]	[b]	[c]	[d]	[e]
Lifetime [1]			20	12	12	15	20
Capacity Loss Multipliers							
Secondary voltage	Current	[2]	1.267	1.256	1.256	1.256	1.245
	MECo projection	[3]	1.183	1.203	1.203	1.193	1.183
MECo Mixed	Current	[4]	1.247				
	Projected	[5]	1.175				
On-Peak Energy Loss Multipliers							
Secondary voltage	Current	[6]	1.19	1.184	1.184	1.184	1.178
	MECo projection	[7]	1.123	1.14	1.14	1.131	1.123
MECo Mixed	Current	[8]	1.178				
	Projected	[9]	1.118				
Off-Peak Energy Loss Multipliers							
Secondary voltage	Current	[10]	1.129	1.125	1.125	1.125	1.121
	MECo projection	[11]	1.071	1.086	1.086	1.079	1.071
MECo Mixed	Current	[12]	1.118				
	Projected	[13]	1.068				
% Energy On-Peak [14]			70%	40%	48%	57%	40%

Notes: [1]: Lifetimes for b and e are from Exhibit H-5, Appliance Efficiency and Energy Crafted Home non-electric heat, respectively. No estimates are given for a, c, and d. See Chernick and Espenhorst, 1989. The California Energy Commission, "Cal. Energy Demand", 6/89, p. 2-26, uses 11.2 for water heaters, 12.3 for clothes dryers, 19.1 for ranges, and 20-22.4 for space heat. MECo gives chiller lifetimes of 10, 15, and 20 years for Design 2000, 15 years for Energy Initiative. Lifetime given as "site-specific" in H-5.

[2], [4], [6], [8], [10], [12]: Current energy and capacity losses are from 5/1/90 NEES C&LM Annual Report, p 28, table II-B-2. We assume that the losses for commercial and industrial users are reported at the primary/secondary mix, and that the losses for the residential customers are reported at the secondary voltage level. Losses for chilling are summer only. Losses for space heat are winter only. All other end-uses are the simple average of the summer and winter losses.

[3], [5], [7], [9], [11], [13]: Mass Electric, 10/90, Book II, exhibit H-5. a. Energy Initiative, 20 year conservation measures. b., c. See 1. Projected losses correspond to measure lifetime. Ranges and clothes dryers are not in the Mass Electric filing.

[14]: Mass Electric, 10/90, Book II, Exhibit H-4. Chilling, p 2. Hot water, p 28. Space heat, p 34. Range and dryer from Chernick and Espenhorst, 1989.

Table 4: DPU Value for Environmental Externalities, DPU 89-239. 16-Apr-91

Power Plants

Emission	Value $/lb [3]	All Gas CC [1] Quantity lbs/MMBTU [4]	Value $/MMBTU [5]	All Oil CC [2] Quantity lbs/MMBTU [6]	Value $/MMBTU [7]	Months on gas/oil [8]	
NOx	3.25	0.036	0.117	0.1	0.33		
SOx	0.75	0.001	0.001	0.315	0.24		
VOCs	2.65	0.033	0.087	0.017	0.05		
TSP	2.00	0.001	0.002	0.001	0.00		
CO	0.43	0.021	0.009	0.018	0.01		
CO2	0.011	117	1.287	163	1.79	10	7
CH4	0.11	0.002	0.000	0.002	0.00	2	5
N2O	1.98	0	0.000		0.00		
Sum [9]			1.50		2.41	1.65	1.88
Heat rate [10]			8,500		8,700	8,533	8,583
c/kWh [11]			1.28		2.10	1.41	1.61

NOTES:

[1], [2], [4], [6], [10]: Emission factors for Manchester Street. N2O dropped.
[3]: Monetized externalities adopted by the MDPU, 89-239.
[5]: [3] * [4].
[7]: [3] * [6].
[8]: All gas and all oil CC adder weighted by hypothetical gas/oil usages.
[9]: Sum of $/MMBTU adder for each emission.
[10]: Gas/oil CC weighted by number of months on each fuel.
[11]: [10] * [9] / 10,000.

Table 5: Boston Gas Avoided Costs, nominal$/MMBTU 16-Apr-91

Direct Costs

	Heating Season		Baseload			
	Propor	Insul	Annual	Summer	Winter	Water Heating
1991	4.93	4.34	3.28	2.77	3.80	3.69
1992	5.29	4.68	3.52	2.96	4.10	3.96
1993	7.07	6.43	4.70	3.11	6.73	5.29
1994	7.26	6.59	4.95	3.42	6.87	5.53
1995	7.81	7.11	5.24	3.62	7.30	5.89
1996	8.18	7.45	5.50	3.85	7.60	6.17
1997	8.95	7.78	5.78	4.08	7.91	6.57
1998	9.76	8.54	6.19	4.33	8.55	7.08
1999	9.71	8.43	6.50	4.85	8.56	7.30
2000	10.09	8.76	6.82	5.13	8.91	7.64
2001	10.73	9.34	7.22	5.40	9.47	8.10
2002	11.10	9.65	7.54	5.70	9.81	8.43
2003	11.50	9.98	7.86	5.98	10.17	8.77
2004	12.23	10.65	8.29	6.27	10.80	9.28
2005	12.69	11.03	8.65	6.57	11.22	9.66
2006	13.22	11.48	9.02	6.86	11.68	10.07
2007	13.93	12.11	9.46	7.17	12.30	10.58
2008	14.50	12.60	9.87	7.49	12.81	11.03
2009	15.12	13.14	10.31	7.83	13.37	11.51
2010	15.89	13.82	10.80	8.18	14.04	12.07
2011	16.59	14.43	11.28	8.55	14.65	12.61
Measure Lifetime						
12	$54.49	$48.32	$36.29	$26.62	$48.27	$40.84
15	$64.68	$57.17	$43.23	$31.88	$57.28	$48.59
20	$78.80	$69.45	$52.84	$39.18	$69.76	$59.33

Source: Boston Gas, Report on Integrated Resource Management, 9/21/90, Appendix D.
Gas avoided costs calculated with NEEI-90 fuel prices. See attached tables.

MECo Nominal Discount Rate 9.53%

Table 5A: DPU Value for Environmental Externalities, DPU 89-239. Chillers and Residential Applications

16-Apr-91

Emission factors by end-use technology, in lbs/MMBTU

Emission	Value $/lb	Engine Chiller		Absorption Chiller	Space Heat	Domestic Hot Water	Clothes Dryer	Range
	[1]	[2] high	[2.5] low	[3]	[4]	[5]	[6]	[7]
NOx	3.25	3.505	0.58	0.105	0.105	0.1155	0.055	0.065
SOx	0.75	0.0006	0	0.0006	0.0006	0.0006	0.0006	0.0006
VOCs	2.65	0.10	0.005	0.005	0.005	0.005	0.005	0.005
TSP	2.00	0.005	0.005	0.005	0.005	0.005	0.005	0.005
CO	0.43	0.18	0.18	0.02	0.02	0.02	0.02	0.02
CO2	0.011	110	110	110	110	110	110	110
CH4	0.11	1.23	0.003	0.003	0.003	0.003	0.003	0.003
N2O	1.98	0	0	0	0	0	0	0
Sum [8]		13.09	3.20	1.58	1.58	1.62	1.42	1.45
Lifetime [9]		20	20	20	20	12	12	15
PV Multiplier [10]		12.67	12.67	12.67	12.67	8.96	8.96	10.51
PV-Externalities [11]		$165.78	$40.48	$20.06	$20.06	$14.50	$12.73	$15.29

Notes: [1]: Massachusetts DPU, 89-239.

[2]: TecoGen NOx and CO emission data gathered by personal communications with TecoGen. All other emissions, except VOCs and CH4, are assumed to equal space heating emissions. Ranges reflect emissions for space heating, low end, and reciprocating engines (for pipeline compressors), high end.

[2.5]: Emissions controlled by catalytic converter. Additional cost is approximately $1,000.

[3], [4], [5], [6], [7]: NOx emissions include 0.005 lb/MMBTU for compressor emissions.

[3]: Absorption chiller emissions assumed equal to space heating emissions.

[4]: EPA, AP-42 4th edition, September, 1985, residential boiler emissions.

[5], [6], [7]: Emissions relative to space heating taken from Hittman, 1974.

[8]: $/lb adder * lb/MMBTU emission for each emission. Total $/MMBTU adder.

[9]: Lifetimes from Exhibit H-4.

[10]: PV of $1 over lifetime at 4.81% discount rate.

[11]: [8] * [10].

ATTACHMENT PLC-4

DETAILED COMPUTATION OF

RESIDENTIAL FUEL-SWITCHING COST-EFFECTIVENESS

We examine the system cost-effectiveness of fuel switching four residential end-uses: space heating, water heating, ranges, and dryers. We use MECo data, or data provided by MECo on discovery, as the baseline for measure characteristics. For space and water heating, we consider a range of usage, extending 30% above and below the baseline. Gas use is based on electric use and the relative efficiencies of the gas and electric units. These calculations are discussed below.

MECo's 1990 Load Forecast indicates 40-45% penetration of electric space heat in new homes.[18] Our analysis indicates that gas is cost-effective in new construction compared to both resistance and heat pump heating over a wide range of energy use. This is also true for existing homes.

MECo's load forecast does not separate heat pump energy and demand use from resistance heat. Thus, we use MECo's assumption that heat pumps use 70% of the energy of resistance heat. We also assume that the peak contribution by heat pumps is the same as for resistance heat. In fact, on very cold days, the heat pump may use more energy and demand than resistance; not only is the heat pump

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[18]MECo 1990 Load Forecast, Vol 2, pages 35-44 discuss several market failures. The most significant market failure, according to MECo, is the prevalence of speculative housing. While there is very little speculative housing being built currently, there are other manifestations of the split-incentive problem that a MECo program should address. Volume 1 of the 1988 Load Forecast provides additional information about the forces driving the penetration of electric heat. These include an increasing share of multifamily homes and an increasing penetration of heat pumps. These factors justify MECo intervention on behalf of installing gas.

operating in resistance mode, but fans are working, energy is lost through ducts, and the cool air blowing from the heating system may result in higher thermostat settings.

We consider both new and existing homes, and small, medium, and average uses for both new and existing homes. The medium use, existing home is the base case, about equal to MECo's average usage, and small and large uses are sensitivities 30% below and above the medium use case. New homes are assumed to use 20% less energy than the existing homes of the same size. Demand is also proportional.

We use MECo data for the Energy Crafted Home program, Exhibit H-4 page 36, for the pattern of demand use of an electrically heated home. We have omitted the peak savings from the non-heating months, May through September. We believe that the summer peak savings MECo attributes to space heat result from such factors as lighting savings, air conditioning savings, or other efficient appliances. These factors are separate from the space heating we are considering.

The MECo 1990 Load Forecast, page 51, provides an estimate of 7,200 kWh/year as average unsupplemented electric space heat use. This includes a mix of single- and multi-family homes, as well as resistance and heat pump systems. We increase this to 10,000 kWh/year for an existing, medium home heated with resistance heat. In DR BGC-18, MECo gives the average contribution to peak by residential space heat: 2.08 kW. We use this figure as the coincident peak kW demand for an existing, medium home with electric heat.

Electricity use for gas systems is taken from the MECo 1990 Load Forecast. We assign the energy to on- and off-peak rating periods using the 40/60 split MECo assumes for electric use. Gas use is based on the electric use and the efficiency of the gas equipment.[19]

Tables 1.1 - 1.3 present the three sizes of new homes. Energy and demand use are as follows:

	Coincident peak (kW)	Annual energy (kWh) Resistance	Heat Pump
Large home	2.16	10,400	7,280
Medium home	1.66	8,000	5,600
Small home	1.16	5,600	3,920

	Gas use (MMBTU)	
Efficiency:	Standard	High
Large home	44	39
Medium home	34	30
Small home	24	21

We assume a 20 year life for all systems. A more complex analysis that considered the life of separate components of a fossil system, flue, burner, boiler, may be justified on a site-specific basis. A large portion of the conversion investment may have a life in excess of 20 years.

Energy, externalities, and distribution costs are the 20-year present values from Table 1, Attachment PLC-3. Losses are MECo's

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[19]We calculate gas use as:

electricity use in kWh * .003413 BTU/kWh / efficiency of gas unit.

projected secondary losses for space heat. The gas cost is the proportional load shape from Table 5, Attachment PLC-3. Externalities are shown in Table 5A, Attachment PLC-3.

For new construction, the capital costs for the standard efficiency gas, resistance, and heat pump systems are from the 1990 MECo Load Forecast, pages 41-43. MECo indicates the cost for a resistance system is $4,150. A heat pump costs $5,663. A gas system costs $6,620. BGC analyses have found that the incremental cost of a 91% AFUE gas furnace, compared to the standard 80% AFUE is $500; thus, the cost of a high-efficiency system is $7,120.

We assume $50 in annual maintenance costs for all non-resistance heat systems. Heating systems generally require some annual checkup in order to maintain reliability and achieve manufacturer lifetime. We have seen a variety of annual O&M cost estimates, ranging from zero for some gas systems to $150/year for both condensing gas units and heat pumps.[20]

For existing houses, we draw on a variety of sources for capital costs. For homes with central air conditioning ductwork, CECARF estimates the cost to install a gas system is $1,700.[21] The cost for a high efficiency gas unit is $2,200. The cost to install a heat pump is $1,500. For homes without ductwork, we rely on VEIC

[20]VEIC data indicates zero maintenance for some gas systems. Several electric utilities offer or contemplate a $25-$50 rebate for annual central air and/or heat pump maintenance. The high estimate is from Heidell, et al, ACEEE, 1988 Proceeding, Volume 4, p 4.38-4.49.

[21]CECARF, "Oil, Gas, or...," 5/89.

data for conversion costs. We estimate the total cost to install a gas system in a house without ductwork to be $3,270. A high efficiency system is $3,770. We estimate the cost to install a heat pump is $2,600.

The small, new home, not surprisingly, is the case with the smallest net savings, but gas is still the fuel of economic choice.

We consider a variety of water heating applications. Average energy use for controlled and uncontrolled water heaters is from the 1990 MECo Load Forecast. Average contribution to peak for controlled units is from DR BGC-18. JUMP provides this data for uncontrolled units. The load forecast indicates higher energy use for controlled units, which must be larger and/or hotter to provide the same heat storage as uncontrolled units.

We have some additional reservations about the analysis of the controlled water heaters. The Final Report of the Narragansett Electric Company on the Customer Load Control Project, 5/27/88, indicates that when controlled units end the control period, the maximum demand is 30% higher than the maximum demand for an uncontrolled unit. This almost inevitably will have some detrimental effect on distribution equipment. This effect could be magnified by the clustering of control units. Water heaters are often returned to service over the course of an hour or more, to prevent the entire population returning to service at the same time. While this reduces the adverse effects (along with the benefits of control), it does not eliminate the effects. Water heater control programs probably should be given zero (or negative) credit for reducing distribution capacity. We have not modelled the control unit in this manner; fuel-switching is cost-effective even if the controlled water heater receives the full distribution credit.

One cost we do include is an estimate of the lifetime revenue requirement associated with the control equipment. We estimate that the cost to control a water heater is approximately $200. This includes estimates for the radio receiver and transmitter, wiring, and metering requirements. The revenue requirement associated with a primary distribution investment of $176/kw is $382. We estimate the cost of the control equipment is $448. For comparison, the capital cost per point of the MECo load-control program is about $500.

The capital cost estimates for gas units are from VEIC. The capital cost for the electric water heaters are from Wisconsin Energy Conservation Corporation.

Data on ranges and dryers are largely unchanged from our 12/89 report. MECo has not provided any information regarding peak or energy use beyond that in the Load Forecast and the JUMP report, and thus we have not changed these inputs. We use these two sources for measure characteristics. The cost of the measures is based on surveys of local appliance distributors such as Sears and Montgomery Ward.

The total societal cost to serve each technology is the sum of the capital cost plus the lifetime PV of the electric cost, the O&M cost, and the gas cost, if any. In each case we modelled, the gas system was less expensive than the competitive electric system.

