STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 5270-CV-1

Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy In Re: Fuel-Switching Issues for CVPS
Docket No. 5270-CV-3

Docket No. 5270-CV-3

Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy In Re: CVPS Program Designs

Docket No. 5686

Design and Implementation of CVPS Residential Controlled Water-Heating DSM Measures

PREFILED REBUTTAL TESTIMONY OF PAUL L. CHERNICK

ON BEHALF OF THE VERMONT DEPARTMENT OF PUBLIC SERVICE

June 1, 1994

Mr. Chernick's testimony responds to CVPS's direct testimony on risk, rate impacts, participant costs, externalities, space-and water-heating load, the appropriate benefit-cost test, the economics of DSM deferral, and related topics.

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I. Introduction and Summary

Q: Are you the same Paul Chernick who filed direct testimony in these proceedings?

A: Yes.

Q: What is the purpose of this rebuttal testimony?

A: My testimony discusses topics raised in the direct testimony of Central Vermont Public Service Corporation (CV).[1] While both the Department and CV believe that "fuel-switching should be implemented when expected societal benefits exceed costs and customers choose to switch" (Bentley, p. 24, lines 9–10), the parties interpret differently the terms "benefits," "costs," and even "choose."

Q: What subjects do you cover in this testimony?

A: I start by dealing in turn with the four "adjustments" to the societal test proposed by CV and illustrated in Exhibit BWB-6:

1. the treatment of fuel-price risks,
2. the "deadweight loss" of rate increases,
3. customer transaction costs,
4. externalities.

Deehan lists items 1, 2, and 4 as the "new analysis and information" that CV is providing in these proceedings.

As is shown in Exhibit BWB-6, CV's risk adjustment results in a large reduction in the present value of its cost-effectiveness test (which is no

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[1]Unless otherwise specified, the references are to the testimony filed on April 4, 1994.

longer the societal test), while rate impacts and transaction costs produce small reductions and CV's treatment of externalities is contradictory.[2] As I discuss each of these four adjustments, I consider related CV arguments.

In addition, I deal with four additional topics raised in CV's direct:

5. the load shape of electric space heating and water heating, including water-heater load control;
6. CV's defense of the rate impact measure (RIM);
7. the economics of deferral of cost-effective DSM, including fuel switching; and
8. electrotechnologies.

I do not include testimony on avoided costs, other than a response to Awerbuch's criticism of the Board's 10% risk adder for DSM (considered in §II.B). The other avoided-cost issues were considered in my direct testimony.

Q: Please summarize your rebuttal testimony.

A: CV's testimony consists primarily of theoretical constructs and contrived excuses for not implementing the fairly straightforward strategy for acquiring the cost-effective DSM resources ordered in Docket Nos. 5270 and 5270 CV-1.

II. Fuel Switching and Risk

Q: Which CV witnesses deal with the risks of fuel switching?

[2]While Exhibit BWB-6 includes an upward adjustment to fuel-switching benefits due to inclusion of electric externalities based on the stipulated values, CV argues that no externality benefits should be reflected in valuing fuel switching.

A: Awerbuch, Bower, Deehan, and Bentley all discuss this issue. Awerbuch is the primary CV witness on this issue, and most of my rebuttal on this point will deal with his testimony. Deehan primarily repeats Awerbuch's erroneous conclusions, while Bower's testimony on this point is general and vague. Bentley misapplies Awerbuch's results, as I explain below.

Awerbuch's testimony deals primarily with the differential risks of fossil fuels and electric rates, from the participant perspective. He and Deehan also argue that the Board should abandon its general risk adder for DSM. I consider these points in turn.

A. Awerbuch's Risk-Adjusted Discounting of Direct Fuel Use

Q: Please summarize Awerbuch's analysis.

A: Awerbuch correctly notes that the present value of a project or decision can be determined as the sum of the present value of each of the components cash flow streams (costs and benefits), and that the discount rate of each component can be adjusted to reflect the riskiness of that component. Awerbuch's basic approach is essentially the same as the one I developed in my 1987 testimony in Massachusetts DPU 88-19, and summarized in subsequent publications.[3] As I did in my much earlier work, Awerbuch concludes that fuel prices are correlated with economic outcomes of interest, and offers an interesting attempt to apply the CAPM to the valuation of risk

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[3]Chernick, Paul. 1988. "Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 553-557, and Chernick, Paul, John Plunkett, and Jonathan Wallach. 1993. *From Here to Efficiency* Vol. 5. Harrisburg: Pennsylvania Energy Office, 121–26.

in utility planning.[4] Unfortunately, Awerbuch makes at least three types of errors: one major conceptual error, several theoretical errors, and data errors.

While Awerbuch acknowledges that the consistency of the Capital Asset Pricing Model with reality is questionable, he claims that the problems in estimation of risk with his method are "limited," and that he uses the CAPM only conceptually (p. 10). In fact, the problems with his analysis are numerous and fatal, and he uses the results very specifically and quantitatively.

Awerbuch expresses many strange ideas. Of these, many are not particularly important to his conclusions, but they suggest that his testimony is focused more on applying rarefied financial theory (which may or may not accurately describe the behavior of financial markets) than on understanding real consumer energy decisions. For example, Awerbuch

- Asserts that corporations use risk-adjusted discount rates to screen projects (p. 17). This may be true for some decisions in some corporations, and financial theorists argue that is should be true everywhere, but the reality is that most companies use simpler decision rules (such as internal rate of return or years to payback) for evaluating most decisions, including energy-efficiency investments.
- Appears to suggest (p. 20) that interest-rate risks should not matter to many households because interest rates are tied to inflation (in which case real interest rates would not vary so much), jobs are "claims on earned income streams" that are inflation-protected, and financial

[4]Unlike other CV witnesses (Bennett and Hanisch, Bentley), Awerbuch has documented his analysis fairly clearly, even though he often does not explain the reasons for his analytical decisions.

portfolios rise with inflation.[5] From this tenuous train of reasoning, Awerbuch concludes that borrowers should select ARMs, but then concludes that they do not behave according to his theory.[6]

- Assumes that a recession implies that bond and house "returns" are low (p. 23). This does not appear to be correct. If interest rates fall in the recession, bond prices will rise. Also, most homeowners do not earn a useful annual return on their homes; if their homes' prices rise, they cannot realize that gain, since they need a home to live in and any replacement home would also rise in price. Similarly, homeowners do not suffer in a recession (unless they were planning to sell their homes and move to another housing market that is not in recession).
- Rationalizes (pp. 23, 38) his erroneous finding that end-use fuel is riskier that utility power supply by asserting that CV is more likely to use solar and renewables than are its customers. With respect to solar, the reverse is surely true, and likely to remain so, since Vermont is a poor prospect for utility solar-electric applications, but solar water heating is feasible. While CV has some wood-fired generation in its mix, its customers probably use considerably more wood for heating.
- Asserts that in a competitive market, an HVAC contractor would sign a 20-year contract to provide future services at an expected rate of return less than the risk-free rate he could earn on Treasury securities (p. 34). Awerbuch does not explain why the HVAC service market is not

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[5]In fact, increasing interest rates tend to depress stock and bond returns, not increase them.

[6]Awerbuch's argument on page 20 is difficult to follow, since he makes a series of peculiar assertions, reaches unlikely conclusions, points out that his theory does not fit reality, and then draws another set of conclusions from the inconsistency of his first theory.

competitive, or offer any evidence that the 20-year fixed-price contracts he posits are actually available.[7]

1. Conceptual Error: the Participant Test

Q: What is Awerbuch's major conceptual error?

A: Awerbuch examines the risks *to the participant*, rather than to *society*, or to CV's ratepayers as a whole. His basic argument can be restated as follows.

If you use propane, you bear all the fuel-price risk yourself. If you use electricity, you increase CV oil use and the oil risk to ratepayers, but you bear only a small part of that risk yourself. You also increase CV's weather-sensitivity risk, over-and under-building risk, etc. Using electricity increases total oil use and total risk more than using propane, but you bear only a small part of that risk, so why should you worry.

Awerbuch essentially treats a market barrier (the risk transfer in the electric market) as a good thing.[8]

Q: Is there any doubt that Awerbuch uses the participant test as the basis for his analysis of risk?

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[7]This assertion, like many of his other assertions about a household's valuation of a home, or a job, suggests that Awerbuch is so preoccupied with financial theory that he assumes people act as his theory suggests, rather than adapting the theory to accommodate reality.

[8]While spreading the same amount of risk over more people is probably desirable, increasing total cost and total risk is undesirable. Awerbuch does not explain why he takes the participant perspective, ignoring risks for non-participants. This approach appears to be inconsistent with his use of stock-market beta. He measures risk as contribution to the systematic risk in the financial markets, and expresses no concern about non-systematic risk. Yet the risk-sharing he advocates reduces only the non-systematic risk of individual customers.

A: No. Awerbuch states that the results of his analysis would be affected by the electric rate charged to the participant. He admits to using rates, rather than avoided costs, and argues that the *social* benefit of electric heat is increased by the discount to TOD — which he calls controlled — customers. (pages 33-34)

Q: What would be the results of applying Awerbuch's approach to the societal test?

A: It would make fuel-switching and DSM more attractive. Awerbuch cites Lind (p 12) to the effect that benefits of fuel savings will be negatively correlated with GNP, implying that the discount rate used for these benefits should be low. Since DSM saves fuel, and fuel switching saves total fuel,[9] those avoided fuel costs should, by Awerbuch's logic, be discounted at low discount rates. More DSM would be cost-effective under the risk-adjusted societal test (using Awerbuch's measures of risk) than under the traditional societal test.

Furthermore, utility #6 oil appears to be riskier than residential #2 oil or propane in every analysis I have performed, using Awerbuch's version of beta (β), or a corrected beta, and compared to Vermont per-capita income, unemployment, or the stock market, or in regressions of income on energy prices and time.

If the Board were to follow Awerbuch's practice of selecting the participant test over the societal perspective, it would encourage a tragedy of

[9]Bentley (pp. 22-23) argues that hypothetical ground-source electric heat pumps (as opposed to the resistance heating dominant in Vermont), powered exclusively by hypothetical new super-efficient combined-cycle plants, would be as efficient as direct fossil use. He does not attempt to demonstrate that the heat pumps would be cost-effective.

the commons: each customer would be encouraged to minimize his risk (and cost), while increase the total risk (and cost) for CV's ratepayers as a whole.

2. *Theoretical Errors*

Q: What theoretical errors does Awerbuch make?

A: Awerbuch applies a theory developed to price out the risks of financial assets to the very different risks of fuel prices, confuses costs with the rate of change in cost, and mischaracterizes the diversification of household assets and risks.

a) The Nature of Fuel-Price Risk

Q: What error does Awerbuch make in characterizing fuel price risks?

A: He assumes that oil prices behave like stock prices are assumed to behave for the CAPM: that they vary in a random walk. If this were true, the probability distribution of short-and long-term oil price changes would be the same after a sharp price rise as after a sharp price drop. That is now obviously untrue (although I will plead that it was not so clear in the mid-1980s, when many minds, including mine, were stuck in the old assumption that oil prices were driven by exogenous and inexorable forces). Oil is a resource market, and whatever goes up too far must come down.

Q: Does this tendency of fuel prices to compensate for fluctuations imply that oil prices are not risky?

A: No. Short-term price (or return) fluctuations may cause problems, but not on the order of long-term price fluctuations. Treasury bond prices vary, and tend to vary with the stock market (since they compete for capital) but T bonds do not have β risk, since their long-term return is assured. They do have a liquidity premium or term premium. Oil has some of the same characteristics, although it probably has a non-zero beta risk as well.

Oil price risk does not grow uniformly over time. If a risk-adjusted β were to be used to discount oil prices, it should reflect the low short-term risk, higher risk in the medium term corresponding to upward price fluctuations (on the order of 5 years), and lower (or negative) incremental risk beyond that time.

Q: What is the practical effect of this error?

A: Since Awerbuch thinks of oil as having unlimited β-type risk, he assumes that oil prices can rise rapidly for many years in row, and remain at high levels for long periods. On p. 38, line 3, Awerbuch posits "a twenty-year stream of high oil payments," and suggests that the price of oil would be so high that fuel-switching back to electricity would be cost-effective for the participant.

As shown in Exhibit ___ (PLC-42), oil prices have never reached parity with CV rates, and the more modest run-ups in oil price have resulted in strong downward market corrections. A customer who switched from electricity to oil for space and water heating in 1970 (at 1993 technology) would have experienced lower energy bills each year from 1970–93. These savings would have covered annual payments for the fuel-switching equipment of over $1,000.

Even though Awerbuch determines that a customer today would be better off with electricity than with oil, due to his perceived differential in risk, he has not considered whether an electrically-heated household that had converted to oil in the past would *ever* actually have been worse off with oil, given the great historical variability in actual oil prices. Exhibit ___ (PLC-

R43) shows the total heating and hot water bill for an electric space and water heating (S&WH) customer with total S&WH consumption of 16,000 kWh in each year 1970–93, compared to a customer with the same thermal loads but 80% as efficient oil S&WH systems. The oil-heated customer has lower heating bills in each year. This result can be attributed in part to the non-randomness of the oil-price walk through time: the rapid run-ups in 1974 and 1980 could not be continued, or even sustained.[10]

b) Confusing Costs with the Rate of Change in Cost

Q: How does Awerbuch confuse costs with the rate of change in cost?

A: Awerbuch does not compute the correlation of fuel prices or rates with market returns. Instead, he correlates the percentage change in price with return, which does not reflect the outcomes of concern to customers. Consumers are concerned with the size of their energy bill, rather than the change in their bills. A year in which energy bills rise from $500 to $550 is preferable to one in which bills fall from $1000 to $950. Yet Awerbuch's computations of β treat the first year as bad and the second as good.[11]

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[10]Since Exhibit ___ (PLC-43) also provides annual Vermont per-capita income, it can be used to place the hypothetical example on p. 19 of Bower's testimony in perspective. While Bower argues that an oil-heated customer will be worse when the economy is "doing badly," Exhibit ___ (PLC-43) shows that the oil-heated customer will actually do better in the electric-heated customers in poor years (1975, 1993), as well as in good years (1989). In fact, the oil-heated customer had a lower bill in 1993 than 1987, while the electrically-heated customer had a higher bill in 1993 (the bad time) than in 1987 (the good time). Bower's simple example does not fit reality any better than Awerbuch's theoretical model.

[11]The use of the percentage changes also distort results, since a 50% increase from $1 to $1.50/gal is treated as being larger than a subsequent 33% decrease from $1.50 to $1 per gallon, even though the two changes cancel out.

Awerbuch refers to the change in energy price as the "return on" oil or propane or electricity rates, as if the homeowner were an investor buying and selling fuel for speculative purposes. This treatment follows simplistically from Awerbuch's reliance on the CAPM, in which the return (or change in asset value) is the investment outcome for the year. The energy outcome for year is the bill, not the change in the bill. Using the change in energy prices as a measure of customer welfare would be like using the change in rates of return as a measure of investor welfare.[12] The energy bill, like the investment return, is a change in wealth.

I made this error seven years ago, and Awerbuch has faithfully reproduced it.

Q: Does this error matter?

A: Yes. Exhibit ___ (PLC-R44) shows an example in which two variables are positively correlated, and rise together. It is obvious that times with high values of x also have high values of y. Yet the change in y is negatively correlated with the change in x, and the β of one with respect to the other would be negative.

Q: Does that really happen?

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[12]Awerbuch's concept of a "return" on oil, electric rates, or "propane rates" is equivalent to the "risk-free return" column that he computes on p. 3 of Exhibit SA-1. On that page, unlike every other comparable page of the exhibit, Awerbuch computes the risk-free return as the *change in government bond yields* between years, rather than the yield on the bonds. I assume that the error in computation of the risk-free return on that one page is a spreadsheet-programming error, rather than a fundamental error in his understanding of the concept of return.

A: Yes. Exhibit ___ (PLC-R45) computes the βs with respect to Vermont personal income per capita of various fuels (Vermont residential #2 oil and propane, Massachusetts utility #6 oil, representing typical CV oil purchases) and various measures of CV residential rates. The fuel prices and electric rates are all positively correlated with income; Vermont's economy has tended to do well when fuel prices and electric rates are high.[13]

Exhibit ___ (PLC-R46) computes the βs of the *changes* in fuel prices and rates with respect to *changes* in Vermont personal income per capita. The βs of the changes are negative for all the fuels and for Rate 1. In other words, income tends to fall (or rise least) in years in which fuel prices rise, and rise when fuel prices fall. The annual changes in the variables are negatively correlated, even though the variables are positively correlated.

Awerbuch expected to find fuel prices negatively correlated with income, based on his readings of various wise men and of *US News and World Report* (p. 30). He thought that he had found such a relationship, but he had only found that the *changes* in income tend to be negatively correlated with *changes* in fuel prices.

Q: Is your positive correlation between fuel prices and income explained by an upward time trend in both variables?

A: It does not appear so. Fuel prices peak in the middle of the data set, and are not much higher at the end of the data period than at the beginning. Income does rise with time. The correlation of income with time is not particularly important, since we are not concerned with whether fuel prices *cause* income

[13] These effects are relatively weak for #6 oil and Rate 1.

to vary, but only with whether high fuel prices tend to coincide (for whatever reason) with low income; this is not the case.

To get a sense of how the correlation of income with time might affect the relationship between prices and income, I conducted a series of regressions. Exhibit ___ (PLC-R47) shows the results of regressions of Vermont per-capita income on various energy costs and time. Time is significant in each case, since incomes have risen secularly. With time in the equation, the coefficient of the fuel variable is negative for residential oil and propane use, utility #6 oil, and average residential electric rates, with #6 oil having a much more negative coefficient than the residential fuels (all measured in $/MMBTU).[14]

Hence, even if we looked at the time-trend-adjusted relationship between energy prices and income, which I do not believe is appropriate, residential fuels move in the same direction as average electric rates, and the utility's incremental energy source, #6 oil, moves much more than the residential fuels.

c) Diversification of Household Assets and Risks

Q: How does Awerbuch mischaracterize the nature of household assets and risks?

A: First, he assumes that the welfare of homeowners and renters is correlated with the financial securities market (actually, just the S&P 500, which is a small part of the total securities market). He even asserts (p. 23, line 22) that the stock market tracks performance of other assets, including housing. This

[14]These negative coefficients may result from the non-linearity of the time trend, and should not be taken too seriously.

is very unlikely. The annual economic outcome for most household must depend on earned income (supplemented by investment income and government assistance), net of fixed (or hard-to-control) costs. For renters, high housing values increase costs, and decrease discretionary income.

Second, as an afterthought, related to an obscure argument about whether fuel switching is a "public" project, Awerbuch does look at the correlation between average residential rates, oil, and personal income, but only for *total national* personal income (not Vermont income, or per-capita income), and again only for changes in the variables, not their actual values.

Third, while he notes that heating bills are a large part of household income, Awerbuch ignores the fact that electric heating bills are a large, non-diversifiable risk for individual households. An increase in electric rates can cause a household income crisis in itself. Since electric heating bills are higher fraction of household income than fossil heating bills, the disposable income of electric-heating customers will correlate with electric rates more closely than the disposable income of fossil-heating customers will correlate with fuel prices.

Exhibit ___ (PLC-R48) shows how changes in electric and fuel prices might affect a typical fuel-switching candidate. Using electricity for space and water heating, the customer is subject to an increase of $228 from a 10% increase in electric prices (including non-heating uses), but only $60 due to a 10% increase in fossil fuel prices, including gasoline. Using oil, the customer might be subject to $108 higher cost due to a 10% increase in fossil fuel prices, and $62 for a 10% electric rate increase. The oil-heating customer's risks are smaller, and better diversified between electricity and fossil fuels. In addition, the oil-heated household starts with an energy bill $1,373 lower than the electric-heated household. Thus, electric heating customers are exposed to losing more dollars from an already smaller discretionary budget due to price fluctuations than are fossil-heating customers, for comparable price fluctuations.

Q: How should Awerbuch have compared the riskiness of alternative fuels?

A: He should have examined the correlation of fuel prices with respect to some measure of the welfare of Vermont households, such as personal income or disposable income per household. It is difficult to specify any unique measure of welfare for Vermont. Income is one candidate, but so are total energy bills, unemployment, income net of energy and some set of other fixed costs (a sort of statewide discretionary income), and other measures.

Exhibit ___ (PLC-R45) lists the correlations and βs for each of the fuels discussed above with respect to Vermont personal income per capita. The fuel prices and electric rates are all positively correlated with income: Vermont's economy has tended to do well when fuel prices and electric rates are high; energy prices have been low when Vermont personal income was low (and households most needed the low costs).

Exhibit ___ (PLC-R49) shows computations similar to those in Exhibit ___ (PLC-R45), but using Vermont unemployment rate as the measure of welfare. The significance of the signs of correlation coefficients is reversed in this case; negative values are good, since we want energy costs to vary inversely with unemployment rate. Rates 1 and 3 are negatively correlated with unemployment (which is good), but the average residential rate and the fuels are positively correlated with unemployment (which is bad). Among the fuels, #6 oil is three times as correlated with unemployment as is #2 oil, and ten times as much as propane. For comparison, Exhibit ____(PLC-R50) lists the correlation coefficients and βs for the changes in values, as they are erroneously computed by Awerbuch.

Thus, whether fuel-price variation is good or bad for Vermont depends on how Vermont's portfolio of welfare is measured. In any case, #6 oil is the riskiest fuel for the Vermont economy.

3. *Data Errors*

Q: What errors does Awerbuch make in selecting his data?

A: He makes several errors.

Total national income: As I mentioned above, in the limited analyses Awerbuch performs to measure variation of energy costs with respect to personal income, he uses national income, not Vermont income, and total income, not per-capita or per-household income. Awerbuch offers no excuse for using national income, and I cannot see why Vermont energy users would care about the correlation of their energy bills with income in Texas or California. Nor does Awerbuch explain why having more people in the country (which raises total personal income, all else equal) makes the country better off in that particular year.

New York data: Awerbuch uses New York, rather than Vermont, fuel prices, for some reason. I do not know whether this odd choice of fuel-price proxies matters.

Average rates: Awerbuch uses the average electric rate and Rate 3 (which he calls "controlled heating," for some reason) in his analyses. For space and water heating customers on Rate 1, the appropriate rate to use would be the tail-block rate, weighted by seasonal usage; tail block rates (especially heavily winter-weighted heating consumption) are likely to be more volatile than the average rate.

Data selection: For some of his analyses, Awerbuch uses a very peculiar 6-yr. period of data, from 1985–1990. Awerbuch also estimates βs for oil and average electric rates (but not his "controlled" rate, even though he presents the data) for 21-year periods, but the data still end in 1990.[15] Awerbuch provides 1991 data, including annual increases, for all his variables, and lists 1992 energy prices (1992 financial data are readily available), but apparently ignores these values in his computations. Some of Awerbuch's results may have been affected by his selection of analysis periods.

For some reason, Awerbuch's Exhibit SA-1 does not include a longer-term analysis of propane prices, even though that exhibit documents the derivation of a 5-yr. propane β and 5-and 20-yr. βs for all other variables. On p. 22, Awerbuch reports a twenty-year propane beta of-0.1, identical to the 20-yr. beta he reports for the "essentially riskless" residential electric rates. The remainder of Awerbuch's analyses ignore the 20-yr. propane and electric-rate betas, and use the 5-yr. oil and electric-rate betas.

Risk projections: Awerbuch assumes that the risks that he thinks he observes in the historical data will also continue into the indefinite future. There is a strong argument (supported by many academic economists and

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[15]Awerbuch refers to his analyses as producing 5-yr and 20-yr βs, since he use these number of annual changes. His only excuse for relying on the shorter analysis period (which reduces the apparent riskiness of electric rates, compared to oil and especially propane) is that stock betas are often computed for five-year periods (p. 21). Since stock prices are available daily, five years of stock price data can be a lot of data. For example, ValueLine computes βs for 5 years of weekly data, or 260 data points. Awerbuch has only 5 data points in a five-year series.

consultants specializing in the oil industry) that future oil prices will be less volatile than past ones, due to changes in oil market structure, diversification of sources, and the disintegration of OPEC solidarity. If Awerbuch's presumption were accepted by the securities market (in which he places great faith as a measure of value), he would be able to show that the stock market imputed a negative β to oil-producer resource bases. Oil would be a counter-cyclical investment, like gold, whose value traditionally rises in bad times. Awerbuch presents no such demonstration; I doubt that many major investors are betting on oil as a hedge against low market returns (or recession, or much of anything else, other than high oil prices *per se*). In any case, as shown in Exhibit ___ (PLC-R51), the βs of oil stocks are positive, suggesting that oil prices do not move in the counter-cyclical fashion assumed by Awerbuch and Bower.

