STATE OF VERMONT
PUBLIC SERVICE BOARD

DOCKET NO. 5724
Petition of Central Vermont Public Service for rate increase of 8.9% to take effect November 1, 1994

SURREBUTTAL TESTIMONY
OF
JOHN J. PLUNKETT AND
PAUL L. CHERNICK
ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

August 22, 1994

Plunkett and Chernick respond to the criticisms by CVPS witnesses of Plunkett's direct testimony.

Exh 15 –
add graph

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I. INTRODUCTION AND SUMMARY

Q: Are you the same John Plunkett who prefiled direct testimony in this case on May 27, 1994?

A: Yes, I am.

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

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

Q: Mr. Chernick, summarize your qualifications.

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

I was a utility analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, since August 1990 in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached as Exhibit____JJP/PLC-R-1.

Q: What is the purpose of your testimony?

A: We refute portions of the rebuttal testimony filed by CVPS witnesses Gamble, Bentley, and Chamberlin on July 29, 1994.

Q: Summarize the CVPS testimony to which you respond here.

A: In its rebuttal testimony, CVPS maintains that

- the Department is attacking the Company for making reasonable "pacing adjustments" to the acquisition of discretionary demand-side resources which will improve cost-effectiveness (Bentley and Chamberlin);
- the Department opposes CV's updating of original participation and savings projections with more realistic estimates based on "lessons learned" from experience with the programs (Gamble and Chamberlin);
- The Company has not understated its avoided costs as alleged by the Department (Bentley and Chamberlin);
- The Department seeks to penalize CVPS for opposing DPS positions, for not meeting goals, for not being the best, and because DPS witnesses are engaged in "utility bashing." (Gamble and Chamberlin).

Q: Summarize your surrebuttal testimony.

A: First, CVPS has at last disclosed its much-touted "slip" or "deferral" analysis, which is purported to demonstrate that deferring DSM will increase net benefits to CVPS customers. After correcting for errors and biases in Central Vermont's avoided costs, Bentley's analysis indicates no economic advantage from deferring discretionary DSM acquisitions. Indeed, the analysis of alternative DSM timing presented by Chamberlin shows that postponing long-lived DSM acquisitions *increase* costs to society. The economics of DSM deferral are treated in Section II of this testimony.

Even if DSM deferral were cost-effective, the program amendments that CVPS has implemented to postpone acquisitions are imprudent, contrary to claims by CVPS witnesses Gamble and Chamberlin.

- Contrary to Board policy the Company has failed to develop, analyze, and implement alternative program modifications that would increase net benefits without reducing participation and comprehensiveness.
- The Company has failed to strengthen lost opportunity programs where savings have fallen below expectations, or even to analyze these market segments properly.
- Rather than correct obvious deficiencies in the small C&I retrofit program, CVPS has practically eliminated the opportunity for most small commercial and industrial customers to benefit from comprehensive efficiency retrofits. Expansion and enhancements to this program will increase net benefits to CVPS customers.
- Central Vermont's changes to the large C&I retrofit program jeopardize comprehensiveness in a program where savings have exceeded expectations in the past.

Section III of this testimony treats these issues further.

With respect to its avoided cost projections, CVPS has acknowledged that some of the corrections proposed by DPS witness Chernick are valid. Bentley's opposition to other corrections are shown to be without merit. The Board should disregard Bentley's denial of the other inconsistencies identified by the DPS in the Company's avoided costs. Chamberlin's misleading comparison of Central Vermont's avoided costs with those of other utilities deserves absolutely no weight in the Board's consideration of these issues. Surrebuttal of the Company's weakening positions on avoided costs is presented in Section IV.

The Company attempts to deflect the Department's recommendation for penalties by dodging responsibility for its underlying DSM mismanagement. Chamberlin falsely claims inconsistency between Plunkett's testimony in this case and his testimony on behalf of the Potomac Electric Power Company by distorting the former and mis-applying the latter. Gamble resorts to outrageous claims about the culpability of the Department for faulty program planning and design by CVPS. Section V of this testimony reaffirms the interlocking nature of the four sources of DSM mismanagement that warrant the ROE penalty recommended in Plunkett's direct testimony: imprudent C&I program amendments, misrepresented avoided costs, steadfast refusal to acquire cost-effective fuel-switching resources, and mismanagement and promotional misuse of its load-control program.

II. THE COMPANY'S DEFERRAL ANALYSIS DOES NOT SHOW INCREASED NET BENEFITS FROM POSTPONING DSM

Q: What evidence does CVPS provide in its rebuttal testimony concerning the economics of deferring DSM?

A: The Company offers the following three pieces of evidence purported to demonstrate that postponing DSM spending and savings will increase net benefits to society.

(1) Bentley presents his "slip" analysis as Exhibit____BWB-R-1. It compares benefits and costs of two streams of DSM spending and savings under two sets of avoided costs.