Table 1.1: Residential Single-Family Space Heating for a New, Large Home. Page 1 16-Apr-91

			Fuel: Natural Gas		Electricity	
	Efficiency		80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)			0	0	2.16	2.16
Energy (kWh) (2)			183	183	10,400	7,280
Peak (a)			73	73	4,160	2,912
Off-peak (b)			110	110	6,240	4,368
Gas (MMBTU) (3)			44	39		
Lifetime (4)			20	20	20	20
II. Electricity Cost	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$1,755	$1,755
Distribution (6)	$697	1.183	$0	$0	$1,785	$1,785
Peak Energy (7)	$0.62	1.123	$51	$51	$2,916	$2,041
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$3,113	$2,179
Externalities (9)	$0.35	1.092	$69	$69	$3,929	$2,750
Total (10)			$175	$175	$13,498	$10,510
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$3,496	$3,074		
Externalities (12)	$20.06	1.043	$928	$816		
Total (13)			$4,425	$3,890		
IV. Equipment cost						
Capital (14)			$6,620	$7,120	$4,150	$5,663
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$7,253	$7,753	$4,150	$6,296
Grand Total (18)			$11,853	$11,818	$17,648	$16,807

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$11,853	$11,818	$17,648	$16,807
B. Net Savings from Standard Efficiency			$5,795	$4,954
C. Net Capital Cost of Standard Eff Gas			$2,470	$957
D. Net Operating Savings from Gas			$8,265	$5,277
E. Cost/Benefit Ratio			0.30	0.18
F. Net Savings from High Efficiency			$5,830	$4,988
G. Net Capital Cost of High Efficieny Gas			$2,970	$1,457
H. Net Operating Savings from Gas			$8,800	$5,812
I. Cost/Benefit Ratio			0.34	0.25

Notes:

[1]: No appreciable coincident peak assumed for gas units. Electric kW based on average contribution to peak, see medium existing house. Demand is scaled by energy use.
[2]: MECo 1988 Forecast: 1992 fossil auxiliary use, p 73; heat pump energy use is 70% of resista p 72. Energy use is 130% of medium. MECo assumes 40% peak energy use, Exhibit H
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: MECo 1988 Forecast, p60-62; gas high efficiency = gas standard + $500 (BGC testimony in DPU 90-320, Table 2, Exhibit 20.
[15]: Average O&M cost, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 1.2: Residential Single-Family Space Heating for a New, Medium Home. Page 1 16-Apr-91

			Fuel: Natural Gas		Electricity	
		Efficiency	80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)					1.66	1.66
Energy (kWh) (2)			183	183	8,000	5,600
Peak (a)			73	73	3,200	2,240
Off-peak (b)			110	110	4,800	3,360
Gas (MMBTU) (3)			34	30		
Lifetime (4)			20	20	20	20
II. Electricity Cost						
	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$1,350	$1,350
Distribution (6)	$697	1.183	$0	$0	$1,373	$1,373
Peak Energy (7)	$0.62	1.123	$51	$51	$2,243	$1,570
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$2,395	$1,676
Externalities (9)	$0.35	1.092	$69	$69	$3,022	$2,116
Total (10)			$175	$175	$10,383	$8,085
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$2,689	$2,364		
Externalities (12)	$20.06	1.043	$714	$628		
Total (13)			$3,404	$2,992		
IV. Equipment cost						
Capital (14)			$6,620	$7,120	$4,150	$5,663
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$7,253	$7,753	$4,150	$6,296
Grand Total (18)			$10,832	$10,921	$14,533	$14,381

Table 1.2: Residential Single-Family Space Heating for a New, Medium Home. Page 2 16-Apr-91

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$10,832	$10,921	$14,533	$14,381
B. Net Savings from Standard Efficiency			$3,701	$3,549
C. Net Capital Cost of Standard Eff Gas			$2,470	$957
D. Net Operating Savings from Gas			$6,171	$3,873
E. Cost/Benefit Ratio			0.40	0.25
F. Net Savings from High Efficiency			$3,612	$3,461
G. Net Capital Cost of High Eff Gas			$2,970	$1,457
H. Net Operating Savings from Gas			$6,582	$4,284
I. Cost/Benefit Ratio			0.45	0.34

Notes:

[1]: Demand is proportional to energy:demand for existing medium home.
[2]: Assumed base case resistance energy use for new homes: 8,000 kWh.
MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: MECo 1988 Forecast, p60-62; gas high efficiency = gas standard + $500 (BGC 90-320, 1990).
Capital cost for standard efficiency gas heat, resistance, and heat pumps.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - ([10] + [13] + [16]) for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - ([10] + [13] + [16]) for high efficiency gas.
[I]: [G] / [H].

Table 1.3: Residential Single-Family Space Heating for a New, Small Home. Page 1 16-Apr-91

			Fuel: Natural Gas		Electricity	
		Efficiency	80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)					1.16	1.16
Energy (kWh) (2)			183	183	5,600	3,920
Peak (a)			73	73	2,240	1,568
Off-peak (b)			110	110	3,360	2,352
Gas (MMBTU) (3)			24	21		
Lifetime (4)			20	20	20	20
II. Electricity Cost						
	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$945	$945
Distribution (6)	$697	1.183	$0	$0	$961	$961
Peak Energy (7)	$0.62	1.123	$51	$51	$1,570	$1,099
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$1,676	$1,173
Externalities (9)	$0.35	1.092	$69	$69	$2,116	$1,481
Total (10)			$175	$175	$7,268	$5,659
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$1,883	$1,655		
Externalities (12)	$20.06	1.043	$500	$439		
Total (13)			$2,383	$2,095		
IV. Equipment cost						
Capital (14)			$6,620	$7,120	$4,150	$5,663
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$7,253	$7,753	$4,150	$6,296
Grand Total (18)			$9,811	$10,023	$11,418	$11,956

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$9,811	$10,023	$11,418	$11,956
B. Net Savings from Standard Efficiency			$1,607	$2,145
C. Net Capital Cost of Standard Eff Gas			$2,470	$957
D. Net Operating Savings from Gas			$4,077	$2,468
E. Cost/Benefit Ratio			0.61	0.39
F. Net Savings from High Efficiency			$1,395	$1,933
G. Net Capital Cost of High Eff Gas			$2,970	$1,457
H. Net Operating Savings from Gas			$4,365	$2,756
I. Cost/Benefit Ratio			0.68	0.53

Notes:

[1]: Demand is proportional to energy:demand for existing medium home.
[2]: Small home assumed to use 70% of energy of large home.
MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: MECo 1988 Forecast, p60-62; gas high efficiency = gas standard + $500 (BGC, 1990).
Capital cost for standard efficiency gas heat, resistance, and heat pumps.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 2.1: Residential Single-Family Space Heating for an Existing, Large Home with Ductwork.

			Fuel: Natural Gas		Electricity	
	Efficiency		80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)			0	0	2.70	2.70
Energy (kWh) (2)			183	183	13,000	9,100
Peak (a)			73	73	5,200	3,640
Off-peak (b)			110	110	7,800	5,460
Gas (MMBTU) (3)			55	49		
Lifetime (4)			20	20	20	20
II. Electricity Cost						
	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$2,194	$2,194
Distribution (6)	$697	1.183	$0	$0	$2,231	$2,231
Peak Energy (7)	$0.62	1.123	$51	$51	$3,645	$2,551
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$3,891	$2,724
Externalities (9)	$0.35	1.092	$69	$69	$4,911	$3,438
Total (10)			$175	$175	$16,872	$13,138
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$4,370	$3,842		
Externalities (12)	$20.06	1.043	$1,160	$1,020		
Total (13)			$5,531	$4,862		
IV. Equipment cost						
Capital (14)			$1,700	$2,200	Assumed Base	$1,500
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$2,333	$2,833	$0	$2,133
Grand Total (18)			$8,039	$7,871	$16,872	$15,271

Table 2.1: Residential Single-Family Space Heating for an Existing, Large Home with Ductwork.

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$8,039	$7,871	$16,872	$15,271
B. Net Savings from Standard Efficiency			$8,833	$7,232
C. Net Capital Cost of Standard Eff Gas			$1,700	$200
D. Net Operating Savings from Gas			$10,533	$6,799
E. Cost/Benefit Ratio			0.16	0.03
F. Net Savings from High Efficiency			$9,002	$7,401
G. Net Capital Cost of High Efficieny Gas			$2,200	$700
H. Net Operating Savings from Gas			$11,202	$7,467
I. Cost/Benefit Ratio			0.20	0.09

Notes:

[1]: Demand is proportional to energy:demand for existing medium home.
[2]: Energy use is 130% of medium existing home; heat pump is 70% of resistance, p72. MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: CECARF, "Oil, Gas or...?," May 1989, p 17.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 2.2: Residential Single-Family Space Heating for an Existing, Medium Home with Ductwork.

		Fuel:	Natural Gas		Electricity	
		Efficiency	80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)					2.08	2.08
Energy (kWh) (2)			183	183	10,000	7,000
Peak (a)			73	73	4,000	2,800
Off-peak (b)			110	110	6,000	4,200
Gas (MMBTU) (3)			43	38		
Lifetime (4)			20	20	20	20
II. Electricity Cost	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$1,688	$1,688
Distribution (6)	$697	1.183	$0	$0	$1,716	$1,716
Peak Energy (7)	$0.62	1.123	$51	$51	$2,804	$1,963
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$2,993	$2,095
Externalities (9)	$0.35	1.092	$69	$69	$3,778	$2,645
Total (10)			$175	$175	$12,979	$10,106
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$3,362	$2,955		
Externalities (12)	$20.06	1.043	$893	$785		
Total (13)			$4,254	$3,740		
IV. Equipment cost						
Capital (14)			$1,700	$2,200	Assumed Base	$1,500
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$2,333	$2,833	$0	$2,133
Grand Total (18)			$6,763	$6,749	$12,979	$12,239

Table 2.2: Residential Single-Family Space Heating for an Existing, Medium Home with Ductwork.

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$6,763	$6,749	$12,979	$12,239
B. Net Savings from Standard Efficiency			$6,216	$5,476
C. Net Capital Cost of Standard Eff Gas			$1,700	$200
D. Net Operating Savings from Gas			$7,916	$5,043
E. Cost/Benefit Ratio			0.21	0.04
F. Net Savings from High Efficiency			$6,230	$5,491
G. Net Capital Cost of High Eff Gas			$2,200	$700
H. Net Operating Savings from Gas			$8,430	$5,557
I. Cost/Benefit Ratio			0.26	0.13

Notes:

[1]: Demand is MECo's estimate of average contribution to peak, DR BGC-18.
[2]: Assumed base case energy use for existing resistance electric heated home.
MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: CECARF, "Oil, Gas or...?," May, 1989, p 17.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 2.3: Residential Single-Family Space Heating for an Existing, Small Home with Ductwork.

			Fuel: Natural Gas		Electricity	
		Efficiency	80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)					1.46	1.46
Energy (kWh) (2)			183	183	7,000	4,900
Peak (a)			73	73	2,800	1,960
Off-peak (b)			110	110	4,200	2,940
Gas (MMBTU) (3)			30	26		
Lifetime (4)			20	20	20	20
II. Electricity Cost						
	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$1,181	$1,181
Distribution (6)	$697	1.183	$0	$0	$1,201	$1,201
Peak Energy (7)	$0.62	1.123	$51	$51	$1,963	$1,374
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$2,095	$1,467
Externalities (9)	$0.35	1.092	$69	$69	$2,645	$1,851
Total (10)			$175	$175	$9,085	$7,074
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$2,353	$2,069		
Externalities (12)	$20.06	1.043	$625	$549		
Total (13)			$2,978	$2,618		
IV. Equipment cost						
Capital (14)			$1,700	$2,200	Assumed Base	$1,500
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$2,333	$2,833	$0	$2,133
Grand Total (18)			$5,487	$5,627	$9,085	$9,208

Table 2.3: Residential Single-Family Space Heating for an Existing, Small Home with Ductwork.

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$5,487	$5,627	$9,085	$9,208
B. Net Savings from Standard Efficiency			$3,598	$3,721
C. Net Capital Cost of Standard Eff Gas			$1,700	$200
D. Net Operating Savings from Gas			$5,298	$3,288
E. Cost/Benefit Ratio			0.32	0.06
F. Net Savings from High Efficiency			$3,458	$3,581
G. Net Capital Cost of High Eff Gas			$2,200	$700
H. Net Operating Savings from Gas			$5,658	$3,648
I. Cost/Benefit Ratio			0.39	0.19

Notes:

[1]: Demand is proportional to energy/demand for medium home.
[2]: Energy use is 70% of medium existing home; heat pump is 70% of resistance, p72.
MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: CECARF, "Oil, Gas, or...?," May, 1989, p 17.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 3.1: Residential Single-Family Space Heating for an Existing, Large Home without Ductwork.

			Fuel: Natural Gas		Electricity	
	Efficiency		80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)			0	0	2.70	2.70
Energy (kWh) (2)			183	183	13,000	9,100
Peak (a)			73	73	5,200	3,640
Off-peak (b)			110	110	7,800	5,460
Gas (MMBTU) (3)			55	49		
Lifetime (4)			20	20	20	20
II. Electricity Cost						
	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$2,194	$2,194
Distribution (6)	$697	1.183	$0	$0	$2,231	$2,231
Peak Energy (7)	$0.62	1.123	$51	$51	$3,645	$2,551
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$3,891	$2,724
Externalities (9)	$0.35	1.092	$69	$69	$4,911	$3,438
Total (10)			$175	$175	$16,872	$13,138
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$4,370	$3,842		
Externalities (12)	$20.06	1.043	$1,160	$1,020		
Total (13)			$5,531	$4,862		
IV. Equipment cost						
Capital (14)			$3,270	$3,770	Assumed Base	$2,635
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$3,903	$4,403	$0	$3,268
Grand Total (18)			$9,609	$9,441	$16,872	$16,406

Table 3.1: Residential Single-Family Space Heating for an Existing, Large Home without Ductwork.

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$9,609	$9,441	$16,872	$16,406
B. Net Savings from Standard Efficiency			$7,263	$6,797
C. Net Capital Cost of Standard Eff Gas			$3,270	$635
D. Net Operating Savings from Gas			$10,533	$6,799
E. Cost/Benefit Ratio			0.31	0.09
F. Net Savings from High Efficiency			$7,432	$6,966
G. Net Capital Cost of High Efficieny Gas			$3,770	$1,135
H. Net Operating Savings from Gas			$11,202	$7,467
I. Cost/Benefit Ratio			0.34	0.15

Notes:

[1]: Demand is proportional to energy:demand for existing medium home.
[2]: Energy use is 130% of medium existing home; heat pump is 70% of resistance, p72.
MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: VEIC unpublished study, provided as part of DR MECo-60.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 3.2: Residential Single-Family Space Heating for an Existing, Medium Home without Ductwork.

			Fuel: Natural Gas		Electricity	
		Efficiency	80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)					2.08	2.08
Energy (kWh) (2)			183	183	10,000	7,000
Peak (a)			73	73	4,000	2,800
Off-peak (b)			110	110	6,000	4,200
Gas (MMBTU) (3)			43	38		
Lifetime (4)			20	20	20	20
II. Electricity Cost	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$1,688	$1,688
Distribution (6)	$697	1.183	$0	$0	$1,716	$1,716
Peak Energy (7)	$0.62	1.123	$51	$51	$2,804	$1,963
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$2,993	$2,095
Externalities (9)	$0.35	1.092	$69	$69	$3,778	$2,645
Total (10)			$175	$175	$12,979	$10,106
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$3,362	$2,955		
Externalities (12)	$20.06	1.043	$893	$785		
Total (13)			$4,254	$3,740		
IV. Equipment cost						
Capital (14)			$3,270	$3,770	Assumed Base	$2,635
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$3,903	$4,403	$0	$3,268
Grand Total (18)			$8,333	$8,319	$12,979	$13,374

Table 3.2: Residential Single-Family Space Heating for an Existing, Medium Home without Ductwork.

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$8,333	$8,319	$12,979	$13,374
B. Net Savings from Standard Efficiency			$4,646	$5,041
C. Net Capital Cost of Standard Eff Gas			$3,270	$635
D. Net Operating Savings from Gas			$7,916	$5,043
E. Cost/Benefit Ratio			0.41	0.13
F. Net Savings from High Efficiency			$4,660	$5,056
G. Net Capital Cost of High Eff Gas			$3,770	$1,135
H. Net Operating Savings from Gas			$8,430	$5,557
I. Cost/Benefit Ratio			0.45	0.20

Notes:

[1]: Demand is proportional to energy:demand for existing medium home.
[2]: Assumed base case energy use for existing resistance electric heated home.
MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: VEIC unpublished study, provided as part of DR MECo-60.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 3.3: Residential Single-Family Space Heating for an Existing, Small Home without Ductwork.

			Fuel: Natural Gas		Electricity	
		Efficiency	80% Standard	91% High	Resistance	Heat Pump
I. Energy Use						
Demand (kW) (1)					1.46	1.46
Energy (kWh) (2)			183	183	7,000	4,900
Peak (a)			73	73	2,800	1,960
Off-peak (b)			110	110	4,200	2,940
Gas (MMBTU) (3)			30	26		
Lifetime (4)			20	20	20	20
II. Electricity Cost	Unit Cost	Losses Projected				
NEP Charge (5)	$686	1.183	$0	$0	$1,181	$1,181
Distribution (6)	$697	1.183	$0	$0	$1,201	$1,201
Peak Energy (7)	$0.62	1.123	$51	$51	$1,963	$1,374
Off-Peak Energy (8)	$0.47	1.071	$55	$55	$2,095	$1,467
Externalities (9)	$0.35	1.092	$69	$69	$2,645	$1,851
Total (10)			$175	$175	$9,085	$7,074
III. Gas Cost						
PV $/MMBTU (11)	$78.80	Included	$2,353	$2,069		
Externalities (12)	$20.06	1.043	$625	$549		
Total (13)			$2,978	$2,618		
IV. Equipment cost						
Capital (14)			$3,270	$3,770	Assumed Base	$2,635
Annual O&M (15)			$50	$50		$50
PV of O&M (16)			$633	$633		$633
Total (17)			$3,903	$4,403	$0	$3,268
Grand Total (18)			$7,057	$7,197	$9,085	$10,343

Table 3.3: Residential Single-Family Space Heating for an Existing, Small Home without Ductwork.