4. Awerbuch's Theory is Inconsistent with Experience

Q: Is Awerbuch's treatment of risk supported by the empirical evidence in this case?

A: No. CV witnesses Deehan (e.g., p. 29, line 1) and Gamble complains that too many customers are switching fuels. As Deehan summarizes CV's position, customers make uneconomic fuel switches "due to their perceptions of private cost savings" (p. 22, lines 25–26). If customers really valued the risks of oil in the manner suggested in Exhibit SA-4, all of the conversions would be from oil to electricity, not vice versa.[16]

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[16]This would be especially true if the intangible costs discussed in several CV witnesses' testimony were added to Awerbuch's analysis.

5. Bentley's Application of Awerbuch's Risk Adder

Q: How does Bentley apply Awerbuch's risk adder in his revision of the societal test?

A: Incorrectly. As shown in IR 72, Bentley discounted his estimate of CV avoided costs at the 0.12% discount rate the Awerbuch estimated for residential electric rates.[17] Even if Awerbuch's computations were correct in the context of his preferred participant cost test, Awerbuch did not estimate the β of CV avoided costs. Bentley's application of risk-adjusted discounting is a chimera of participant and societal perspectives, and is totally meaningless.

Q: What would be the result of systematically applying Awerbuch's approach?

A: I conducted an analysis of some marginal fuel-switching options, using discount rates that appear to be consistent with Awerbuch's approach. CV's avoided fuel costs are #6 oil, the price of which is more volatile than the price of #2, or off-system sales into a market priced at #6 oil. As shown in Exhibit ___ (PLC-R52), the Awerbuch-beta for investors (using *changes* in oil price, as opposed to the real β for oil users, which would use the actual oil price in each year) of #6 oil with respect to the S&P 500 is-0.46, compared to the-0.7 Awerbuch uses for #2 oil. I discount all non-fuel costs at the 7.1% Awerbuch (p. 34) uses for oil-heating maintenance and replacement costs. Based on Awerbuch's estimate of propane beta of-0.1, I use a 5.16%

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[17] I will identify response to DPS discovery on CV's direct case as "IR xx." Earlier discovery responses will be identified by set number, as in my direct.

discount rate for propane (a risk-free rate of 6%, plus-0.1 x 8.4% market risk premium).

The results of a series of fuel-switching analyses are shown in Exhibit ___ (PLC-R53). Each page shows the results for switching a high-use ripple-controlled water heater to oil or propane, in a high-cost installation, using the RII avoided costs. Page 1 shows the results for the standard discounting rules: the oil option is cost-effective, while propane is not. Page 2 shows the results of discounting all oil (and off-system sales) costs at the 0.12% rate computed by Awerbuch for residential heating oil, propane at 5.16%, and non-fuel costs at 7.10%; oil remains cost-effective, although only marginally, while propane is cost-effective by a wide margin, due to the reduction in discount rate for avoided oil costs. Page 3 shows the same risk-adjusted computation, but uses oil discount rates derived from the βs computed in Exhibit ___ (PLC-R52); recognizing the higher risk of #6 oil, compared to residential #2 oil or propane, results in very high net present values for both the oil and the propane conversions.

These computations follow Awerbuch's approach as measuring risk in terms of changes in variables, and computing systematic risk with respect to the S&P 500. I do not believe that the results are particularly meaningful. As shown in Exhibit ___ (PLC-R45), residential oil and propane prices actually have a risk-mitigating effect on Vermont personal income, so it is not clear that a downward adjustment in discount rates is justified. However, if dependence on oil is risky, fuel switching reduces that risk, and more fuel switching is cost-effective when that risk is consistently reflected in discount rates.

B. Other Risk Issues

Q: On what basis do Awerbuch and Deehan critique the Board's 10% risk-based preference for DSM?

A: Awerbuch argues that fuel-switching is inflexible and that supply resources can also have short lead times and small unit sizes (pp. 11–19, 48–52). Awerbuch ignores

- the load-following benefits of DSM, including the increase in the number of installations as load grows, and the increased savings when equipment is used more heavily in extreme weather and economic boom times;[18]
- reduced fuel risk, due to the reduced amount of fuel required for direct fossil heating;
- avoided or highly diversified risks of construction cost overruns and schedule slippage;
- avoided or highly diversified risks of reliability in operation, and premature retirement.

Awerbuch compares the size and lead-time of DSM resources, not to the large units in CV supply plan, but to small, expensive, inefficient units that are not important resources for any major utility. If CV's supply plan consisted only of these small units, direct avoided costs would be much higher.[19] Deehan (p. 13, lines 16–19) notes that these "small increments" of supply are available, but does not suggest that CV will actually acquire any

[18]Deehan (p. 13) asserts that retrofits have no load-following benefits, apparently based on the misconception that only installation rates (and not utilization) follow load.

[19]As I noted above, Awerbuch also argues that CV will adopt solar and renewable energy faster than its customers.

such resources. He only notes that "bidding procedures are likely to identify these opportunities where economic." In addition, CV's current supply mix consists largely of Vermont Yankee, a highly risky resource.

On pp. 11–19, Awerbuch argues that fuel-switching lacks flexibility, due to the commitment to the furnace or boiler. In contrast, Awerbuch considers supply options to be flexible, since generators can be repowered, or even sold.[20] However, he ignores fact that most of fuel-switching cost is fuel, which is not as committed as capital.[21] Fuel use provides automatic flexibility, in that the cost is incurred only to the extent that it is needed; fuel costs are reduced when the weather is warm, the house is vacant, and especially if it is demolished. If oil and propane prices rise, gas service is likely to be extended, allowing additional systems to be converted to use natural gas. Some systems will also be convertible to wood: at least the distribution equipment and flue are in place. In any case, Awerbuch has not demonstrated that fuel-price increases of a magnitude large enough to cause significant regret are likely or plausible.

Deehan (p. 13) asserts that customer control and a "large and variable" fuel cost component creates a "persistence risk" with respect to fuel switching. As shown in Exhibits ___ (PLC-42 and 43), even the wide historical swings in oil prices never made electricity competitive with oil.[22]

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[20]Perhaps Awerbuch could suggest a strategy to CV to recover its sunk investment in Vermont Yankee.

[21]His arguments about flexibility cut against his general preference for solar and renewable technologies.

[22]If, at some point in the future, electric costs are very low and oil prices manage to become (and stay) very high, some switching back to electricity could occur. Since this would presumably occur at a time that electricity is inexpensive to produce and deliver, it would

III. The Social Cost of Rate Impacts

Q: Who discusses the social costs of rate increases?

A: This issue is developed primarily by Bower, summarized by Deehan, and applied by Bentley, who also estimates the rate impacts of DSM and fuel switching.

Q: Please summarize Bower's testimony on rate impacts.

A: Bower starts with the observation that higher electric rates tend to result in lower electric sales. He then estimates the magnitude of the sales reduction per unit of rate increase (the price elasticity) and uses a very simple theoretical model to translate that reduction in electric sales in a cost to customers.

Bower assumes a long-run price elasticity of demand for electricity of-0.7; based on this, he finds that an increase in electric rates of 0.36¢/kWh (or 2.84% of the 12.67¢ rate without the increase) would decrease sales by 2%, or 60 GWh/year. Bower further assumes that each avoided kWh avoids costs, including environmental externalities, of 7.27¢/kWh, but that customers value the reduced energy consumption at the average of the pre-and post-increase rates (or 12.85¢/kWh). Hence, he concludes that each kWh of savings due to the rate effect is a 12.85-7.27 = 5.58¢ loss to society, and that the annual *loss* to society from the price increase is 60 GWh x 5.58¢/kWh, or $3,348,000.[23] Deehan and Bentley refer to this as a *dead-weight loss.*

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impose no great burden on CV or its successor utility. These circumstances seem unlikely to occur soon enough to substantially affect the cost-effectiveness of fuel-switching options.

[23]This 60 GWh/year is a decline compared to what sales would have been with no price increase, and it takes place over a period of time.

Q: Is Bower's analysis correct?

A: His basic point is correct. Increased electric rates do reduce sales. Prices that are above marginal costs can result in customers taking uneconomic actions to reduce their energy use. Bower's computation simply repeats a portion of the analysis of various authors who have developed "new" DSM tests, including Hobbs (who seems to be the seminal source in this field), the other references Bower provided in IR 35, and Chamberlin and Herman.[24]

Like these earlier publications, Bower errs in glossing over the question of *when* customers make the estimated reduction in usage, and in equating all reductions in electric use with costs to society. Unlike those other analyses, he ignores the offsetting societal benefits of DSM. The question is not just how much customers conserve, but when and how they do so, and what else they are doing at the same time.

It is also important to recall that the relevance of Bower's argument hangs on the relationship of marginal costs and rates. Deehan admits that "rate increases...give rise to real societal resource costs *when rates are already above marginal costs*" (p. 14, lines 13–14, emphasis in original). If marginal costs plus externalities exceed tail-block energy rates, as they well may, rate increases move prices towards marginal costs.

Q: Are CV rates above marginal costs?

A: CV certainly thinks so. Bower makes this assertion (based on CV representations to him, not his own analysis), as do Deehan (p. 15, lines 7–8; p. 26) and Spinner (p. 3, lines 15–16).

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[24]Chamberlin, John, and Patricia Herman. 1993. "Why All 'Good' Economists Reject the Rim Test, *Proceedings: 6th National Demand-Side management Conference EPRI* TR-102021. Palo Alto: Electric Power Research Institute, pp. 231–237

This is not an issue that I have explored in depth. However, the avoided costs I developed for screening DSM measures can give us a first cut on this issue. Spinner's claim that Rate 3 is priced below long-run marginal cost is based on "a quick estimate of today's long-run marginal costs" short-run fuel costs of 2.5–3.5¢/kWh plus 1.2¢/kWh for capacity, compared to an average rate of 7.1¢/kWh. This computation ignores metering, billing, and other customer costs, even though the customer charge appears to be included in the average rate computation. It also excludes T&D capacity, losses, externalities, and capitalized energy. My estimate of real-levelized avoided costs for Rate 3 (from our measure-screening results and work papers, previously provided) are 10.2¢/kWh for clock control and 8.9¢/kWh for ripple, respectively 44% and 25% higher than the current rate.[25]

The current level of Rate 3 is clearly below real-levelized avoided costs, which are less than the long-run marginal cost (since early years with lower marginal costs are averaged in) and any increase in rates would improve price signals (Dehan, p. 39, line 7–10). Rate 14 is even further below marginal cost, and some of the other controlled rates also appear to be well below marginal cost, although I have not computed avoided costs for the load shape of each rate. I doubt that any CV rate is significantly above long-run marginal cost.

If rates are not above long-run marginal costs, Bower's argument reverses. The dead-weight loss becomes a windfall gain.

[25]Rate-3 marginal costs also include marginal customer costs, since the Rate-3 meter is required only for water heating, so the rate is even more under-priced than is suggested by the comparison of avoided demand and energy costs.

A. *Prices and Sales: the Long and Short of Elasticity*

Q: Over what time period do rate increases affect energy consumption?

A: Some effects of the price increase would be nearly instantaneous: the increase will encourage consumers to turn off unneeded lights, use less hot water, let soup cool more before putting it in the refrigerator. Others phase in over time: the increase may influence decisions about the efficiency, size, and features of appliances they purchase, homes they buy, and retrofit projects, including fuel switching and insulation. Some of those decisions may be made within a year or two of the increase, but others will not occur until ten or twenty years have elapsed. Some of the short-run effects may be replaced with long-run effects, as customers replace an inefficient system they were reluctant to use, with an efficient one they can use more.

Bower's estimated sales reduction of 60 GWh per year is the long-run price-elasticity effect of the initial rate increase. Similarly, $3,348,000 is the annual loss in the long run.

Q: What effect does the timing have on the value of customer response to the rate increase?

A: By the time Bower's sales reduction in sales takes place, the discounted value will be small, and many other events will have obscured the effect. Bower estimates short-run price elasticity to be -0.2 (IR 43). If the sales reduction is phased from short-run to long-run elasticity over twenty years in a roughly linear fashion, and the value of the loss were actually $3.3 million at the long-run value, it would be less than $1 million in the first year, about

$1.1 million in the second, and so forth.[26] At a 9.25% discount rate, the annual levelized cost of this loss, over the phase-in period, is $1.7 million, about half the $3,348,000 suggested by Bower.[27]

Even this estimate overstates the long-run effect of the initial rate increase. The peak rate effect of the implementation period will decline over time, as the DSM costs are amortized, the uneconomic investments that make rates higher than marginal cost are depreciated, CV's front-loaded power-supply contracts (especially Hydro Quebec) become more competitive, and avoided costs rise. As the rate differential between the base case and the DSM case declines over time, the effect on load declines and may reverse.

B. Price, Sales, and Losses to Society

Q: Would Bower's application of Hobbs' approach to valuing the sales reduction due to increased rates be correct, if it were modified to reflect timing, as you describe above?

A: No. Bower assumes that all incremental price-induced conservation is economically inefficient.[28] Not all reductions in loads are costs.

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[26]Bower asserts that 85% of the elasticity effect would occur within five years (IR 45). This estimate is derived in IR 45 from Bower's unsupported assumption about the functional form of the transition from short-run to long-run elasticity (Bower introduces the functional form with "assume that the basic relationship is...") and an equally unsupported coefficient ("assuming that...b = .286"—an assumption that Bower does not support in any way). Bower's assumed transition path is inconsistent with any major role in long-run elasticity for responses that take a long time to reach maturity, including appliance efficiency, appliance size, fuel choice, or building-shell efficiency.

[27]The levelized cost varies with the discount rate and the period over which the load reduction is phased in.

In the past, the period for which Bower's estimates of elasticity were developed, the costs represented by the demand curve, and hence the reduction in load due to a price increase, would comprise different costs that come into play at different times:

1. The implicit cost to ratepayers of better housekeeping: being more aware of energy usage, remembering to turn off lights as they leave the room, fixing leaking hot-water faucets sooner rather than later, teaching their children to use electricity carefully;
2. The inconvenience of becoming more knowledgeable about energy use and efficient appliances, so as to make investment and purchasing decisions;
3. The lost amenity value of accommodating to a lower level of energy use, such as wearing a warmer sweater in the house;
4. The implicit cost of a lower quality of energy services, such as being cooler, using a smaller refrigerator (or one without an ice maker), or getting up in the middle of the night to turn off a light;
5. Any direct damages from reduced energy services, such as health problems from very low thermostat settings;
6. The inconvenience of purchasing and installing energy-efficient equipment (such as CFLs);

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[28]Bower ignores all market barriers, assumes that all cost-effective efficiency actions have been taken, treats the demand curve as a series of rational tradeoffs between the cost of electricity and the costs of doing without electricity, and thus concludes that any further reduction in consumption must be inefficient, so long as rates exceed marginal cost. This flawed line of reasoning also leads to the RIM test. Bower's reification of the abstract demand curve is reminiscent of Awerbuch's treatment of the CAPM: each witness assumes uncritically that a model represents reality, and each is lead to erroneous conclusions.

7. The incremental cost of an efficient appliance or insulation; and

8. The inconvenience of selecting contractors, and specifying and schedule the installation of energy-efficiency measures and fuel switching.

Some of these items though costs in the economic sense, are actually activities that are socially encouraged, such as responsibility (#1) and education (#2). Other items are real costs, but do not impose a burden on the state's economy; this category includes responses that involve lower levels of comfort (#3 and #4) or require a little extra work (#6 and #8).[29] Only items such as #5 and #7 impose the sort of cash costs that would be reflected in state income accounts.[30] Foregoing energy-using appliances and extra features (part of item #4) will usually reduce the household's capital expenditures, as well as its electric bill.

DSM programs further reduce the costs of items #2, #6, #7, and #8. For example, the inconvenience of selecting contractors and specifying and scheduling retrofit work is reducible through well-designed utility DSM programs that reduce participant effort and risk. Thus, one of the effects of a rate increase may be increased (and more enthusiastic) participation in utility DSM programs. Another effect may be that the same level of participation can be maintained with smaller utility incentives. Thus, what might have been a cost without DSM programs becomes a benefit with DSM.

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[29]The customers who react in this way incur costs only to the extent that they do additional work. The extra work and the extra cost negate one another, leaving no change in Vermont economic activity or disposable income.

[30]Item #5 also imposes health costs that are quite real, even if they are small and are not captured in income accounts.

In sum, only a portion of the elasticity response reflects real costs in any sense, and even a fraction of those costs are simply nuisances and inconveniences, even in the pre-DSM era.[31] The small portion of the elasticity response that corresponds to real reductions in Vermont's disposable income or productivity is further reduced by the existence of DSM programs. Exhibit ___ (PLC-54) illustrates the way these effects might change over time, and indicates which of them are cash costs.

Q: Why does Bower count these reducible costs as though they were costs of DSM?

A: Bower's analysis may have been influenced by his assumption that there are "no significant market barriers" to fuel switching (p. 16). Reducible costs are exactly what the Department and the Board have referred to as market barriers, and if there are no market barriers, then it must follow that no costs are reducible. (Conversely, the reducibility of costs demonstrates the existence of market barriers.) Consequently, Bower treats all costs as irreducible, whether they are or not.

In fact, a rate increase may inspire a customer to go looking for a more efficient appliance, but an effective DSM program may result in the customer bearing little additional cost to reduce his energy use.

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[31]Bower cannot estimate the mix of these effects (IR 41, 43), although he believes that the availability of fuel-switching would increase the elasticity in space and water heating (IR 42), implying that other end uses would have long-run price elasticities more moderate than-0.7. Bower's responses suggest that a significant portion of his perceived social costs would consist of cost-effective fuel-switching from electricity to fossil fuels.

C. *Offsetting Societal Benefits of DSM*

Q: Does Bower's testimony discuss all of the modifications of the societal cost test that are discussed in the literature that developed the rate impact feedback analysis he presents?

A: No. First, many of the articles in Bower's bibliography (IR 35), starting with Hobbs, as well as Chamberlin and Herman, discuss *rebound,* the increase in consumption due to the lower cost of energy services for participants.[32] Bower's testimony mentions rebound only as a contributor to increased emissions, and ignores the economic effects of the rebound itself. As discussed in some detail by Hobbs and others, any increase in energy use due to the reduced cost of energy services (e.g., a lower annual cost to keep a home at 56°, rather than 55°) implies that the participants value the increase in service more than the increase in the bill (at the low post-DSM cost per degree Fahrenheit). Assuming that rates are at least as high as marginal costs (as CV certainly contends), the cost of the rebound is less than the bill increase, and hence less than the benefits. The net benefits of a measure that reduces usage from A to B, but then results in rebound to C, are thus

a. avoided costs (A→C)
b. + customer rebound benefits (B→C)
c. - avoided costs due to rebound (B→C)
d. - measure costs

[32] This is also true of Stoft and Gilbert, provided by Bower in IR 34, p. 17, and quoted by Bower in IR 47.

Since (b) > (c), this net benefit is greater than the simple societal benefit estimate of (a)-(d).[33] The Board recognized in Docket No. 5270 GMP-1 that rebound increases social benefits. Bower fails to acknowledge the social benefits of rebound, even while deploring its minor environmental costs.[34]

Second, a number of critiques of the societal test note that DSM programs reduce measure costs to free riders, through group purchasing, reduced transaction costs, simplified participation. This reduction in societal costs should also be included in the societal test.[35]

Bower's direct testimony ignores both of these effects (other than the selective reference to rebound in his discussion of environmental effects), both of which increase the net value of the societal test.

Q: Are there additional indirect societal effects of fuel switching that Bower ignored?

A: Yes. Bower ignores the increased attractiveness of Vermont with DSM than without. Using fossil fuels rather than electricity for heating space and water will reduce the cost of living and doing business in Vermont. The increase in disposable income and in business activity would be beneficial to the Vermont economy, and may even increase demand for CVPS electricity,

[33]I have generally interpreted the total resource cost test or societal test to include the benefits of rebound, so I do not consider inclusion of this effect as a deviation from the societal test.

[34]Bower had several opportunities in his discovery responses (IR 34, 38, 47) to correct this oversight. He does not include rebound benefits in any of his own list of corrections to the societal test, but does admit that rebound should be treated as a benefit, when forced to confront the issue directly (IR 38.d.i, 47).

[35]On discovery, Bower acknowledges this benefit (IR 34.d.iii), if only grudgingly and by excluding these "real transaction savings" from a general exclusion of effects on free riders.

through increased prosperity rather than through the inefficient use of electricity for heating space and water. This broader regional rebound effect will tend to reduce CV electric rates, offsetting any undesirable effects that might actually occur as a result of slightly higher rates.

Bower also ignores the effect of gas conversions on gas rates; if falling electric sales increase electric rates and push them away from marginal costs, rising gas sales would decrease gas rates and move them closer to marginal costs.[36] Bower refuses to include this rate effect for gas conversions, other than as they affect the participants in fuel switching (IR 34.d.ii).

Q: What is the net social effect of a rate increase due to DSM?

A: Depending on the relationship between marginal costs (including externalities) and tailblock rates, there may be a small social cost or benefit due to increased rates. If there is a net cost of the rate increase itself, it is likely to be largely or entirely offset by rebound, free-rider benefits, increased economic prosperity, and (for fuel switching) beneficial effects on gas rates.

Q: How does Bentley apply Bower's adjustment?

A: Bentley assumes that the dead-weight loss is 5.5¢/kWh saved by fuel-switching, starting in the first year after implementation. In his example (IR 72), saving 7,100 kWh results in a loss of 7100 x 0.055 = $391. This treatment implies that the long-run elasticity equals the short-run elasticity, and that both are-1.0, not the-0.7 and-0.2 Bower estimates. On the other

[36]This observation assumes that VGS rates are above marginal costs. Given the economies of scale in gas transmission and distribution, and the incremental costing of expansion on the Trans-Canada Pipeline, this seems likely.

hand, Bentley includes only one year of the rate effect, which understates the effect Bower would estimate.

Q: Is Bentley's application of Bower's adjustment correct?

A: No. In addition to Bentley's multiple errors in applying Bower's estimates, Bentley grossly overestimates the difference between marginal costs and rates. None of CV's rates appear to be much above long-run marginal cost, and many are well below marginal cost. Hence, Bentley should be computing a windfall gain, not a deadweight loss.

Bentley's computation of the effects of DSM on the societal test should also include rebound, benefits to free riders, benefits to Vermont Gas customers, and the economic stimulus of lower bills.

IV. Environmental Externalities

Q: Who testifies on environmental issues for CV?

A: Various parts of this topic are addressed by Bennett and Hanisch, Bentley, Bower, and Deehan. The only environmental position taken in Deehan's testimony summarizing CV's recommendations is that the Board not use the 5% environmental externality adder for fuel switching. Bower and Bennett and Hanisch also urge that the 5% adder be discontinued, at least for fuel-switching.[37] The DPS-RII analyses did not use the 5% adder, but used pollutant-specific values from the stipulation in Docket No. 5270-CV-4. Other positions expressed by Bennett and Hanisch, and Bentley, include the

[37] Bower also offers some confused comments on the computation of externality values (p. 14. line 12–22) and his selective argument on rebound (p. 14, line 22–p. 14, line 9), which I discuss in §III.C.

assertions that emissions from electric generation are lower than those from direct fossil combustion, that fuel switching will increase Vermont air pollution, violate Vermont air-quality standards, and increase Vermont compliance costs.

Bennett and Hanisch provide the bulk of CV's data and analysis on environmental effects, but actually provide little substantive support for CV's positions.

A. *Estimates of Electric system emissions*

Q: Does CV properly compute the emissions reduction due to fuel switching and decreased electric generation?

A: No. CV's estimates of emissions from electric generation are consistently understated, as can be seen by comparing Exhibits JLH-1 to 4, and p. 13 of Exhibit JLH-5, to the documented emission results in Exhibit JJP-15.

For example, Exhibit JLH-4 shows electric-utility emissions of CO_2 decreasing by 50,000 tons in 1996 in conjunction with an identical 50,000-ton increase in emissions from fossil combustion in Vermont. Exhibit JJP-15, page A-5, shows a 41,000-ton decrease in electric emissions in conjunction with a 10,000-ton increase in emissions from direct fossil use.[38] The 4:1 ratio of emissions in Exhibit JJP-15 is easily shown to be about right: the marginal source of electricity in 1996 is a #6-oil boiler, operating at about 34% efficiency and 15% line losses, or roughly 29% delivered efficiency. The direct fossil uses are roughly 80% as efficient as electricity at the end use, or

[38]Bennett and Hanisch assume 100% of electric space-and water-heating customers fuel-switch in some analyses, while in others they assume 80% switch. Resource Insight estimated about 30% participation.