(2) Chamberlin computes the net benefits from implementing a generic lighting measure under Central Vermont's projected avoided costs, assuming different measure lives, over a range of installation dates. This analysis is presented in his rebuttal testimony at pp. 23-25 and shown in Exhibit____JHC-R2.

(3) Chamberlin compares the net benefits projected under the Company's Amended Case with those projected under the Lessons Learned Case.

A. Mr. Bentley's Deferral Analysis

Q: What does Mr. Bentley find from his slip analysis?

A: Bentley compares what he calls the Reference Case with a Deferred Case of DSM spending and savings under two sets of avoided costs, a set of "reference" avoided costs and a set of "new" avoided costs. The Deferred DSM Case postpones seven years of DSM spending and twenty-three years of savings by five years, from a start date of 1993 to a start date of 1998. The economics of deferral are shown by comparing the present worth of benefits and costs of the two streams under a single set of annual avoided costs.

For ease of comparison, Bentley's analysis is summarized in Exhibit____JJP/PLC-R-2, and reproduced in detail in. Exhibit____JJP/PLC-3, pp. 3-6. Under the reference avoided costs, Bentley's analysis shows a penalty from deferring DSM of $1.1 million. Exhibit____JJP/PLC-R-3, pp. 3 and 5, shows that while the Deferred Case has a higher benefit-cost ratio (2.78 vs. 2.43), net benefits of the portfolio decline slightly ($69.0 million in the Deferred Case vs. $70.2 million in the Reference Case).[1] Under Bentley's new avoided costs, however, the economics of deferral improve markedly under Bentley's assumptions. His deferral analysis under his new avoided-cost scenario is presented on pp. 7 and 9 of Exhibit____JJP/PLC-R-3. The Reference portfolio produces net benefits of $50.5 million; the Deferred DSM portfolio produces net benefits of $63.6 million, a $13 million improvement. It was this result which presumably formed the economic basis for the Company's conclusion in 1993 that "pacing adjustments" would improve the cost-effectiveness of its DSM portfolio.[2]

[1] As shown in Exhibit____JJP/PLC-R-3, the benefit-cost ratio tends to increase with deferral, even when net benefits decline. This corroborates Plunkett's direct testimony that improvements in benefit-cost ratios do not necessarily imply improvements in cost-effectiveness. The Company has shown a tendency to decide among competing alternatives on the basis of benefit-cost ratio rather than net benefits. For example, in the Company's petition for approval of its proposed modifications, CVPS sought to justify the changes by noting the higher benefit-cost ratio of the Amended Case over the Lessons Learned and Reference Cases.

[2] The Company first mentioned this analysis in its outline of its case in Docket Nos. 5270-CV-1&3 and 5686. The Department sought this analysis from the Company in several interrogatories without success. For example, DPS posed the following question to the

Q: Are lower levels of avoided costs responsible for the increased net benefits that Mr. Bentley found for DSM deferral?

A: Not entirely. The reason for this reversal is not just that "new" avoided costs are lower. The pattern of avoided costs over time also exerts a strong influence on the outcome of the deferral analysis. In Bentley's analysis, there is a wide divergence between avoided costs in the early years—when costs are discounted the least—and avoided costs in later years, compared to the pattern of avoided costs in the Reference case.[3]

Company in its fourth set of data requests, Question 25, dated November 19, 1993, in Docket Nos. 5270-CV-1&3 and 5686:

> Q: Please provide any analysis CV has performed or commissioned on the optimal timing of DSM or fuel-switching, including all work papers.

On December 9, 1993, Bentley responded as follows:

> A: If and when CV addresses optimal timing of DSM as a part of this Docket, the analysis requested will be filed. The Company provided informal data to the DPS on Sept. 14, 1993 by Fax to Bill Steinhurst. Connecticut Valley Electric Company filed DSM deferral analyses to the NHPUC Staff and a copy is enclosed.

The Company did not provide the cited material with its response. Question 26 of the Department's fourth set asked:

> Q: If it is CV's position that delay of implementation of one or more cost-effective DSM or fuel-switching programs would reduce the present value of social costs, please provide the basis for that belief.

Bentley's response was for the Department to "see the response to 25 above." The first time RII or any DPS witness testifying in Docket Nos. 5270-CV-1&3, 5686, or 5724 saw Bentley's spreadsheet was when CV finally presented this analysis in his rebuttal testimony in this case, ten months after it was originally conducted.

[3] Roughly speaking, the pre-2000 nominal avoided costs in the Reference Case start at about half the value of post-2000 period, and rise rapidly during the early period. Under the "new" avoided costs, values start at about a third of the level reached later in the period, around 2003, and before then rise relatively slowly.

Q: Are Mr. Bentley's analysis and conclusions valid?