	Fuel: Natural Gas		Electricity	
Efficiency	80% Standard	91% High	Resistance	Heat Pump
V. Summary				
A. Total Cost	$7,057	$7,197	$9,085	$10,343
B. Net Savings from Standard Efficiency			$2,028	$3,286
C. Net Capital Cost of Standard Eff Gas			$3,270	$635
D. Net Operating Savings from Gas			$5,298	$3,288
E. Cost/Benefit Ratio			0.62	0.19
F. Net Savings from High Efficiency			$1,888	$3,146
G. Net Capital Cost of High Eff Gas			$3,770	$1,135
H. Net Operating Savings from Gas			$5,658	$3,648
I. Cost/Benefit Ratio			0.67	0.31

Notes:

[1]: Demand is proportional to energy/demand for large home and energy use for small home.
[2]: Energy use is 70% of medium existing home; heat pump is 70% of resistance, p72.
MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: VEIC unpublished study, provided as part of DR MECo-60.
[15]: Typical O&M costs, see text.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

			Fuel: Natural Gas		Electricity	
		AFUE	65%	85%	94%	94%
			Free-	Zone	Uncontrolled	Controlled
I. Energy Use			Standing	Boiler		
Coincident Demand (kW) (1)			0	0	2.21	0.52
Energy (kWh) (2)			0	0	4,618	6,338
Peak (a)			0	0	1,847	1,847
Off-peak (b)			0	0	2,771	2,771
Gas (MMBTU) (3)			23	17		
Lifetime (4)			12	12	12	12
II. Electricity Cost						
	Unit Cost	Losses Projected				
NEP Charge (5)	$1,087	1.183	$0	$0	$2,841	$669
Distribution (6)	$493	1.183	$0	$0	$1,290	$303
Peak Energy (7)	$0.44	1.123	$0	$0	$916	$916
Off-Peak Energy (8)	$0.33	1.071	$0	$0	$978	$978
Externalities (9)	$0.00	1.092	$0	$0	$0	$0
Total (10)			$0	$0	$6,025	$2,866
III. Gas Cost						
PV $/MMBTU (11)	$40.84	Included	$931	$712		
Externalities (12)	$14.50	1.043	$345	$264		
Total (13)			$1,275	$975		
IV. Equipment cost						
Capital (14)			$800	$700	$385	$833
Annual O&M (15)			$25	$25	0	$10
PV of O&M (16)			$224	$224	$0	$90
Total (17)			$1,024	$924	$385	$922
Grand Total (18)			$2,299	$1,899	$6,410	$3,788

	Fuel: Natural Gas			Electricity	
	AFUE	65% Free-Standing	85% Zone Boiler	Uncontrolled	Controlled
V. Summary					
A. Total Cost		$2,299	$1,899	$6,410	$3,788
B. Net Savings from Free-Standing Gas Unit				$4,110	$1,488
C. Net Capital Cost of Free-Standing Gas Unit				$415	($33)
D. Net Operating Savings from Gas				$4,525	$1,366
E. Cost/Benefit Ratio				0.09	-0.02
F. Net Savings from Zone Boiler				$4,510	$1,888
G. Net Capital Cost of Zone Boiler				$315	($133)
H. Net Operating Savings from Gas				$4,825	$1,666
I. Cost/Benefit Ratio				0.07	-0.08

Notes:

[1], [2]: No kW or kWh attributed to DHW systems.
[1], [2]: Medium usage controlled and uncontrolled DHW are base cases. High usage is 130% of medium usage. No change in on/off peak energy for controlled unit.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: Gas cost from VEIC, CV Collaborative Filing, 2/90. Electric costs from personal communications with Wisconsin Energy Conservation Corporation.
[15]: Typical O&M costs.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

			Fuel: Natural Gas		Electricity	
		AFUE	65% Free-Standing	85% Zone Boiler	94% Uncontrolled	94% Controlled
I. Energy Use						
Demand (kW) (1)			0	0	1.70	0.40
Energy (kWh) (2)			0	0	3,552	4,875
Peak (a)			0	0	1,421	1,421
Off-peak (b)			0	0	2,131	2,131
Gas (MMBTU) (3)			18	13		
Lifetime (4)			12	12	12	12
II. Electricity Cost	Unit Cost	Losses Projected				
NEP Charge (5)	$1,087	1.183	$0	$0	$2,186	$514
Distribution (6)	$493	1.183	$0	$0	$992	$233
Peak Energy (7)	$0.44	1.123	$0	$0	$704	$704
Off-Peak Energy (8)	$0.33	1.071	$0	$0	$752	$752
Externalities (9)	$0.00	1.092	$0	$0	$0	$0
Total (10)			$0	$0	$4,634	$2,204
III. Gas Cost						
PV $/MMBTU (11)	$40.84	Included	$716	$548		
Externalities (12)	$14.50	1.043	$265	$203		
Total (13)			$981	$750		
IV. Equipment cost						
Capital (14)			$800	$700	$385	$833
Annual O&M (15)			$25	$25	0	$10
PV of O&M (16)			$224	$224	$0	$90
Total (17)			$1,024	$924	$385	$922
Grand Total (18)			$2,005	$1,674	$5,019	$3,126

	Fuel: Natural Gas		Electricity	
AFUE	65%	85%	94%	94%
V. Summary	Free-Standing	Zone Boiler	Uncontrolled	Controlled
A. Total Cost	$2,005	$1,674	$5,019	$3,126
B. Net Savings from Free-Standing Gas Unit			$3,014	$1,121
C. Net Capital Cost of Free-Standing Gas Unit			$415	($33)
D. Net Operating Savings from Gas			$3,429	$1,089
E. Cost/Benefit Ratio			0.12	-0.03
F. Net Savings from Zone Boiler			$3,345	$1,452
G. Net Capital Cost of Zone Boiler			$315	($133)
H. Net Operating Savings from Gas			$3,660	$1,320
I. Cost/Benefit Ratio			0.09	-0.10

Notes:

[1], [2]: No kW or kWh attributed to DHW systems.
[1], [2]: DR BGC-18 for peak kW of controlled DHW. JUMP data provides uncontrolled DHW peak. MECo assumes 40% peak energy use, Exhibit H-4. This does not vary if unit is con
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: Gas cost from VEIC, CV Collaborative Filing, 2/90. Electric costs from personal communications with Wisconsin Energy Conservation Corporation.
[15]: Typical O&M costs.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

Table 4.3: Residential Water Heater: Low Usage

	Unit Cost	Losses Projected	Fuel: Natural Gas 65% Free-Standing	85% Zone Boiler	Electricity 94%	94% Controlled
		AFUE	65% Free-Standing	85% Zone Boiler	94%	94% Controlled
I. Energy Use						
Demand (kW) (1)			0	0	1.19	0.28
Energy (kWh) (2)			0	0	2,486	2,486
Peak (a)			0	0	995	995
Off-peak (b)			0	0	1,492	1,492
Gas (MMBTU) (3)			12	9		
Lifetime (4)			12	12	12	12
II. Electricity Cost						
NEP Charge (5)	$1,087	1.183	$0	$0	$1,530	$360
Distribution (6)	$493	1.183	$0	$0	$694	$163
Peak Energy (7)	$0.44	1.123	$0	$0	$493	$493
Off-Peak Energy (8)	$0.33	1.071	$0	$0	$526	$526
Externalities (9)	$0.00	1.092	$0	$0	$0	$0
Total (10)			$0	$0	$3,244	$1,543
III. Gas Cost						
PV $/MMBTU (11)	$40.84	Included	$501	$383		
Externalities (12)	$14.50	1.043	$186	$142		
Total (13)			$687	$525		
IV. Equipment cost						
Capital (14)			$800	$700	$385	$833
Annual O&M (15)			$25	$25	$0	$10
PV of O&M (16)			$224	$224	$0	$90
Total (17)			$1,024	$924	$385	$922
Grand Total (18)			$1,711	$1,449	$3,629	$2,465

	Fuel: Natural Gas		Electricity	
AFUE	65% Free-Standing	85% Zone Boiler	94%	94%
V. Summary				
A. Total Cost	$1,711	$1,449	$3,629	$2,465
B. Net Savings from Free-Standing Gas Unit			$1,918	$754
C. Net Capital Cost of Free-Standing Gas Unit			$415	($33)
D. Net Operating Savings from Gas			$2,333	$722
E. Cost/Benefit Ratio			0.18	-0.05
F. Net Savings from Zone Boiler			$2,180	$1,016
G. Net Capital Cost of Zone Boiler			$315	($133)
H. Net Operating Savings from Gas			$2,495	$883
I. Cost/Benefit Ratio			0.13	-0.15

Notes:

[1], [2]: No kW or kWh attributed to DHW systems.
[1], [2]: Medium usage controlled and uncontrolled DHW are base cases. Low usage is 70% of medium usage. No change in on/off peak energy for controlled unit. MECo assumes 40% peak energy use, Exhibit H-4.
[3]: Gas use is proportional to resistance heating; resistance kWh * .003413/efficiency.
[4]: Witness Hicks, Exhibit H-5.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: Gas equipment cost from VEIC, CV Collaborative Filing, 2/90. Electric equipment costs from personal communications with Wisconsin Energy Conservation Corporation.
[14]: Control cost is $385 for tank plus $448 as total control equipment cost. See text.
[15]: Typical O&M costs.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].
[F]: [A] for electric option - [A] for high efficiency gas unit.
[G]: [14] for high efficiency gas - [14] for electric option.
[H]: [10] for electric option - {[10] + [13] + [16]} for high efficiency gas.
[I]: [G] / [H].

	Unit Cost	Losses Projected	Fuel: Natural Gas	Electricity	
I. Energy Use					
Demand (kW) (1)			0	0.12	
Energy (kWh) (2)			0	431	
Peak (a)			0	243	
Off-peak (b)			0	188	
Gas (MMBTU) (3)			2.89		
Lifetime (4)			15	15	
II. Electricity Cost					
NEP Charge (5)	$1,275	1.193	$0	$183	
Distribution (6)	$579	1.193	$0	$83	
Peak Energy (7)	$0.52	1.131	$0	$142	
Off-Peak Energy (8)	$0.39	1.079	$0	$78	
Externalities (9)	$0.32	1.108	$0	$153	
Total (10)			$0	$639	
III. Gas Cost					
PV $/MMBTU (11)	$43.23	Included	$125		Annual Base
Externalities (12)	$15.29	1.043	$46		
Total (13)			$171		
IV. Equipment cost					
Capital (14)			$500	$400	
Annual O&M (15)			$10	0	
PV of O&M (16)			$105	$0	
Total (17)			$605	$400	
Grand Total (18)			$776	$1,039	

	Fuel: Natural Gas	Electricity
V. Summary		
A. Total Cost	$776	$1,039
B. Net Savings from Gas Unit		$263
C. Net Capital Cost of Gas Unit		$100
D. Net Operating Savings from Gas		$363
E. Cost/Benefit Ratio		0.28

Notes:

[1], [2], [3], [4]: Chernick and Espenhorst, 1989.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: Chernick and Espenhorst, 1989.
[15]: Estimate of annual tune-up cost.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].

	Unit Cost	Losses Projected	Fuel: Natural Gas	Electricity	
I. Energy Use					
Demand (kW) (1)			0	0.13	
Energy (kWh) (2)			0	823	
Peak (a)			0	426	
Off-peak (b)			0	395	
Gas (MMBTU) (3)			3.04		
Lifetime (4)			12	12	
II. Electricity Cost					
NEP Charge (5)	$1,087	1.203	$0	$170	
Distribution (6)	$493	1.203	$0	$77	
Peak Energy (7)	$0.44	1.14	$0	$214	
Off-Peak Energy (8)	$0.33	1.086	$0	$141	
Externalities (9)	$0.30	1.111	$0	$276	
Total (10)			$0	$879	
III. Gas Cost					
PV $/MMBTU (11)	$36.29	Included	$110		Annual Base
Externalities (12)	$12.73	1.043	$40		
Total (13)			$151		
IV. Equipment cost					
Capital (14)			$550	$350	
Annual O&M (15)			$10	0	
PV of O&M (16)			$90	$0	
Total (17)			$640	$350	
Grand Total (18)			$790	$1,229	

	Fuel: Natural Gas	Electricity
V. Summary		
A. Total Cost	$790	$1,229
B. Net Savings from Gas Unit		$438
C. Net Capital Cost of Gas Unit		$200
D. Net Operating Savings from Gas		$638
E. Cost/Benefit Ratio		0.31

Notes:

[1], [2], [3], [4]: Chernick and Espenhorst, 1989.
[5]: NEP Demand Charge from Table 2. Winter kW [1] * [5] * capacity losses.
[6]: Secondary distribution from Table 1. Winter kW [1] * [6] * capacity losses.
[7], [8], [9]: From Table 1. $/kWh times kWh times losses.
[10]: [5] + [6] + [7] + [8] + [9].
[11]: Table 5.
[12]: Table 5A.
[13]: [11] + [12].
[14]: Chernick and Espenhorst, 1989.
[15]: Estimate of annual tune-up cost.
[16]: [15] * present value multiplier. PV $1 over 20 years at MECo discount rate.
[17]: [14] + [16].
[18], [A]: [10] + [13] + [17].
[B]: [A] for electric option - [A] for standard efficiency gas unit.
[C]: [14] for standard efficiency gas - [14] for electric option.
[D]: [10] for electric option - {[10] + [13] + [16]} for standard gas.
[E]: [C] / [D].

ATTACHMENT PLC-5

Detailed Computation of
Fuel-Switching Cost-Effectiveness
for Commercial Chilling

Page one of the analysis for each size of chiller shows the coincident peak kW, on- and off-peak kWh, and gas use, if any, of each appliance. The utility avoided costs, discussed in PLC-3, are also shown. These values are used to calculate the societal cost to serve each end-use. Data on commercial chilling peak and energy use is from Xenergy's report to the Rhode Island Fuel Switching Task Force and MECo sources, particularly the 1990 C&LM Management Accounting filing.

Page two of the analysis shows the capital and annual operation and maintenance cost of each chiller. We show the total cost of each option and the net savings of using gas directly at the end-use. We also show the capital cost of the gas equipment and the lifetime present value of the operating savings of the gas appliance compared to the electric options.

Page three shows the Xenergy chilling data. It also adjusts the Xenergy data with MECo assumptions regarding chiller contribution to coincident peak and chiller energy use.

The cost-benefit ratio is the capital cost premia of the gas appliance divided by the operating savings. The ratio is from the social cost perspective, and calculated according to the MECo methodology.[9] With this approach a positive value less than one

[9]MECo divides the incremental capital cost of the more efficient appliance by the PV of the operating savings over the life of the measure. The 1990 Load Forecast, Vol I, pp. 27-29 and 5/90 C&LM Annual Report, pp. 57-62 provide discussions of the method.

indicates a cost-effective option. A negative figure could indicate either a cost-effective, if the net savings is positive, or non-cost-effective option, if the net savings is negative. A figure greater than one indicates a non-cost-effective choice.

This analysis does not consider other costs, such as program administration costs or hook-up costs.

Tables 6A through 6E provide the analysis of commercial chilling applications. We estimate the societal cost to serve electric- and gas-fired chillers with sizes of 5, 20, 50, 125, and 250 tons of different configurations. We consider gas-fired absorption chiller for all five sizes, and engine chiller for 125 and 250 tons chilling applications. On the electric side, we look at efficient packaged units, air- and water-source heat pumps, air- and water-cooled reciprocating, and high efficiency centrifugal units with and without variable speed drive (VSD). We also consider gas-fired desiccant assistance to an existing chiller and partial and full ice-storage options.

This analysis is appropriate for either new construction or rehabilitation/renovation when a chiller is being replaced. With some modifications, it could be used to determine cost-effectiveness of the early-retirement of an operating chiller.[10] The analysis includes energy use, capital cost, and lifetime

[10]The most important parameter to adjust is the cost and life of the electric unit. The kW demand, energy use, annual operating cost of the existing equipment, and remaining life as well as cost and similar operating data for a replacement electric unit would all have to be considered.

operating cost. This analysis indicates fuel-switching is cost-effective across a wide range of chiller sizes.

1. Data and sources

a. Electric and gas use

For each chiller size, Xenergy provides kW/ton and COP. We calculate summer maximum kW demand, coincident peak kW demand, peak and off-peak energy use, gas use if applicable, and the externalities of serving chiller load. We also calculate capital costs and lifetime PV O&M costs. As discussed earlier the analysis calculates net savings and cost/benefit ratios.

Page three of the chiller analysis for each size chiller shows Xenergy's estimates of kW/ton chiller demand.[11] We calculate summer coincident demand and energy use with two MECo inputs.[12] First, MECo assumes an 80% coincidence factor for commercial chilling. Thus, the maximum kW demand is kW/ton times tons and the summer coincident demand is this result times the 80% coincidence factor. Second, MECo estimates that, on average, non-storage chillers

[11]Xenergy's estimates are from a draft report to the Rhode Island Fuel switching Task Force (FSTF). MECo's affiliate, Narragansett Electric, is a party to the FSTF. Additionally, MECo refers to a draft of the study in response to BGC-118.

[12]Both assumptions are taken from June 1990 C&LM Management Accounting, Measurement, and Rate Plan, page 8. MECo presents a different calculation for the coincident summer kW for chillers with VSD, but the explanation is obtuse, and we use the 80% coincidence factor.

operate for 1,000 hours per year. Energy use in kWh is summer kW times 1,000.

We have several estimates for splitting the total energy use to on- and off-peak. Xenergy assumes 66% of the energy use is on-peak and 34% off-peak. MECo assumes new HVAC equipment will operate on-peak 70% of the hours of operation, and retrofit HVAC will operate on-peak for 75% of the hours of operation. Throughout this analysis, we use the 70/30 split as a mid-range estimate.