2.75 times as efficient as delivered electricity. If the carbon content per MMBTU of the #6 oil is about 40% higher than that of the average fuel-switching fuel, the ratio of carbon saved to carbon emitted by the fuel switch would be just the 4:1 shown in Exhibit JJP-15.

CV's estimates of electric emissions also jump around from year to year, as shown in Exhibits JLH 1-4. There is no reason for these emissions to change so abruptly: CV's emission rates are simply wrong.

Q: Why are Bennett and Hanisch's emission rates so different from those you developed?

A: Unfortunately, despite the extraordinary bulk of their exhibits, Bennett and Hanisch do not provide any derivation of the electric emissions they used in their analyses, so it is difficult to be certain how CV wound up with understated emission rates. However, the primary reason for CV's understated and erratic emission rates appears to be reliance on an own-load dispatch simulation (IR 1), similar to, not identical to, that in Bentley's avoided costs.[39] It is certainly clear from Bennett and Hanisch's testimony that they confuse CV's own-load dispatch with the real changes in emissions that occur due to changes in CV load.[40]

Bentley also attempts to conflate CV's generation mix with the marginal generation mix (p. 23, lines 4–5), but admits that basing emissions estimates on CV own-load dispatch is incorrect, and that emissions are actually determined by NEPOOL dispatch (p. 20, lines 16–23).[41] Bentley does not

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[39]See pp. 11 and 21 of my direct testimony.

[40]See p. 3, lines 12-14; p. 5, line 5.

[41]Bentley (p. 28; IR 73) argues the inclusion of Merrimack 2 in CV emissions overstates emissions, compared to realistic NEPOOL emissions. However, Bentley fails to note that (1)

explain why CV intentionally used the wrong method for estimating emissions rates. In any case, my direct testimony provides the correct approach.

Q: Does CV direct testimony on electric emissions demonstrate any problems other than the use of own-load dispatch?

A: Yes, CV's witnesses are confused about a wide range of issues.

- In JLH-5, Hanisch (p. 12) expresses the opinions that nuclear should be assumed to be part of the NEPOOL margin, and that nuclear could be the marginal fuel for NEPOOL dispatch even though oil plants were running.[42]
- Bennett and Hanisch suggest on page 9 that some of the understated electric emissions decreases they report will not occur "as it is unlikely that some of the power plants will be capable of changing their production to adjust for such a small change in demand." Bennett and Hanisch do not indicate what they think happens to the excess energy that is generated but not consumed.
- A cryptic note on p. 13 of Exhibit JLH-5 notes without explanation that "electric generation was adjusted by 80%" in the comparison of electric and fossil fuel emissions.
- Bentley is also confused about emissions. On page 23, lines 4–5, he confuses the mix of installed capacity with the marginal energy mix.

Merrimack is only included in CV dispatch until 1998 and (2) he assumed that a large portion of avoided energy in that period came from Vermont Yankee, understating emission estimates.

[42]I assume that Hanisch is the author of Exhibits JLH-5, 8, and 10, even though the reports do not specify an author.

- Bentley asserts that fuel-switching does not lead to large peak reductions, compared to the energy reduction and thus is not particularly "well-suited to reduce peak loads and thus to reduce emissions from fossil-fired power plants running on the margin" (page 23, lines 1219). This question and answer confuses the concepts of *peak* (the hour(s) with the highest load) and *margin* (the last kW in each hour), and also incorrectly assumes that fossil fuels are marginal only in peak hours.

The documentation of Bennett and Hanisch's assumptions about electric emissions (IR 1) demonstrates a number of errors, most of which understate electric emissions. Some of the avoided generation and emissions data (and the implied emission rates) are reproduced in Exhibit ___ (PLC-55) to Exhibit ___ (PLC-57).

- Bennett and Hanisch assume that a significant fraction (13–30% in the 1990s) of marginal energy comes from a mysterious "other" source with no emissions. This may be a disguised application of their assumption that nuclear plants are sometimes the marginal resources on the NEPOOL system. Exhibit ___ (PLC-56) lists the percentage of avoided energy that Bennett and Hanisch assume is from the zero-emission "other" resource.
- As summarized in Exhibit ___ (PLC-57), the "firm pool purchases," which appear to represent capacity purchases, have reasonable oil-steam emission rates for 1994–1998,[43] but from 1999 onward are

[43]It is not clear what these purchases represent before 1998, when CV plans to purchase 50 MW of oil-steam capacity. Like CV's planned oil-steam purchase, these firm purchases disappear after 2005.

assumed to have the emission characteristics of gas-fired combined-cycle plants.[44] CV's most recent resource plan and avoided costs are premised on purchases of cheap old oil-fired capacity, not expensive new gas combined-cycle.

- As also summarized in Exhibit ___ (PLC-57), the "non-firm pool purchases," which appear to represent economy energy purchases, have emission rates that are far too low for oil, even though Bennett and Hanisch claim to have assumed that oil is the marginal fuel on the NEPOOL system and the source of CV purchases.[45]
- Bennett and Hanisch assume that fuel switching will result in reduction of generation from a CV baseload combined cycle, starting in 1999. CV does not have any combined-cycle units in its supply plan until 2000.[46]
- For some reason, Bennett and Hanisch assume that fuel-switching would actually *increase* Wyman output in 1999, while decreasing

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[44]I provide Bennett and Hanisch's estimates of emission rates from Wyman 4, which burns low-sulfur (0.5%) oil. Other oil plants in New England would he similar emissions, although most burn higher-sulfur oil.

[45]The year-to-year variability is partially due to the rounding in the data Bennett and Hanisch provided.

[46]It is not clear whether Bennett and Hanisch treat the construction of the combined-cycle to be avoidable, or only its dispatch. CV's avoided costs treat only 2.86 MW (15% of the load decrement) of combined-cycle as avoidable in 2000, rising linearly to 100% of the load decrement by 2006 (IR 7-6).

emissions of cleaner resources.[47] This change in mix is difficult to rationalize.

- Bennett and Hanisch apparently assume that McNeil operates on 100% gas throughout the analysis period.

B. Violation of Air Standards

Q: What do Bennett and Hanisch conclude about the effect of fuel-switching on violation of Vermont air standards?

A: In Exhibit JLH-8, Table 2 (p. 6) Bennett and Hanisch estimate that a single-family home can emit enough arsenic and nickel to exceed Vermont "action levels," and that five homes aggregated as a "townhouse" could also exceed the action level for cadmium. In Exhibit JLH-8, Table 3 (p. 6), Bennett and Hanisch estimate that either housing type could slightly exceed Vermont hazard limiting values for chromium and nickel.[48]

Q: What is the significance of these results?

A: Not much. The action levels are simply administrative tools to determine whether further analysis is required, under regulations that do not apply to residential heating systems (Bennett and Hanisch p. 14).

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[47]The mysterious "other," the non-existent CV combined-cycle plant, firm purchases from NEPOOL's non-existent surplus of combined cycle, and non-firm purchases from some mysteriously clean source.

[48]Bennett and Hanisch (p. 20) say that they concentrate on oil because "established emission standards are not yet available for hazardous emissions factors for hazardous air contaminants in natural gas and propane," but they do not establish that there *are* any hazardous contaminants in gas and propane.

The HLVs apply only to the industrial facilities that fail the action level screen, and represent peak annual ambient air levels. The maximum value is converted to an annual average by multiplying by 0.1 (p. 10). This value may be appropriate for base-load industrial operation, but seems unlikely for a low-load-factor load such as heating. The ambient air levels in Table 3 correspond to the worst case in terms of location, wind flow, atmospheric stability, and terrain; more detailed analysis shows much lower emissions and no exceedences of the HLVs (Table 6).

In addition, Bennett and Hanisch overestimate fuel use. All of Bennett and Hanisch's analysis are conducted for heating, rather than water heating. Water heating dominates fuel-switching potential but produces smaller peak emissions per household.[49] They assume the heating system uses 1 gallon/hr; for the action-level analysis, they assume continuous operation at 1 gallon/hr.[50] This fuel use is equivalent (at 80% efficiency) to about 32 kW of heating load, which at a 30% load factor would imply heating energy use of over 80,000 kWh, roughly five times the average space-heating usage 17,451 kWh reported in Exhibit JLH-5, Table 1. For the analysis of action levels, Bennett and Hanisch assume continuous operation at these phenomenal levels for 8 hours. Remarkably enough, Bennett and Hanisch use this inflated value for townhouses, as well as single-family homes.

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[49]Gas water heaters are rated at 84,000 to 105,000 BTU/hr, or roughly 0.6 to 0.8 gallon/hr. Since water-heating loads are not as coincident as space-heating loads, the peak usage for Bennett and Hanisch's "townhouse" would be considerably less than five times these values.

[50]A house that uses 1 gal/hr, at a 30% load factor, would use about 2,500 gallons/year. This would be a very large oil user, even with the relatively low shell efficiency typical of older oil-fired homes. For a converted electrically-heated home, fuel use is likely to be still less.

C. Net Effects on Vermont Air Pollution and Compliance Costs

Q: Do Bennett and Hanisch demonstrate that Vermont pollution would increase significantly due to a fuel-switching program?

A: No. At page 10, they assert that the fuel switching would increase emissions of criteria pollutants in Vermont by 2–3%. This figure is not the percentage increase in Vermont emissions, since it is the ratio of Bennett and Hanisch's estimate of fuel switching emissions (for an unrealistic 80% of customers switching, and without any fossil conservation measures) divided by Vermont *power plant* emissions.[51] But Bennett and Hanisch report that all regulated sources produce only 1020% of Vermont emissions, and power plants are probably only a small part of regulated emissions in Vermont. Hence, the increase would be more like 0.1% to 0.6% of Vermont emissions, even under Bennett and Hanisch's unreasonable assumptions.[52]

Bennett and Hanisch include emissions from vehicles delivering fossil fuels as part of the costs of fuel switching (p. 4), but fail to include any similar secondary environmental effects related to electric power delivery, such as from T&D maintenance and construction. The magnitude of Bennett and Hanisch's estimate of these secondary effects is smaller than the uncertainties in emission factors, and is of no practical significance.

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[51]Bennett and Hanisch assume 80% participation in fuel-switching in Exhibit JLH-5 (p. 5). Other parts of their analysis may assume 100% participation.

[52]Bennett and Hanisch also point out that the decrease in regional emissions due to reduced generation from dirty utility plants would be a smaller percentage of NEPOOL power plant emissions than end-use fossil fuel emissions would be as a percentage of Vermont power plant emissions. Even Bennett and Hanisch admit that the end-use emissions are much smaller than the reduction in power plant emissions; they attempt to distort the relative size of the impact by dividing by different divisors.

Bennett and Hanisch also claim that propane emits a significantly higher level of air pollution than natural gas (page 3, lines 10-12). Exhibit ___ (PLC-58) shows that this is not true, even for Bennett and Hanisch's assumed emission rates. That exhibit also shows that the updated EPA data used by Bennett and Hanisch generally indicates lower propane emissions than the data I presented in my direct.

Bennett and Hanisch seem generally confused about the difference between the origin and the fate of emissions (e.g., p. 14, lines 3–6). Emissions from outside the state blow into Vermont, and Vermont emissions blow out. Bennett and Hanisch avoid any comparison of ambient air toxics, or deposition of toxics, from in-state and out-of-state generation, with the amounts produced by in-state fossil end uses.[53]

Interestingly, Exhibit JLH-9 indicates that the wind blows from south and southeast (at least in Burlington) more often than I thought when I wrote my direct testimony. This suggests that fossil generation in southern NY, western Massachusetts, and Connecticut may contribute more to Vermont air quality and environmental problems than upstate New York and Ontario. In any case, marginal regional electric energy sources are upwind of Vermont, and reducing Vermont electric generation will reduce those emissions.

Deehan relies on Bennett and Hanisch's claim that the environmental benefits fall outside Vermont (p. 17).[54] All of CV's conclusions on environmental effects are dependent on this flawed assertion.

[53]Indeed, the major problems with air toxics may be deposition into water supplies and the food chain, rather than ambient air concentrations.

[54]Bower (p.14, line 1–11) makes a similar assumption without evidentiary support)

Q: Do Bennett and Hanisch establish that fuel-switching will increase Vermont's costs for environmental compliance, or that compliance costs will preclude economic growth?

A: No. This portion of their argument depends on their confused argument about emissions, and speculation on the form of future regulations.

D. Environmental Effects of Fuel Switching and New Supply

Q: What comparisons does CV offer of the environmental effects of DSM and new supply?

A: Bentley and Bennett and Hanisch provide these comparisons.

Q: What comparison does Bentley offer of the environmental effects of DSM and new supply?

A: Bentley asserts that the utility-sponsored MIT AGREA project has found that DSM is not "the only or the best" option for reducing emissions. I would agree that DSM is not the only option, and that its environmental effects are not as large as options on the supply side. After all, switching all oil and coal plants to gas would eliminate 100% of sulfur emissions; no DSM program can hope to do this. I disagree with Bentley's conclusion that this implies that DSM is not the "best" option for reducing emissions. Demand-side management, including fuel-switching, reduces costs, while most supply options increase costs.

Bentley (p. 22) also argues that primary energy use and emissions might be lower with gas combined-cycle plants and high-efficiency heat pumps than with direct fossil use. Given the small amount of gas-combined-cycle energy in CV's avoided energy mix until well into the next century, and the low penetration of heat pumps in Vermont, this argument is not very relevant.

Q: What comparison do Bennett and Hanisch offer of the environmental effects of DSM and new supply?

A: Exhibit JLH-10 compares the emissions of fossil fuels at the end use to those of a gas-burning combined-cycle plant built in 1994.[55] This is a fairly academic exercise, since CV cannot build a new combined-cycle plant in 1994, and probably not until 1997 or later. The Company does not plan to build any gas combined-cycle capacity until 2000, and does not expect combined-cycle capacity to be all of its incremental power supply until 2006. Furthermore, if CV could build gas combined-cycle capacity early, there would be a considerable economic penalty for doing so. I estimate that the difference between combined-cycle costs and CV's avoided energy costs is about $550/kW for the period from 1994 through 1999. The hypothetical new plant costs money, while fuel-switching saves money, avoiding costs that the combined-cycle plant cannot: a higher-cost energy-load shape, T&D, line losses, and reserves.

In addition, Bennett and Hanisch's emission factors for this analysis appear to be based on gas-only combined cycle, immediately after initial operation, with brand-new low-NOx burners and fresh SCR catalyst (minimizing NOx per MMBTU) and a brand new turbine (minimizing BTU/kWh). The average emissions over the life of the unit are likely to be greater.

[55]While Exhibits JLH-11 and JLH-12 purport to summarize the results from Exhibit JLH-10, I cannot derive these exhibits from the results reported on p. 7 of Exhibit JLH-10.

V. Transaction Costs and Market Barriers

A. Market Barriers and Non-market Costs

Q: What is CV's position on market barriers?

A: Company witnesses assert that no market barriers to fuel switching exist. Deehan (p. 8, p. 27) argues that prices "can't possibly represent" a market barrier to fuel switching, suggests that this implies that no other barriers exist, and asserts that "services are being offered that overcome possible sources of market imperfections" (p. 8, line 13).[56] Deehan (p. 23, lines 17–20) also asserts that Spinner's testimony demonstrates that there are no market barriers to fuel switching. On p. 33, lines 2–3, Spinner *assumes* no market barriers "or alternatively, programs that minimize them." I see no demonstration in Spinner's testimony that market barriers do not exist. Bower (p. 16) assumes there are no market barriers to fuel switching based on Sutherland, who assumes, in effect, that there are no market barriers to any kind of energy conservation.[57] If the Board accepts this argument, it should probably reject all utility DSM investments.

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[56]Deehan assumes that CV's rates are above marginal costs, which may be incorrect. If Deehan were correct that inefficient pricing is the only potential market barrier, and that CV's rates are over-priced, no market barriers would exist for any DSM.

[57]Sutherland, Ronald. "Market Barriers to Energy Efficient Investment," *The Energy Journal* 12(3):15–34, cited in IR 49. Among other things, Sutherland (p. 16) asserts that most market barriers discussed "in the conservation literature.... are not significant deterrents to conservation investments."

The Department's direct testimony addressed this point, and I will not repeat those arguments here. CV has offered sweeping conclusions, but no new evidence on market barriers.

Q: What is CV's position with respect to non-market costs?

A: Bower, Deehan, Awerbuch, and Gamble all express opinions on the significance of non-market costs in fuel-switching and DSM in general. All these CV witnesses believe that fuel-switching imposes additional costs on participants, either in the context of arranging the fuel switch (transaction costs), enduring the process of the switch (inconvenience), or tolerating a lower quality of service or continuing distress (service quality or "attributes"). Each of the witnesses asserts that customers perceive the on-site use of fossil fuels, or the conversion from electricity, to be unpleasant or undesirable, imposing non-market costs on participants in any fuel-switching program.

Q: Does CV adequately document and analyze the potential non-market costs of fuel switching?

A: No. CV does not provide any evidence to support the assertions regarding the costs of using fossil fuels. In addition, the CV witnesses generally do not distinguish between intrinsic characteristics of fossil-fueled space-and water-heating (which may impose irreducible costs on the customers who switch fuels) and the market barriers that impose costs on customers who choose to switch fuels in the absence of an effective program.

Q: Please provide some examples of CV's failure to document the existence of the costs it asserts for fossil fuel use.

A: Bower refers repeatedly to "attributes" that differ between electricity and fossil fuels. On discovery (IR 54), he lists four "attributes:" "delivery reliability, cleanliness of the house, price stability, and demeanor of personnel." Bower does not provide any evidence indicating that electricity is superior to fossil fuels with regard to the other attributes. Other than the cleanliness effect of the installation of fossil equipment, it is not clear that electricity has any intrinsic advantage over fossil fuels in terms of these attributes. I discussed the risks and stability of electric rates and fossil fuel prices in §II above; electricity has no clear advantage over fossil fuels. A customer confronted with a surly CV representative has limited recourse; a customer who does not like his propane or oil dealer can switch to another dealer.

While Awerbuch (p. 40) asserts and Bower (IR 54) suggests that electricity is more reliable than fossil fuels, neither author presents any evidence that this is the case. As discussed in my direct testimony (p. 44; see also IR 5-45), CV has difficulty maintaining reliable electric supply in severe winter weather conditions.[58] Electric service can be lost due to a problem on CV equipment, such as services and transformers, that affect no other customers (and hence is unlikely to be reported, if the home is unoccupied), and in customer-owned equipment, particularly fuses. In any case, a customer who is particularly concerned with reliability would be likely to obtain back-

[58]A small emergency generator can operate the thermostat and auxiliaries necessary to keep fossil systems operating without electricity. Propane and gas water-heating systems can operate without electricity. While Awerbuch suggests that the cost of a "home-watch" service could be as large as the fuel-switching incentive (I assume that is what he means by "inducement proceeds," p. 24, lines 18-19), he does not explain how electric heat would avoid this expense, or account for the multiple benefits of the service he hypothesizes.

up heating sources (a wood stove, a kerosene heater) for either electric or fossil heating systems.

Deehan lists several possible costs of fuel switching: "free space lost to systems that have larger space requirements,...additional exposure to carbon monoxide poisoning..., the value of a more automated system" (p. 4, lines 16–18). He fails to show that any of these costs are significant for properly designed programs: modern space-heating systems are compact, fossil water heaters take up no more space than electric water heaters, sealed combustion avoids carbon monoxide build-up in the home, and fossil systems operate as automatically as electric systems.[59]

Q: Please provide some examples of CV's failure to distinguish between the intrinsic costs of using fossil fuel, and the market barriers to fuel-switching without a program.

A: Bower (IR 55) recognizes that "a well-designed fuel switching program.... could...lower transaction costs," but treats all costs as irreducible in his analysis. He asserts that "more than 50%" of the "value-cost differences" he discusses (but does not quantify) "would persist in a well-designed fuel-switching program," but he provides no basis for this opinion. A well-designed fuel-switching program should reduce problems with both cleanliness (in installation, and in proper selection of vented equipment) and in the demeanor of installation personnel (since contractors will be reluctant

[59]Perhaps Deehan is contrasting electricity to wood heat, or perhaps he considers the need for fuel deliveries as being inconsistent with automation.

to lose the repeat business of the fuel-switching program).[60] In short, Bower assumes that market barriers are real costs and cannot be eliminated.

Awerbuch takes an even more extreme position on market barriers, treating them as desirable things, which should be reinforced by the PSB and CV, rather than eliminated. On pages 5, 24, and 38–44, he discusses a variety of market barriers, including concerns with cash flow; the hassle of applying for loans and supervising contractors; the time and energy required to implement a customer-driven fuel switch; and capital constraints. The RII-DPS program designs deal with the cash-flow, loan-application, contractor-supervision, time commitments, personal energy, and capital budgeting issues Awerbuch discusses. As he did with respect to risk-shifting, Awerbuch urges to leave these imperfections in the energy market, rather than correct them.

Awerbuch takes a particularly strange position with respect to capital rationing, which he describes as a rational and unavoidable reason for customers to avoid spending money on DSM (pp. 41–44).[61] One of the most obvious objectives of DSM programs is to eliminate constraints on the availability of capital.[62] The RII-DPS fuel-switching program would achieve

[60]Since Bower is so vague about the nature of the "attributes," I cannot determine whether he is concerned with the demeanor of installation personnel, meter-readers and fuel-truck drivers, customer accounts representatives, or somebody else.

[61]Awerbuch's discussion of the importance of capital rationing seems to be inconsistent with his claim that corporations use risk-adjusted discount rates to select projects. He also takes a confusing position on access to capital, insisting that only a limited "amount of capital [is] available," even if "financing...is readily available" (p. 42, lines 5–13). Both these statements cannot be true at the same time.

[62]Even the leading advocates of the RIM test, such as Larry Ruff, acknowledge that capital constraints are a market barrier that a utility may legitimately eliminate through financing programs.

this end, since customers would make little or no capital contribution to the switch. Rather than viewing the elimination of this inefficient constraint as an advantage of DSM, Awerbuch accepts the market barrier as part of the natural order, and appears to criticize any DSM program that attempts to overcome it.[63] He concludes his discussion of capital rationing (p. 44, line 15) by asserting that "it would be inefficient to second guess the consumer's judgments," presumably by providing the financing necessary to overcome the capital constraint.

Q: Can you determine why Awerbuch takes these peculiar positions on market barriers?

A: Awerbuch (p. 39, lines 24–26) assumes that DSM programs can only compensate customers for the costs they incur, rather than reduce or eliminate those costs.[64] In reality, many costs can be eliminated by DSM programs, and are no longer real costs. Judging from his testimony, Awerbuch appears to be unaware of the rationale for DSM programs developed since the mid-1980s. His testimony seems to be premised on the assumption that we live in the best of all possible worlds, and that we have the most efficient of all possible energy markets.

[63] I had some difficulty following Awerbuch's argument on this point, due to the internal contradictions and to the dissolution of this argument back into his risk-adjusted discount rate argument on pp. 42–43.

[64] Awerbuch assumes that market barriers consist primarily of time requirements, and concludes that market barriers are higher for high-income customers, requiring stronger incentives for those customers (p. 39, line 18–24). In fact, market barriers tend to be more formidable for low-income customers, as discussed in the direct testimony of Plunkett at pp. 30-35.

Awerbuch may indeed have been isolated from the debate over DSM program design and screening, and may never have heard of market barriers, or program design strategies for eliminating them. However, CV is well aware of these issues, from the collaborative, the order in Docket No. 5270, and extensive negotiation and litigation over program design principles. CV's sponsorship of Awerbuch's naive testimony on market barriers adds nothing to the current debate.[65]

Q: Does CV take a position regarding the significance of the customer's knowledge of his own situation?

A: Deehan (pp. 4–5, 7; p. 27, lines 19-20), Bower (pp. 20–21), Awerbuch (p. 41, lines 1–3) all suggest that the fact that customers have some special information means that the utility has no role in fuel-switching. If this were true for fuel switching, it would also be true for other DSM actions, since the customer will always know things the utility does not, and vice versa. The Company has not demonstrated that its inability to acquire all possible information about fuel-switching opportunities (including that held only by the potential participants) will result in any significant error rates in selection of cost-effective systems.

Q: Has CV attempted to estimate the non-market costs to customers?