A: No. First, and most important as discussed further below, his "new" avoided costs are severely biased downward in the early years. Correcting mistakes and eliminating the most egregious biases in Bentley's analysis eliminates the apparent advantage to deferral. Second, the deferral depicted in his analysis understates the costs of slowing DSM implementation. The Company proposes to stretch out the acquisition process, which requires CVPS to incur fixed program delivery costs over more years; Bentley's analysis assumes that all additional DSM programs and costs are eliminated for five years, and that programs can be re-started at the same (real) cost five years later. A more realistic analysis would count the costs of deactivating and reactivating the portfolio hypothesized by CVPS.

Q: What changes did you examine in your re-analysis of the Mr. Bentley's slip analysis?

A: We varied the following aspects of Bentley's analysis:

Implementation period. The deferral of 1993 implementation really was no longer relevant or realistic by late 1993, when the implementation subject to deferral began in 1994. Our re-analysis shifts implementation four years, starting from 1994 to 1998, rather than shifting implementation five years from 1993 to 1998 as Bentley does. We also tested a five-year deferral from 1994 to 1999. The 1994 start date was used throughout the RII re-analysis summarized in Exhibit____JJP/PLC-R-2.

CVPS filed avoided costs. The avoided costs filed by the Company in this case and in Docket Nos. 5270-CV-1&3 and 5686 — and used by Chamberlin in his rebuttal testimony — were substituted for the completely undocumented avoided costs Bentley used his September 1993 analysis.

CVPS corrected avoided costs. The filed CVPS avoided costs contain a number of relatively undisputed errors which Chernick corrected in his direct testimony in Docket Nos. 5270-CV-1&3 and 5686. The CVPS corrected avoided costs developed by Chernick were used in the re-analysis, both with and without externalitites and risk adjustments (externalities separately, and then combined with risk adjustment).

RII avoided costs. In addition to presumably unintentional mistakes, the filed CVPS costs suffer from a number of serious biases and inconsistencies. Our re-analysis also uses the RII avoided costs projections which rectify the Company's misrepresentations of its avoided costs, both with and without externalitites and risk adjustments (externalities separately, and then combined with risk adjustment).

In all, we examined 28 alternative scenarios involving variations in DSM avoided costs and implementation schedules.

Q: How significant are the variations in the four sets of avoided-costs scenarios you examined in your re-analysis of CVPS DSM deferral?

A: The differences between the four patterns of avoided costs are significant. Exhibit____JJP/PLC-R-4 plots annualized values per MWh of Bentley's new, CVPS filed, CVPS corrected, and RII avoided costs. The latter three sets include externaltiies and risk adjustments.[4]

- Differences among the four sets are greatest before 2004, diminishing somewhat thereafter.

[4] Since Bentley does not document the avoided costs used in his deferral analysis, we do not know whether they include the Board-ordered adders, stipulated values, or no values at all.

- Bentley's new avoided costs are significantly lower than the CVPS filed avoided costs between 1996 and 2000. Bentley's new avoided costs do not reach the CVPS filed values until 2006; after then, Bentley's new avoided costs exceed the CVPS filed values through 2015. These differences — lower avoided costs in the early years and higher avoided costs in later years — strongly favor deferral.
- The CVPS corrected avoided costs are substantially higher than the CVPS filed values between 1998 and 2002; the differences narrow yet persist thereafter.
- Finally, the RII avoided costs are higher than the CVPS corrected values throughout the analysis period, with several exceptions: 1998 and 1999, where the RII projections are considerably lower than the CVPS corrected avoided costs, and 2001 and 2004, where the two sets are essentially the same.

Q: What effect did changing the base case for implementation deferral have on the Bentley analysis?

A: The $13.0 million advantage for deferral diminishes to $9.1 million, as indicated in Exhibit____JJP/PLC-R-2. This is substantially less than the increased net benefits found by Bentley when he unreasonably assumed that 1993 implementation — already three-quarters complete—could be deferred.

Q: What does the deferral analysis show when the CVPS avoided costs filed in this case are used in place of Mr. Bentley's new avoided costs, assuming deferral of the portfolio from 1994 to 1998?

A: It indicates an economic penalty of $0.6 million, as shown on Exhibit____JJP/PLC-R-2 (details of which are provided by comparing p. 12

with p. 13 or p. 14 of Exhibit____JJP/PLC-R-3.[5] In other words, even the Company's own misrepresentation of its avoided costs fails to support its claim that pacing adjustments it proposes will increase the cost-effectiveness of its DSM portfolio.

Q: How do the results of Mr. Bentley's analysis change if the mistakes CVPS made in its avoided cost projections are corrected?

A: As shown on Exhibit____JJP/PLC-R-3, the deferral penalty increases an order of magnitude, to $6.1 million from the $0.6 under the Company's filed avoided costs. Even if externalities and risk adjustments are excluded, the analysis shows a $0.4 million penalty from deferral. Thus, even if benefits are confined to direct monetary benefits to CVPS customers, corrected for the Company's mistakes, DSM deferral will make them worse off.[6]

Q: Do the economics of deferral change if the RII avoided costs are used instead of the Corrected avoided costs?