MECo provides different load shapes for the NEPCo demand charge for storage cooling and other HVAC. The HVAC savings shape reflects a combination of such factors as proper sizing of units, more efficient fans, and possibly heating effects. To focus this analysis on chilling, we use the storage cooling load shape to consider cooling benefits only.

Added gas use, in MMBTU, is based on the relative efficiency of the gas and electric units and the total energy use of the electric chiller. We calculate gas use as:

COP(electric) / COP(gas) * kWh(electric) * .003413 MMBTU/kWh.

The electric unit used to estimate gas use is the electric unit immediately adjacent to the gas units. The gas use is not very sensitive to which unit is chosen, as there is a near-linear relationship between COP and kWh.

b. Measure Life

Xenergy assumes a 20 year life for HVAC. MECo assumes HVAC measure lives of 10, 15, 20, and 30 years for Design 2000. MECo assumes 15-year non-storage cooling measures and 20 year storage cooling retrofit measures for Energy Initiative. We have chosen 20 years as a mid-estimate.

c. Capital and operation and maintenance costs

For both capital and O&M costs, we use Xenergy's mid-range costs. The capital costs include purchase of the unit, installation, and in the case of the gas units, a fan coil or small air handling unit. Xenergy states costs in $/ton, and we restate the costs in dollars.

We include cooling tower costs for all gas-fired units and the following electric units: centrifugal chillers, water-cooled reciprocating chillers, and water-source heat pumps.[13] Xenergy provides cooling tower tonnage requirements, as well as cooling tower costs.[14] In some places, however, Xenergy uses inconsistent configurations of cooling towers for electric chilling and comparable gas chilling.[15] For consistency, we use the estimates Xenergy provides for complete systems, where available.

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[13]Xenergy Revised Draft Final Report to the Rhode Island Fuel Switching Task Force, page 5-8.

[14]Xenergy FSTF, Table 5-7 and 5-10 respectively.

[15]See examples in Appendices F and H.

We assume the O&M costs remain constant in real terms over the life of the chiller. We calculate the PV of the lifetime O&M as the annual O&M times the PV of $1 at 4.81% per year over the life of the equipment.

2. Calculations

a. Electric avoided costs from PLC-3

Peak and off-peak energy costs and externalities are from Table 1 of attachment PLC-3, and are for the PV of the equipment life. Losses for externalities are the on- and off-peak losses weighted by the on- and off-peak kWh use for each technology. The value of the energy is the rating period kWh use times the avoided energy cost times losses. Externalities are valued at total kWh use times the externality adder times the weighted losses, where losses are weighted by kWh in each rating period. Total energy is the sum of on-peak, off-peak energy, and externalities.[16]

The NEPCo demand charge is from Table 2 of Attachment PLC-3 and the marginal distribution cost is from Table 1, Attachment PLC-3. Both are present valued over 20 years. Capacity losses are from Table 3, Attachment PLC-3. The value of the capacity, both the NEPCo demand charge and distribution, is the seasonal maximum kW reduction times the appropriate capacity cost times losses.

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[16]The analysis for each HVAC size is on two pages. Page A, lines 6, 7, and 8 provide the energy costs and externalities. Energy losses are shown immediately to the right of the appropriate costs. The user selects the losses.

Total electric cost is the sum of the avoidable energy, externalities, and capacity costs, all valued at secondary voltage. This is our estimate of the societal cost to serve the electric load.

b. Gas avoided costs

We value gas use for commercial chilling as summer baseload for 20 year measure life for the gas avoided costs in Table 5, Attachment PLC-3. Losses are included in the avoided costs, but must be added to externalities.[17] Externalities are from Table 5A, Attachment PLC-3. Thus, total gas cost is gas use times the summer baseload gas cost plus gas use times externalities times losses.

3. Cost-benefit analysis

The total societal cost to serve each technology is the sum of the capital cost plus the lifetime PV of the electric cost, the O&M cost, and the gas cost, if any. All gas systems are cost-effective alternatives to electric chillers. In the case of storage options, the negative cost-benefit ratio is due to both the lower capital cost of the gas equipment and the significant lifetime operating saving.3

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[17]Since most losses are unaccounted-for gas associated with winter sales, this treatment overstates summer gas costs.

Table 1: Electricity Costs and Added Gas Costs 5 Ton Chiller Systems Page 1 16-Apr-91

I. Peak and Electricity Use

Demand			Gas Absorption	Efficient Electric (Packaged)	Electric Air Source Heat Pump	Electric Water Source Heat Pump	Sources
Summer kW [1]			1	4.6	4.92	4.4	See page 3.
Energy							
Peak Energy (kWh) [2]			700	3,220	3,444	3,080	MECo
Off-peak Energy [3]			300	1,380	1,476	1,320	MECo
Total [4]			1,000	4,600	4,920	4,400	See page 3.
Measure life [5]	20						
II. Electric Costs	Unit Cost Projected	Loss Multiplier Secondary					Losses: Table 3.
PV Energy Costs ($/kWh)							Energy costs: Table 1
Peak Energy [6]	$0.62	1.123	$491	$2,257	$2,414	$2,159	
Off-peak Energy [7]	$0.47	1.071	$150	$688	$736	$659	
MECo Externalities [8]	$0.35	1.107	$383	$1,763	$1,885	$1,686	Externalities: Table 1
Total Energy			$1,024	$4,708	$5,036	$4,504	With Externalities
PV $/kW NEP Demand Charge [9]	$851	1.183	$1,006	$4,629	$4,951	$4,428	Table 2.
PV $/kW Distribution [10]	$697	1.183	$825	$3,795	$4,059	$3,630	Distribution cost: March 1991 DR BGC-88
Total Electric Avoided Costs [11]			$2,855	$13,132	$14,045	$12,561	
III. Gas Costs							
Gas Use MMBTU [12]			94				See page 3.
PV Summer $/MMBTU [13]	$39.18	Included	$3,678				Table 5.
Externalities [14]	$20.06	1.043	$1,964				Table 5A.
Total Gas Costs [15]			$5,643				[13] + [14]

Notes:

[1], [4]: Xenergy report for Rhode Island Fuel Switching Task Force. See page 3.

[2], [3]: Total energy use is from Xenergy report. Exhibit H-4 indicates 70% on-peak for new construction, 75% for retrofit HVAC, and Xenergy assumed 66% on-peak. This analysis uses 70% for all HVAC.

[5]: 20 years used as a typical endpoint. See Table 3, note 1 and text.

[6], [7], [8], [10]: Energy, externality, and distribution costs are from Table 1. Loss multiplier is from Table 3. Energy cost is rating period energy use times PV of rating period energy cost times rating period loss multiplier.

[8]: Losses are weighted by on-peak and off-peak energy use. Externality cost is PV of externalites times loss multiplier times total energy use.

[9]: NEP Demand Charge savings from Table 2. Total NEPCo demand cost is summer kW times capacity value times capacity loss multiplier.

[10]: Distribution savings from Table 1. Total distribution cost, to secondary, is summer kW times PV of 3/91 distribution, to secondary, cost times capacity loss multiplier.

[11]: Total Energy + [9] + [10].

[12]: Gas use based on 1,000 hours of use and relative efficiency of gas and electric units.

[13]: Gas avoided costs for chilling from Table 5. Avoided costs include losses.

[14]: Externalities from Table 5A. BGC loss factor from 9/21/90 Report on IRM.

[15]: Total gas cost: [12] * [13] + [12] * [14] * loss factor.

	Gas Absorption	Efficient Electric (Packaged)	Electric Air Source Heat Pump	Electric Water Source Heat Pump
IV. Equipment Costs				
A. Capital Cost	$7,625	$4,100	$4,900	$3,200
B. Annual O&M Cost	$250	$300	$300	$300
C. PV O&M Costs	$3,166	$3,800	$3,800	$3,800
D. Total Equipment Cost	$10,791	$7,900	$8,700	$7,000
V. TOTALS				
E. Total Cost	$19,289	$21,032	$22,745	$19,561
F. Net Savings from Gas		$1,743	$3,456	$272
G. Net Capital Cost of Gas		$3,525	$2,725	$4,425
H. Net Operating Savings from Gas		$5,268	$6,181	$4,697
I. Cost/Benefit Ratio		0.67	0.44	0.94

Notes:
[A], [B]: From Xenergy Report to the Rhode Island Fuel Switching Task Force, Tables 5-7, 5-8.
[C]: Annual O&M, [B] times present value of $1 over measure lifetime disounted at MECo's 4.81% real discount rate.
[D]: [A] + [C].
[E]: [D] + [11] + [15]
[F]: Total cost of electric option - total cost of gas chiller, [D-electric] - [D-gas].
[G]: Capital cost of gas - capital cost of electric, [A-gas] - [A-electric].
[H]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-gas] - [15-gas] - [B-gas].
[I]: [G] / [H].

chiller_size: 5

Chiller size (Tons): 5

coinc_fact 0.80

Fuel type:	Gas absorption	Electric Efficient packaged	Electric Air-source heat pump	Electric Water-source heat pump
[1]: Capital	$7,625	$4,100	$4,900	$3,200
[2]: O&M/yr	$250	$300	$300	$300
[3]: kW/T	0.25	1.15	1.23	1.10
[4]: COP	0.51	3.05	2.85	3.20
[5]: kW coincident demand	1.00	4.60	4.92	4.40
[6]: Total kWh	1,000	4,600	4,920	4,400
[7]: kWh on-peak	700	3,220	3,444	3,080
[8]: kWh off-peak	300	1,380	1,476	1,320
[9]: MMBtu gas	94	--	--	--

Notes:

[1], [2]: Xenergy (1990), Tables 5-7, 5-8, 5-9 and 5-10, midrange and 2/91 update.

[1]: Xenergy does not include cooling tower costs in 5 ton absorption chiller or in the water-source heat pump.

[3], [4]: Xenergy (1990), Tables 3-1, 3-2 and 2/91 update.

[5]: [3] x T for unit x .80. The .80 coincidence factor is from MECO 1990 C&LM Accounting Plan, 6/8/90, p.8.

[6]: [5] x 1000. 1,000 hours of use from Ibid.

[7]: 70% of total, from exh. H-4, 10/90 MECo DSM filing.

[8]: 30% of total, from Ibid.

[9]: [4]electric/[4]gas x [6] efficient electric x .003413.

Table 2: Electricity Costs and Added Gas Costs — 20 Ton Chiller Systems — Page 1 — 16-Apr-91

I. Peak and Electricity Use			Gas LiBr Absorption (Yazaki)	Efficient Electric (Packaged)	Electric Air Source Heat Pump	Electric Water Source Heat Pump	Electric Air-cooled Reciprocating Chiller	Sources
Demand								
Summer kW [1]			0.48	18.4	19.68	17.6	17.76	See page 3.
Energy								
Peak Energy (kWh) [2]			336	12,880	13,776	12,320	12,432	MECo
Off-peak Energy [3]			144	5,520	5,904	5,280	5,328	MECo
Total [4]			480	18,400	19,680	17,600	17,760	See page 3.
Measure life [5]	20							
II. Electric Costs	Unit Cost	Losses Projected Secondary						Losses: Table 3.
PV Direct Energy Costs ($/kWh)								Energy: Table 1
Peak energy [6]	$0.62	1.123	$236	$9,028	$9,656	$8,635	$8,714	
Off-peak Energy [7]	$0.47	1.071	$72	$2,754	$2,946	$2,634	$2,658	
MECo Externalities [8]	$0.35	1.107	$184	$7,051	$7,541	$6,744	$6,806	Table 1
Total Energy			$491	$18,833	$20,143	$18,014	$18,178	With Externalities
PV $/kW NEP Demand Charge [9]	$851	1.183	$483	$18,515	$19,803	$17,710	$17,871	Table 2.
PV $/kW Distribution [10]	$697	1.183	$396	$15,180	$16,236	$14,520	$14,652	Distribution cost: March 1991 DR BGC-
Total Electric Avoided Costs [11]			$1,370	$52,528	$56,182	$50,244	$50,701	
III. Gas Costs								
Summer Base MMBTU [12]			177					See page 3.
PV $/MMBTU [13]	$39.18	Included	$6,948					Table 5.
Externalities [14]	$20.06	1.043	$3,711					Table 5A.
Total Gas Costs [15]			$10,658					[13] + [14]

Notes:

[1], [4]: Xenergy report for Rhode Island Fuel Switching Task Force. See page 3.

[2], [3]: Total energy use is from Xenergy report. Exhibit H-4 indicates 70% on-peak for new construction, 75% for retrofit HVAC, and Xenergy assumed 66% on-peak. This analysis uses 70% for all HVAC.

[5]: 20 years used as a typical endpoint. See Table 3, note 1 and text.

[6], [7], [8], [10]: Energy, externality, and distribution costs are from Table 1. Loss multiplier is from Table 3. Energy cost is rating period energy use times PV of rating period energy cost times rating period loss multiplier.

[8]: Losses are weighted by on-peak and off-peak energy use. Externality cost is PV of externalites times loss multiplier times total energy use.

[9]: NEP Demand Charge savings from Table 2. Total NEPCo demand cost is summer kW times capacity value times capacity loss multiplier.

[10]: Distribution savings from Table 1. Total distribution cost, to secondary, is summer kW times PV of 3/91 distribution, to secondary, cost times capacity loss multiplier.

[11]: Total Energy + [9] + [10].

[12]: Gas use based on 1,000 hours of use and relative efficiency of gas and electric units.

[13]: Gas avoided costs for chilling from Table 5. Avoided costs include losses.

[14]: Externalities from Table 5A. BGC loss factor from 9/21/90 Report on IRM.

[15]: Total gas cost: [12] * [13] + [12] * [14] * loss factor.

Table 2: Electricity Costs and Added Gas Costs 20 Ton Chiller Systems Page 2

	Gas LiBr Absorption (a)	Efficient Electric (Packaged) (b)	Electric Air Source Heat Pump (c)	Electric Water Source Heat Pump (d)	Electric Air-cooled Reciprocating Chiller (e)
III. Equipment Costs					
A. Capital Cost	$35,088	$16,400	$19,600	$12,800	$24,496
B. O&M Costs	$500	$300	$300	$300	$400
C. PV O&M Costs	$6,333	$3,800	$3,800	$3,800	$5,066
D. Total Equipment Cost	$41,421	$20,200	$23,400	$16,600	$29,562
V. TOTALS					
E. Total Cost	$53,450	$72,727	$79,582	$66,844	$80,263
F. Net Savings from Gas		$19,278	$26,132	$13,394	$26,813
G. Net Capital Cost of Gas		$18,688	$15,488	$22,288	$10,592
H. Net Operating Savings from Gas		$37,966	$41,620	$35,682	$37,405
I. Cost/Benefit Ratio		0.49	0.37	0.62	0.28

Notes: [A], [B]: From Xenergy Report to the Rhode Island Fuel Switching Task Force, Tables 5-7, 5-8.
[C]: Annual O&M, [B] times present value of $1 over measure lifetime discounted at MECo's 4.81% real discount rate.
[D]: [A] + [C].
[E]: [D] + [11] + [15]
[F]: Total cost of electric option - total cost of gas chiller, [D-electric] - [D-gas].
[G]: Capital cost of gas - capital cost of electric, [A-gas] - [A-electric].
[H]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-gas] - [15-gas] - [B-gas].
[I]: [G] / [H].

Table 2: Comparison of Gas and Electric Chillers PLC-5

Chiller size (Tons): 20

Fuel type:	Gas LiBr absorption (Yazaki)	Electric Efficient packaged	Electric Air-source heat pump	Electric Water-source heat pump	Electric air-cooled reciprocating chiller
[1]: Capital	$35,088	$16,400	$19,600	$12,800	$24,496
[2]: O&M/yr	$500	$300	$300	$300	$400
[3]: kW/T	0.03	1.15	1.23	1.10	1.11
[4]: COP	1.08	3.05	2.85	3.20	3.2
[5]: kW coincident demand	0.48	18.40	19.68	17.60	17.76
[6]: Total kWh	480	18,400	19,680	17,600	17,760
[7]: kWh on-peak	336	12,880	13,776	12,320	12,432
[8]: kWh off-peak	144	5,520	5,904	5,280	5,328
[9]: MMBtu gas	177	--	--	--	--

Notes:

[1]: Xenergy omits cooling tower costs from water-source heat pump.

[1], [2]: Xenergy (1990), Tables 5-7, 5-8, 5-9 and 5-10, midrange and 2/91 update.

[3], [4]: Xenergy (1990), Tables 3-1, 3-2 and 2/91 update.

[5]: [3] x T for unit x .80. The .80 coincidence factor is from MECO 1990 C&LM Accounting Plan, 6/8/90, p.8.

[6]: [5] x 1000, 1,000 hours of use from Ibid.

[7]: 70% of total, from exh. H-4, 10/90 MECo DSM filing.

[8]: 30% of total.

[9]: [4]electric/[4]gas x [6] efficient electric x .003413.