A: The only such estimate is presented in Gamble's testimony. She offers an estimated transaction cost of $230/customer (p. 35). In response to a discovery request for the exact derivation of this estimate, Gamble asserted

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[65]Bower's assumption (p. 16) that there are no market barriers implies a similar perspective, because assuming no market barriers leads to the conclusion that DSM programs can only compensate participants for their irreducible costs.

that 43% of fuel-switching customers had reported transaction costs, and that the average for these customers was $530/customer, based on "dollar and time costs, where customers' time was priced out at an hourly wage based upon their average annual reported income" (IR 143). No derivation of the $530 value was provided, and it cannot be derived from the summary survey data provided in IR 144, for reasons I will explain below.

The accompanying survey data (IR 144) shows fuel-switching households losing 23 hours of work time, spending 12 hours on selecting a contractor, 9 hours on organizing and "getting ready," 17 hours on clean-up, ten hours apparently performing their own installations, and 12 hours in "miscellaneous loss of time." In addition to the 17 hours of homeowner cleaning labor, the summary shows $300 in clean-up costs, as well as $100 (and five hours, which may be the cleaners' time, or may be the householders') for professional house cleaning.[66]

The supplementary response to IR 143 indicates that Gamble's testimony (and hence Deehan and Bentley's testimony that relied on it), the original IR 143 and IR 144, were all wrong. Gamble used the time and cost estimates of people who did not switch fuels, rather than those that did.[67] Her corrected estimate is $145 (43% of $336), not $230.[68] Furthermore, the "summary statistics" reported in IR 144 turn out to be individual reports,

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[66]Gamble does not explain the overlapping, vague, and inconsistent data provided in the summary.

[67]The mis-estimation of fuel-switching time and costs appears to be a significant market barrier.

[68]She rounds $144.48 to $145.

rather than average or median values. The average time reported was only 15 hours, not the 23–50 hours suggested by IR 144.

Q: Did Gamble use the correct data in her revised estimate?

A: It appears that the surveyed fuel-switchers may have undertaken fuel-switching on their own. At best, the estimates of transaction costs are for CV's poorly designed program, rather than an efficient program that overcomes these market barriers. A well-designed program would not require participants to miss work, interview and negotiate with multiple contractors, organize or supervise the project, perform or pay for extensive cleaning, install their own equipment, or otherwise lose much time.[69] Gamble errs in assuming that a good DSM program will have no advantages over CV's information-only program, or no program at all.

Gamble's own data suggests the range of improvement possible with a fuel-switching program. Of the 47 respondents, 27 reported no time or cost, and 11 more reported spending no money and less than nine hours. Less than 20% of the respondents were thus responsible for virtually all the reported costs. Indeed, three respondents were responsible for half the costs; they reported spending 46, 40, and 30 hours on their fuel-switching projects, and the latter respondent reported spending $300 for cleaning. Simplifying the design and contracting process so that these customers spent the average time and money would cut the average transaction cost to about $75, even pricing participants' time at their salary rate.

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[69]Someone may have to be at the house to let the installers in first thing in the morning, but they should not require constant supervision.

Gamble also errs in assuming all time at home in connection with the fuel switch was used exclusively to supervise the retrofit. While a family member may have chosen to be at home during the work, that person may have been catching up on chores, gardening, reading, or what not for most of the time period. Alternatively, the family member may have chosen to stay home because of an interest in the work being done. In either case, the day off may have been more like vacation than work. The survey does not provide any evidence on the value of the time at home, such as how much the family member would have paid to avoid staying home.[70]

B. Incentives and Coercion

Q: Which CV witnesses suggest that a CV-funded fuel-switching program would coerce customers into switching fuels?

A: Deehan (e.g., p. 5, line 20) and Awerbuch take this position to some extent, implicitly assuming that a fuel-switching program would override customer preferences, forcing or enticing them to switch fuels.

For example, Awerbuch urges the Board to "refrain from imposing a generic...criterion" on consumers (p. 20). The Department does not propose that any criterion be "imposed" on consumers. Each customer will be free to apply his own participant test to the societally cost-effective fuel-switching options offered. Our design would not force fossil fuels on the people who actually prefer electricity.

Similarly, Awerbuch (p. 40, lines 22–26) argues that some customers are sensitive to the smell of fossil fuels, object to pilot lights (which are

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[70]This might be a negative number for some customers.

largely obsolete, anyway), or fear any sort of flames in their home, and would thus require high incentives to *induce* fuel switching.[71] Awerbuch does not identify any fuel-switching program design that would have the undesirable feature he describes here. This is not a problem with the Department's proposed design, which does not attempt to compensate customers for these costs. Customers who *want* to continue using electricity would be free to continue doing so, and the Department has not proposed an escalating schedule of incentives to entice them to switch fuels.

VI. Load Shape of Water and Space Heating

Q: What issues does CV raise in its April testimony on load shape of water and space heating?

A: Spinner argues that changes in daily load shape and the loss of space-and water-heating load has created "room" in the load shape for more load control; that space-and water-heating do not contribute much to peak load; that CV load control reduces actual peaks; and that CV's load data are valid and useful.

Spinner's data continues to be confusing and inconsistent. As summarized in Exhibit ___ (PLC-59), various load data that Spinner uses in his testimony report different peak hours, purportedly for the same load measure and the same day. For example, the hourly load data Spinner says he used in developing Exhibit HMS-6 (IR 116) identifies different peak hours for December 27–29, 1993, than those listed on p. 29 of his testimony. On p.

[71] These concerns are unlikely to be important for the majority of electric water-heating customers, who already have fossil heat in their homes.

38, line 22–23 of his testimony, Spinner selects the "five highest-load hours from the winter of 1993–94 on a total-area-load (TAL) basis" and lists them on p. 39 (Spinner also presents four of these hours as peaks on p. 24). On this list, however, four of the five hours are inconsistent with company load data (IR 116); in the case of the fifth hour, (12/27/93 at 6 p.m.), the times correspond, but the load values are different. It is unlikely that these three days contain the greatest loads for the winter of 1993–94 overall.

Even if we accept the hours chosen by Spinner on p. 39, the values he lists for both TAL and retail loads are different from those provided in IR 116. Exhibit ___ (PLC-60), p. 1, compares these values. The loads on p. 39 are 9–27 MW higher than the loads in IR 116, for the same hour.

Similarly, Spinner reports different peak load levels for the same hour and the same load measure. For example, there are six days for which Spinner reports total-area-peak loads in Exhibit HMS-2 that are different than those he reports in Exhibit HMS-3 (the difference is by as little as one MW, but is sometimes more; see Exhibit ___ (PLC-60), p. 2). Furthermore, in the years (1988–89) for which Exhibit HMS-2 overlaps the hourly load data that CV previously provided on disk, the loads do not match, often by differences that are too great to attribute to rounding differences. The largest differences in peak load values occur as follows:

1/14/88 (5 MW, 476 v. 481)
12/12/88 (3 MW, 475 v. 472)
12/22/89 (10 MW, 454 v. 464)
12/27/89 (5 MW, 488 v. 483)

and the largest differences in average hourly loads are as follows:

1/4/89 (2 MW, 425 v. 423)

12/27/89 (2 MW, 425 v. 427)

This information is summarized in Exhibit ___ (PLC-60), p. 3.

Furthermore, as shown in Exhibit ___ (PLC-61) the statistical results shown in Exhibit HMS-5 are inconsistent with the data underlying Exhibit HMS-6, even for such simple statistics as mean, minimum, and maximum.[72]

Either Spinner's data are wrong, or he is not presenting the information that he purports to provide.

A. Room for More Load Control

Q: How does Spinner argue that there is room for more load control on the CV system?

A: Spinner (p. 10, Exhibit HMS-2) argues that daily load factor on peak days has declined between 1988–89 and 1991–94, and thus that load curves have been "degraded". He argues that peak-day load factors have fallen due to the loss of load control (p. 10, lines 9–10), particularly controlled space-and water-heating load (p. 10; p. 12, line 18). From these assertions, Spinner concludes that increasing load control would return the degraded load curves to their pre-1990 excellence, imply that more load control is feasible and cost-effective.

Deehan (p. 19, lines 16–18) repeats Spinner's conclusion.

Q: Is there a trend toward lower peak-day load factors?

A: There might be, but no such trend can be confirmed from Spinner's data. Spinner acknowledges that "it is hard to discern a trend" (p. 11), but asserts that the curves have "degraded somewhat" (p. 13). Indeed, as demonstrated

[72]These problems go on and on.

by the regression in Exhibit ___ (PLC-62), using the data in Exhibit HMS-2, the difference between peak day load factors reported by Spinner in 1988–89 and 1991–94 is not statistically significant.

Furthermore, Exhibit HMS-2 presents hand-picked, arbitrary data. Spinner does not include data for every year;[73] presents a different number of days for each year, from one day in 1991 to nine days in 1993; uses different ranges of heating degree days (HDD), with no days under 56 HDD in 1989 or under 68 HDD in 1994, but as little as 42 HDD in 1992; and is unable to provide any objective criteria or rationale for selecting the days he used (IR 86).[74]

Even if there was a change in load factor, it may be due to something other than the loss of controlled loads. The mix of load between classes and between end uses may have changed over time, due to the change in economic conditions and other factors. On any particular day, the CV load factor may also be affected by NEPOOL's use of CV's dispatchable interruptible contracts.

Q: Does Spinner demonstrate that a higher peak-day load factor is feasible?

A: No. A lower daily load factor does not imply that there is anyplace to shift load. The daily load factor may be low because loads are very low in the middle of the night; few loads can be shifted from a peak at 8 a.m., 1 p.m., or 6 p.m. to a peak at 2 a.m. Even if each peak day has some low-load periods during the day, the "passive" controls, such as clocks and TOD rates, will

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[73]He asserts that there were no peak conditions in 1990 (IR 87). This is a peculiar claim.

[74]Spinner says that the "days chosen were days I considered interesting …" because they were cold, loads were high, or CV interrupted load (IR 86). It does not appear that Spinner applied any consistent rule, other than his "interest."

only work if the low loads occur at the same time each day; this is not the case for CV. The shifting off-peak could be utilized to some extent by real-time controls, such as ripple and interruptibles, if CV knew its loads in real time (which it does not) and were able to forecast daily load shapes (which is difficult for any utility).

Exhibit ___ (PLC-63) provides examples of CV peak days with these characteristics. Page 1 of the exhibit shows the daily load curve for 1/11/91, when load was flat all day but much lower at night. Page 2 is the load shape for 12/27/92, when load could have been moved to the midday hours from the evening peak, while page 3 shows the loads for 1/11/93, when mid-day loads could be moved to the evening. No static control strategy could accommodate both shifts.

Q: Has Spinner demonstrated that additional water heating load would increase daily load shapes?

A: Spinner asserts that this is the case (p. 12, line 1-4), but he does not demonstrate it. He asserts the a 1% increase in peak day load factor would require the addition of about 144 MWh of daily energy. He then posits that each additional water heater would add 15 kWh of daily "non-peak coincident" load.[75] Spinner then asserts that 9,600 water heaters would improve the peak-day load factor by 1%. He fails to mention that water heater all contribute to peak load; at a typical peak contribution of roughly 0.6 kW per uncontrolled or clock-controlled water heater, the 9600 water heaters would add almost 6 MW to peak load, and would have virtually no

[75] This value seems somewhat high; if the peak day were typical of average use, the annual usage would be 5,475 kWh/yr. On the other hand, cold weather does increase water heater loads.

effect on the daily load factor. Spinner does not make a "subtle point" here (p. 12, line 5), but an incorrect one.

In the conclusion to the daily-load-factor section of his testimony, Spinner (p.13, lines 1–2) asserts that the decline in Rate-3 saturation proves that "Rate 3 is in no way over-subscribed or causing *extra* capacity costs to be incurred by the system." This claim is not supported by Spinner's data, even if they are properly selected, or by his dimly perceived trends, even if they are real.

Q: If peak-day load factors have declined over time, has Spinner demonstrated that this is undesirable?

A: No. Spinner does not provide any evidence supporting his assumption that high peak-day load factors are actually advantageous. High peak-day load factors are not necessarily good. They limit the effective capacity of storage hydro and other energy-limited resources, and increase the number of hours near peak, when system reliability is most at risk.

B. Contribution of ESH and EWH to peak load

1. Current and Historical Contributions

Q: What arguments does Spinner provide on the contribution of space and water heating to CV peak load?

A: Spinner asserts that the contribution of ESH and EWH are not driving peak load growth, and that the loss of ESH and EWH has lowered the load curve, in addition to "degrading" peak-day load curves (p. 10, lines 12–14).

Spinner apparently pursues this issue because he believes that the economics of fuel-switching are somehow related to the historical trends in electric space-heating load (p. 29, lines 9–11), such as the change in load contributions from 1972 to 1992 (for which Spinner provides estimates in Exhibit HMS-7). These historical data are simply irrelevant to the societal test, as is the issue of whether CV would be winter-peaking in the absence of space-heating load.

Deehan repeats Spinner's historical summary at some length at pp. 18–19, and praises Spinner's testimony as readable and informative to "anyone who is interested in gaining an intuitive feel for what has happened to thermal loads on Central Vermont's system over the last quarter century" (pp. 19–20). However, he does not explain why this history is relevant to the current issues.

Q: Does Spinner's discussion of space-heating load growth provide any useful information?

A: Only one piece. Spinner (p. 10, line 20, and p. 11, line 1) admits that closing Rate 11 in 1987 "stopped the momentum of load growth of the mid-day period." In other words, even Spinner recognizes that Rate 11 is shifting load onto the mid-day peak. This admission supports the phase-out of the discount for Rate 11, as proposed by DPS Witness Plunkett.

Q: What other arguments does Spinner advance with respect to the peak contribution of ESH and EWH load?

A: He continues to confuse the allocation of embedded costs with marginal cost causation (e.g., line 10 of page 13), arguing that the cost-effectiveness of new load control must be averaged with the cost-effectiveness of old load control, rather than being judged on its own. He extends this argument beyond Rate 3, to include all rate design innovations CV has ever made, as discussed in §VI.C below.

On page 30, line 12, Spinner asserts that residential ESH load at the time of system peak is around 11 MW; this estimate is based on an 80% load factor (IR 128). In other filings, CV has estimated space-heating load factors between 14% and 61%; for screening, CV assumes about 50% load factor. Based on NEPOOL's estimate of the Vermont space-heating load factor, a better peak estimate might be 28 MW, as derived in Exhibit ___ (PLC-64). Given Spinner's methodology for estimating commercial ESH contribution to peak (IR 128), any increase in the residential ESH peak estimate will proportionately increase the commercial estimate.

2. *Changes in Weather Sensitivity over Time*

Q: What arguments does Spinner offer with respect to the weather sensitivity of the CV system over time?

A: He makes two inconsistent arguments. On page 11, he asserts that the CV system was less weather-sensitive in 1988-89 than in the 1960s and 1970s, but in 1991–94 has "now returned to its prior upward sloping relationship" (p. 11, lines 17–18). On pp. 14–19, he asserts that recent data (1994, or 1987–94) shows reduced weather sensitivity, suggesting that space-heating load has left the system.

Q: Are the changes described on page 11 meaningful?

A: No. This is part of the analysis in Exhibit HMS-2, using hand-picked data. Spinner finds it "remarkable" that daily load factor increases with HDD (p. 11, lines 18–19). In fact, this is the expected relationship; while heating has low *annual* load factor, it operates throughout cold days (and perhaps even more at night, when temperatures are lower and there is no sun), producing high peak-day load factors.

The trend lines that Spinner draws in Exhibit HMS-2 are not significantly different between 1988–89 (the weather-insensitive period) and 1991–94 (when Spinner sees weather sensitivity re-emerging). Exhibit ___ (PLC-62) provides the result of a regression on all the data Spinner used in 1988–94; the dummy variable identifying the change in the response to HDD between the time periods (YEARDUM*HDD) is not significant.

Spinner's results in Exhibit HMS-2 also change with the choice of data points, as shown by the regression results in Exhibit ___ (PLC-65). For example:

- Spinner includes only 5 days under 50 HDD, all in 1992–93. Removing these days produces a steeper slope on the trend line in the years 1991–94 (0.110 v. 0.091).[76]
- Including only January data produces a steeper slope in the trend line in 1988–89 (0.080 v. 0.013) and a flatter slope in 1991–94 (0.085 v. 0.092); the two time periods become indistinguishable.
- Including only January data and HDD>50 produces slopes of .080 in 1988-89 and-0.019 (a negative relationship between HDD and load factor) in 1991–94.

Even with Spinner's own data, trends can vary according to selection criteria.

Q: Has Spinner demonstrated that the CV system is much less weather sensitive than it was in the early 1980s?

[76]Spinner also uses a few weekend days in his analysis. Of the 48 days presented, 5 appear to be weekend days (4 in 1968–1977 and 1 in 1992).

A: No. Spinner makes this claim on p. 15, lines 18-19, based on the data in Exhibit HMS-3. He observes that, even though the "average week" in January 1994 was 17.4% colder than the 1981–94 average, the increase in weekly energy requirements from the preceding September is 1.5% below average, and the increase in peak load from September to January is 27.7% below average.[77] All these computations use total-area-load data. There are a number of problems with this analysis, and Spinner's conclusion, including the following:

- The data presented in Exhibit HMS-3 contain serious distortions. The data labeled "Wkly. TAL (MWH)" are not the energy requirements of the peak week, but the monthly energy requirements, divided by *the number of Fridays in the month* (IR 105). Spinner uses the same process to produce his "Avg. Wkly. HDD." Hence,
  - A January that appears mild in Exhibit HMS 2 (e.g., 1986, at 302 HDD, compared to 1994 at 360 HDD), but happened to have five Fridays, may have actually been quite cold (January 1986 had 1512 HDD, compared to 1439 in 1994).[78]
  - Exhibit HMS-2 shows 1994 as having the greatest January energy sendout; in fact, sendout was greater in 1986, 1987, 1988, 1991, and 1992, but each of these Januarys had five Fridays.

[77]I assume that "average weekly HDD" is actually total HDD in the peak week, which would be an interesting statistic to compare to total weekly energy requirements, although it is unclear why Spinner thinks it is relevant to the hourly peak. It is possible that Spinner is actually presenting a truly irrelevant HDD value, such as weekly HDD averaged over the weeks in January.

[78]The line for each year in Exhibit HMS-2 includes January data in the next calendar year.

- The percentage change in sendout from September to the next January (one of Spinner's principal outputs) is overstated in years with five September Fridays and understated in years with five January Fridays.[79]

- The September data are not weather-normalized, so some of the fluctuations in the ratio of loads between January and September may be due to the variation in September weather.
- The January data are not adjusted for the effects of weather on tourism and related loads, potentially an important source of load fluctuation for CV.
- January 1994 was unusually snowy (which would reduce snow-making demand) and presented severe transportation problems, which may have reduced loads in some periods.
- Spinner uses January loads in all years, even though annual power-year peaks occur in December in many years.
- Spinner uses TAL data, which are irrelevant to CV cost causation.

In addition to the fact that his data are meaningless, Spinner proves too much from too little information. Peering intently at January 1994, he finds (in essence) that the ratio to HDD of the energy and peak "swings" since the previous September is lower than the long-term average. Exhibit ____ (PLC-65) computes these ratios for the long-term average, January 1994, December 1993, Spinner's data for January 1992, and January 1992 restated to remove

[79]Spinner computes a 33.7% change (or swing) in energy sendout from September 1991 to January 1992; IR 103 shows that energy output actually increased from 182 GWh to 304 GWh, or 67%.

the effect of the fifth Friday on Spinner's peculiar averages.[80] The average peak swing is about 0.11 percentage points per HDD, while the average weekly energy swing is 0.12 points/HDD. In January 1994, Spinner's data show ratios of 0.07 points/HDD for peak and 0.10 for energy, which might suggest that peak load was about 40% less weather sensitive and that energy was about 15% less weather sensitive than in the long-run average.

However, this sharp drop in weather sensitivity is restricted to January 1994. I compute a peak ratio of 0.09 and an energy ration of 0.20 for December 1993, which would imply that 50% of the reduction in peak weather-sensitivity, and *all* of the reduction in energy weather sensitivity, occurred between 12/29/93 and 1/27/94. Spinner's own data for the 1991–92 power year show ratios of 0.12 for energy and 0.11 for demand (both equal to the long-run average), implying that *all* of the reduction from the average to January 1994 occurred in just two years.[81]

If Spinner's data meant anything, identifying the events that caused the startling changes in just two years (or just one month) would be very important. More likely, Spinner has selectively used January 1994 data and a series of incorrect computations to support a claim that is not true.

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[80] I computed "weekly" HDD and energy for December 1993 using 4 weeks, for consistency with September 1993 and January 1994.

[81] Correcting for Spinner's erroneous treatment of different Januarys as having different numbers of weeks, I find that the energy ratio in 1991–92 was 0.20, well above Spinner's average. This makes Spinner's claim of a secular downward trend in weather sensitivity even more absurd.

Q: Does Spinner support his claim (p. 17) that this change in weather-sensitivity (if there is one) is due to seasonal, TOD, and controlled water-heating rates?

A: No. Any real change is as likely to be due to generally higher rates, energy conservation, customer-initiated fuel switching, changes in the class load mix, and other factors, as to CV rate designs—although seasonal rates may encourage conservation and fuel-switching, and TOD rates may shift some load off the peak hour (depending on the timing of the periods and the actual peaks). As I demonstrated in my direct testimony, controlled water heating is as likely to increase peak load as to decrease it. Controlled water heating energy use is no less weather-sensitive than is uncontrolled water heating. There is no reason to believe that TOD rates reduce peak-week energy consumption.

Q: What is the significance of the regression analyses presented in Exhibit HMS-4 and pages 17–19 of Spinner's testimony?

A: Not much. Spinner finds that the time trend of peak growth from 1980–86 virtually disappears in 1987–94. This is no surprise: loads have been virtually stagnant since 1987. The coefficient of the HDD (or temperature) variable is also about 15% lower in 1987–94 than in 1980–86. This suggests that conservation and fuel-switching have decreased the sensitivity of CV's loads to cold weather.

It is not clear that the fall in oil prices (Spinner, p. 18) was particularly important in changing the weather-sensitivity of the system. The closure of the promotional space-heating Rate 11, higher electric rates, and other changes, may be just as important.

C. *The Effectiveness of Load Control*

Q: How does Spinner purport to demonstrate the effectiveness of load control?

A: Spinner does not directly analyze the effects of either the clocks or ripple control on Rate 3, or any other specific load control option. Instead, he hides these effects by combining them with all other elements of a broadly defined load-control portfolio (including self-selected off-peak and TOD rates, ski areas, and perhaps street lighting as well).[82] The portfolio is mostly TOD rates; it is hard to distinguish actual shifts due to TOD rates and the effect of self-selection, in which naturally off-peak customers choose to be on the TOD rates, and more on-peak customers stay on the non-portfolio rates.

As shown in Exhibit HMS-6, p. 16, even Spinner's portfolio has a poor load factor. In two of the five years, the portfolio peaks at the same time as the system, reducing system load factor. Clearly, in these years, a proportionate shift of energy from the non-portfolio "baseline" load shape to the portfolio load shape would increase peak load. In other years, portfolio is near peak at system peaks. Exhibit ___ (PLC-67) summarizes the portfolio load factors, which are consistently lower than the system load factors Spinner reports. Moving additional energy usage with the average load shape of Spinner's "baseline" loads to the average portfolio load shape would increase CV's peak. Moving average load from the portfolio to the "baseline" shape would reduce peak load.

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[82]Deehan (p. 25, lines 24–26) attempts to recast the 6/18/93 testimony of Spinner and Anderson in terms of the overall portfolio, even though that testimony dealt directly with Rate-3 clock-controlled load shapes.

In addition to mixing together multiple load-control measures (including rate designs without any real control at all), Spinner continues his past practice of arguing for incremental load control, based on the purported effects of the embedded quantity of control as compared to no control at all. My direct testimony explained why this approach is incorrect.

Q: Does Spinner provide any analysis of individual load-control options?

A: Some. On p. 26, Spinner provides a table for Rate 3, Rate 11, and the ski-area contracts of minimum load, maximum load, and the difference between these loads (or "swing") for 12/27/95–12/29/93. Spinner states that "these wide swings, combined with correlation information, point to a very effective *risk minimizing* load management portfolio that is well managed and should be left intact." However, these swings do not necessarily match system load requirements. For example, on 12/29, the peak TAL and retail loads occurred at noon, when Spinner estimates Rate-3 loads were quite high (25.9 MW, well above the middle of the swing) and Rate-11 loads were at roughly the middle of the swing.[83] The mid-day and late-evening peaks are high-load periods for Rate 3 and Rate 11. These load-control options are likely to increase, not decrease, peak loads.