A: Not by as much as changing from Bentley's new avoided costs, to or changing from CVPS filed to CVPS corrected avoided costs. Under the RII avoided costs, the economic penalty from deferring implementation from 1994 to 1998 is $7.5 million. Five-year deferral reduces net societal benefits by $9.5 million.

Q: All your re-analysis involves deferral from 1994 to 1998, a four-year deferral, whereas Mr. Bentley originally examined a five year deferral,

[5] If a five-year deferral is modeled from 1994, then the penalty increases to $1.6 million (comparing pp. 12 and 14 of Exhibit____JJP/PLC-R-3.

[6] The risk adder compensates for additional direct costs avoided by DSM.

from 1993 to 1998. What effect does going to a five year deferral have on the analysis?

A: In all avoided costs scenarios but Bentley's, deferring DSM implementation by another year further reduces the net benefits of the portfolio. Under Bentley's September 1993 avoided costs assumptions, deferring implementation from 1998 to 1999 increases net benefits by 0.3 million.

B. Dr. Chamberlin's Testimony And Analysis Regarding DSM Deferral

Q: What does Dr. Chamberlin claim to show in his testimony concerning the benefits of deferring DSM acquisitions?

A: According to Chamberlin, his analysis proves that deferring DSM will increase net benefits. He reaches this conclusion by observing that the present worth of avoided-cost benefits from a generic DSM measure reach a maximum if savings are acquired after 1994. Referring to the first graph in his Exhibit____JHC-R2, Chamberlin finds that the maximum 1994? present worth of benefits from a measure with a 5-year or a 10-year life occur in 1997, and decline thereafter; for 15-and 20-year measure lives, the maximum benefits occur in 1995, which then fall somewhat through 1997, and then drop precipitously thereafter.

Q: Has Dr. Chamberlin drawn the correct conclusion from his analysis?

A: No, he has not. What he has succeeded in showing is that it is better for society to defer installation of long-lived measures from 1994 to 1995, and shorter-lived measures from 1994–96 to 1997. However, he has also demonstrated that society is better off if CVPS *accelerates* to 1995 the installation of all measures with lives of 15 years or longer that are now scheduled for acquisition after 1995. Likewise for measures with lives between 5 and 10 years, Chamberlin's analysis demonstrates that benefits will increase if post-1997 acquisition is advanced to 1997.

Of course, it is simply not feasible to install all discretionary efficiency measures in a single year. Central Vermont's Reference Case therefore had a built-in deferral in the sense that some installations are postponed over a number of years. The practical implication of Chamberlin's analysis is that installation should be centered as much as possible between 1995 for long-lived measures and 1997 for shorter-lived measures.[7] Chamberlin's analysis therefore indicates that the Company will maximize benefits by proceeding with full-scale acquisition of cost-effective discretionary resources.[8]

Q: **Has Dr. Chamberlin succeeded in demonstrating that CVPS has maximized net benefits with the Amended Case, as he implies on p. 23 of his rebuttal testimony?**

A: No. First, his comparison between Lessons Learned and Amended Cases is not valid, as Plunkett explained in his direct testimony, pp. 17–21. The fundamental flaws in the program plans underlying the Amended Case

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[7] Based on results of correcting Bentley's analysis, discussed above, it is safe to conclude that Chamberlin's analysis would show maximum benefits even earlier than he reports in his testimony and exhibit. if he had updated CV a.c. to reflect DPS corrections.

[8] Consequently, Chamberlin's analysis offers another basis for computing the economic damage created by the Company's failure to pursue appropriate strategies to increase installation rates of cost-effective fuel-switching in its residential retrofit programs during 1992-1994. This delay has caused the center of program installations to be deferred by at least two years. Fuel-switching measures last over 20 years. The damage could then be computed by using Chamberlin's analysis, after applying the proper load shape, the number of kWh/year of average annual savings under a properly designed retrofit program, two years of delay, and appropriately corrected avoided costs.

strongly suggest that alternatives would produce greater net benefits. And as explained below and in Plunkett's direct testimony, the Lessons Learned Case embodies inappropriately pessimistic presumptions about achievable participation and savings.

Second, the finding of increased net benefits does not stand when the Amended Case is compared with the Reference Case, which Plunkett testified earlier is a more appropriate basis for comparison with the Amended Case. We used an approach similar to that taken by Chamberlin, and applied it to both 1994-95 expenditures, and to lifetime program expenditures reported by CVPS in its petition to amend its pre-approved DSM programs.

First, we multiplied the benefit-cost ratio reported by CVPS for the Amended and Reference Cases for 1994-95 by the total program costs for those years. Even though the Amended case shows a higher benefit-cost ratio (2.05) than the Reference Case (1.80), it produces lower net benefits ($10.7 million vs. $14.2 for the Reference Case). In other words, the additional program costs of $7.6 million in the Reference Case buy $11.1 million more in benefits than the Amended Case, with an incremental benefit-cost ratio of 1.46.