I. Peak and Electricity Use			Gas LiBr Absorption (Yazaki)	High-Efficiency (Packaged)	Reciprocating Chiller Water Cooled	Reciprocating Chiller Air Cooled	Sources
Demand							
Summer kW [1]			1.2	46	32	44	See page 3.
Energy							
Peak Energy (kWh) [2]			840	32,200	22,400	30,800	Peak & off-peak: MECo
Off-peak Energy [3]			360	13,800	9,600	13,200	
Total [4]			1,200	46,000	32,000	44,000	See page 3.
Measure life [5]	20						
II. Electric Costs	Unit Cost	Losses Projected Secondary					
PV Direct Energy Costs ($/kWh)							Energy cost and
Peak energy [6]	$0.62	1.123	$589	$22,570	$15,701	$21,588	externalities: Table 1.
Off-peak Energy [7]	$0.47	1.071	$180	$6,885	$4,790	$6,586	Losses: Table 3.
MECo Externalities [8]	$0.35	1.107	$460	$17,627	$12,263	$16,861	
Total Energy			$1,228	$47,082	$32,753	$45,035	
PV $/kW NEP Demand Charge [9]	$851	1.183	$1,208	$46,289	$32,201	$44,276	NEP Demand Savings: Table 2.
PV $/kW Distribution [10]	$697	1.183	$990	$37,949	$26,399	$36,299	Distribution cost: March 1991 DR BGC-88
Total Electric Avoided Costs [11]			$3,426	$131,320	$91,353	$125,610	Losses: Table 3.
III. Gas Costs							
Summer Base MMBTU [12]			443				See page 3.
PV $/MMBTU [13]	$39.18	Included	$17,369				Gas cost: Table 5.
Externalities [14]	$20.06	1.043	$9,277				Gas externalities: Table 5A.
Total Gas Costs [15]			$26,646				

Notes:

[1], [4]: Xenergy report for Rhode Island Fuel Switching Task Force. See page 3.

[2], [3]: Total energy use is from Xenergy report. Exhibit H-4 indicates 70% on-peak for new construction, 75% for retrofit HVAC, and Xenergy assumed 66% on-peak. This analysis uses 70% for all HVAC.

[5]: 20 years used as a typical endpoint. See Table 3, note 1 and text.

[6], [7], [8], [10]: Energy, externality, and distribution costs are from Table 1. Loss multiplier is from Table 3. Energy cost is rating period energy use times PV of rating period energy cost times rating period loss multiplier.

[8]: Losses are weighted by on-peak and off-peak energy use. Externality cost is PV of externalites times loss multiplier times total energy use.

[9]: NEP Demand Charge savings from Table 2. Total NEPCo demand cost is summer kW times capacity value times capacity loss multiplier.

[10]: Distribution savings from Table 1. Total distribution cost, to secondary, is summer kW times PV of 3/91 distribution, to secondary, cost times capacity loss multiplier.

[11]: Total Energy + [9] + [10].

[12]: Gas use based on 1,000 hours of use and relative efficiency of gas and electric units.

[13]: Gas avoided costs for chilling from Table 5. Avoided costs include losses.

[14]: Externalities from Table 5A. BGC loss factor from 9/21/90 Report on IRM.

[15]: Total gas cost: [12] * [13] + [12] * [14] * loss factor.

Table 3: Electricity Costs and Added Gas Costs 50 Ton Chiller Systems Page 2

	Gas LiBr Absorption (Yazaki)	Electric High-Efficiency (Packaged)	Electric Reciprocating Chiller Water Cooled	Electric Reciprocating Chiller Air Cooled
III. Equipment Costs				
A. Capital Cost	$73,930	$41,000	$44,740	$28,250
B. O&M Costs	$500	$300	$575	$575
C. PV O&M Costs	$6,333	$3,800	$7,283	$7,283
D. Total Equipment Cost	$80,263	$44,800	$52,023	$35,533
V. TOTALS				
E. Total Cost	$110,335	$176,119	$143,375	$161,143
F. Net Savings from Gas		$65,785	$33,041	$50,808
G. Net Capital Cost of Gas		$32,930	$29,190	$45,680
H. Net Operating Savings from Gas		$98,715	$62,231	$96,488
I. Cost/Benefit Ratio		0.33	0.47	0.47

Notes: [A], [B]: From Xenergy Report to the Rhode Island Fuel Switching Task Force, Tables 5-7, 5-8.
[C]: Annual O&M, [B] times present value of $1 over measure lifetime disounted at MECo's 4.81% real discount rate.
[D]: [A] + [C].
[E]: [D] + [11] + [15]
[F]: Total cost of electric option - total cost of gas chiller, [D-electric] - [D-gas].
[G]: Capital cost of gas - capital cost of electric, [A-gas] - [A-electric].
[H]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-gas] - [15-gas] - [B-gas].
[I]: [G] / [H].

Table 3: Comparison of Gas and Electric Chillers PLC-5

Chiller size (Tons): 50

Fuel type:	Gas LiBr absorption (Yazaki)	Electric high-efficiency packaged	Electric reciprocating chiller water-cooled	Electric reciprocating chiller air-cooled
[1]: Capital	$73,930	$41,000	$44,740	$28,250
[2]: O&M/yr	$500	$300	$575	$575
[3]: kW/T	0.03	1.15	0.80	1.10
[4]: COP	1.08	3.05	4.40	3.20
[5]: kW coincident demand	1.2	46.0	32.0	44.0
[6]: Total kWh	1,200	46,000	32,000	44,000
[7]: kWh on-peak	840	32,200	22,400	30,800
[8]: kWh off-peak	360	13,800	9,600	13,200
[9]: MMBtu gas	443	--	--	--

Notes:

[1], [2]: Xenergy (1990), Tables 5-7, 5-8, 5-9 and 5-10, midrange and 2/91 update.

[2]: Cooling tower costs /T from 40T; packaged from 20T.

[3], [4]: Xenergy (1990), Tables 3-1, 3-2.

[5]: [3] x T for unit x .80. The .80 coincidence factor is from MECO 1990 C&LM Accounting Plan, 6/8/90, p.8.

[6]: [5] x 1000, 1,000 hours of use from ibid.

[7]: 70% of total, from exh. H-4, 10/90 MECo DSM filing.

[8]: 30% of total.

[9]: [4]electric/[4]gas x [6] packaged electric x .003413.

Table 4: Electricity Costs and Added Gas Costs   125 Ton Chiller Systems Page 1   16-Apr-91

Demand	Unit Cost	Losses	Gas LiBr Absorption (Yazaki)	Gas TecoChill Engine Chiller	Electric Reciprocating Chiller Water Cooled	Electric Centrifugal High-Efficiency	Electric Centrifugal High-Eff VSD	Sources
Summer kW [1]			3	2	80	55	45	Xenergy
Energy								
Peak Energy (kWh) [2]			2,100	1,400	56,000	38,500	31,500	MECo
Off-peak Energy [3]			900	600	24,000	16,500	13,500	MECo
Total [4]			3,000	2,000	80,000	55,000	45,000	See page 3.
Measure life [5]	20							
II. Electric Costs	Unit Cost	Losses Projected Secondary						Losses: Table 3.
PV Direct Energy Costs ($/kWh)								Table 1.
Peak energy [6]	$0.62	1.123	$1,472	$981	$39,252	$26,986	$22,079	
Off-peak Energy [7]	$0.47	1.071	$449	$299	$11,974	$8,232	$6,735	
MECo Externalities [8]	$0.35	1.107	$1,150	$766	$30,656	$21,076	$17,244	
Total Energy			$3,071	$2,047	$81,882	$56,294	$46,059	
PV $/kW NEP Demand Charge [9]	$851	1.183	$3,019	$2,013	$80,502	$55,345	$45,282	Table 2.
PV $/kW Distribution [10]	$697	1.183	$2,475	$1,650	$65,998	$45,374	$37,124	Distribution cost: March 1991 DR BGC-
Total Electric Avoided Costs [11]			$8,564	$5,710	$228,382	$157,013	$128,465	
III. Gas Costs								
Summer Base MMBTU [12]			1,112	751				See page 3.
PV Gas Use $/MMBTU [13]	$39.18	Included	$43,578	$29,415				Table 5
Externalities Absorption [14]	$20.06	1.043	$23,275					Table 5A
Engine [15]	$40.48	1.043		$31,701				Table 5A
Total Gas Costs [16]			$66,853	$61,116				Gas cost + externalities

Notes:

[1], [4]: Xenergy report for Rhode Island Fuel Switching Task Force. See page 3.

[2], [3]: Total energy use is from Xenergy report. Exhibit H-4 indicates 70% on-peak for new construction, 75% for retrofit HVAC, and Xenergy assumed 66% on-peak. This analysis uses 70% for all HVAC.

[5]: 20 years used as a typical endpoint. See Table 3, note 1 and text.

[6], [7], [8], [10]: Energy, externality, and distribution costs are from Table 1. Loss multiplier is from Table 3. Energy cost is rating period energy use times PV of rating period energy cost times rating period loss multiplier.

[8]: Losses are weighted by on-peak and off-peak energy use. Externality cost is PV of externalites times loss multiplier times total energy use.

[9]: NEP Demand Charge savings from Table 2. Total NEPCo demand cost is summer kW times capacity value times capacity loss multiplier.

[10]: Distribution savings from Table 1. Total distribution cost, to secondary, is summer kW times

	Gas LiBr Absorption (Yazaki)	Gas TecoChill Engine Chiller	Electric Reciprocating Chiller Water Cooled	Electric Centrifugal High-Efficiency	Electric Centrifugal High-Eff VSD
III. Equipment Costs					
A. Capital Cost	$181,925	$169,225	$64,225	$118,863	$149,863
B. Annual O&M Cost	$500	$1,800	$575	$700	$700
C. PV O&M Costs	$6,333	$22,798	$7,283	$8,866	$8,866
D. Total Equipment Cost	$188,258	$192,023	$71,508	$127,729	$158,729
IV. TOTALS					
E. Total Cost	$263,675	$258,848	$299,890	$284,741	$287,194
F. Net Savings from Yazaki			$36,215	$21,066	$23,519
G. Net Capital Cost of Yazaki			$117,700	$63,062	$32,062
H. Net Operating Savings from Yazaki			$153,915	$84,128	$55,581
I. Cost/Benefit Ratio			0.76	0.75	0.58
J. Net Savings from TecoChill			$41,041	$25,893	$28,345
K. Net Capital Cost of TecoChill			$105,000	$50,362	$19,362
L. Net Operating Savings from TecoChill			$146,041	$76,255	$47,707
M. Cost/Benefit Ratio			0.72	0.66	0.41

Notes:
[A], [B]: From Xenergy Report to the Rhode Island Fuel Switching Task Force, Tables 5-7, 5-8.
[C]: Annual O&M, [B] times present value of $1 over measure lifetime discounted at NECo's 4.81% real discount rate.
[D]: [A] + [C].
[E]: [D] + [11] + [16]
[F]: Total cost of electric option - total cost of gas chiller, [D-electric] - [D-gas].
[G]: Capital cost of gas - capital cost of electric, [A-gas] - [A-electric].
[H]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-absorption] - [16-absorption] - [B-absorption].
[I]: [G] / [H].
[J]: Total cost of electric option - total cost of engine chiller, [E-electric]- [E-engine].
[K]: Capital cost of gas - capital cost of engine chiller, [A-electric] - [A-engine].
[L]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-engine] - [16-engine] - [B-engine].
[M]: [K] / [L].

Table 4: Comparison of Gas and Electric Chillers PLC-5

Chiller size (Tons): 125

Fuel type:	Gas LiBr absorption (Yazaki) [a]	Gas TecoChill engine chiller [b]	Electric reciprocating chiller water-cooled [c]	Electric centrifugal high efficiency [d]	Electric centrifugal hi-eff VSD [e]
[1]: Capital	$181,925	$169,225	$64,225	$118,863	$149,863
[2]: O&M/yr	$500	$1,800	$575	$700	$700
[3]: kW/T	0.03	0.02	0.80	0.55	0.45
[4]: COP	1.08	1.60	4.40	6.45	7.75
[5]: kW coincident demand	3	2	80	55	45
[6]: Total kWh	3,000	2,000	80,000	55,000	45,000
[7]: kWh on-peak	2,100	1,400	56,000	38,500	31,500
[8]: kWh off-peak	900	600	24,000	16,500	13,500
[9]: MMBtu gas	1,112	751	--	--	--

Notes:

[1], [2]: Xenergy (1990), Tables 5-7, 5-8, 5-9 and 5-10, midrange and 2/91 update.
[a] and [d] scaled from 100T, [e] = [d] + $35,000.

[3], [4]: Xenergy (1990), Tables 3-1, 3-2.

[5]: [3] x T for unit x .80. The .80 coincidence factor is from MECO 1990 C&LM Accounting Plan, 6/8/90, p.8.

[6]: [5] x 1000. 1,000 hours of use from Ibid.

[7]: 70% of total, from exh. H-4, 10/90 MECo DSM filing.

[8]: 30% of total.

[9]: [4]electric/[4]gas x [6]electric x .003413.

I. Electric Costs			Gas LiBr Absorption (Hitachi)	TecoChill Engine Driven	Centrifugal Chiller High-Eff	Centrifugal Chiller VSD (York)	Sources
Demand							
Summer kW [1]			6	4	110	90	See page 3.
Energy							
Peak Energy (kWh) [2]			4,200	2,800	77,000	63,000	Peak & off-peak: MECo
Off-peak Energy [3]			1,800	1,200	33,000	27,000	
Total [4]			6,000	4,000	110,000	90,000	See page 3.
Measure life [5]	20						
	Unit Cost Projected	Losses Secondary					
PV Direct Energy Costs ($/kWh)							Energy cost and
Peak energy [6]	$0.62	1.123	$2,944	$1,963	$53,971	$44,158	externalities: Table 1.
Off-peak Energy [7]	$0.47	1.071	$898	$599	$16,464	$13,471	Losses: Table 3.
MECo Externalities [8]	$0.35	1.107	$2,299	$1,533	$42,152	$34,488	
Total Energy			$6,141	$4,094	$112,588	$92,117	
PV $/kW NEP Demand Charge [9]	$851	1.183	$6,038	$4,025	$110,690	$90,565	NEP Demand Savings: Table 2.
PV $/kW Distribution [10]	$697	1.183	$4,950	$3,300	$90,747	$74,248	Distribution cost: March 1991 DR BGC-88
Total Electric Avoided Costs [11]			$17,129	$11,419	$314,025	$256,930	
II. Gas Costs							
Summer Base MMBTU [12]			2,242	1,513			Gas use: page 3.
PV $/MMBTU [13]	$39.18	Included	$87,838	$59,290			Gas cost: Table 5.
Externalities Absorption [14]	$20.06	1.043	$46,913				Gas externalities:
Engine [15]	$40.48	1.043		$63,897			Table 5A.
Total Gas Costs [16]			$134,750	$123,187			

Notes:

[1], [4]: Xenergy report for Rhode Island Fuel Switching Task Force. See page 3.

[2], [3]: Total energy use is from Xenergy report. Exhibit H-4 indicates 70% on-peak for new construction, 75% for retrofit HVAC, and Xenergy assumed 66% on-peak. This analysis uses 70% for all HVAC.

[5]: 20 years used as a typical endpoint. See Table 3, note 1 and text.

[6], [7], [8], [10]: Energy, externality, and distribution costs are from Table 1. Loss multiplier is from Table 3. Energy cost is rating period energy use times PV of rating period energy cost times rating period loss multiplier.

[8]: Losses are weighted by on-peak and off-peak energy use. Externality cost is PV of externalites times loss multiplier times total energy use.

[9]: NEP Demand Charge savings from Table 2. Total NEPCo demand cost is summer kW times capacity value times capacity loss multiplier.

[10]: Distribution savings from Table 1. Total distribution cost, to secondary, is summer kW times

	Gas LiBr Absorption (Hitachi)	Gas TecoChill Engine Driven	Electric Centrifugal Chiller High-Eff	Electric Centrifugal Chiller VSD (York)
III. Equipment Costs				
A. Capital Cost	$254,290	$265,150	$141,000	$176,000
B. Annual O&M Cost	$1,750	$1,800	$1,000	$800
C. PV O&M Costs	$22,165	$22,798	$12,665	$10,132
D. Total Equipment Cost	$276,455	$287,948	$153,665	$186,132
IV. TOTALS				
E. Total Cost	$428,334	$422,554	$467,691	$443,062
F. Net Savings from Hitachi			$39,357	$14,728
G. Net Capital Cost of Hitachi			$113,290	$78,290
H. Net Operating Savings from Hitachi			$152,647	$93,018
I. Cost/Benefit Ratio			0.74	0.84
J. Net Savings from TecoChill			$45,137	$20,508
K. Net Capital Cost of TecoChill			$124,150	$89,150
L. Net Operating Savings from TecoChill			$169,287	$109,658
M. Cost/Benefit Ratio			0.73	0.81

Notes:
[A], [B]: From Xenergy Report to the Rhode Island Fuel Switching Task Force, Tables 5-7, 5-8.
[C]: Annual O&M, [B] times present value of $1 over measure lifetime discounted at NECo's 4.81% real discount rate.
[D]: [A] + [C].
[E]: [D] + [11] + [16]
[F]: Total cost of electric option - total cost of gas chiller, [D-electric] - [D-gas].
[G]: Capital cost of gas - capital cost of electric, [A-gas] - [A-electric].
[H]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-absorption] - [16-absorption] - [B-absorption].
[I]: [G] / [H].
[J]: Total cost of electric option - total cost of engine chiller, [E-electric]- [E-engine].
[K]: Capital cost of gas - capital cost of engine chiller, [A-electric] - [A-engine].
[L]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-engine] - [16-engine] - [B-engine].
[M]: [K] / [L].