Rate-3 clocks would have contributed significantly to three of the six retail peaks listed on page 24, and probably even more heavily to the peaks on those days listed in IR 116.

Q: Can you determine what Spinner means when he says CV's load-control options are "complimentary"?

[83]The Rate-3 minimum load is probably understated, at least as a long-term average, since this small sample may not include a representative mix of off-time clocks.

A: So far as I can determine, Spinner's use of "complimentary" really means "crippled."[84] He explains (pp. 27–28) that the Rate-3 clocks and some TOD rates shift load onto peak, so ripple and interruptibles are needed to shift load back off the peaks. Hence, the potential benefits of real-time control are consumed in compensating for the peaks caused by other load controls.

Q: Does Spinner demonstrate that "capturing the vast majority of [load-control] benefits requires few hours of interruption," as he asserts on p. 39?

A: No. He does not demonstrate that a few hours of interruption has any benefit, especially for clock-controlled interruptions and those dispatched using the wrong measure of load.

Q: Have you performed any new analyses of the contribution of clock-controlled and ripple water heaters to CV peak loads?

A: Yes. Spinner (p. 24) lists what he says are the five highest-load days since CV began collecting load research data; since one day is reported to have two identical peaks, six high-load hours are identified. Exhibit ___ (PLC-68), page 1, compares loads of uncontrolled water heaters to clock-controlled water heaters (both from VLS) and ripple-controlled water heaters (from CV metered data). On two of the mid-day peak hours listed on p. 24, the clock-controlled water heaters contributed more to the peak hour than did the uncontrolled water heaters. Ripple contributed no load during one of these two peaks, but during the other peak (and one more mid-day peak), ripple load was higher than uncontrolled load. The average clock-controlled load

[84] I assume that the word Spinner meant to use in describing CV's load-control resources was not "complimentary," but "complementary," since they are neither free nor flattering.

(0.55 kW) was about the same as the average uncontrolled load (0.56 kW), while the average load of ripple-controlled water heaters was 0.02 kW less than uncontrolled (0.58 kW).

On p. 39, Spinner lists what he says were the five highest-load hours in 1992–1993. Four of the peaks occur at the same times as the peaks presented on p. 24. A comparison of the values reported for Rate-3 loads and an estimate of Rate-3 loads based on VLS and CV metered-load data produces different results. Exhibit ___ (PLC-68), page 2, compares uncontrolled, clock-controlled, and ripple peaks at these hours. The average clock load (0.64 kw) was 0.08 kW higher than the average uncontrolled load (0.56 kW), and the average ripple load (0.57 kW) was 0.01 kW more than uncontrolled.

Exhibit ___ (PLC-68), page 3, provides a similar computation for the January and December peaks reported in CV's FERC Form 1 since December 1991 (when the CV metered data become available). Based on VLS data for clock-controlled and uncontrolled water heaters, and CV data for ripple, the average peak contribution on these five peaks was 0.58 kW for uncontrolled, 0.49 kW for clock-controlled, and 0.69 kW for ripple.

D. Validity of CV load data

Q: How does Spinner purport to demonstrate that CV's load data is correct?

A: Spinner (p. 36) admits that CV does not use the loads for which it bears capability responsibility in either the dispatch of its load control options or the analyses previously filed with the Board. Indeed, CV has no alternative for dispatch purposes; since it does not know its own load, it must use the TAL.[85]

Spinner has admitted that ripple controls (and interruptible contracts) cannot be operated at the right times, since CV does not have the right load data in real time. Nonetheless, he argues that TAL correlates fairly closely with CV's actual load.[86] From this correlation, Spinner appears to conclude that ripple works, although he still presents no data on when ripple was actually used.[87]

Spinner reports a correlation of TAL with "retail" load of 0.999, based on a 72-hour period in December 1993 (p. 37). But the correlation coefficient is lower 0.88 for 12/93 as a whole (CVPS Exhibit 1A, injunction hearing), and there is no correlation in the top hours reported on p. 39.[88] The order of the peaks listed on p. 39 is not the same for TAL as for "retail" load.[89] Furthermore, relying on TAL would lead to different (and wrong) choices if the days had occurred in a different order. If the 12/28 load shape had

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[85]Spinner (p. 36, line 16–17) says, "TAL were the only data available to system controllers on a real-time basis—so this is the only measure of load that CVPS system operators could minimize." In some places, such as Exhibit HMS-3, Spinner refers to TAL as a measure of energy requirements, but he also uses TAL as a measure of peak load.

[86]Spinner refers to "retail load," but may mean "corporate consolidated load" or "consolidated retail load" as he uses those terms on pages 36-37, which seems to describe the load for which CV bears capability responsibility.

[87]On request, CV made available some data on ripple dispatch for recent years, but could not provide a comprehensive listing over time.

[88]Once again, the data on p. 39 is inconsistent with the data in IR 116.

[89]Spinner (p. 37) mentions that "the 5 highest TAL and consolidated peak hours occurred during 5 *common* hours," but fails to note that the order of peaks is different.

occurred on 12/26, operators would have thought there was no problem on 12/27, when in fact the previous peak was being exceeded by 5 MW (or 1%).

Q: Has Spinner demonstrated that Rate 3 lowers costs?

A: No. Spinner has not shown that actual operation of clocks and ripple (dispatched on TAL) over time reduces peak load compared to uncontrolled load. In essence, Spinner admits to using archaic dispatch rules, from a time when TAL was virtually the same as the load for which CV bore capability responsibility.

Q: Does CV purport to demonstrate that heating water on Rate 3 controls is less expensive than heating water with fossil fuels?

A: No.

VII. Central Vermont's Opposition to the Societal Test

Q: What positions does CV sponsor in opposition to the Board's use of the Societal test?

A: Awerbuch, Bentley, Bower, Deehan, and Spinner all argue yet again on behalf of the RIM; Bentley and Deehan support the use of the benefit-cost (B:C) ratio, rather than NPV; Awerbuch proposes a "Public Project" test, presumably to be used as an additional screen; and Deehan proposes a "no regrets" test.[90]

[90] At one point, Bower (6) agrees that the societal test is the correct test. Awerbuch appears to prefer the participant and RIM tests, and never performs or suggests the application of a societal test.

A. Defense of the RIM

Q: Which CV witnesses provide support for the use of the RIM test in DSM planning?

A: No CV witness actually proposes in so many words that the RIM be substituted for the societal test, but Awerbuch, Deehan, and Spinner all take positions equivalent to advocating the RIM. Awerbuch (p. 20, line 3; p. 41, lines 1–3, p. 44, line 15) and Deehan (p. 8, line 14–15; p. 27, lines 20–21; p. 28, lines 18–20) repeatedly argue that the Board should not second-guess customer decisions; if customers do not implement DSM when faced with rates equal to or exceeding avoided costs, the Board should assume that the customers have some good reason for not doing so, and must incur some unmeasured cost in implementing efficiency options. This is a standard argument for the RIM, popularized by Larry Ruff. If the Board accepted this argument, it would have to prohibit all DSM incentives except where avoided costs exceed rates, and cap incentives at the difference between avoided costs and rates.[91]

Company witnesses also apply the RIM test in their arguments. Spinner (pp. 20, 31, 40) and Deehan (p. 19, line 58) justify electric space heating on the grounds that it lowers winter rates. This is a straight-forward implementation of the RIM test. Deehan (p. 27, lines 17–18) claims that CV's refusal to provide incentives for fuel-switching "ensures the delivery of fuel-switching services at lower cost to the system than if additional incentives are given to switchers." This statement is true if "cost" is measured by the utility or RIM tests, but not under the societal test. As I

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[91] Avoided costs exceed rates for some CV rates, perhaps most.

discussed in §V.A, a well-designed DSM program will reduce transaction and non-market costs, compared to customer-initiated fuel switching, even for the customers who would have switched without the program (i.e., free riders). Hence, Deehan acts as if the Board had adopted the RIM as the primary cost-effectiveness test for DSM.

B. Benefit-cost Ratios

Q: Where does CV advocate the use of benefit:cost ratios to compare alternative measures?

A: Deehan argues that CV "fuel-switching measures have had lower apparent benefit-cost ratios...than have the non-fuel-switching measures.... As such, the Board's societal test has indicated that fuel-switching measures have been economic but they haven't been as cost-effective as non-fuel switching DSM measures, which has results in lower overall benefit cost ratios for the DSM programs as a whole" (p. 37, lines 7–12). Deehan appears to suggest that the fuel-switching measures have reduced the cost-effectiveness of DSM, due to their lower B:C ratios.[92]

Q: Should CV screen alternative DSM treatments using the benefit:cost ratio or the net present value of the measures?

A: The net present value is the proper criterion. This point is explained in the direct testimony of DPS witness Plunkett (pp. 27-30); Exhibit DPS-SHP-1, App. A7-4 to the testimony of DPS witness Parker; and the discovery

[92]As Bentley clarifies (p. 18), the ratios to which Deehan referred do not include program costs. Fuel-switching may increase program benefit-cost ratios, even if fuel-switching measures have lower benefit-cost ratios than non-fuel-switching measures, since fuel switching can greatly increase benefits without increasing program costs.

responses related to that exhibit (Response to CV Discovery Question 274). Exhibit ___ (PLC-69) consists of an excerpt from *From Here to Efficiency*, discussing this issue in greater detail.

C. New Criteria

Q: Please describe Awerbuch's "public project" criterion.

A: Awerbuch (pp. 25–32) constructs a complex argument, in which he asserts that any DSM action is a "public project," like building a highway. He sees these public projects as being justified only where there are broad public benefits and widely distributed risks. Regardless of whether the criteria Awerbuch recites are appropriate in determining whether highways should be built privately or publicly, applying the criteria to overcoming market barriers with DSM seems like a great leap.[93]

Q: How does Awerbuch propose to apply this standard to DSM?

A: In Awerbuch's view, the Board should not order any action simply to reduce total costs; every Board action must also have broad benefits and spread risk. In general, DSM programs both reduce and spread risk of undertaking energy efficiency investment, allowing customers to proceed with cost-effective energy efficiency actions. Thus, DSM would generally seem to pass the public project criterion on the portfolio level, although Awerbuch might reject each specific measure for not having broad enough benefits.

Q: How does Awerbuch propose to apply this standard to fuel switching?

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[93]It may be less of a leap for Awerbuch, who does not appear to believe that market barriers exist.

A: Awerbuch imposes an even stiffer version of the public-project criterion for fuel switching, since he would also apparently require that the participants not pay much for fuel-switching, or bear much risk, even for their own fuel, and even if their energy costs are reduced. As I read Awerbuch, he might reject public financing of highways, because some highway users will spend a large percentage of their discretionary income on a car, including risky maintenance and repair costs.

Q: Has Awerbuch provided a compelling argument for the use of his public-project criterion?

A: No. He does not explain why his criterion is superior to the societal test, and why societal benefits should be foregone to pursue the application of this criterion. It is clear from other portions of his testimony that Awerbuch does not support energy-efficiency programs; the public project criterion is an essentially arbitrary rule to screen out additional DSM.

Q: Please describe Deehan's no-regrets test.

A: Deehan suggests that "Our charge should not be to entice customers to take action that in the long run may turn out to be inappropriate." (p. 5) In the long run, *any* action (including adoption of electrotechnologies) may turn out to be inappropriate. Deehan's no-regrets test is a prescription for total inaction.

VIII. Deferral

Q: Who testifies on the economics of deferring cost-effective fuel-switching and DSM in general?

A: Awerbuch, Bower, Bentley, and Deehan all testify in connection with this issue. Deehan simply summarizes the testimony of the other witnesses.

Awerbuch argues for deferral, based on his results that fuel-switching is not cost-effective from a participant perspective. If fuel-switching is a net loser, of course CV would want to delay it. However, the DPS only proposes that CV encourage fuel switches that are cost-effective.

Bower (pp. 16–20) and Bentley (pp. 28–29), discuss the concept of deferral or "slip." Their discussion of the concept, and Bower's numerical example, explain why deferral may be cost-effective in some situations. However, neither witness provides any evidence that deferral is cost-effective for fuel-switching on the CV system.

Q: Would deferral of cost-effective fuel-switching and other cost-effective DSM increase the benefits of CV's DSM portfolio?

A: It is likely that the theoretically optimal timing of many measures would be later than 1995. For example, fuel-switching to gas, and switching large customers to oil, might generate the highest net present value of benefits if undertaken immediately, but the NPV of switching smaller users to oil might be maximized by 1997 installation, and the NPV of propane switches might peak in 1999.

Unfortunately, DSM measures cannot always be optimized separately. The fuel-switching program will require several years to complete, so not all measures can be installed at exactly the optimal time. The same program would deliver gas, oil, propane, and kerosene fuel-switching, as well as other measures, so the extent to which the implementation order can be optimized with respect to each fuel is limited.[94] To some extent, it may be feasible to treat customers in the order of decreasing consumption, although energy consumption by end use can be determined only approximately prior to intake to the program.[95] Hence, to a large extent, the real choice is between faster and slower implementation of the overall program. CV has not demonstrated that deferral or elongation of a cost-effective DSM program would be cost-effective, given current projections of avoided costs. Indeed, the direct testimony of DPS Witness Plunkett demonstrates that faster implementation is preferable to slower implementation.

In summary, while deferral analysis can be useful and appropriate in some circumstances, the possibility of slightly improving the net present value of DSM through optimized timing should not be allowed to interfere with the timely acquisition of DSM resources that are cost-effective under an initial implementation schedule. The Company expresses much more interest in this side-issue of optimal timing than in actually capturing efficiency resources, or increasing net benefit by prompt program modification, better program design, and improved resource characterization.

IX. Electrotechnologies

Q: What is CV's position on the promotion of electric consumption?

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[94]The program might be designed to perform inspections, tightening, and preliminary design, but delay the installations for some fuel types. This program structure is likely to increase transaction costs enough to offset the optimization benefits, but might be cost-effective in some circumstances.

[95]The exception to this rule occurs when an end-use is separately metered, such as water heating under Rate 3.

A: Bentley asserts that certain electrotechnologies (by which he seems to mean new or improved electric applications) can replace fossil end use and pass the societal test (pp. 11–12). He also concludes that these technologies might slightly reduce rates.[96]

Q: Under what circumstances should CV promote electric end uses?

A: Increased electric penetration is desirable where it is desired by users and decreases societal costs. Promotion of these end-uses by CV may be generally reasonable, so long as the promotion does not increase costs for other ratepayers. The RIM is an appropriate screening test for sales promotion, since these promotions do not serve to minimize the costs of energy services normally provided by electricity, and thus are beyond the scope of electric IRP. There is no compelling reason for CV ratepayers to pay for minimizing the cost of other types of services.[97]

Q: What action should the Board take at this time with respect to CV promotion of electric uses?

A: Given CV's very vague representations in this proceeding, any Board action would be premature. Once CV is prepared to present a detailed demonstration that particular electric applications are cost-effective, it should present that information to the Board, and make appropriate requests for specific regulatory approval.

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[96]Bentley does not provide any details on his cost-effectiveness assumptions, so we do not know what incentives (if any) Bentley assumed, whether these end uses are really cost-effective, or whether they are likely to reduce rates.

[97]We do not expect CV to intervene in other sectors of the economy that could bear improvement, including the health care market or improvement of scenic vistas, except to remedy problems that may be caused by CV's own actions.

The promotion of electric uses does not require most of the special ratemaking applicable to energy efficiency programs. In promoting electric sales, CV does not incur lost revenues (it increases revenues), and should require no incentive or special provision for deferral of costs (since shareholders receive all the additional non-fuel revenues until the next rate case)..

X. Conclusions

Q: Please summarize your conclusions from this rebuttal testimony.

A: My major conclusions can be summarized as follows:

- The risk adjustment for fuel switching proposed by CV uses the wrong test (participant rather than societal), inappropriate computations, and the wrong data.
- It is not clear that any risk adjustment is appropriate, but if it is, then the adjustment to electric avoided cost is greater than adjustment to fossil fuel costs, increasing the cost-effectiveness of fuel switching.
- The estimate sponsored by CV for the social cost of rate increases is overstated, in that it ignores the time required for the assumed elasticity effect, overstates the difference between rates and marginal costs, ignores the cost-reducing effects of DSM programs, and mixes together desirable and undesirable reactions to higher rates.
- Many, and perhaps all, of CV's rates are below marginal costs. Rate increases would bring rates closer to marginal costs and decrease societal costs.

- The environmental costs of CV electric supply are much larger than assumed in CV's analyses.
- Both electric generation and end-use fuels produce air pollutants; in general, direct use of fuels for space and water heating produce lower regional levels of pollution.
- CV has not demonstrated that fuel switching will have any adverse effect on Vermont ambient air quality or compliance costs.
- With an efficient program design, fuel switching need not impose significant transaction or other non-market costs.
- The evidence provided by CV in these proceedings supports the conclusion that Rate 3 water-heater control, and CV's load-control "portfolio" as a whole, increase CV's peak load. CV peaks would be lower if some controlled loads reverted to uncontrolled levels, and still lower if those loads switched to other fuels.
- Peak loads on CV's system remain sensitive to weather, and space heating remains a significant portion of peak load.
- It is clear that CV dispatches its load control based on *total area load*, which is the wrong measure of load and leads to incorrect dispatch decisions.
- The societal test remains the correct screening test for DSM options, including fuel switching. The proposals by CV to replace the societal test with the RIM, the participant test, a "public project" test, or a no-regrets test, should be rejected.
- In some situations, deferral of a cost-effective DSM resource can increase the net benefits of the resource. Nothing in these proceedings

suggests that deferral of DPS's proposed fuel-switching program would be cost-effective.

- Promotion of appropriate electric applications is not inconsistent with fuel-switching from electricity to fossil fuels in other applications. In these proceedings, CV has yet to establish that any particular applications are cost-effective, or to request any Board action in connection with such promotion.

Q: Do you have any response to Deehan's request, on page 9 of his testimony, that Rate 13 be reopened?

A: I see no reason to reopen Rate 13. If storage space-heating is cost-effective, it can be obtained through Rate 9. Rate 9 imposes the same off-peak rate for all end uses, rather than creating a lower rate for an end use (space heating) for which usage is positively correlated with system load and hence avoided energy costs. The discount in Rate 13 is likely to take the rate further from marginal costs.

Q: Does this conclude your rebuttal testimony?

A: Yes.

Vermont Residential Oil Prices, and Electric Rates

Year	CV Average Residential Electric Rate (cents/KWh)	Vermont Residential Heating Oil ($/MMBTU)	(cents/KWh equivalent)
	[1]	[2]	[3]
1970	8.04	5.33	1.45
1971	8.71	5.39	1.47
1972	9.23	5.25	1.43
1973	9.08	5.66	1.54
1974	10.43	7.91	2.16
1975	10.90	7.71	2.10
1976	11.22	7.77	2.12
1977	10.61	8.18	2.23
1978	10.99	8.18	2.23
1979	9.95	9.73	2.66
1980	9.40	12.91	3.52
1981	9.90	14.43	3.94
1982	9.67	13.36	3.64
1983	9.46	11.90	3.25
1984	9.36	11.27	3.07
1985	9.64	10.50	2.86
1986	10.75	8.56	2.33
1987	10.60	7.92	2.16
1988	10.16	7.56	2.06
1989	9.88	7.91	2.16
1990	10.85	8.87	2.42
1991	10.28	7.72	2.11
1992	10.58	6.78	1.85
1993	10.34	6.46	1.76

Sources:

[1] For 1970-1992: Exhibit__SA-1, p. 5 of Dr. Shimon Awerbuch's Testimony Exhibits Docket Nos. 5270-CV1 and CV2 and Docket No. 5686, April 4, 1994.
For 1993, the average residential rate estimate is calculated by dividing Residential Electric Revenues by Residential Electric Sales.
"Historical Statistics," Central Vermont Public Service Corporation, Annual Report 1993.

[2] "Energy Price Estimates by Sector, Vermont." Energy Information Administration/ State Energy Price and Expenditure Report, for years 1970-1990.
Bruce Bawks, Refined Petroleum Product Supply and Prices Division, Energy Information Administration, for years 1991-1993.
1991 Price=$1.019/gallon
1992 Price=$0.922/gallon
1993 Price=$0.89/gallon

Notes:

[3] Unit conversion of [2] at 80% efficiency.

Net Income and Total Bills, Electric and Oil Heat

		With Electric Space and Water Heat			With Oil Space and Water Heat			
Year	VT Per Capita Personal Income In real dollars [1]	Electric Water Heating and Electric Space Heat Expenses [2]	Other Electric End Use Expenses [3]	VT Per Capita Personal Income net of electricity expenses [4]	Electric Water Heating and Electric Space Heat Expenses [5]	Other Electric End Use Expenses [6]	Payment for Fuel-Switch [7]	VT Per Capita Personal Income net of energy expenses [8]
1970	$11,704	$1,287	$483	$9,934	$232	$483		$10,989
1971	12,336	1,393	522	10,421	235	522		11,578
1972	12,464	1,477	554	10,434	229	554		11,681
1973	13,089	1,453	545	11,091	247	545		12,297
1974	12,971	1,670	626	10,675	345	626		11,999
1975	12,859	1,745	654	10,460	336	654		11,868
1976	13,505	1,796	673	11,035	339	673		12,492
1977	13,509	1,698	637	11,174	357	637		12,515
1978	14,399	1,759	660	11,981	357	660		13,383
1979	14,690	1,592	597	12,501	425	597		13,668
1980	14,692	1,504	564	12,624	563	564		13,564
1981	15,087	1,585	594	12,908	630	594		13,863
1982	15,251	1,548	580	13,123	583	580		14,088
1983	15,429	1,513	568	13,348	519	568		14,343
1984	16,156	1,498	562	14,097	492	562		15,102
1985	16,500	1,543	579	14,379	458	579		15,464
1986	16,804	1,719	645	14,441	373	645		15,786
1987	17,437	1,695	636	15,106	346	636		16,455
1988	18,043	1,626	610	15,808	330	610		17,104
1989	18,464	1,581	593	16,290	345	593		17,526
1990	18,534	1,735	651	16,148	387	651		17,497
1991	18,333	1,645	617	16,072	337	617		17,380
1992	18,609	1,692	635	16,282	296	635		17,679
1993	18,489	1,655	621	16,213	282	621		17,586

Notes:

All values are in constant 1993 dollars.

[1] Source: Riley Allen, Vermont Public Service Department.

[2] Expenses were calculated using average residential electric rates from Exhibit__SA-1, p. 5 of Dr. Shimon Awerbuch's Testimony Exhibits Docket Nos. 5270-CV1 and CV2 and Docket No. 5686, April 4, 1994, for 1970-1992. and from "Historical Statistics," Central Vermont Public Service Corporation, Annual Report 1993. Assume ESH + EWH=16000 KWh/yr for all years

[3] *Assume other electric end uses=6000 KWh/yr for all years*

[4] equals [1]-[2]-[3]

[5] Assume same ESH + EWH as [2], but at 80% efficiency. Expenses were calculated using Vermont residential oil #2 prices from the following sources: *"Energy Price Estimates by Sector, Vermont." Energy Information* Administration/ State Energy Price and Expenditure Report, for years 1970-1990. Bruce Bawks, Refined Petroleum Product Supply and Prices Division, Energy Information Administration, for years 1991-1993.