Second, we applied the same approach to the lifetime present-worth of program costs for each scenario reported by CVPS in the spreadsheets accompanying its petition to amend DSM programs. For the Reference Case and Amended Case, program costs total $74.4 million and $31.0 million, respectively. Respective benefit-cost ratios of 1.80 and 2.05 imply net benefits of $59.5 million for the Reference Case and $32.5 million for the Amended Case. Thus, the changes underlying the Amended Case reduce program net benefits in the Reference Case by $27.0 million.

C. Conclusions On The Economics Of DSM Deferral

Q: Based on your analysis and interpretation of Central Vermont's deferral analyses, what do you conclude regarding the deferral of discretionary DSM?

A: According to CVPS, its primary motivation for cutting back DSM spending is the desire to maximize net benefits of DSM, consistent with least-cost-planning objectives. Almost a year after making this claim, CVPS now introduces three separate analyses to support its underlying premise. Neither stands up to close scrutiny. The Company has failed to demonstrate that deferral of discretionary efficiency resources is in its customers' economic interests, even if CVPS were not making imprudent program modifications.

We confess that the results of our re-analysis of Bentley's deferral analysis heighten our suspicion that CVPS deliberately misrepresented avoided costs in the earlier years in order to justify cutbacks that CVPS upper management had decided to make in advance of economic analysis.[9]

Q: Are you testifying that deferring discretionary DSM acquisitions is imprudent and unreasonable?

A: Not necessarily. There may be other reasons to defer DSM acquisitions, even if it means some sacrifice in DSM net benefits. In the interest of mitigating near-term rate impacts, it may be advisable to reduce DSM spending over the next few years. The optimal acquisition pace may also be influenced by other constraints, such as limitations on managerial resources, infrastructure

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[9] Plunkett's direct testimony indicated that he had insufficient information to determine whether CVPS falsified its avoided cost projections. The surrebuttal testimony of Parker rebuts Central Vermont's contention that DSM program cuts were made from the 'bottom up," not from the "top down."

development, or financing capability. The Company has yet to present any credible analysis to establish whether or how these other factors should be considered in limiting near-term DSM acquisitions. On the other hand, DPS analysis of alternative implementation schedules in Docket Nos. 5270-CV-1&3 and 5686 indicates that a longer acquisition period can lower rate impacts with a moderate sacrifice in net benefits.

III. THE COMPANY'S PROGRAM AMENDMENTS ARE IMPRUDENT

Q: Ms. Gamble denies your claim that CVPS is "dramatically reducing the ability of its customers to participate and obtain benefits from cost-effective conservation programs." Does the information she presents on p. 10 of her rebuttal testimony alter your conclusion?

A: No. She indicates that the total number of participants in all CVPS programs in 1994–95 will be reduced by only 5 percent. Gamble's testimony is misleading on two counts. First, comparing the number of participants conceals CV's failure to improve comprehensiveness of participant savings and proposals actually to *reduce* comprehensiveness. Second, the total number of participants obscures changes in the definition and composition of participation between scenarios.

Q: Has CVPS succeeded in modifying its programs "so as to not reduce their overall comprehensiveness," as Ms. Gamble testifies (p. 10)?

A: No. In my prefiled direct testimony, Exhibit____JJP-2, I showed that CVPS amended programs for commercial and industrial customers would reduce savings per participant. I also testified that CVPS has not taken steps to increase comprehensiveness of savings by participants. Further, I testified that CVPS is proposing modifications to program designs that practically guarantee reductions in comprehensiveness. In particular, the Company's proposal to cap incentives in the large C&I retrofit program will substantially weaken the comprehensiveness of customer efficiency investments.

In the residential sector, CVPS has vigorously opposed improvements that would improve comprehensiveness, as evidenced by its testimony in Docket Nos. 5270-CV-1&3 and 5686. In particular, CVPS has opposed reasonable proposals that would increase implementation of cost-effective fuel-switching by customers participating in the Residential High Use Program. The Company even attacked DPS recommended program modifications that do not involve fuel-switching which would further increase savings by participating customers (i.e., blower-door guided air sealing at the time of an energy audit). The Company has also fought changes in the Residential New Construction Program that would reduce electric and non-electric consumption by participants.

Q: How does Ms. Gamble's simple comparison obscure significant changes in the composition and number of participants in the amended case?

A: Witness Gamble's simple comparison is further misleading for two reasons. First, it hides the fact that CVPS plans to abandon retrofits for small C&I customers, as I discussed in my direct testimony at pp. 23-28. Second, Gamble appears to count as a participant anyone who engages in any act of participation. This distorts the effect of the modifications in two ways. Gamble appears to include as a participant anyone who receives an energy audit, no matter what measures, if any, are installed thereafter. Gamble also appears to count a participant once for each stage of measure implementation. This latter point distorts changes in the industrial retrofit program, in which CVPS expects each participating customer to undertake an average of two acts of measure installation. Each customer is counted twice in the Amended Case, but only once in the Reference Case.