Chiller size (Tons): 250

Fuel type:	Gas LiBr absorption (Yazaki) [a]	Gas TecoChill engine driven [b]	Electric centrifugal chiller hi-eff [c]	Electric centrifugal chiller VSD (York) [d]
[1]: Capital	$254,290	$265,150	$141,000	$176,000
[2]: O&M/yr	$1,750	$1,800	$1,000	$800
[3]: kW/T	0.03	0.02	0.55	0.45
[4]: COP	1.08	1.60	6.45	7.75
[5]: kW coincident demand	6	4	110	90
[6]: Total kWh	6,000	4,000	110,000	90,000
[7]: kWh on-peak	4,200	2,800	77,000	63,000
[8]: kWh off-peak	1,800	1,200	33,000	27,000
[9]: MMBtu gas	2,242	1,513	--	--

Notes:

[1], [2]: Xenergy (1990), Tables 5-7, 5-8, 5-9 and 5-10, midrange and 2/91 update.
[a] is average of 100 - 200 and 300 - 600; [d] = [c] + $35,000.

[3], [4]: Xenergy (1990), Tables 3-1, 3-2.

[5]: [3] x T for unit x .80. The .80 coincidence factor is from HECO 1990 C&LM Accounting Plan, 6/8/90, p.8.

[6]: [5] x 1000. 1,000 hours of use from Ibid.

[7]: 70% of total, from exh. H-4, 10/90 HECo DSM filing.

[8]: 30% of total.

[9]: [4]electric/[4]gas x [6]electric x .003413.

	Unit Cost	Losses	Gas LiBr Absorption (Hitachi)	TecoChill Engine Driven	Partial Storage	Full Storage	Sources
I. Electric Costs							
Demand							
Summer kW [1]			6	4	82	0	Xenergy, 2/21/91 Update
Energy							
Peak Energy (kWh) [2]			4,200	2,800	68,250	0	Xenergy
Off-peak Energy [3]			1,800	1,200	225,000	293,250	
Total [4]			6,000	4,000	293,250	293,250	
Measure life [5]	20						
	Unit Cost	Losses Projected Secondary					
PV Direct Energy Costs ($/kWh)							Energy cost and
Peak energy [6]	$0.62	1.123	$2,944	$1,963	$47,838	$0	externalities: Table 1.
Off-peak Energy [7]	$0.47	1.071	$898	$599	$112,255	$146,305	Losses: Table 3.
~~Peak Energy (kWh)~~ [2] type	$0.35	weighted	$2,299	$1,533	$109,909	$108,681	
Total Energy		by kWh	$6,141	$4,094	$270,002	$254,986	
PV $/kW NEP Demand Charge [9]	$851	1.183	$6,038	$4,025	$82,514	$0	Table 2.
PV $/kW Distribution [10]	$697	1.183	$4,950	$3,300	$67,648	$0	March 1991 DR BGC-88
Total Electric Avoided Costs [11]			$17,129	$11,419	$420,164	$254,986	Losses: Table 3.
II. Gas Costs							
Summer Base MMBTU [12]			2,242	1,513			See page 3.
PV $/MMBTU [13]	$39.18	Included	$87,838	$59,290			-Gas cost: Table 5.
Externalities Absorption [14]	$20.06	1.043	$46,913				Gas externalities:
Engine [15]	$40.48	1.043		$63,897			Table 5A.
Total Gas Costs [16]			$134,750	$123,187			

Notes:

Gas end-use equipment data is unchanged from Table 6E.

[1], [4]: Xenergy report for Rhode Island Fuel Switching Task Force, 2/21/91 update.

[2], [3]: Total energy use and time pattern is from Xenergy update.

[5]: 20 years used as a typical endpoint. See Table 3, note 1 and text.

[6], [7], [8], [10]: Energy, externality, and distribution costs are from Table 1. Loss multiplier is from Table 3. Energy cost is rating period energy use times PV of rating period energy cost times rating period loss multiplier.

[8]: Losses are weighted by on-peak and off-peak energy use. Externality cost is PV of externalites times loss multiplier times total energy use.

[9]: NEP Demand Charge savings from Table 2. Total NEPCo demand cost is summer kW times capacity value times capacity loss multiplier.

[10]: Distribution savings from Table 1. Total distribution cost, to secondary, is summer kW times PV of 3/91 distribution, to secondary, cost times capacity loss multiplier.

[11]: Total Energy + [9] + [10].

[12]: Gas use based on 1,000 hours of use and relative efficiency of gas and electric units.

[13]: Gas avoided costs for chilling from Table 5. Avoided costs include losses.

[14], [15]: Externalities from Table 5A. BGC loss factor from 9/21/90 Report on IRM.

[16]: Total gas cost: Gas Use * gas cost + gas use * externalities * loss factor.

	Gas LiBr Absorption (Hitachi)	Gas TecoChill Engine Driven	Partial Storage	Full Storage
III. Equipment Costs				
A. Capital Cost	$254,290	$265,150	$210,145	$308,395
B. Annual O&M Cost	$1,750	$1,800	$1,000	$1,000
C. PV O&M Costs	$22,165	$22,798	$12,665	$12,665
D. Total Equipment Cost	$276,455	$287,948	$222,810	$321,060
IV. TOTALS				
E. Total Cost	$428,334	$422,554	$642,975	$576,046
F. Net Savings from Hitachi			$214,641	$147,713
G. Net Capital Cost of Hitachi			$44,145	($54,105)
H. Net Operating Savings from Hitachi			$258,786	$93,608
I. Cost/Benefit Ratio			0.17	-0.58
J. Net Savings from TecoChill			$220,421	$153,493
K. Net Capital Cost of TecoChill			$55,005	($43,245)
L. Net Operating Savings from TecoChill			$275,426	$110,248
M. Cost/Benefit Ratio			0.20	-0.39

Notes:
[A], [B]: From Xenergy Report to the Rhode Island Fuel Switching Task Force, Tables 5-7, 5-8.
[C]: Annual O&M, [B] times present value of $1 over measure lifetime disounted at NECo's 4.81% real discount rate.
[D]: [A] + [C].
[E]: [D] + [11] + [16]
[F]: Total cost of electric option - total cost of gas chiller, [D-electric] - [D-gas].
[G]: Capital cost of gas - capital cost of electric, [A-gas] - [A-electric].
[H]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-absorption] - [16-absorption] - [B-absorption].
[I]: [G] / [H].
[J]: Total cost of electric option - total cost of engine chiller, [E-electric]- [E-engine].
[K]: Capital cost of gas - capital cost of engine chiller, [A-electric] - [A-engine].
[L]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-engine] - [16-engine] - [B-engine].
[M]: [K] / [L].

I. Electric Costs			Gas-Fired Dessicant Cooling	Electric System	Sources
Demand					
Summer kW [1]			0	77	BGC
Energy					
Peak Energy (kWh) [2]			0	250,193	BGC
Off-peak Energy [3]			0	349,807	
Total [4]			0	600,000	
Measure life [5]	20				
	Unit Cost Projected	Losses Secondary			
PV Direct Energy Costs ($/kWh)					Energy cost and
Peak energy [6]	$0.62	1.123	$0	$175,366	externalities: Table 1.
Off-peak Energy [7]	$0.47	1.071	$0	$174,522	Losses: Table 3.
	$0.35 weighted		$0	$226,867	
Total Energy			$0	$576,755	
PV $/kW NEP Demand Charge [9]	$851	1.183	$0	$77,483	Table 2.
PV $/kW Distribution [10]	$697	1.183	$0	$63,523	March 1991 DR BGC-88
Total Electric Avoided Costs [11]			$0	$717,761	Losses: Table 3.
II. Gas Costs					
Summer Base MMBTU [12]			1,750		Gas use: BGC
PV $/MMBTU [13]	$39.18	Included	$68,557		Gas cost: Table 5.
Externalities Absorption [14]	$20.06	1.043	$36,616		Gas externalities:
Engine [15]	$40.48	1.043			Table 5A.
Total Gas Costs [16]			$105,173		

Notes:
[1], [2], [3], [4]: BGC study.
[5]: 20 years used as a typical endpoint. See Table 3, note 1 and text.
[6], [7], [8], [10]: Table 1.
[9]: Table 2.
[11]: [2]*[6]*[peak loss factor] + [3]*[7]*[off-peak loss factor] + [4]*[8]*loss factor + [1]*[9]*capacity loss factor + [1]*[10].
[12]: See page 3.
[13]: See Table 5.
[14], [15]: See Table 5A.
[16]: [12] * [13] + [12]*adder for technology*loss factor.

Table 7: Electricity Costs and Added Gas Costs
Dessicant Cooling vs Electric

	Gas-Fired Dessicant Cooling	Electric
III. Equipment Costs		
A. Capital Cost	$99,690	??
B. Annual O&M Cost	$4,800	??
C. PV O&M Costs	$60,794	$0
D. Total Equipment Cost	$160,484	$0
IV. TOTALS		
E. Total Cost	$265,657	$717,761
F. Net Savings from desiccant cooling		$452,104
G. Net Capital Cost of desiccant		$99,690
H. Net Operating Savings from desiccant		$551,794
I. Cost/Benefit Ratio		0.18

Notes:
[A], [B]: BGC data
[C]: Annual O&M, [B] times present value of $1 over measure lifetime disounted at MECo's 4.81% real discount rate.
[D]: [A] + [C].
[E]: [D] + [11] + [16]
[F]: Total cost of electric option - total cost of gas chiller, [D-electric] - [D-gas].
[G]: Capital cost of gas - capital cost of electric, [A-gas] - [A-electric].
[H]: Operating cost of electric option - operating cost of gas chiller, [11-electric] + [B-electric] - [11-absorption] - [16-absorption] - [B-absorption].
[I]: [G] / [H].

ATTACHMENT PLC-6

Attachment 6

Update to Carbon Dioxide Mitigation Costs

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April 17, 1991

The value for CO_2 adopted by the Massachusetts Department of Public Utilities (DPU) was based on RII's analysis of tree-planting costs in the U.S. Here we provide several estimates of the cost of specific CO_2 reduction measures, the costs of meeting various CO_2 emissions targets for the U.S. and abroad, and additional tree-planting cost estimates that support our earlier analysis. These estimates reconfirm that \$22/ton CO_2 is a reasonable, and probably understated, valuation for CO_2 emissions in utility planning.

The Cost of Carbon Dioxide Emissions Stabilization

Estimation of the costs of meeting stabilization targets are complicated by uncertainty regarding the supply curve for reducing or offsetting CO_2 emissions, including factors such as the potential and costs of electric and fossil-fuel conservation, and the effectiveness of tree-planting for permanent CO_2 sequestration. For each idendified general abatement strategy, we must determine the availability of specific measures for offsetting U.S. CO_2 emissions. For example, tree-planting in Latin America and improved efficiency in Eastern Europe may be relatively cheap CO_2 abatement strategies. However, they are not generally available for offsetting U.S. CO_2 emissions, since these countries will require these offsets for their own energy sector growth.

If we make the reasonable assumption that domestic CO_2 emissions must be reduced through abatement strategies within the U.S., then we diminish some of the complexity of determining a value for CO_2. However, other major unknowns include the costs and technical and economic potential of energy efficiency (including the costs of capability building), renewable technologies, fuel switching, tree-planting and CO_2 scrubbing within the U.S.

While we have a good idea of the mitigation measures generally available, and some idea of their potential as mitigation strategies, we are unsure at this time which specific CO_2-reducing measures will be required to mitigate global warming. Therefore, in this analysis we looked at a wide variety of CO_2 abatement measure costs and targets.

Several industrialized nations have adopted CO_2 emissions stabilization or reduction targets. Typically, these are stated in terms such as stabilization at 1985 levels by the year 2000 or reduction of 20% from 1988 levels by 2010. In addition, many individual states have set goals for CO_2 emissions reductions, such as Oregon and New York, and other states, including Massachusetts, require explicit valuation of CO_2 emissions reductions in utility planning. The U.S. is virtually the only industrialized nation that does not yet have an explicit CO_2 emissions stabilization or reduction policy.

The costs of these programs provide estimates of the value of reducing CO_2 emissions. An incomplete but representative list of CO_2 reduction targets is attached as Table 1. Several cost estimates follow in Tables 2-5. In many cases, the listed costs are average costs for a strategy, rather than marginal costs. The marginal costs are typically much higher than the average values. We has not reviewed all of the assumptions behind the estimates in all of the studies, but the reported results indicate that the costs of achieving currently proposed CO_2 reduction targets will be significantly higher than \$22/ton CO_2.

Tables 6 and 7 also show estimates of the costs of meeting specific reduction targets in several countries including the U.S. The data underlying these tables was taken from a recent World Wildlife Fund study. The WWF data indicates that the average cost of achieving the indicated target reduction is on the order of \$33/ton CO_2 for the U.S. (Table 6). Also based on the data in the WWF study, Table 7 indicates that the costs of several measures required to achieve reduction targets for the developed countries will be very high.[1]

Costs of Domestic Tree Planting

The U.S. Forestry Service recently prepared a study on the costs of sequestering carbon through tree planting.[2] Moulton and Richards (M&R) compiled data on the amount of marginal crop, pasture and forest lands suitable for tree-planting and aggregated the data by state and by type. Using rental rates paid under the national Conservation Reserve Program (CRP), a voluntary program paying farmers to convert marginal farm acreage to other uses, M&R generate a cost curve for CO_2 sequestration through tree-planting on marginal crop land.

M&R understates the costs of sequestration in many ways, several of which are explicitly stated by the authors. First, the authors assume that land owners would participate in a tree-planting program for rental rates which asre vary low compared to land values in many regions of the country. For example, in the

[1] In some cases (particularly Canada) not all of the relevant assumptions were provided in the WWF study. The author of the Canada study was unable to resolve the inconsistencies.

[2] Moulton and Richards, 1990.

Northeast, current CRP rental payments for a 10-year lease are roughly 1-2% of typical land values. This low rental payment for the CRP program may be acceptable because the land-owners are holding the land for development, and any short-term marginal income on the property is a windfall. Clearly, land owners would be unlikely to set aside developable land for 40 years, and plant trees which would make development more expensive, for such a low rental rate. In other parts of the country, rental rates on the order of 10% are required under the CRP program. Even at these rates, it is not clear that farmers would plant trees on their property for the same rents.[3]

Second, M&R assume that the trees are planted essentially instantaneously, and that they begin to sequester significant levels of carbon as soon as they are in the ground. M&R point out that the trees would not actually start to sequester carbon at the annual levels they assume until 5-15 years after planting. M&R's assumption has the effect of inflating the amount of carbon sequestered over the forty year life of the program, and spreading the costs of the program over higher carbon uptake levels.

A third understatement of the costs is that the study period ends after 40 years, without including funds or a plan for ensuring that the carbon is permanently fixed and that the sequestration is not reversed by clearing of the forest. This factor is the most difficult to address and correct, but could significantly raise the costs of the program.

Fourth, the measure costs are averages for the existing program, and are much lower than the highest-cost projects already undertaken. The measure cost for large increments of tree-planting may be substantially higher. Of the factors contributing to M&R's understatements, this may well be the most important factor.

The analysis presented in Tables 8-12 attempts to correct two of the understatements of M&R's cost estimates. We assume that land-owners would require a substantial premium to the average CRP rents in order to participate in a voluntary tree-planting effort. We expect land-owners would participate if the land were essentially purchased over the program life, and so we estimated the rental payments based on full land costs. This does not seem to be an unrealistic assumption given that the trees will not be harvested for at least 40 years, and no costs associated with removing the trees are included in the program costs. The other correction is for the timing of the carbon uptake of the trees, which will not reach the levels used by M&R until 5-15 years after

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[3]Certainly, if the CRP program continues, and the two programs competed for acreage, the tree-planting program would probably require a substantial premium.

planting. No adjustment was made for the ultimate fate of the trees (and partial carbon release), which would further lower the amount of carbon sequestered and raise the unit cost ($/lb C) of the program. No adjustment was made to account for the fact that planting would have to be staggered over several years, and not occur instantaneously. Nor was any adjustment made for the difference between average and marginal measure costs.

Table 12 summarizes the results from this analysis. It shows that for tree planting targets on the order of a 20% reduction from 1990 levels, the costs of marginal tree planting would be approximately $28/ton CO_2. Including the costs of permanently fixing the carbon beyond the life of the project would make this cost much higher.

Carbon Dioxide Valuation in Other States

The value for CO_2 adopted by the New York Public Service Commission (NYPSC) of $0.001/lb CO_2 was roughly one-tenth that recommended by the NYSEO and was chosen strictly for policy reasons. The NYSEO will be releasing a new cost study of CO_2 abatement measures soon, and expects that its new value will be higher than its previously recommended value, and more than an order of magnitude higher than the value adopted by the NYPSC.[4] The value adopted in California of $0.0035/ton CO_2 was based on the costs of tree planting to achieve energy benefits from reduced cooling load from shading in California. Clearly this is a limited opportunity, and not generally applicable to other areas of the nation. The Nevada PSC, the most recent state to adopt explicit externality values, adopted the $22/ton CO_2 adopted in Massachusetts.

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[4]Conversation with A. Sanghi, NYSEO, March 6, 1991.

Table 1.