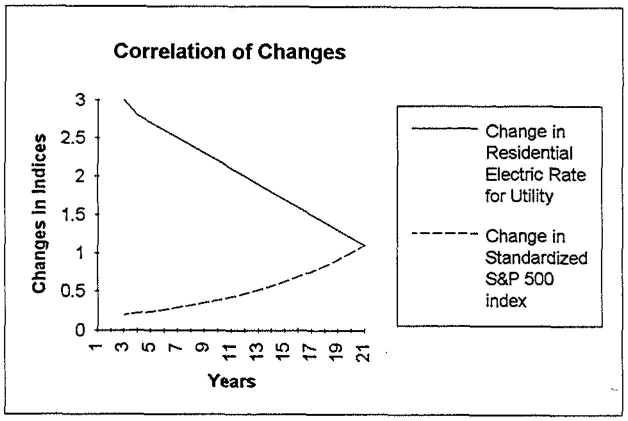
1991 Price=$1.019/gallon
1992 Price=$0.922/gallon
1993 Price=$0.89/gallon

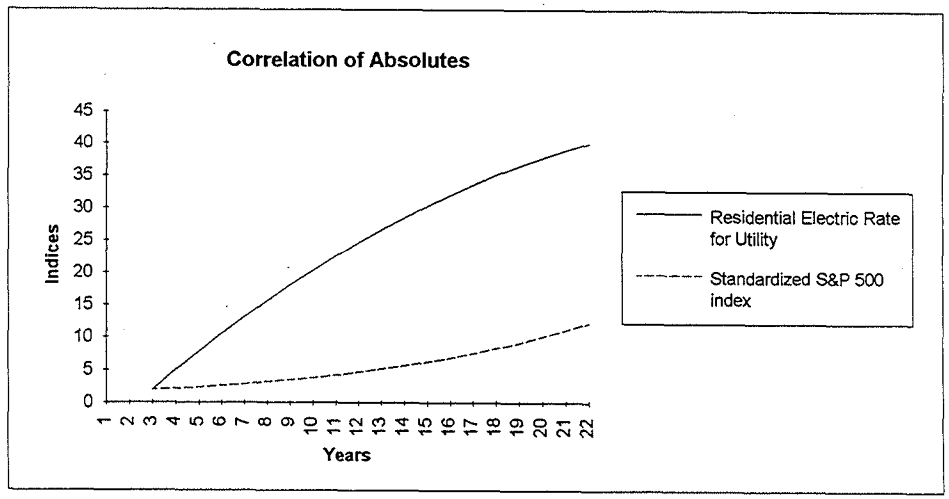
[6] equals [3]

[7] *Copayment for oil-fired equipment; not specified for this analysis.*

[8] equals [1]-[5]-[6]-[7]

Positive Correlation of X to Y, with Negative Correlation of Change in X to Change in Y





Variance and Beta of Vermont Per-Capita Income and Energy Prices

Variance of Vermont real per capita income	Time period
5.270	1970-1993
4.425	1970-1990
1.593	1982-1993

	Covariance with Vermont real per capita income	Beta	Time Period
Vermont oil price #2 (residential)	0.943	0.179	1970-1993
Vermont propane price (residential)	1.925	0.435	1970-1990
Massachusetts oil price #6 (utility)	0.202	0.046	1970-1990
CV residential electric rate #1	0.473	0.297	1982-1993
CV residential electric rate #3	1.122	0.213	1970-1993
CV average residential electric rate	0.672	0.127	1970-1993

Notes: Betas are calculated by dividing the covariance by the variance for the appropriate time period.

Changes in Vermont Per-Capita Income and Energy Prices

Variance of Vermont real per capita income	*Time Period*
0.000502	1971-1993
0.000480	1971-1990
0.000323	1983-1993

	Covariance with Vermont real personal income per capita	*Beta*	*Time Period*
Vermont oil price #2 (residential)	-0.000519	-1.035	1971-1993
Vermont propane price (residential)	-0.000907	-1.888	1971-1990
Massachusetts oil price #6 (utility)	-0.001880	-3.913	1971-1990
CV residential electric rate #1	-0.000113	-0.348	1983-1993
CV residential electric rate #3	0.000146	0.290	1971-1993
CV average residential electric rate	0.000026	0.051	1971-1993

Note: Betas are calculated by dividing the covariance by the variance for the appropriate time period.

Regression of Per Capita Income (in thousands of dollars) on Time and Energy Prices
Case 1: Residential Oil #2

Regression Statistics

Multiple R	0.991
R Square	0.982
Adjusted R Square	0.980
Standard Error	0.325
Observations	24

Analysis of Variance

	df	*Sum of Squares*	*Mean Square*	*F*	*Significance F*
Regression	2	118.995	59.497	562.969	5.73E-19
Residual	21	2.219	0.106		
Total	23	121.2143			

	Coefficients	*Standard Error*	*t Statistic*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-627.575	19.401	-32.347	1.11E-20	-667.922	-587.228
Year	0.325	0.010	33.077	6.72E-21	0.304	0.345
Vermont Residential #2 Oil Price (Dollars per Million Btu)	-0.0430	0.0270	-1.5934	0.1247	-0.0992	0.0131

Case 2: Residential Propane

Regression Statistics

Multiple R	0.993
R Square	0.986
Adjusted R Square	0.984
Standard Error	0.266
Observations	21

Analysis of Variance

	df	*Sum of Squares*	*Mean Square*	*F*	*Significance F*
Regression	2	87.220	43.610	614.762	2.71E-17
Residual	18	1.277	0.071		
Total	20	88.496			

	Coefficients	*Standard Error*	*t Statistic*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-676.219	21.074	-32.088	1.12E-18	-720.493	-631.945
Year	0.350	0.011	32.611	8.16E-19	0.327	0.372
Vermont Residential Propane Price (Dollars per Million Btu)	-0.0754	0.0253	-2.9873	7.28E-03	-0.1285	-0.0224

Case 3: Utility Oil #6

Regression Statistics

Multiple R	0.995
R Square	0.990
Adjusted R Square	0.989
Standard Error	0.222
Observations	21

Analysis of Variance

	df	*Sum of Squares*	*Mean Square*	*F*	*Significance F*
Regression	2	87.612	43.806	891.986	9.90E-19
Residual	18	0.884	0.049		
Total	20	88.496			

	Coefficients	*Standard Error*	*t Statistic*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-660.563	16.013	-41.251	7.93E-21	-694.206	-626.920
Year	0.341	0.008	42.167	5.13E-21	0.324	0.358
Massachusetts Utility #6 Oil Price (Dollars per Million Btu)	-0.1307	0.0286	-4.5705	1.86E-04	-0.1907	-0.0706

Case 4: Average Residential Electric Rate

Regression Statistics

Multiple R	0.990
R Square	0.980
Adjusted R Squar	0.978
Standard Error	0.339
Observations	24

Analysis of Variance

	df	*Sum of Squares*	*Mean Square*	*F*	*Significance F*
Regression	2	118.798	59.399	516.229	1.40E-18
Residual	21	2.416	0.115		
Total	23	121.214			

	Coefficients	*Standard Error*	*t Statistic*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-627.599	21.379	-29.356	9.84E-20	-672.059	-583.139
Year	0.325	0.011	29.575	8.33E-20	0.302	0.348
CV Average Electric Rate (cents per KWh sold)	-0.0776	0.0985	-0.7877	4.39E-01	-0.2824	0.1272

Case 5: Residential Electric Rate #1

Regression Statistics

Multiple R	0.961
R Square	0.923
Adjusted R Squ	0.906
Standard Error	0.387
Observations	12

Analysis of Variance

	df	*Sum of Squares*	*Mean Square*	*F*	*Significance F*
Regression	2	16.172	8.086	54.004	9.71E-06
Residual	9	1.348	0.150		
Total	11	17.520			

	Coefficients	*Standard Error*	*t Statistic*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-641.020	64.355	-9.961	7.69E-07	-786.601	-495.438
Year	0.331	0.032	10.211	6.00E-07	0.257	0.404
CV Electric Rate #1 (cents per KWh sold)	0.0745	0.0511	1.4561	1.73E-01	-0.0412	0.1902

Case 6: Residential Electric Rate #3

Regression Statistics

Multiple R	0.990
R Square	0.981
Adjusted R S	0.979
Standard Err	0.330
Observation	24

Analysis of Variance

	df	*Sum of Squares*	*Mean Square*	*F*	*Significance F*
Regression	2	118.921	59.460	544.381	8.10E-19
Residual	21	2.294	0.109		
Total	23	121.214			

	Coefficients	*Standard Error*	*t Statistic*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-599.035	25.529	-23.465	1.45E-17	-652.125	-545.945
Year	0.310	0.013	23.536	1.35E-17	0.282	0.337
CV Electric Rate #3 (cents per KWh)	0.1687	0.1266	1.3327	1.96E-01	-0.0945	0.4319

Sensitivity of Customer Welfare to Electric and Oil Prices

	Electric space and water heat				Fossil space and water heat			
	Heating bill	ther Electric	Gasoline	Total	Heating bill	Other Electric	Gasoline	Total
Base Case	$1,655	$621	$800	$3,076	$282	$621	$800	$1,703
Electric increase o 10%	$1,821	$683	$800	$3,304	$282	$683	$800	$1,765
Fuel increase of 10%	$1,655	$621	$880	$3,156	$310	$621	$880	$1,811

Variance and Beta of Vermont Unemployment and Energy Prices

Variance of Vermont Unemployment Rate	Time Period
2.359	1970-1993
2.570	1970-1990
1.754	1982-1993

	Covariance with Vermont Unemployment Rate	Beta	Time Period
Vermont oil price #2 (residential)	0.348	0.147	1970-1993
Vermont propane price (residential)	0.099	0.038	1970-1990
Massachusetts oil price #6 (utility)	0.992	0.386	1970-1990
CV residential electric rate #1	-1.512	-0.862	1982-1993
CV residential electric rate #3	-0.309	-0.131	1970-1993
CV average residential electric rate	0.204	0.086	1970-1993

Notes: Betas are calculated by dividing the covariance by the variance for the appropriate time period.

Changes in Vermont Unemployment and Energy Prices

Variance of Vermont Unemployment Rate	*Time Period*
0.060064	1971-1993
0.060064	1971-1990
0.056134	1983-1993

	Covariance with Vermont Unemployment Rate	*Beta*	*Time Period*
Vermont oil price #2 (residential)	0.006506	0.108	1971-1993
Vermont propane price (residential)	-0.002152	-0.036	1971-1990
Massachusetts oil price #6 (utility)	0.025217	0.420	1971-1990
CV residential electric rate #1	-0.000007	0.000	1983-1993
CV residential electric rate #3	-0.000991	-0.016	1971-1993
CV average residential electric rate	0.003992	0.066	1971-1993

Note: Betas are calculated by dividing the covariance by the variance for the appropriate time period.

Value Line Betas for Oil-Producer Stocks

Company	Beta
Anadarko petro	1.15
Apache Corp	0.90
Chieftain Int'l	0.75
Dekalb Energy	0.55
Forest Oil	0.95
Louisiana Land	1.00
Maxus Energy	1.15
Mesa Inc	0.60
Noble	0.95
Oryx Energy	0.90
Plains Petro	0.90
Pogo Producing	0.90
Sun Energy	0.70
Triton Energy	1.00
Union Texas	0.90
Wainoco Oil	1.05
Average	0.90

Source: The Value Line Investment Survey Edition 12," Part 3 Ratings and Reports," June 5, 1992, pp. 1833-1849.

Awerbuch-Style Betas for Residential #2 and Utility #6 Oil

Variance of Market Return	*Time Period*
0.0179	1971-1991
0.0187	1971-1990

	Covariance with market return	*Beta*	*Time Period*
Return on No. 2 Oil VT	-0.0083	-0.46	1971-1991
Return on No. 6 Oil MA	-0.01916	-1.02	1971-1990

Note: Betas are calculated by dividing the covariance by the variance for the appropriate time period.

Effects of Risk-Adjusted Discounting on the Societal Test
Case 1: Using Original Assumptions

Measure Description	ID Number	Present Value of Avoided Cost [1]	Present Value of Fuel Switching Cost [2]	Benefit-Cost Ratio [3]	PV of Net Benefits [4]
Oil Stand alone DHW	WO2HE+r	$7,976	$6,539	1.22	$1,437
LP Stand Alone DHW: Low Use LP	WP5HE+r	$7,976	$8,235	0.97	($259)

Notes:

[1] Present Values are calculated using the real discount rate
[2] see [1]
[3] equals [1]/[2]
[4] equals [1] - [2]

Assumptions:		
	Inflation	4.25%
	Nominal discount rate	9%
	Lifetime = 50 years	
	Base year = 1994	

Effects of Risk-Adjusted Discounting on the Societal Test

Case 2: Using Awerbuch's residential oil beta as a proxy for oil #6 beta

Measure Description		ID Number	Present Value of Avoided Cost [1]	Present Value of Fuel Switching Cost [2]	Benefit-Cost Ratio [3]	PV of Net Benefits [4]
Oil Stand alone DHW	[i]	WO2HE+r	$5,501			
Oil Stand alone DHW	[ii]	WO2HE+r	$12,499			
Oil Stand alone DHW	[iii]	WO2HE+r	**$17,999**	**$17,945**	**1.0**	**$54**
LP Stand Alone DHW: Low Use LP	[iv]	WP5HE+r	$5,501			
LP Stand Alone DHW: Low Use LP	[v]	WP5HE+r	$12,499			
LP Stand Alone DHW: Low Use LP	[vi]	WP5HE+r	**$17,999**	**$12,871**	**1.4**	**$5,128**

Notes:

[1] Avoided Cost notes:

[i] AVC value includes capitalized energy cost, capacity costs, externalities and risk. Present value is calculated using the real discount rate for non-fuel costs.

[ii] AVC value includes energy costs. Present Value is calculated using the real discount rate for fuel and off-system sales.

[iii] Total AVC = [1] + [2]

[iv] see [i]

[v] see [ii]

[vi] Total AVC = [3] + [4]

[2] Present values are calculated using the real discount rate for the appropriate fuel

[3] equals [1]/[2]

[4] equals [1] - [2]

Assumptions

Inflation 4.10%

Nominal discount rates for Avoided Costs:

- Non-fuel costs 7.10%
- Fuel and off-system sales 0.12%

Nominal discount rates for Fuel-switching Costs:

- Oil 0.12%
- Propane 5.16%
- Non-fuel costs 7.10%

Lifetime = 50 years

Base year = 1994

Effects of Risk-Adjusted Discounting on the Societal Test
Case 3: Using Historical Vermont oil #2 beta and Massachusetts oil #6 beta

Measure Description		ID Number	Present Value of Avoided Cost [1]	Present Value of Fuel Switching Cost [2]	Benefit-Cost Ratio [3]	PV of Net Benefits [4]
Oil Stand alone DHW	[i]	WO2HE+r	$5,501			
Oil Stand alone DHW	[ii]	WO2HE+r	$20,657			
Oil Stand alone DHW	[iii]	WO2HE+r	**$26,158**	**$14,027**	**1.9**	**$12,131**
LP Stand Alone DHW: Low Use LP	[iv]	WP5HE+r	$5,501			
LP Stand Alone DHW: Low Use LP	[v]	WP5HE+r	$20,657			
LP Stand Alone DHW: Low Use LP	[vi]	WP5HE+r	**$26,158**	**$12,871**	**2.0**	**$13,287**

Notes:

[1] Avoided Cost notes:
- [i] AVC value includes capitalized energy cost, capacity costs, externalities and risk. Present value is calculated using the real discount rate for non-fuel costs.
- [ii] AVC value includes energy costs. Present Value is calculated using the real discount rate for fuel and off-system sales.
- [iii] Total AVC = [1] + [2]
- [iv] see [i]
- [v] see [ii]
- [vi] Total AVC = [3] + [4]

[2] Present values are calculated using the real discount rate for the appropriate fuel

[3] equals [1]/[2]

[4] equals [1] - [2]

Assumptions: Inflation 4.10%

Nominal discount rates for Avoided Costs:

Non-fuel costs	7.10%
Fuel and off-system sales	-2.40%

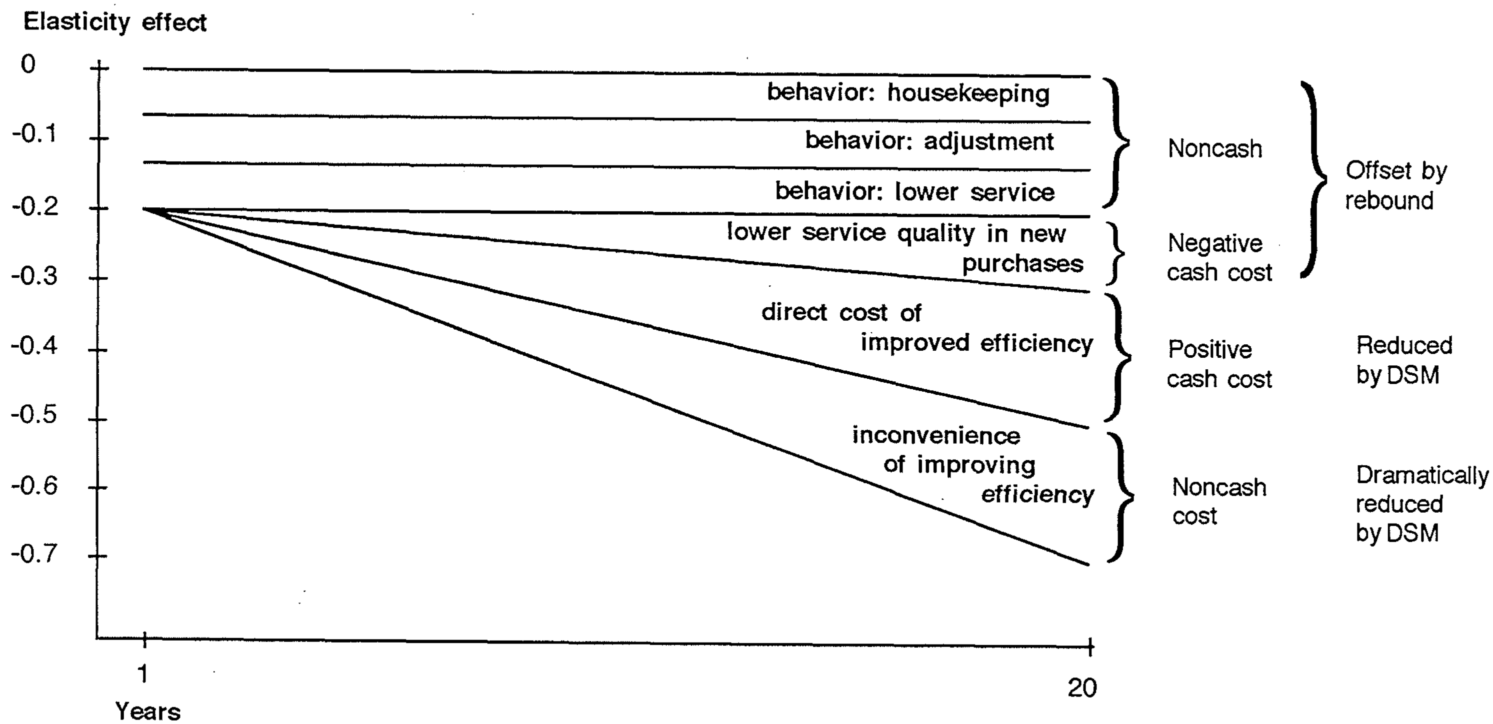
Nominal discount rates for Fuel-switching Costs:

Oil	1.80%
Propane	5.16%
Non-fuel costs	7.10%

Lifetime = 50 years

Base year = 1994

Illustration of Elasticity Effects over Time



Emissions Rates Implied by CVPS Emissions (Summaries for Selected Years)

20% run		lbs/MWh (* 1000 for CO2)					
1994	GWH	SO2	NOx	Part	CO2	CO	VOCs
Merrimack	0.62	19.355	22.581	3.226	3.226	3.226	0.000
Canal	13.77	19.463	2.760	0.000	1.452	0.436	0.000
McNeil	3.7	0.000	1.622	0.000	0.541	2.162	0.000
Firm Pool Pur	3.48	10.920	4.598	1.149	2.299	0.000	0.000
Wyman	5.58	7.168	2.509	0.000	1.434	0.358	0.358
Non-Firm Pool	15.21	0.920	0.263	0.131	0.263	0.000	0.000
CV GT's	0.5	4.000	8.000	0.000	4.000	4.000	0.000
Other	18.43	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	61.29	6.102	1.566	0.131	0.751	0.326	0.033

40% run							
1995	GWH						
Merrimack	5.17	18.956	17.408	1.161	1.547	0.000	0.000
Canal	16.78	9.535	2.265	0.238	1.549	0.358	0.119
McNeil	7.5	0.000	1.867	0.000	0.800	2.400	0.267
Firm Pool Pur	29.99	10.870	2.467	1.000	1.734	0.400	0.067
Wyman	6.88	7.558	2.616	0.000	1.744	0.581	0.000
Non-Firm Pool	17.42	1.033	0.230	0.230	0.115	0.000	0.000
CV GT's	1.48	2.703	8.108	0.000	2.703	1.351	0.000
Other	38.41	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	123.63	5.322	2.022	0.356	0.890	0.340	0.049

80% run							
1997	GWH						
Merrimack	59.99	18.903	17.203	1.200	1.800	0.200	0.000
McNeil	34.72	0.000	1.786	0.058	0.691	2.535	0.230
Firm Pool Pur	105.07	11.021	2.627	1.047	1.770	0.400	0.095
Wyman	2.28	7.018	2.632	0.000	1.754	0.877	0.877
Non-Firm Pool	9.82	0.815	0.407	0.204	0.000	0.204	0.000
CV GT's	0.72	2.778	8.333	0.000	2.778	2.778	0.000
Other	30.57	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	243.17	9.532	5.700	0.765	1.332	0.609	0.082

100% run 1999	GWH	lbs/MWh (* 1000 for CO2) SO2	NOx	Part	CO2	CO	VOCs
CCBase	69.64	0.000	0.316	0.057	0.976	0.661	0.144
McNeil	27.16	0.000	1.915	0.000	0.368	3.387	0.295
Firm Pool Pur	161.38	0.000	0.359	0.099	1.053	0.706	0.186
Wyman	-15.09	7.422	2.386	0.000	1.723	0.398	0.133
Non-Firm Pool	4.12	1.456	0.000	0.000	0.000	0.000	0.000
CV GT's	2.13	3.756	7.512	0.939	2.817	1.878	0.939
Other	55.17	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	304.51	-0.322	0.368	0.072	0.749	0.821	0.158

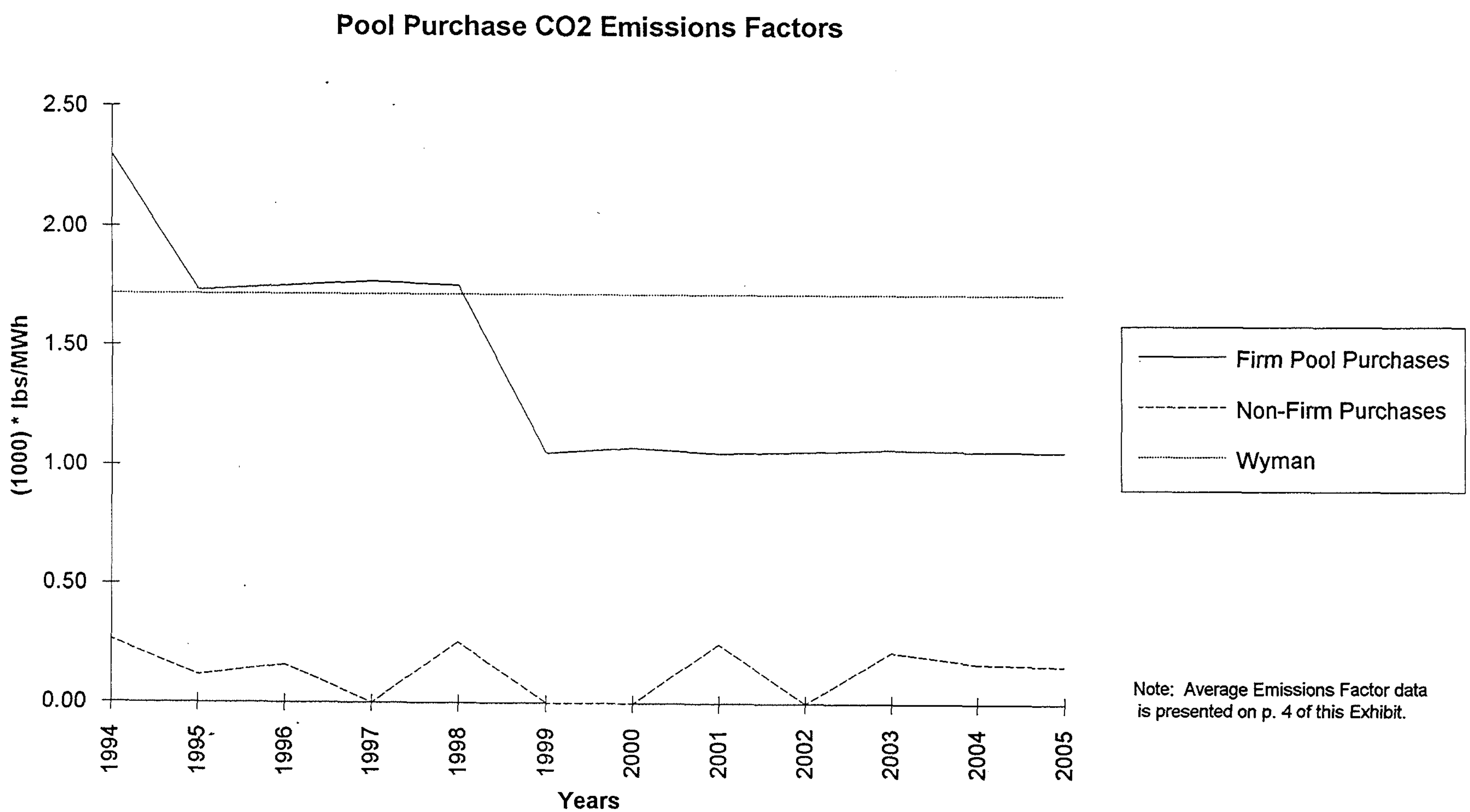
100% run 2005	GWH						
CCBase	184.02	0.000	0.315	0.076	0.978	0.641	0.141
McNeil	12.17	0.000	2.136	0.000	0.493	3.615	0.329
Wyman	5.13	7.797	2.729	0.390	1.949	0.390	0.000
Firm Pool Pur	152.75	0.000	0.354	0.092	1.061	0.694	0.170
CCInter	-37.33	0.000	0.375	0.107	1.125	0.804	0.214
Non-Firm Pool	-12.68	1.104	0.158	0.000	0.158	0.000	0.000
GT	0.4	0.000	0.000	0.000	5.000	10.000	0.000
CV GT's	0.09	0.000	0.000	0.000	0.000	0.000	0.000
Other	0.38	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	304.93	0.085	0.446	0.085	1.036	0.800	0.157

Note: Data from IR1

Annual Energy From Zero-Emissions "Other" Resource Displaced by Fuel Switching, as modeled by CVPS

Year	Other (GWh)	Total (GWh)	Other as Percent of Total
1994	18.43	61	30.1%
1995	36.41	122	29.9%
1996	34.78	182	19.1%
1997	30.57	243	12.6%
1998	84.20	304	27.7%
1999	55.17	305	18.1%
2000	49.30	305	16.2%
2001	1.94	305	0.6%
2002	1.05	305	0.3%
2003	12.77	305	4.2%
2004	0.32	305	0.1%
2005	0.38	305	0.1%
2006	2.91	305	1.0%
2007	0.22	305	0.1%
2008	0.06	305	0.0%
2009	0.12	305	0.0%
2010	0.10	305	0.0%
2011	0.02	305	0.0%
2012	0.13	305	0.0%

Source: Item 1, provided in response to DPS Data Request Set 1, Question 1, in Docket Nos. 5270-CV-1 and 5270-CV-3.