Q: **Does Ms. Gamble's testimony concerning 1992–1993 program activity bridge the "wide gulf" you found between the Company's "DSM planning and the explicit DSM policies issued by its regulators" (Gamble rebuttal, p. 10)?**

A: No. Gamble suggests that the Company has immunized itself from Board penalties because the programs it implemented in 1992-93 were approved by the Board and that the savings claimed for these programs exceeded goals. Neither is relevant to my recommendation that CVPS be penalized for failing to follow least-cost planning objectives for DSM established by the Board. As explained in my prefiled direct testimony and reiterated here, shareholder penalties should be imposed in order to rectify four related sources of Company mismanagement.

Q: **Has the Board put CVPS on notice that it is responsible for correcting program design and implementation to maximize net benefits?**

A: Yes. As I indicated in my direct testimony at pp. 8-14, the Board instructed CVPS to continuously monitor and evaluate program performance, and to make mid-course corrections to increase benefits through increased savings or decreased costs. In approving programs CVPS operated in 1992-93, the Board directed CVPS to look for signs that programs warranted changes to increase participation or savings. For example, such instructions were issued with regard to the residential high-use program and in the small C&I

program.[10] Most recently, by letter dated January 20, 1994, the Board told CVPS,

> When proposing changes to its DSM program designs, CVPS should address the following issues:
>
> 2) the need to continue and strengthen lost opportunity programs;
>
> 3) the possibility of improving the cost-effectiveness of programs by redesigning them to *increase* participation, rather than by cutting back participation targets
>
> 4) the importance of maintaining the comprehensiveness of programs across customer classes; and,
>
> 5) the value of continuing existing programs long enough to refine program design assumptions *before* cutting programs back.[11]

Q: Has CVPS followed Board instructions on the need to improve program design and implementation before proposing cutbacks?

A: No. The rebuttal testimony of witnesses Gamble and Chamberlin completely ignores this policy. Proposed deviations in the Amended Case from the Reference Case go beyond realistic updates to measure savings and eligible population, and deferral of participation. Moreover, CVPS ignored Board policies by failing to seek improvements in programs where performance fell below expectations. Even worse, CVPS proposals have created new problems where none existed.

[10] See PSB Order of 7/19/91 with regard to the RHU program and fuel-switching incentives and PSB Order of 5/29/91, pp. 39-46.

[11] Hudson, Susan (PSB), Letter to Morris Silver, CVPS, 1/20/94, p. 3; emphasis in original.

Q: In what areas does CVPS revise program assumption that extend beyond straightforward application of changed circumstances or more realistic information?

A: Because CVPS has so poorly documented its supposed "lessons learned," the Department has not been able to separately identify all the unsupported changes in program planning assumptions that CV proposes. Nevertheless, several examples stand out.

At least some of CVPS lessons learned are based on its erroneous avoided costs and faulty measure characterization. The Company has admitted errors in both areas.[12] This is particularly true with regard to fuel switching, where CVPS reduced the number of participants for which fuel switching would be applicable based on the percentage of customers "that pass societal tests with new avoided costs."[13]

As another example, CVPS chose to reduce achievable participation and savings in the motor-replacement component of the market-driven programs based on selective application of other utility experience. The Company has yet to provide details on why this experience should justify reduced savings, particularly when other utilities such as British Columbia Hydro have achieved high participation and market transformation in the replacement motor market.

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[12]. Bentley has acknowledged some of the corrections recommended by Chernick;. Gamble admits that CV's failure to include the replacement costs of electric heating equipment in its fuel-switching measure screening is a mistake.

[13] Petition of Central Vermont Public Service Corporation to Amend its Implementation Plans for Its Conservation, Efficiency, and Load Management Programs, December 1993, Exhibit 4, p. 4.

In other cases, CVPS has merely extrapolated implementation results to the future, without exploring alternatives or gathering other information that might lead to increased savings.

Q: In what program areas has CVPS failed to obtain adequate information or propose alternative approaches before reducing planned investment and savings?

A: As DPS Witness Plunkett explained in his direct testimony, in a number of programs CVPS is improperly extrapolating disappointing results of early implementation as "lessons learned." As Plunkett discussed on pp. 22–23 of his direct testimony, monitoring and evaluation revealed that comprehensiveness was a problem among participants in the non-residential new construction program. At least one aspect of the program—the structure of design incentives—would tend to frustrate comprehensiveness. Nevertheless, CVPS "has not proposed specific program amendments to address this problem," as Plunkett pointed out on direct.