Selected CO2 Reduction Targets

Source		Target for CO2 Emission Reductions	Implied % reduction from base, assuming base annnual growth of CO2 emissions of: 2%	1%
[1]	IPCC	Over 60% immediate reduction needed to stabilize concentrations at today's levels.	NA	NA
[2]	Krause, et al.	25% reduction required by industrialized countries from 1990 levels by 2005.	44%	35%
		50% reduction required by industrialized countries from 1990 levels by 2015.	70%	61%
[3]	Canada	Stabilization at 1990 levels by 2000.	18%	9%
[4]	United Kingdom	Stabilization at 1990 levels by 2005.	26%	14%
[5]	Norway	Stabilization at 1990 levels by 2000.	18%	9%
[6]	Japan	Stabilization at 1990 levels by 2000.	18%	9%
[7]	Sweden	Stabilization at 1990 levels by 2000.	18%	9%
[8]	Denmark	20% reduction from 1990 levels by 2000.	34%	27%
[9]	Netherlands	3-5% reduction from 1989-90 levels by 2000.	20-22%	12-14%
[10]	Austria	20% reduction from 1990 levels by 2005.	41%	31%
[11]	New Zealand	20% reduction from 1990 levels by 2000.	34%	27%
[12]	Oregon	20% reduction from 1990 levels by 2005.	41%	31%
[13]	Germany	25% reduction from 1990 levels by 2005.	44%	35%

Sources:

[1]: Global Environmental Change Report, Vol II, No. 11 (6/8/90). p. 4.
[2]: Krause, Bach and Koomey, "Energy Policy in the Greenhouse," Vol 1 (1989), figure 1.6.2.
[3]-[9]: Global Environmental Change Report, Vol II No. 16 (8/17/90), p.4.
[10]: Global Environmental Change Report, Vol II, No. 17 (9/14/90). p. 3.
[12]: Clearing Up, No 368 (6/2/89), p. 2.
[11],[13]: Science News, Mar 1991.

Table 2.

Estimates of the Cost of CO2 Emission Reductions.

	Source and Measure	Cost of reduction (1990$/T CO2)	Percent reduction from base
	[a]	[b]	[c]
[1]	U.S. EPA		
	CO2 scrubbing	$39 - $51	90% of plant stack emissions controlled
[2]	Naill, Belanger and Petersen		
	Conservation		
	high	negative	18% reduction from base
	very high	$76	28% reduction from base
	Reforestation offsets	$24	55% reduction from base
	Coal efficiency tax	$71	12% reduction from base
	Carbon tax		
	$100/Ton C	$154	31% reduction from base
	$250/Ton C	$194	51% reduction from base
	$400/Ton C	$241	53% reduction from base
	$625/Ton C	$300	57% reduction from base
[3]	New York State Energy Office		
	CO2 scrubbing (coal plant)	$47	reduction of 20% of 1988 levels by 2000.
[4]	New York State Energy Plan		
	CO2 scrubbing (coal plant)	$28	reduction of 20% of 1988 levels by 2000.
	CO2 scrubbing (oil plant)	$41	
[5]	NYSEO (FRG externalities workshop)		
	utility sector mix (tree	$48	31% reduction from base by 2008
	planting, conservation, fuel	$91	36% reduction from base by 2008
	switching, renewables, etc...)	$136	39% reduction from base by 2008
		$167	43% reduction from base by 2008

cont...

Table 2. continued

	Source and Measure [a]	Cost of reduction (1990$/T CO2) [b]	Percent reduction from base [c]
[6]	Manne and Richels		
	$250/Ton carbon tax	--	20% reduction of 1990 emissions by 2020 and stabilization thereafter.
[7]	Steinberg and Cheng		
	CO2 scrubbing (coal plant)	$58	90% of plant stack emissions controlled
[8]	Nordhaus		
	mix (sequestration, emission reduction)	$23	17% from base emissions
		$28	21% from base emissions
		$48	25% from base emissions
		$78	34% from base emissions
		$119	42% from base emissions
[9]	Spectrum Economics		
	utility sector mix (tree planting, conservation, fuel switching, renewables, etc...)	$54	25% reduction from base by 2008
		$97	29% reduction from base by 2008
		$189	33% reduction from base by 2008
		$287	37% reduction from base by 2008
[10]	Chernick and Caverhill		
	Carbon sequestration (trees)	$23	N/A
[11]	DOE, Office of Energy Research		
	fuel switching coal to gas 1995	$98	N/A
	2010	$222	
[12]	Worldwatch Institute		
	improving energy efficiency	< 4.58	N/A
	wind power	$27	
	geothermal power	$32	
	wood power	$36	
	steam inj. GT	$51	N/A
	solar-thermal (gas)	$52	
	nuclear power	$153	
	photovoltaics	$235	
	CC coal	$273	

Notes to Table 2:

[b]: 4% annual inflation assumed.

[1]: U.S. Environmental Protection Agency, "Policy Options for Stabilizing Global Climate," draft report to Congress (2/89) Vol II, p. V11-135. Assumes CO2 emissions of 2 lb/kWh.

[2]: Naill, Belanger, Petersen, " A Least-Cost Strategy for CO2 Reduction," from NARUC National Conference on Environmental Externalities (10/90), Table 4.

[3]: New York State Energy Office Division of Policy Analysis and Planning, "Environmental Externality Issue Report" (2/89), Preliminary Draft, p. 11.

[4]: New York State Energy Office, NYS Dep't of Public Service, NYS Dep't of Environmental Conservation, "Draft New York State Energy Plan; Issue 2b: Air Impacts, Electricity," (5/89) p. 36. New York could meet its 20% goal through tree planting and coal plant scrubbing; the 20% goal would not necessitate the more expensive oil plant scrubbing.

[5]: NYSEO paper prepared by A. Sanghi for Oct. 1990 conference. See Table 3 for calculations.

[6]: Manne and Richels, "CO2 Energy Limits: an Economic Cost Analysis for the USA," Energy Journal preprint, (9/89), p.26. The figure provided represents the long-run equilibrium tax. The economic cost of the CO2 reductions is higher than the tax value, due to multiplier effects.

[7]: Steinberg and Cheng, " Systems Study fo the Removal of Recovery, and Disposal of CO2 from Fossil Fuel Power Plants in the U.S.," Brookhaven National Laboratory (2/85).

[8]: Chernick and Caverhill, 1989.

[9]: Nordhaus, 1991. See Table 4 for calculations.

[10]: Spectrum Economics, 1990. See Table 5 for calculations.

[11]: U.S. DOE, Office of Energy Research, "A Preliminary Analysis of U.S. CO2 Emissions Reduction Potential from Energy Conservation and the Substitution of Natural Gas for Coal in the Period to 2010. Feb. 1989.

[12]: Worldwatch Institute, Lester R. Brown, et al. "State of the World 1990."

Table 3.

NYSEO Estimates of the Cost of Attaining CO2 Reduction Targets from 1988 Emission Levels by 2008.

% Reduction from 1988 levels	% Reduction from forecast 2008 base	Reduction from base (millions of tons/yr)	Total Cost (billions 1990$)	Cost ($/lb CO2)
0%	28%	24	0	$0
5%	31%	27	1.2	$44
10%	36%	31	2.6	$84
15%	39%	34	4.3	$126
20%	43%	37	5.7	$154

Notes:

Base case is 63 million tons in 1988 growing at 1.6% pa to 87 million tons in 2008.

Source: NYSEO paper prepared by A. Sanghi for Oct. 1990 externalities workshop at conference sponsored by the German Marshall Fund of the USA, Ladenberg, FRG.

Table 4.

Nordhaus Estimates of Marginal Cost of CO2 Reduction

Reductions of greenhouse gas emissions (% of base)	Equivalent CO2 reduction	Marginal cost of reduction ($/ton CO2)
[1]	[2]	[3]
1%	1%	$0.3
2%	2%	$0.6
3%	3%	$0.8
4%	3%	$1.2
5%	4%	$1.6
10%	8%	$3.3
15%	13%	$8.2
17%	14%	$12.3
20%	17%	$22.7
25%	21%	$27.8
30%	25%	$48.5
35%	29%	$62.9
40%	34%	$78.5
45%	38%	$99.9
50%	42%	$119.0

Notes:

From "A Survey of Estimates of the Cost of Reduction of Greenhouse Gas Emissions", Willian D. Nordhaus (2/22/90), tables 12 and 5. Nordhaus estimates that emissions of CO2 itself count for approximately 84% of annual CO2 equivalent emissions. Column [2] uses that figure to convert from total greenhouse gas emission reduction to CO2 reductions.

Table 5.

Spectrum Economics Estimates of the Cost of CO_2 Reductions from 1988 Emissions Levels

% Reduction from 1988 levels	% Reduction from base	Marginal cost (1988$/ton CO2)	Marginal cost (1990$/ton CO2)
0%			
5%	25%	$50	$54
10%	29%	$90	$97
15%	33%	$175	$189
20%	37%	$265	$287

Source: "Economic Impacts of the Greenhouse Gas Reduction Plan," Spectrum Economics, 1990, figure 17. This report was prepared for the California Coordinating Council.

Table 6.

CO2 Costs as a Percentage of 2005 GNP

Country	2005 GNP (billions 1985$)	% GNP required to acheive 20% CO2 reduction (from base)	Total Cost (millions 1985$)	Millions t/year C reduction	1990$ /ton C	1990$ /ton CO2
	[a]	[b]	[c]	[d]	[e]	[f]
1. United States	$6,700	0.005	$33,500	330.6	$122	$33.3
2. Canada	$670	0.003	$2,010	38.6	$63	$17.1
3. Japan	$11,000	NA	NA	61.6	NA	NA
4. United Kingdom	$1,000	0.003	$3,000	35.6	$101	$27.7
5. Poland	$303	0.003	$909	41.2	$27	$7.2
6. USSR	$2,500	NA	NA	263.0	NA	NA

Notes:

Unless otherwise noted, data in columns [a], [b] and [d] are from: Chandler, W., "Carbon Emissions Control Strategies." World Wildlife Fund (WWF), 1990.

1a. Chandler, W. Extrapolated from 1985 and 2010 population and economic variables. p. 196.
3a. Chandler, W. Extrapolated from figures presented on p. 169.
4a. Chandler, W. Extrapolated from figures presented on p. 124.
6a. Chandler, W. Extrapolated from figures presented on pp. 36, 39.
c. [a]*[b]*1000
d. Reductions by 2005 from base.
e. [c]/[d] inflated to 1990 using the GNP implicit price deflator.
f. [e]*12/44

Table 7.

CO2 Costs of Various Carbon Emission Reduction Measures

Country	Proposed measures	Millions of tons/year C reduced (in 2005)	Total cost (billions 1989$)	$/ton C (1989$)	$/ton CO2 (1989$)	Necessary to acheive 20% reduction by 2005?
	[a]	[b]	[c]	[d]	[f]	[e]
1. United States	Natural gas replacing coal	130	$73	$562	$153	?
	Gas combined cycles	180	$15	$83	$23	Yes
	Nuclear	240	$11	$48	$13	Yes
	Biomass as boiler fuel	240	$50	$208	$57	Yes, w/o
	Biomass liquid fuels	240	$70	$292	$80	new nucl.
2. Canada	Technical potential	50	$18	$350	$95	?
	Increment from economic to technical potential	20	$51	$2,550	$695	?
3. Japan	Carbon tax	60	$389	$6,480	$1,767	Yes
4. United Kingdom	Nuclear/Non-fossil	NA	NA	NA	$286	?
5. Poland	All energy conservation potentials	35	$0.150	$4	$1.2	Yes
	Marginal measure	33	$0.924	$28	$7.6	Yes
6. USSR	Additional renewables	NA	NA	$47	$13	Yes
	CO2 scrubbers	50	$0.963	NA	$0	?

Notes:

Source: Chandler, W., "Carbon Emissions Control Strategies." World Wildlife Fund, 1990.

1a. Nuclear power is assumed to cost 1.3 cents/kWh more than coal.

1b, 1c. Tons of carbon and costs are projected for the year 2010.

2. The assumptions behind these figures were not provided in the study.

4a. Poland's energy conservation options include space heating management, reduction of transmission and distribution losses, buildings insulation, automation and measurement, existing industrial equipment, railway electrification, coal quality improvement, shift to deisel engines in light trucks, and new industrial technology. The marginal measure is new industrial technology.

6b. Figure for CO2 scrubbers is in tons/year CO2.

6d. This cost is one order of magnitude lower than the cost from the source for this chapter, and may reflect uncertainties in the exchange rates.

Exchange Rates:

137 yen/$

.52424 pounds/$

2933 zlotys/$

16.92 rubles/$ (commercial exchange rate)

Table 8.

CO2 sequestration costs in the U.S.
Derived from Moulton and Richards, "Costs of Sequestering Carbon through tree planting and Forest Management in the United States" (Draft, August 27, 1990)

Region	Dry cropland value ($/acre) 1988	Dry cropland value ($/acre) 1990	Adjusted Cropland rent (constant 1990$/a/yr)	Present value of adjusted cropland rent ($/acre) 1990	Cropland potential for the planting program (1000s acres)	Present value of adjusted cropland rent ($/acre)	Present value of adjusted grazing rent ($/acre)	Present value of adjusted forest rent ($/acre)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
NORTHEAST	4,024	4,352	522	7,153	5,300.2	3,287	1,578	552
Connecticut	7,585	8,204	984	13,483	55.2			
Deleware	1,152	1,246	150	2,048	53.0			
Maine	794	859	103	1,411	268.2			
Maryland	2,023	2,188	263	3,596	589.4			
Massachusetts	14,488	15,670	1,880	25,754	36.0			
New Hampshire	NA	0	0	0	9.3			
New Jersey	6,855	7,414	890	12,186	384.3			
New York	840	909	109	1,493	1,616.6			
Pennsylvania	1,507	1,630	196	2,679	2,214.1			
Rhode Island	NA	0	0	0	8.4			
Vermont	975	1,055	127	1,733	65.7			
APPALACHIA	1,054	1,140	137	1,874	9,010.9	1,786	822	288
Kentucky	841	910	109	1,495	2,412.7			
N. Carolina	1,148	1,242	149	2,041	2,476.4			
Tennessee	857	927	111	1,523	2,806.9			
Virginia	1,385	1,498	180	2,462	1,191.5			
West Virginia	1,037	1,122	135	1,843	123.4			
SOUTHEAST	1,079	1,167	140	1,918	6,706.5	1,376	729	255
Alabama	684	740	89	1,216	2,558.8			
Florida	2,299	2,487	298	4,087	375.9			
Georgia	693	750	90	1,232	3,072.7			
S. Carolina	640	692	83	1,138	699.1			
LAKE STATES	646	699	84	1,148	7,347.7	1,132	362	127
Michigan	685	741	89	1,218	1,204.4			
Minnesota	594	642	77	1,056	3,023.2			
Wisconsin	660	714	86	1,173	3,120.1			
CORN BELT	935	1,011	121	1,662	38,103.8	1,688	523	183
Illinois	1,183	1,280	154	2,103	10,227.3			
Indiana	977	1,057	127	1,737	4,687.4			
Iowa	947	1,024	123	1,683	12,261.0			
Missouri	589	637	76	1,047	7,223.7			
Ohio	981	1,061	127	1,744	3,704.4			

cont...

DELTA STATES	692	748	90	1,230	8,457.0	1,191	381	133
Arkansas	599	648	78	1,065	3,276.1			
Louisiana	886	958	115	1,575	2,171.0			
Mississippi	591	639	77	1,051	3,009.9			
NORTHERN PLN	355	384	46	631	14,067.0	662	166	58
Kansas	370	400	48	658	4,475.6			
Nebraska	454	491	59	807	4,620.7			
North Dakota	324	350	42	576	2,579.1			
South Dakota	273	295	35	485	2,391.6			
SOUTHERN PLN	601	650	78	1,068	6,294.0	1,213	340	119
Oklahoma	455	492	59	809	1,395.5			
Texas	747	808	97	1,328	4,898.5			
MOUNTAIN	329	356	43	585	5,675.5	631	278	97
Arizona	NA	0	0		0.0			
Colorado	298	322	39	530	1,072.3			
Idaho	464	502	60	825	2,454.2			
Montana	255	276	33	453	1,714.3			
Nevada	382	413	50	679	0.0			
New Mexico	391	423	51	695	118.1			
Utah	340	368	44	604	109.2			
Wyoming	174	188	23	309	207.4			
PACIFIC	1,108	1,198	144	1,970	4,584.2	1,429	300	105
California	2,000	2,163	260	3,555	503.7			
Oregon	684	740	89	1,216	1,577.4			
Washington	639	691	83	1,136	2,503.1			
TOTAL					105,546.8			

Notes
[1],[2] : From M&R Table 10.
[3] : Column [2] inflated to 1990$ assuming 4% annual inflation.
[4] : Column [3]*0.12
[5] : Present value of cropland rents over 40 years, assuming inflation
of 4% and discount rate of 11.4% nominal (6.77% real assuming 4% inflation).
[6] : From M&R Table 2, column 1.
[7] : Weighted average of land values by region =
(regional sum of [5]*[6])/([6] for each region)
[8] : Column [7]*(ratio of private land rents to private cropland rents taken from M&R Table 10).
[9] : Column [8]*0.35. See R&M Table 10 and p. 22.

Table 9.

Correction for timing of CO2 sequestration (years 11–40).