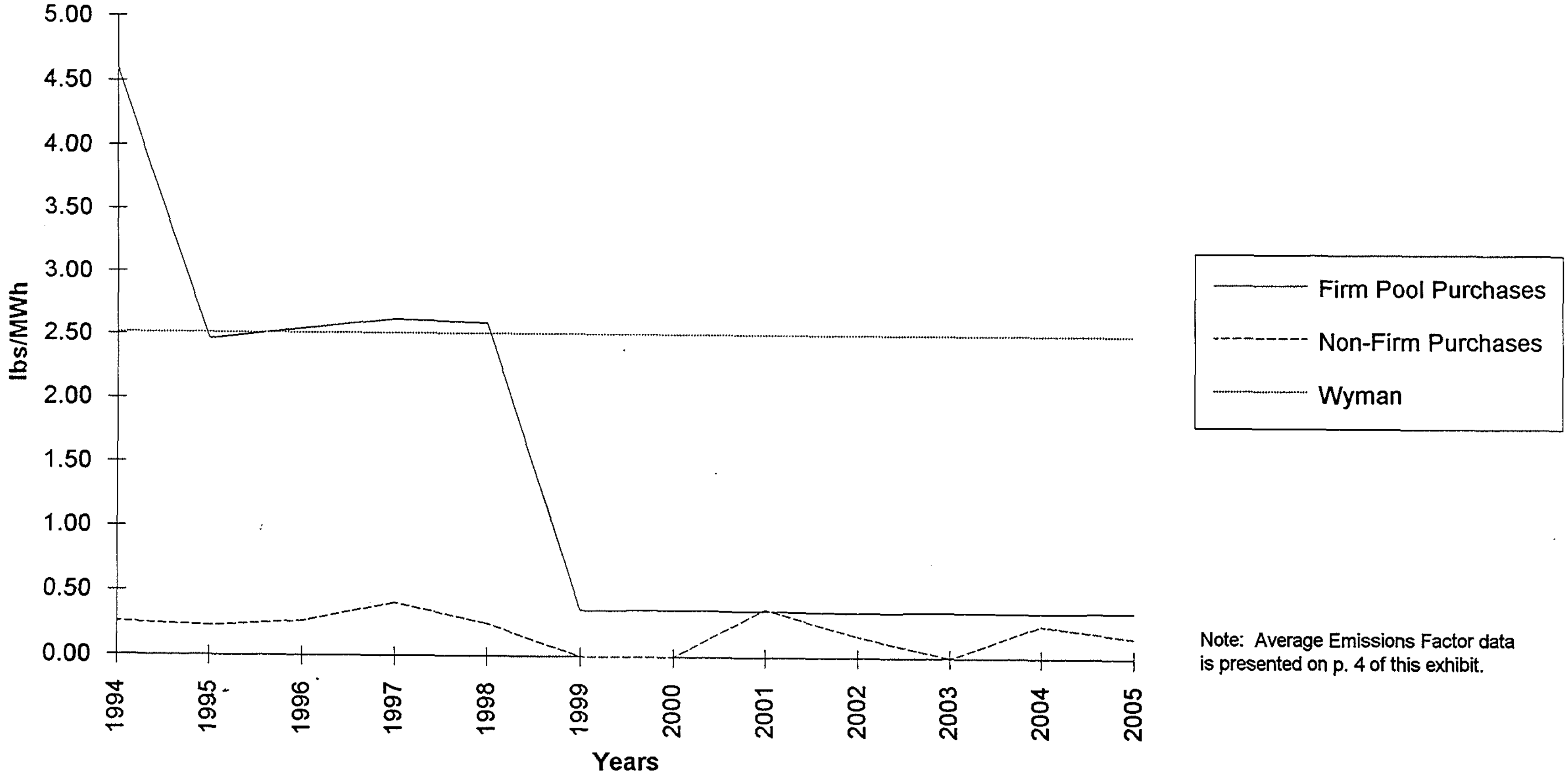


Note: Average Emissions Factor data is presented on p. 4 of this Exhibit.

Pool Purchase SOX Emissions Factors

Note: Average Emissions Factor data is presented on p. 4 of this exhibit.

Pool Purchase NOX Emissions Factors



Note: Average Emissions Factor data is presented on p. 4 of this exhibit.

Pool Purchase Average Emissions Factors

	INPUT	tons (or 1000 tons for CO2)			AVERAGE lbs/MWh (x1000 for CO2)		
	GWH	SOx	NOx	CO2	SOx	NOx	CO2
Firm Pool Purchases							
1994	3.48	19	8	4	10.92	4.60	2.30
1995	29.99	163	37	26	10.87	2.47	1.73
1996	50.27	272	64	44	10.82	2.55	1.75
1997	105.07	579	138	93	11.02	2.63	1.77
1998	170.96	935	222	150	10.94	2.60	1.75
1999	161.38	0	29	85	0.00	0.36	1.05
2000	148.65	0	27	80	0.00	0.36	1.08
2001	149.87	0	27	79	0.00	0.36	1.05
2002	171.36	0	30	91	0.00	0.35	1.06
2003	175.67	0	31	94	0.00	0.35	1.07
2004	165.44	0	29	88	0.00	0.35	1.06
2005	152.75	0	27	81	0.00	0.35	1.06
Non-Firm Purchases							
1994	15.21	7	2	2	0.92	0.26	0.26
1995	17.42	9	2	1	1.03	0.23	0.11
1996	37.69	20	5	3	1.06	0.27	0.16
1997	9.82	4	2	0	0.81	0.41	0.00
1998	23.68	11	3	3	0.93	0.25	0.25
1999	4.12	3	0	0	1.46	0.00	0.00
2000	-0.93	-1	0	0	2.15	0.00	0.00
2001	-16.2	-8	-3	-2	0.99	0.37	0.25
2002	-12.08	-6	-1	0	0.99	0.17	0.00
2003	-9.24	-5	0	-1	1.08	0.00	0.22
2004	-23.78	-13	-3	-2	1.09	0.25	0.17
2005	-12.68	-7	-1	-1	1.10	0.16	0.16
2006	-5.54	-2	-1	0	0.72	0.36	0.00
2007	-13.63	-7	-2	-1	1.03	0.29	0.15
2008	-11.17	-5	-2	-1	0.90	0.36	0.18
2009	-9.31	-5	-2	-2	1.07	0.43	0.43
2010	-13.98	-7	-1	-1	1.00	0.14	0.14
2011	-14.39	-8	-2	-1	1.11	0.28	0.14
2012	-16.13	-9	-2	-1	1.12	0.25	0.12

Compare to Wyman, as if constant over time:
For the years 1994, 1995, 1997, 1999

	SOx	NOx	CO2
Wyman Average	7.44	2.52	1.72

Comparison of TRC and RII End-Use Emissions Factors

TRC Emission Factors

Emission	Emissions (lbs/MMBtu) Oil	Propane	Gas
SO2	0.205	0.003	0.001
NOx	0.130	0.101	0.094
CO	0.036	0.014	0.040
TSP	0.018	0.003	0.000
VOCs	0.005	0.004	0.007

From Exhibit CVPS-JLH-5, pages 5-7.

RII Emission Factors

Emission	Emissions (lbs/MMBtu) Oil	Propane	Gas
SO2	0.288	0.000	0.001
NOx	0.120	0.094	0.095
CO	0.033	0.019	0.019
TSP	0.017	0.005	0.005
VOCs	0.005	0.005	0.005

See Exhibit PLC-24.

Ratio of TRC to RII Emission Factors

Emission	Oil	Propane	Gas
SO2	0.71		1.00
NOx	1.09	1.08	0.99
CO	1.10	0.72	2.11
TSP	1.06	0.58	0.04
VOCs	1.03	0.72	1.45

Inconsistencies in Spinner-reported Peak Hours (p.39)

Date	Five Highest Hours (from IR-116)	Total Area Load (TAL) IR-116 (MW)	Date	Five Highest Hours from p.39	Total Area Load (TAL) p.39 (MW)
12/29/93	12	470	12/29/93	18	471
12/29/93	13	467	12/28/93	18	468
12/28/93	22	470	12/27/93	18	468
12/28/93	21	466	12/27/93	13	467
12/27/93	18	459	12/27/93	12	467
Note:	Shaded areas show the only hour which is in the 5 peak hours for both sources.				

Date	Hour from p.39	Total Area Load (TAL) p.39 (MW)	Total Area Load (TAL) IR-116 (MW)	Total Area Load (TAL) Difference (MW)	Retail p.39 (MW)	Retail IR-116 (MW)	Retail* Difference (MW)
12/29/93	18	471	459	12	423	411	12
12/28/93	18	468	448	20	419	399	20
12/27/93	18	468	459	9	418	409	9
12/27/93	13	467	440	27	424	397	27
12/27/93	12	467	457	10	422	412	10
		Avg. Difference		16			16
Note:	* Differences may be explained by the defintion Spinner uses.						
	It is unclear whether the terms "retail", "load", "consolidated retail load"						
	and "consolidated load" are intended to represent the same load.						

	January Peaks	
	Exhibit	Exhibit
	(HMS-2)	(HMS-3)
	(MW)	(MW)
1988	479	476
1989	475	448
1990	N/A	460
1991	445	468
1992	471	449
1993	440	459

			HMS-2	Anderson		HMS-2	Anderson	
			Avg Hrly	Avg Hrly		Peak	Pk Load	
	Month	Day	Load	Load	Diff?	(MW)	on day	Diff?
1988	1	6	415	415	0	457	457	0
1988	1	7	427	427	0	468	468	0
1988	1	8	423	423	0	476	476	0
1988	1	11	405	405	0	456	457	-1
1988	1	14	436	435	1	476	481	-5
1988	1	15	434	434	0	479	479	0
1988	1	28	405	405	0	445	445	0
1988	12	12	424	424	0	475	472	3
1989	1	4	425	423	2	475	474	1
1989	1	5	429	429	0	466	466	0
1989	12	14	426	427	-1	468	468	0
1989	12	15	418	418	0	461	461	0
1989	12	22	418	418	0	454	464	-10
1989	12	27	425	427	-2	488	483	5

	TAL			Retail	
		IR-116			IR-116
	HMS-5	Data		HMS-5	Data
Mean	413.50	409.53		373.07	369.10
Std. Dev.	48.45	42.64		43.42	37.83
Sum	29772.00	29486.10		26861.14	26575.24
Minimum	320.00	326.87		289.53	296.40
Maximum	471.00	469.80		424.22	427.12

Period of Analysis: 1988-1994
Dependent variable = Load factor
Independent variables:
YEARDUM =1 if 1988-1989 and =0 if otherwise
HDD = Heating Degree Day
HDD*YEARDUM= interaction variable

Regression Statistics	
Multiple R	0.57
R Square	0.33
Adjusted R Square	0.27
Standard Error	1.65
Observations	36

Analysis of Variance

	df	*Sum of Squares*	*Mean Square*	*F*	*Significance F*
Regression	3	42.81	14.27	5.21	0.00482
Residual	32	87.64	2.74		
Total	35	130.44			

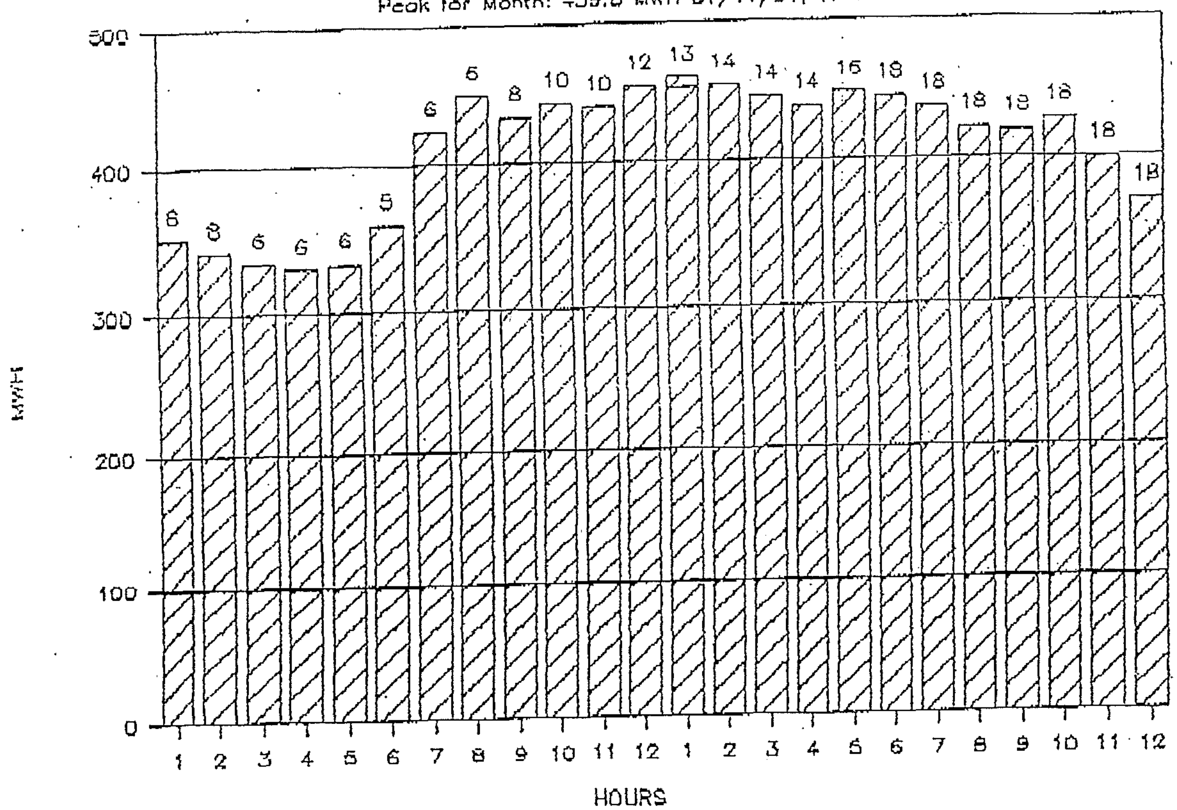
	Coefficients	*Standard Error*	*t Statistic*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	82.96	2.35	35.30	5.88E-29	78.17	87.74
YEARDUM	6.46	5.64	1.14	2.60E-01	-5.04	17.95
HDD	0.0915	0.0393	2.3285	0.0258	0.0115	0.1716
YD*HDD	-0.0789	0.0940	-0.8391	0.4071	-0.2703	0.1126

Source: "CVPS System Total Area Load (TAL) Peak Winter Day Load Factors Over Time," Exhibit_(HMS-2) pp. 1-2. Testimony of Howard M. Spinner on Behalf of Central Vermont Public Service Corporation, April 4, 1994.

RIPPLE CONTROL: 7:00-9:00am
11:00AM-1:30pm
5:00-9:30pm

LOAD SHAPE FOR FRIDAY,01/11/91

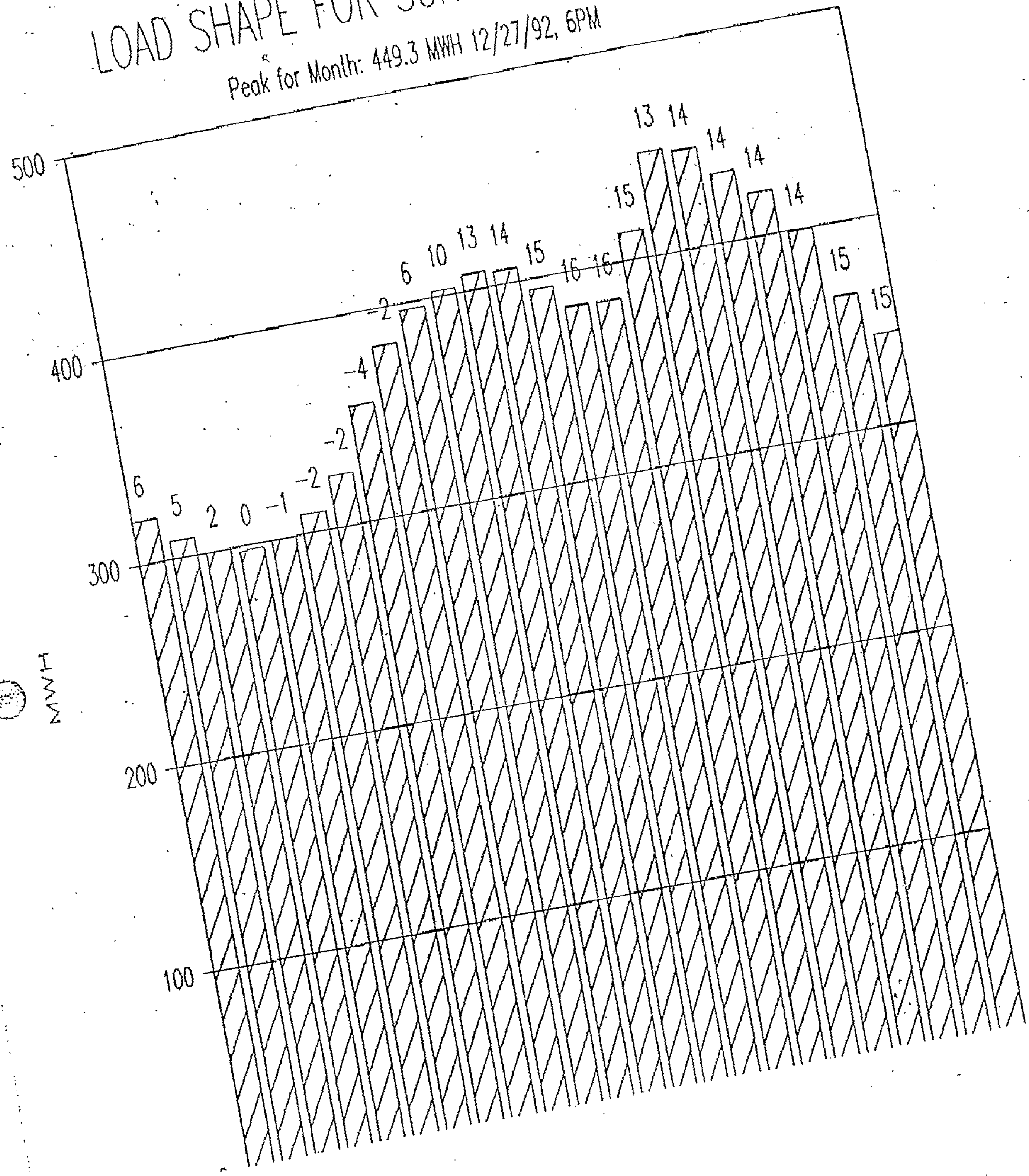
Peak for Month: 459.8 MWH 01/11/91, 1PM



Source: CVPS

LOAD SHAPE FOR SUNDAY, 12/27/92

Peak for Month: 449.3 MWH 12/27/92, 6PM



RIPPLE CONTROL: NONE

Source: CVPS

LOAD SHAPE FOR MONDAY, 01/11/93

Peak for Month: 438.0 MWH 01/11/93, 12N

RIPPLE CONTROL: 7:00am-8:00am
5:00pm-8:00pm

Source: CVPS

Estimate of Space-heating Peak Contribution

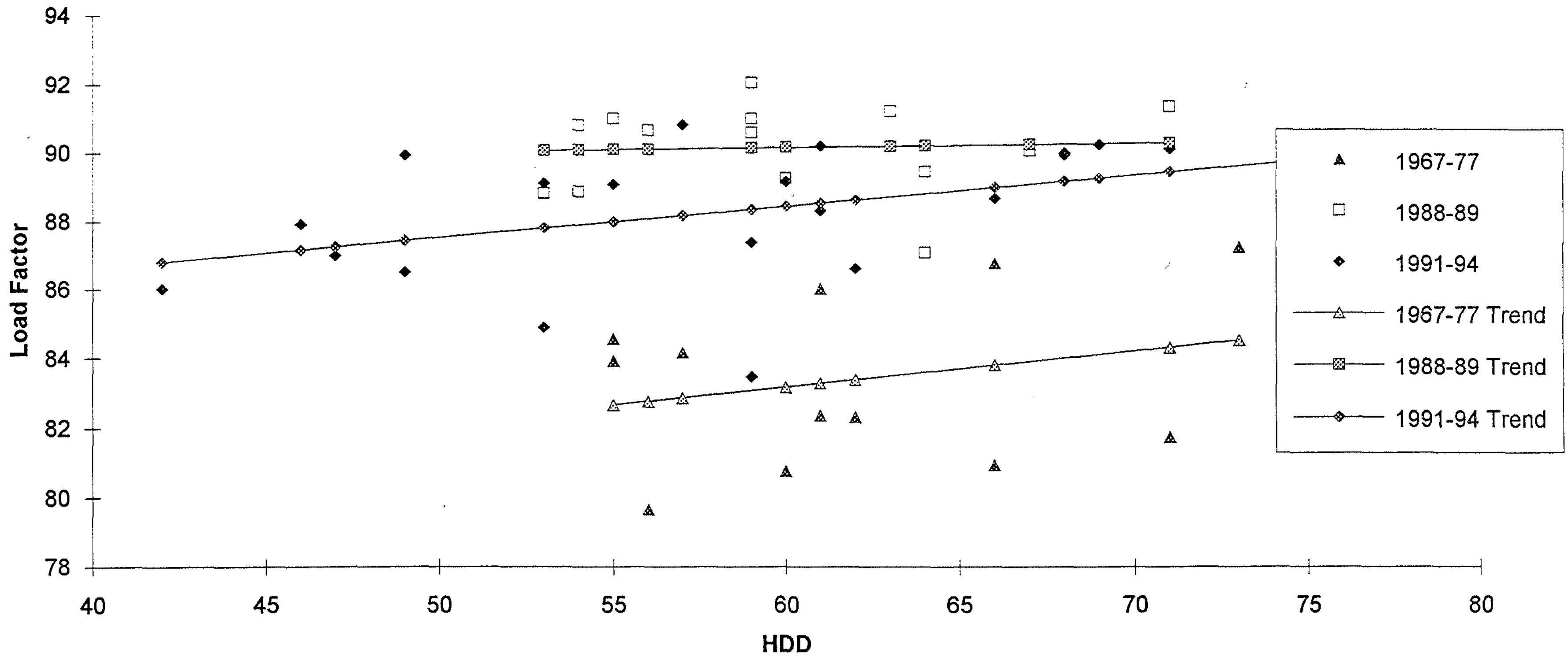
ESH #Customers	Typical Energy (kwh)	Peak (KW)	Total Peak (KW)
2061	1500	0.612	1260
2153	3000	1.223	2633
1063	5000	2.038	2166
1077	7500	3.058	3293
196	11000	4.485	879
2296	18873	7.694	17665
		Total	27898

Notes: Customer counts and typical energy usage from Plunkett, Direct 4/4/94, Exhibit_(JJP-6), except for energy usage of smallest bin which was estimated.