Central Vermont's program modifications are not based on adequate characterization of remaining efficiency potential. Plunkett's direct testimony indicated, as did that of DPS witness Lloyd, that CVPS has not properly characterized the remodeling market (pp. 33–34). The general lack of documentation for changes makes review difficult, as Plunkett testified on direct. CVPS has not identified, characterized and screened new measure for each new case to substantiate lower savings per participant. Nor has CVPS demonstrated that its lower projections of future new construction, and smaller size of new buildings, are consistently reflected in its long-term load forecast.[14]

Perhaps the most egregious example of Central Vermont's failure to explore alternatives to improve savings is in the small commercial and industrial retrofit program. As Plunkett showed in his direct testimony (pp. 23-28), CVPS failed to test alternative program strategies in order to achieve greater participation by the target population—those customers below 100 kW. The Company failed to monitor successful experience by other utilities in reaching similar target audiences, most notably Green Mountain Power, the New England Electric System, and PEPCo.[15] Even when the Board approved implementation of the program as proposed by the Company in 1991, it directed CVPS to explore alternatives if participation objectives were not met.[16] Central Vermont's response in the interim was to refocus the program on larger customers; in the future, CVPS proposes to virtually abandon the retrofit potential of these hard-to-reach customers.

[14] The need to demonstrate such consistency was stated by the Board in Module 5 of its Decision in Docket No. 5270.

[15] Plunkett's responses to CV's data requests in this case provide further details on other utility experience with small commercial and industrial customers. See responses to 11, 13, 15, and 17.

[16] PSB Order of 5/29/91, pp. 39-46. See also PSB Order in Docket 5270-CV-3 of 9/13/91, p. 2, where, after approving the Company's revised incentive levels for the small C&I program 'because they will provide positive cash flow to the customers," the Board noted, 'We are not convinced that a positive cash flow, by itself, will achieve the target penetration levels for these two programs; however, there is room for reasonable doubt upon this question and we are therefore willing to let CVPS try its approach."

Q: Does Ms. Gamble's rebuttal testimony invalidate your claim that targeted customers below 100 kW were under-represented among program participants?

A: No. All that Gamble demonstrated was that most of the customers participating in the program had peak demands of 100 kW or less. She did not show that these customers participated in proportion to their numbers in the eligible population; nor did she demonstrate that the number of participating customers in this size class approached the number targeted by the original program design. In Plunkett's direct testimony, he recommended changes in program design that would be likely to achieve the originally-planned participation, based on successful experience of other utilities.

In response to discovery, Gamble provided information ~~which~~ that contradicts her claim that the customers originally targeted by the pre-approved program were adequately represented. Exhibit____JJP/PLC-R-5 compares the number of 1993 program participants with the number of customers in the eligible population in four customer kW bins: 0-25 kW; 26-50 kW; 51-100 kW; and over 100 kW. This shows that the smallest customers were grossly under-represented compared to customers who were not directly targeted by the pre-approved program. While only 0.7% of all eligible customers with demands 25 kW and below participated, 8.7% of all customers over 100 kW participated. The largest among the originally targeted population — 51-100 kW — participated at a rate of 4.8%.

This evidence makes two things clear. First, Gamble's testimony that smaller customers were well-represented was misleading. Second, the Company has ample evidence that the participation rate among the smallest customers — those below 50 kW — falls far below that of larger customers.

The Board specifically directed CVPS to take corrective action if this proved to be the case. Other utilities have programs specifically designed to reach these customers.[17]

Q: Ms. Gamble states that the testimony and recommendations of DPS witnesses are based on "few facts or studies" (p. 67). Is this true?

A: The answer depends on what one considers facts or studies, and the need for them in reaching conclusions. Careful study of CVPS material by the DPS has been sufficient to reveal flaws in CVPS analysis and planning. A formal "study" is not always needed to detect errors, omissions, or inconsistencies. The Company's inability or failure to disclose detailed sources for changes in program assumptions or plans has prevented the DPS and the Board from determining their validity. In this sense, further study would be needed.[18]

In other instances, the DPS has developed "facts and studies." In some instances, this has required almost Herculean effort, as in the case of the DPS analysis of the effectiveness of CVPS load control. In other cases, such as alternative strategies to improve CVPS programs, the DPS has developed independent analysis. In Docket Nos. 5270-CV-1&3 and 5686, Plunkett presented a complete cost-effectiveness analysis of alternative residential-retrofit and new-construction programs. The Department also analyzed the

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[17] For example, PEPCO's LightSwitch program offers free direct installation to commercial customers 25 kW and below.

[18] The Company's standard for "studies" seems to depend on the originator and the direction of a proposed change to an efficiency program. If it is CVPS that seeks to cut a program's spending, particularly on incentives, then such changes are justified without detailed or definitive analysis. On the other hand, outside proposals to increase program cost-effectiveness through increased spending, especially on incentives, must meet an apparently insurmountable burden of proof.

rate impacts of its program proposals. In Plunkett's direct testimony in this proceeding, the DPS presented participation, savings, and spending projections for the small commercial and industrial retrofit program.

Q: Have you performed economic screening of the small commercial and industrial retrofit program you developed in your direct testimony?

A: Yes.

Q: What does that analysis show?