Region and Type of Land [1]	Tons of carbon per acre per year (years 10–40) [2]	Total discounted tons of carbon 1990 [3]
NORTHEAST		
Crop		
Wet	3.61	23.8
Dry	3.04	20.1
Pasture		
Wet	2.76	18.2
Dry	2.31	15.2
Forest		
Planting	1.20	7.9
Passive Mgnt	0.29	1.9
Active Mgnt	0.58	3.8
LAKE STATES		
Crop		
Wet	3.22	21.2
Dry	2.61	17.2
Pasture		
Wet	2.51	16.6
Dry	2.06	13.6
Forest		
Planting	2.04	13.5
Passive Mgnt	0.56	3.7
Active Mgnt	1.13	7.5
CORN BELT		
Crop		
Wet	2.72	17.9
Dry	2.56	16.9
Pasture		
Wet	2.12	14.0
Dry	2.00	13.2
Forest		
Planting	2.33	15.4
Passive Mgnt	0.64	4.2
Active Mgnt	1.29	8.5

cont...

NORTH PLAINS		
Crop		
Wet	2.86	18.9
Dry	2.61	17.2
Pasture		
Wet	2.23	14.7
Dry	2.03	13.4
Forest		
Planting	3.07	20.3
Passive Mgnt	0.71	4.7
Active Mgnt	1.41	9.3
APPALACHIA		
Crop		
Wet	3.47	22.9
Dry	2.89	19.1
Pasture		
Wet	2.48	16.4
Dry	2.06	13.6
Forest		
Planting	1.05	6.9
Passive Mgnt	0.44	2.9
Active Mgnt	0.87	5.7
SOUTHEAST		
Crop		
Wet	3.38	22.3
Dry	2.85	18.8
Pasture		
Wet	2.46	16.2
Dry	2.03	13.4
Forest		
Planting	1.15	7.6
Passive Mgnt	0.48	3.2
Active Mgnt	0.95	6.3
DELTA STATES		
Crop		
Wet	2.62	17.3
Dry	2.73	18.0
Pasture		
Wet	2.31	15.2
Dry	2.40	15.8
Forest		
Planting	1.03	6.8
Passive Mgnt	0.41	2.7
Active Mgnt	0.81	5.3

cont...

SOUTH PLAINS		
Crop		
Wet	2.84	18.7
Dry	2.36	15.6
Pasture		
Wet	2.50	16.5
Dry	2.08	13.7
Forest		
Planting	1.01	6.7
Passive Mgnt	0.40	2.6
Active Mgnt	0.80	5.3
MOUNTAIN		
Crop		
Wet	3.76	24.8
Dry	3.76	24.8
Pasture		
Wet	3.08	20.3
Dry	3.08	20.3
Forest		
Planting	1.05	6.9
Passive Mgnt	0.28	1.8
Active Mgnt	0.55	3.6
PACIFIC		
Crop		
Wet	2.48	16.4
Dry	2.48	16.4
Pasture		
Wet	1.81	11.9
Dry	1.50	9.9
Forest		
Planting	3.52	23.2
Passive Mgnt	0.36	2.4
Active Mgnt	0.73	4.8

Notes:

[1]: From M&R Table 1.
[2]: From M&R Table 1, column 4. Average carbon uptake is average for years 11-40. Uptake in years 1-10 is assumed to be negligible.
[3]: [2]*(13.696-7.0989). Discount factor is 11.04% nominal (6.77% real assuming 4% inflation)

Table 10.

Unit costs of tree planting.

Region and Type of Land [1]	Land Area (1000s of acres) [2]	Present value of rent ($/acre) 1990 [3]	Cost of Treatment ($/acre) 1990 [4]	Total cost per acre ($/acre) 1990 [5]	Total discounted tons of carbon (tons/acre) 1990 [6]	Unit cost of carbon ($/ton C) 1990 [7]	Unit cost of CO2 ($/ton CO2) 1990 [8]
NORTHEAST							
Crop	10,958						
Wet	5,130	3,287	161	3,448	23.8	145	39.5
Dry	5,828	3,287	163	3,450	20.1	172	46.9
Pasture	2,554						
Wet	1,707	1,578	212	1,790	18.2	98	26.8
Dry	847	1,578	212	1,790	15.2	117	32.0
Forest	9,379						
Planting	2,422	552	151	704	7.9	89	24.2
Passive Mgnt	1,153	552	4	556	1.9	291	79.3
Active Mgnt	5,804	552	43	595	3.8	156	42.4
LAKE STATES							
Crop	24,811						
Wet	16,680	1,132	116	1,248	21.2	59	16.0
Dry	8,131	1,132	111	1,244	17.2	72	19.7
Pasture	2,610						
Wet	1,921	362	114	476	16.6	29	7.8
Dry	689	362	114	476	13.6	35	9.6
Forest	7,049						
Planting	3,545	127	143	270	13.5	20	5.5
Passive Mgnt	1,717	127	4	131	3.7	35	9.7
Active Mgnt	1,788	127	35	161	7.5	22	5.9
CORN BELT							
Crop	78,013						
Wet	38,660	1,688	150	1,838	17.9	102	27.9
Dry	39,353	1,688	144	1,832	16.9	108	29.6
Pasture	10,198						
Wet	4,966	523	201	724	14.0	52	14.1
Dry	5,232	523	201	724	13.2	55	15.0
Forest	7,628						
Planting	1,836	183	143	326	15.4	21	5.8
Passive Mgnt	3,669	183	4	187	4.2	44	12.1
Active Mgnt	2,124	183	35	218	8.5	26	7.0

cont...

NORTH PLAINS							
Crop	24,056						
Wet	7,160	662	105	767	18.9	41	11.1
Dry	16,896	662	105	767	17.2	45	12.2
Pasture	2,247						
Wet	1,698	166	110	276	14.7	19	5.1
Dry	549	166	110	276	13.4	21	5.6
Forest	337						
Planting	28	58	143	201	20.3	10	2.7
Passive Mgnt	214	58	4	62	4.7	13	3.6
Active Mgnt	96	58	30	88	9.3	9	2.6
APPALACHIA							
Crop	15,924						
Wet	6,020	1,786	67	1,854	22.9	81	22.1
Dry	9,904	1,786	67	1,854	19.1	97	26.5
Pasture	8,002						
Wet	3,341	822	96	918	16.4	56	15.3
Dry	4,661	822	96	918	13.6	68	18.4
Forest	14,264						
Planting	6,664	288	125	413	6.9	60	16.3
Passive Mgnt	3,836	288	4	292	2.9	101	27.4
Active Mgnt	3,764	288	51	338	5.7	59	16.1
SOUTHEAST							
Crop	11,876						
Wet	4,690	1,376	66	1,442	22.3	65	17.6
Dry	7,186	1,376	63	1,439	18.8	77	20.9
Pasture	3,112						
Wet	2,484	729	72	802	16.2	49	13.5
Dry	628	729	72	802	13.4	60	16.3
Forest	15,168						
Planting	9,885	255	131	386	7.6	51	13.9
Passive Mgnt	1,314	255	4	260	3.2	82	22.4
Active Mgnt	3,969	255	51	306	6.3	49	13.3
DELTA STATES							
Crop	25,227						
Wet	16,350	1,191	76	1,266	17.3	73	20.0
Dry	8,877	1,191	75	1,265	18.0	70	19.2
Pasture	3,632						
Wet	2,335	381	83	464	15.2	30	8.3
Dry	628	381	83	464	15.8	29	8.0
Forest	7,240						
Planting	3,180	133	153	286	6.8	42	11.5
Passive Mgnt	1,606	133	4	138	2.7	51	13.9
Active Mgnt	2,454	133	52	185	5.3	35	9.5

cont...

SOUTH PLAINS							
Crop	13,446						
Wet	6,050	1,213	62	1,274	18.7	68	18.6
Dry	7,396	1,213	62	1,274	15.6	82	22.3
Pasture	6,082						
Wet	4,611	340	68	408	16.5	25	6.7
Dry	1,471	340	68	408	13.7	30	8.1
Forest	3,840						
Planting	2,016	119	153	271	6.7	41	11.1
Passive Mgnt	927	119	4	123	2.6	47	12.7
Active Mgnt	897	119	52	171	5.3	32	8.8
MOUNTAIN							
Crop	10,940						
Wet	2,470	631	76	707	24.8	28	7.8
Dry	8,470	631	76	707	24.8	28	7.8
Pasture	1,819						
Wet	1,427	278	118	396	20.3	19	5.3
Dry	392	278	118	396	20.3	19	5.3
Forest	5,069						
Planting	838	97	165	263	6.9	38	10.3
Passive Mgnt	3,204	97	4	102	1.8	55	15.0
Active Mgnt	1,026	97	21	118	3.6	32	8.8
PACIFIC							
Crop	9,051						
Wet	3,770	1,429	195	1,624	16.4	99	27.1
Dry	5,281	1,429	195	1,624	16.4	99	27.1
Pasture	1,288						
Wet	920	300	233	533	11.9	45	12.2
Dry	204	300	233	533	9.9	54	14.7
Forest	8,989						
Planting	3,578	105	267	372	23.2	16	4.4
Passive Mgnt	3,041	105	4	109	2.4	46	12.6
Active Mgnt	2,370	105	39	144	4.8	30	8.2

Notes
[1],[2] : From M&R Table 1.
[3] : From Table 1.
[4] : From M&R Table 1, column 3 and inflated to 1990$. Treatment costs are assumed to be dominated by site preparation planting and seeding costs in the first year of the program.
[5] : Column [3] + column [4].
[6] : From Table 2.
[7] : Column [5] / column [6].

Table 11.

Cost–curve development table.

Region [1]	Type of Land [2]		Unit Cost of Sequestered CO2 ($/ton) [3]	Unit Cost of Sequestered Carbon ($/t) [4]	Available Acreage (1000s acres) [5]	Cumulative Acreage (1000s acres) [6]	Rate of Carbon Sequestered (t/a/yr) [7]	Total Carbon Sequestered Annually (1000s t/yr) [8]	Cumulative Carbon Sequestered (1000s tons) [9]
NP	Active Mgt	Forest	2.6	9	96	96	1.41	135	135
NP	Planting	Forest	2.7	10	28	124	3.07	86	221
NP	Passive Mgt	Forest	3.6	13	214	338	0.71	152	373
PC	Planting	Forest	4.4	16	3,578	3,916	3.52	12,595	12,968
NP	Wet	Pasture	5.1	19	1,698	5,614	2.23	3,787	16,754
MT	Wet	Pasture	5.3	19	1,427	7,041	3.08	4,395	21,150
MT	Dry	Pasture	5.3	19	392	7,433	3.08	1,207	22,357
LS	Planting	Forest	5.5	20	3,545	10,978	2.04	7,232	29,589
NP	Dry	Pasture	5.6	21	549	11,527	2.03	1,114	30,703
CB	Planting	Forest	5.8	21	1,836	13,363	2.33	4,278	34,981
LS	Active Mgt	Forest	5.9	22	1,788	15,151	1.13	2,020	37,001
SP	Wet	Pasture	6.7	25	4,611	19,762	2.50	11,528	48,529
CB	Active Mgt	Forest	7.0	26	2,124	21,886	1.29	2,740	51,269
MT	Dry	Crop	7.8	28	8,470	30,356	3.76	31,847	83,116
MT	Wet	Crop	7.8	28	2,470	32,826	3.76	9,287	92,403
LS	Wet	Pasture	7.8	29	1,921	34,747	2.51	4,822	97,225
DS	Dry	Pasture	8.0	29	628	35,375	2.40	1,507	98,732
SP	Dry	Pasture	8.1	30	1,471	36,846	2.08	3,060	101,792
PC	Active Mgt	Forest	8.2	30	2,370	39,216	0.73	1,730	103,522
DS	Wet	Pasture	8.3	30	2,335	41,551	2.31	5,394	108,916
SP	Active Mgt	Forest	8.8	32	897	42,448	0.80	718	109,633
MT	Active Mgt	Forest	8.8	32	1,026	43,474	0.55	564	110,198
DS	Active Mgt	Forest	9.5	35	2,454	45,928	0.81	1,988	112,186
LS	Dry	Pasture	9.6	35	689	46,617	2.06	1,419	113,605
LS	Passive Mgt	Forest	9.7	35	1,717	48,334	0.56	962	114,566
MT	Planting	Forest	10.3	38	838	49,172	1.05	880	115,446
NP	Wet	Crop	11.1	41	7,160	56,332	2.86	20,478	135,924
SP	Planting	Forest	11.1	41	2,016	58,348	1.01	2,036	137,960
DS	Planting	Forest	11.5	42	3,180	61,528	1.03	3,275	141,235
CB	Passive Mgt	Forest	12.1	44	3,669	65,197	0.64	2,348	143,584
NP	Dry	Crop	12.2	45	16,896	82,093	2.61	44,099	187,682
PC	Wet	Pasture	12.2	45	920	83,013	1.81	1,665	189,347
PC	Passive Mgt	Forest	12.6	46	3,041	86,054	0.36	1,095	190,442
SP	Passive Mgt	Forest	12.7	47	927	86,981	0.40	371	190,813
SE	Active Mgt	Forest	13.3	49	3,969	90,950	0.95	3,771	194,583
SE	Wet	Pasture	13.5	49	2,484	93,434	2.46	6,111	200,694
SE	Planting	Forest	13.9	51	9,885	103,319	1.15	11,368	212,062
DS	Passive Mgt	Forest	13.9	51	1,606	104,925	0.41	658	212,720

cont...

CB	Wet	Pasture	14.1	52	4,966	109,891	2.12	10,528	223,248
PC	Dry	Pasture	14.7	54	204	110,095	1.50	306	223,554
CB	Dry	Pasture	15.0	55	5,232	115,327	2.00	10,464	234,018
MT	Passive Mgt	Forest	15.0	55	3,204	118,531	0.28	897	234,915
AP	Wet	Pasture	15.3	56	3,341	121,872	2.48	8,286	243,201
LS	Wet	Crop	16.0	59	16,680	138,552	3.22	53,710	296,911
AP	Active Mgt	Forest	16.1	59	3,764	142,316	0.87	3,275	300,185
AP	Planting	Forest	16.3	60	6,664	148,980	1.05	6,997	307,183
SE	Dry	Pasture	16.3	60	628	149,608	2.03	1,275	308,457
SE	Wet	Crop	17.6	65	4,690	154,298	3.38	15,852	324,310
AP	Dry	Pasture	18.4	68	4,661	158,959	2.06	9,602	333,911
SP	Wet	Crop	18.6	68	6,050	165,009	2.84	17,182	351,093
DS	Dry	Crop	19.2	70	8,877	173,886	2.73	24,234	375,327
LS	Dry	Crop	19.7	72	8,131	182,017	2.61	21,222	396,549
DS	Wet	Crop	20.0	73	16,350	198,367	2.62	42,837	439,386
SE	Dry	Crop	20.9	77	7,186	205,553	2.85	20,480	459,866
AP	Wet	Crop	22.1	81	6,020	211,573	3.47	20,889	480,756
SP	Dry	Crop	22.3	82	7,396	218,969	2.36	17,455	498,210
SE	Passive Mgt	Forest	22.4	82	1,314	220,283	0.48	631	498,841
NE	Planting	Forest	24.2	89	2,422	222,705	1.20	2,906	501,748
AP	Dry	Crop	26.5	97	9,904	232,609	2.89	28,623	530,370
NE	Wet	Pasture	26.8	98	1,707	234,316	2.76	4,711	535,081
PC	Dry	Crop	27.1	99	5,281	239,597	2.48	13,097	548,178
PC	Wet	Crop	27.1	99	3,770	243,367	2.48	9,350	557,528
AP	Passive Mgt	Forest	27.4	101	3,836	247,203	0.44	1,688	559,216
CB	Wet	Crop	27.9	102	38,660	285,863	2.72	105,155	664,371
CB	Dry	Crop	29.6	108	39,353	325,216	2.56	100,744	765,115
NE	Dry	Pasture	32.0	117	847	326,063	2.31	1,957	767,071
NE	Wet	Crop	39.5	145	5,130	331,193	3.61	18,519	785,590
NE	Active Mgt	Forest	42.4	156	5,804	336,997	0.58	3,366	788,957
NE	Dry	Crop	46.9	172	5,828	342,825	3.04	17,717	806,674
NE	Passive Mgt	Forest	79.3	291	1,153	343,978	0.29	334	807,008

Notes:

[1],[2],[3],[4],[5],[7]: Data in these columns is from table 3.
[6]: Sum of column [5].
[8]: [5]*[7]
[9]: Sum of column [8].

Table 12.

Costs of national CO2 reduction targets. (1990$)

Reductions from 1990 Total U.S. emissions [1]	Reductions from year 2000 base emissions [2]	Millions of short tons C [3]	Land requirement (mill acres) [4]	Marginal Cost ($/t CO2) [5]
0%	18.0%	313	150.9	17.6
10%	26.2%	456	204.2	20.9
20%	34.4%	599	261.8	27.9
30%	42.6%	742	316.2	29.6
40%	50.8%	885	NA	>79.3

Notes:

[1]: Emissions in year 1990 are 1,430 million tons carbon.
[2]: Base emissions in year 2000 are 1,743 million tons (2% annual growth).
[3]: [2]*313. Annual offsets do not start until 5-15 years after the trees are planted are constant until year 40, and are zero thereafter.
[4]: Extrapolated from table 4, columns [9] and [6].
[5]: Read from table 4, column [3].