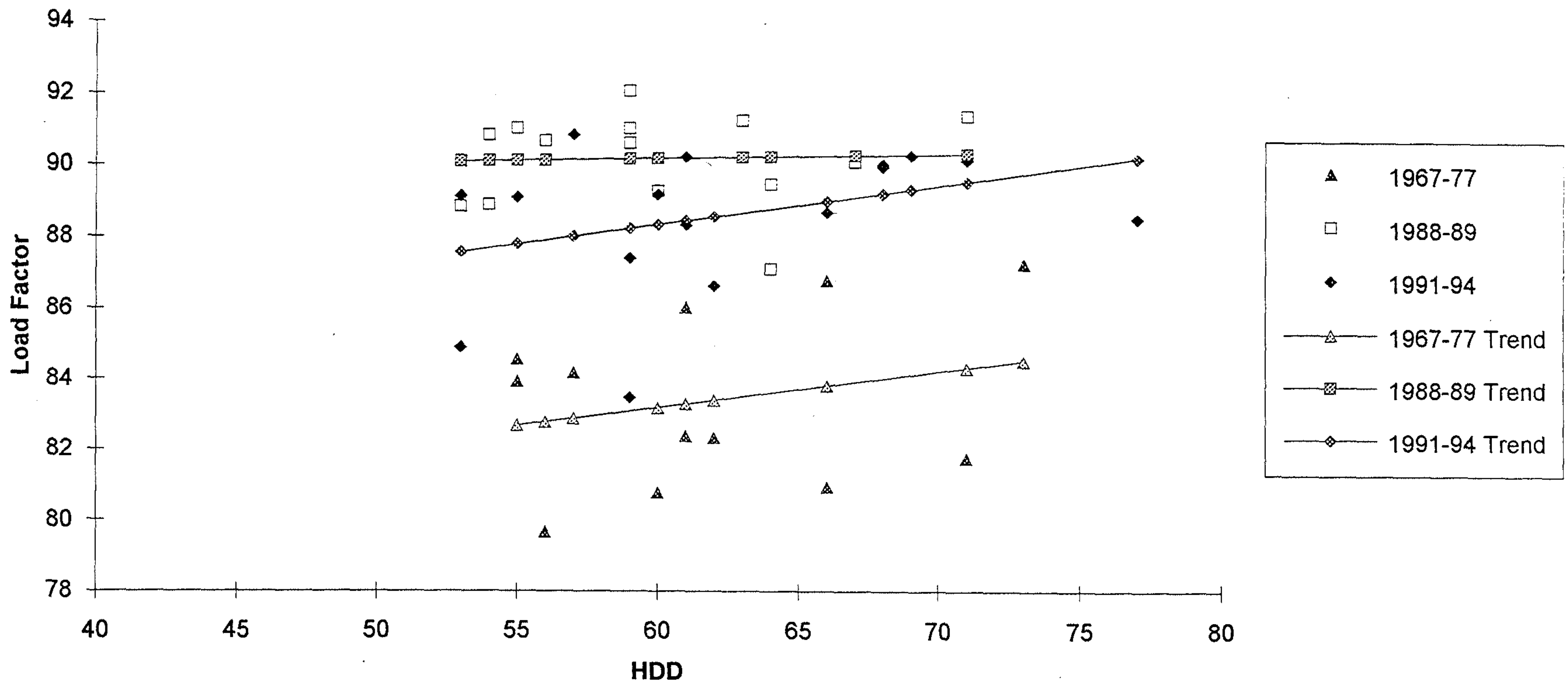
Peak energy assumes 28% load factor

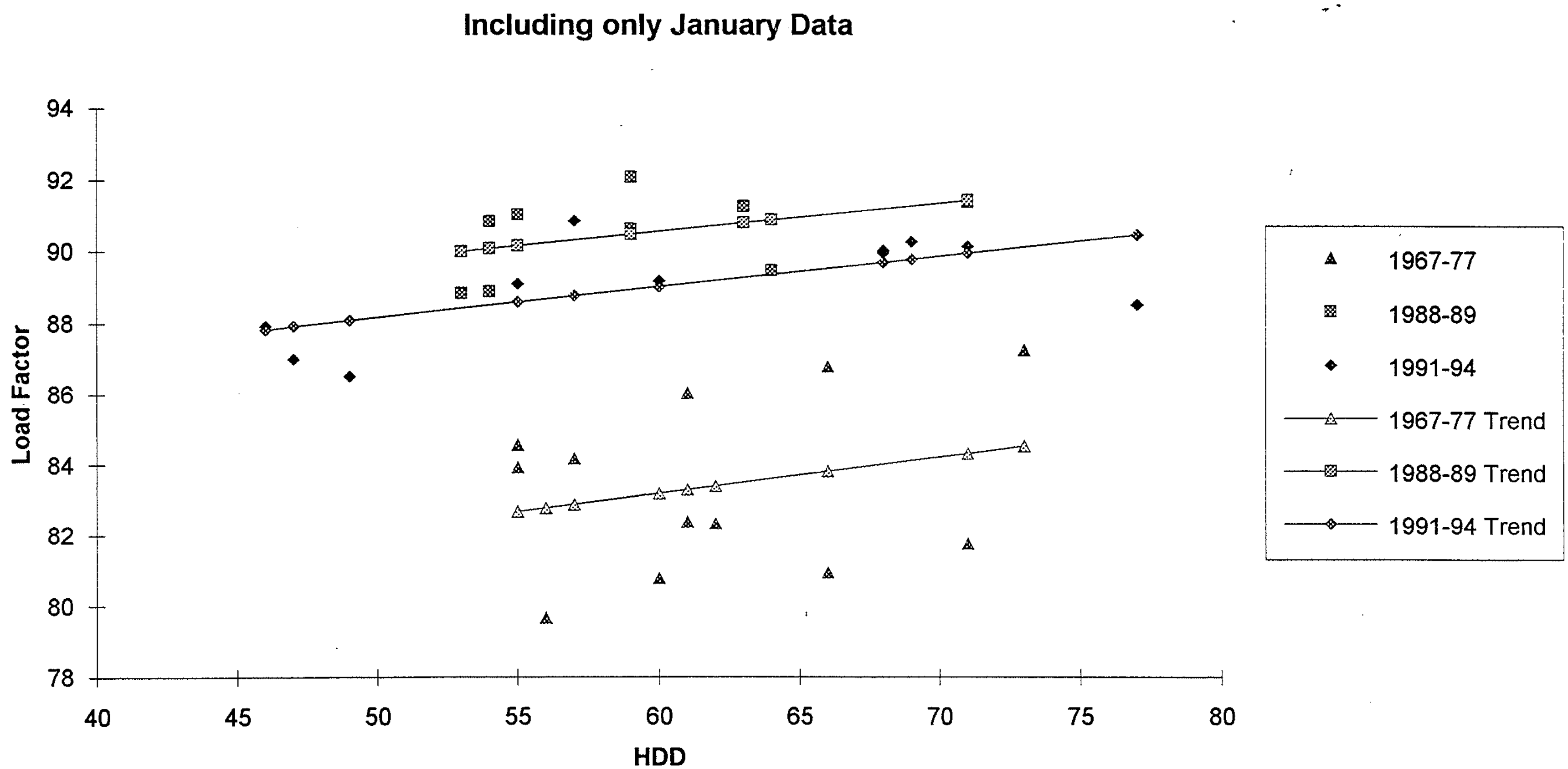
	Slopes from Regressions on Exhibit_(HMS-2) data			
	Spinner in Exhibit_(HMS-2)	Including only HDD>50	Including only January data	Including only January data with HDD>50
1967-77	1.104	0.104	0.104	0.104
1988-89	0.013	0.013	0.080	0.080
1991-94	0.091	0.110	0.085	-0.019

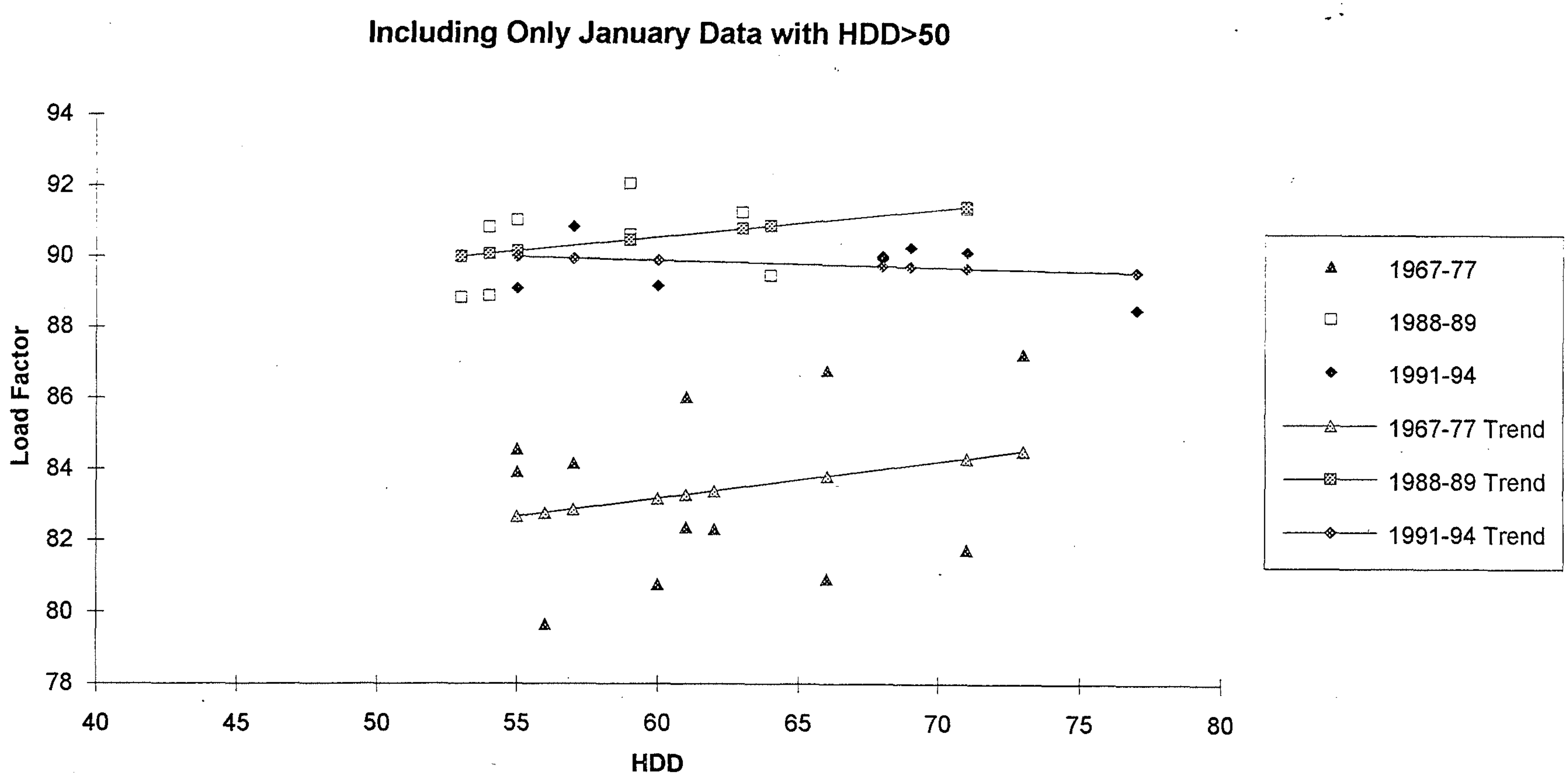
Spinner's Plot from Exhibit_(HMS-2)



Including only HDD>50




Including only January Data
94
92
90
88
86
84
82
80
78
Load Factor
40
45
50
55
60
65
70
75
80
HDD
1967-77
1988-89
1991-94
1967-77 Trend
1988-89 Trend
1991-94 Trend


Including Only January Data with HDD>50
94
92
90
88
86
84
82
80
78
Load Factor
40
45
50
55
60
65
70
75
80
HDD
1967-77
1988-89
1991-94
1967-77 Trend
1988-89 Trend
1991-94 Trend

	Average Weekly HDD	Percentage Change from September: Weekly Energy	Percentage Change from September: Peak Load [1]		Percentage Change per HDD: Weekly Energy	Percentage Change per HDD: Peak Load
Jan-92	275	33.7	30.7		0.12	0.11
1/1/1992 (4 wks)	343.8	42.1	30.7		0.12	0.09
Dec-93	300	55.7	27.2		0.19	0.09
Jan-94	360	37.0	24.7		0.10	0.07
Spinner Average	306.6	37.6	34.2		0.12	0.11
Note:	[1] Dec-93 changes computed from data in IR 103.					

	Hour of Retail Peak	Retail Peak (MW)	Portfolio Load at Retail Pk. (MW) [1]	Average Portfolio Load for Day (MW) [1]	Portfolio Daily Load Factor at Retail Pk.	TAL System Daily L.F. [2]	TAL System Daily L.F. [3]
1/16/92	2:00 PM	419.17	83.79	61.12	72.94	87.59	89.96
1/17/92	2:00 PM	412.99	87.96	64.97	73.87	90.07	89.17
12/27/93	12:00 PM	412.13	82.37	65.67	79.73	89.56	88.68
12/28/93	10:00 PM	427.12	85.26	61.78	72.46	85.95	87.39
12/29/93	12:00 PM	426.16	70.60	61.39	86.95	87.32	88.32
		Avg.	82.00	62.99	77.19	88.10	88.70
Sources:	[1] IR-116, Spinner 5/18/94						
	[2] Exhibit_(HMS-6), Spinner testimony, 4/4/94						
	[3] Exhibit_(HMS-2), Spinner testimony, 4/4/94						

Effect of Controlled Water Heaters on CV Peak Loads (Spinner, p.24)

Date	Hour	CWH (KW)	UCWH (KW)	Delta	Tot. CWH (KW)	Ripple (KW)	Tot. Rip. (KW)	Rate 3 Estimate (MW)	Rate3 P.39 (MW)	CCWH L.F.
1/16/92	2:00 PM	0.49	0.5	-0.01	11025	1.640	12297.72	23.32	N/A	0.85
1/17/92	1:00 PM	0.6	0.53	0.07	13500	0.000	0.00	13.50	N/A	0.69
12/27/93	1:00 PM	0.64	0.53	0.11	14400	1.637	12276.60	26.68	28	0.76
12/27/93	6:00 PM	0.52	0.59	-0.07	11700	0.184	1376.62	13.08	6	0.93
12/28/93	6:00 PM	0.52	0.59	-0.07	11700	0.002	13.20	11.71	6	0.93
12/29/93	6:00 PM	0.52	0.59	-0.07	11700	0.000	0.00	11.70	11	0.93
	Avg.	0.55	0.56	-0.01		0.58				0.85

Notes: Source for CCWH & UCWH is VLS data
Source for Ripple Control Water Heaters is CV metered data
Assumed 22500 CWH units
Assumed 7500 Ripple units
Ripple usage normalized to account for size differences among sample, assuming 15 kw peak day consumption.

Effect of Controlled Water Heaters on CV Peak Loads (Spinner, p.39)

								Rate 3	Rate3	
		CCWH	UCWH		Tot. CWH	Ripple	Tot. Rip.	(MW)	(MW)	CCWH
Date	Hour	(KW)	(KW)	Delta	(KW)	(KW)	(KW)	Estimate	P.39	L.F.
12/29/93	6:00 PM	0.52	0.59	-0.07	11700	0.000	0.00	11.70	11	0.93
12/28/93	6:00 PM	0.52	0.59	-0.07	11700	0.002	13.20	11.71	6	0.93
12/27/93	6:00 PM	0.52	0.59	-0.07	11700	0.184	1376.62	13.08	6	0.93
12/27/93	1:00 PM	0.64	0.53	0.11	14400	1.637	12276.60	26.68	28	0.76
12/27/93	12:00 PM	0.98	0.52	0.46	22050	1.019	7641.78	29.69	29	0.49
	Avg.	0.64	0.56	0.07		0.57				0.81
Notes:	Source for CCWH &UCWH is VLS data									
	Source for Ripple Control Water Heaters is CV metered data									
	Assumed 22500 CWH units									
	Assumed 7500 Ripple units									
	Ripple usage normalized to account for size differences among sample,									
		assuming 15 kw peak day consumption.								

Effect of Controlled Water Heaters on CVPeak Loads
(Based on Dec. Jan. FERC Peaks, 1991-93)

				CCWH	Ripple	UCWH
	Month	Day	Hour	(KW)	(KW)	(KW)
1991	12	27	6:00 PM	0.52	0.50	0.59
1992	1	17	1:00 PM	0.6	0.00	0.53
1992	12	8	6:00 PM	0.52	1.20	0.59
1993	1	19	6:00 PM	0.18	0.10	0.64
1993	12	27	1:00 PM	0.64	1.64	0.53
			Avg.	0.49	0.69	0.58
	Notes:	CV metered load data not available before 12/91.				
		Source for CCWH and UCWH is VLS data.				
		Source for Ripple is CV metered load data, normalized				
		to account for size differences among sample,				
		assuming 5475 kwh annual consumption.				

From Here to Efficiency:

Securing Demand-Management Resources

Volume 4

SCREENING DEMAND-MANAGEMENT OPTIONS

January, 1993

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PENNSYLVANIA ENERGY OFFICE

1. Net benefit versus benefit/cost ratio

The objective of least-cost planning is to reduce the total cost of energy services.[52] A DM option is cost-effective if it contributes to this goal; i.e., if its benefits exceed its costs. Where the alternative to the DM option is inaction (e.g., this luminaire is replaced or it is left unchanged), the option is cost-effective if it has:

- a positive net present value (NPV), defined as the present value of benefits minus the presents value of costs, or
- a benefit-cost ratio (BCR) exceeding unity, where the BCR is the ratio of the present value of benefits to the present value of costs.[53]

Both standards require the present value of benefits to exceed the present value of costs. Anything that passes the NPV test also passes the BCR test.

However, NPV and BCR do not produce the same ordering of multiple alternative actions. Moving from the current or standard situation (e.g., an air conditioner with SEER 10) to option A (e.g., a unit with SEER 13) may produce a higher NPV but a lower BCR than option B (e.g., a unit with SEER 12). This discrepancy frequently causes confusion when options compete.

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[52] The utility's responsibility for reducing costs is generally limited to the costs of those services the utility currently or normally provides. For example, electric utilities are not usually expected to undertake programs to reduce gas or oil energy service costs, although they are expected to take such costs into account in screening programs that primarily reduce electric costs.

[53] Alternatively, the rule can be stated as requiring that the cost-benefit ratio be less than one.

Among those competing, mutually-exclusive DM decisions that pass the societal test, the one delivering the maximum net societal benefit should be selected. The objective of least-cost planning—to minimize costs—can be achieved by selecting actions maximizing the difference between the benefits and costs. Therefore, DM screening should not seek to maximize the benefit-cost ratio of the DM portfolio or individual programs or measures.[54] The BCR test selects the option that provides the "biggest bang for the buck," but does not directly indicate whether a smaller added bang from investing more dollars is also cost-effective.

The difference in the roles of the two tests can be restated in physical terms. The BCR represents a slope, while the NPV represents a height. The objective of DM program design is to maximize net savings, to get to the top of the highest mountain of savings, as measured by NPV. The BCR indicates the steepness of the slope, but not the total height of the mountain.

Consider the choice between two options for reducing infiltration in a residence with electric space heating: Option 1 is a low-cost weatherstripping package, while option 2 is a comprehensive program using a blower door to identify bypasses. Table 1 shows representative costs and savings for each option. Option 2 is more expensive than Option 1, but it saves more kWh.

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[54] Financial and economic theory generally rejects the use of the BCR for screening investments, except where capital is constrained. See Brealey and Myers (1988), pp. 85-86 refer to the profitability index rather than a BCR; Copeland and Weston (1983), pp. 55-57 refer to the present value index rather than BCR. Few major utilities are likely to find that capital constrains investing in DM. Kilmarx and Wallis (1991) suggest using the BCR for screening DM programs (with some implicit caveats regarding protection of lost-opportunity), but incorrectly confuse rate-effect constraints with budget constraints. See Chernick et al. (1992).

Table 1
Net Present Value vs. Benefit/Cost Ratio
Comparing Options for Controlling Infiltration

	Base	Option 1 Low-cost weatherstripping package	Option 2 Comprehensive retrofit	Difference between Option 1 and Option 2
1. Annual space heating usage (kWh)	10,000	9,400	7,000	(2,400)
2. Savings (kWh)		600	3000	2,400
3. Present value of power cost	$5,000	$4,700	$3,500	($1,200)
4. Savings from base		$300	$1,500	$1,200
5. Present value of measure cost		$100	$900	$800
6. New present value (NPV)		$200	$600	$400
7. Benefit:cost ratio (BCR)		3.0	1.67	1.5
8. Total cost	$5,000	$4,800	$4,200	($600)
9. BCR>1		yes	yes	yes
10. Best BCR from base		yes	no	N/A
11. NPV>0		yes	yes	yes
12. Best NPV from base		no	yes	N/A
13. Lowest total cost		no	yes	N/A

Notes:

1., 2., 5. Inputs.

*3. 50 cents/kWh * [1]. The 50 cent/kWh PV is equivalent to, for example, 4.5 cents/kWh over 20 years.*

4. $5000 – [3]

6. [4] – [5]

7. [4]/[5]

8. [3] + [5]

The results of the two tests in Table 1 appear to conflict. The NPV indicates that Option 2 saves $600 and is thus superior to Option 1, which saves only $200. The BCR would suggest the opposite: Option 1 saves $3 for each $1 investment, while Option 2 saves only $1.67 for each $1 investment. The NPV test selects the better option, as can be demonstrated in at least two ways:

- Compare the total costs of providing energy services to the house for each option. As shown in Table 1, the lowest cost of service is achieved by the option with the highest NPV savings, Option 2.
- Examine the incremental cost-effectiveness of upgrading from Option 1 to Option 2. As shown in Table 1, the upgrade is cost-effective, whether measured by the NPV (the upgrade saves $400) or the BCR (the upgrade saves $1.50 per $1 investment). Hence, the upgrade should be pursued and Option 2 is the preferred DM program.

The incremental perspective is particularly interesting: in this context, the NPV and BCR tests will give consistent signals, so that whatever passes one test will pass the other. However, in comparing competing options against a base case, the BCR provides only a pass-fail test, while the NPV can be used to rank-order alternatives. In Table 1, the NPV approach always selects the lowest-cost Option 2; BCR selects the right option only if it is calculated for the incremental costs and benefits of upgrading options.

Using BCRs to screen DM actions creates other problems, besides the inconsistency with minimizing total costs. The BCRs of options will vary, depending on whether a desirable change in costs is treated as an increase in benefit or decrease in costs (Brealey and Myers, 1988). The distinction between a positive benefit and a negative cost (and vice versa) is far from clear. For example, the SPM (CPUC/CEC, 1987) classifies increases in a gas utility's fuel costs due to electric-to-gas fuel switching as a negative benefit but treats other changes in fuel use (including both increased use resulting from non-fuel-switching measures and customer use of non-utility fuels, such as oil and wood) as positive costs. A measure that replaces $15,000 of avoided costs for electricity with $5,000 in alternative fuel at a capital cost of $4,000 would have a BCR of (15,000 - 5,000)/4,000 = 2.5 if the alternative fuel were gas, or 15,000/(5,000 + 4,000) = 1.7 if the fuel were wood. Treating the $5,000 as a negative benefit in the one case and as positive cost in the other, as the SPM does, would result in the erroneous conclusion that the gas option is far superior to wood, even though the two fuels cost the same.[55]