A: Three findings emerge from this analysis. First, it indicates that an enhanced and redesigned program would be highly cost-effective. Results are presented in Exhibit____JJP/PLC-R-6. That exhibit shows that over 16 years of implementation, the program would produce $15.7 million in societal net benefits. Under the utility test, the program generates $12.2 million in net benefits.

Second, program screening indicates that the net benefits of such a program would greatly exceed those of the program CVPS would implement in the Amended Case. According to the Company's Amended Case, its scaled-back small C&I program would produce $2.5 million in net benefits.[19] Thus, the DPS program produces $13.2 million or over four times more in net benefits than the Company's amended version.[20] oops

Third, this analysis demonstrates that CVPS can both enhance a discretionary program to increase participation, while deferring acquisition,

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[19] CVPS reports lifetime program costs (in present worth terms) of $2.9 million, and a benefit-cost ratio of 1.84. This implies total benefits of $5.4 million, or net benefits of $2.5 million. ~2.3 w/ DPS => ~4$ m net ben

[20] Note, however, that the net benefits of the Company's proposal would increase with either CVPS Corrected or RII avoided costs.

and still improve cost-effectiveness. The sixteen-year schedule screened in the DPS analysis represents a relatively slow pace of implementation. Nowhere in Central Vermont's proposal has the Company presented an analysis of such program improvements, despite past Board direction to do so.

Q: Mr. Plunkett, you have testified that CVPS has failed to rectify problems in programs to improve net benefits. Is it your testimony that CVPS has changed programs in ways that would cause economic damage?

A: Yes. As I testified in my direct testimony (pp. 28–30), CVPS has instituted changes in the C&I retrofit programs that will do more than adjust the pace of participation: the restructuring and lowering of incentives is also highly likely to seriously compromise savings comprehensiveness. This is not only in direct conflict with prior Board policy, but also undercuts the Company's stated strategy for pursuing "staged implementation" of increasingly comprehensive efficiency investments among its large industrial customers. This imprudent change is causing immediate damage by creating lost opportunities. This topic is addressed further in the rebuttal testimony of DPS witness Lloyd.

Q: Should the Board accept Ms. Gamble's testimony during cross-examination that there is little danger of creating lost opportunities in commercial/industrial retrofits?

A: No. Lost opportunities can easily occur within the context of retrofit activities and have the potential to be quite significant. The greatest economic impact of these lost retrofit opportunities occurs when the retrofit is a one-time opportunity. For example, in Central Vermont's Large Commercial and Industrial Program, there is always the danger that the customer will only participate once in the program. As Plunkett stated previously, the Company's proposed reduction in customer incentives will make customers less inclined to participate in the program over time. Follow-up implementation would be expected to address more and more costly measures. As a result, follow-up installations would be expected to have longer and longer financial paybacks. Since the Company's proposed changes to customer incentives will make longer payback installations less attractive financially, the danger of creating lost opportunities will increase.

Staged implementation is only appropriate when subsequent efficiency investment is discrete, and not dependent on prior efficiency investments. Otherwise, lost opportunities are quite likely to be created. I have analyzed and discussed the general issue of lost retrofit lighting opportunities, including the economic cost of staged implementation, in a paper which I co-authored with James Peters, my colleague at RII. A copy of this paper is attached as Exhibit____JJP/PLC-R-7. It shows that there is a wide range of lighting efficiency opportunities for CVPS customers which are likely to be lost if comprehensiveness is not obtained in a single treatment.

In fact, lost opportunities could well be a problem in the Commercial/ Industrial Retrofit. The Company does not appear to offer financial incentives or technical assistance to match motor size to load in its Motors Replacement Program, an omission that is likely to create lost opportunities in that program. Lost opportunities are a problem in other CV programs. For example, we know from the Company's evaluation of its New Commercial Construction Program that program participants generally have not installed all cost-effective lighting measures.

Q: How does failure to encourage the matching of motor size to load create lost opportunities?

A: Oversized motors operate less efficiently than motors which are properly matched to their loads. When motors are replaced, there is a one-time opportunity to replace a failed motor with a motor which is properly matched to its load at negative to zero incremental equipment cost. Once an oversized motor is replaced with a new motor of the same size, the only way to match motor size to load to is purchase another motor. Thus, the difference between the equipment cost of matching motor size to load when the old motor has failed versus a retrofit at some other time is approximately the full cost of the motor. Perhaps just as important, a customer is most likely to be prepared to devote attention to a motor specification when it has to be replaced.

Q: Do you agree with Witness Chamberlin's testimony that some of the revisions to program assumptions CVPS proposes are reasonable?

A: Yes. I said in my direct testimony that "no doubt some of the program assumptions in the Lessons Learned Case are valid" (p. 18). In particular, I agree with the Company's proposal to consolidate several lost opportunity programs directed at existing customers into a market-driven program.

Q: What is your response to Dr. Chamberlin's observations that CVPS's amended programs will increase participation over past levels?

A: These observations are beside the point. What is important is that CVPS proposes to sharply reduce savings and investment below pre-approved DSM plans for 1994 and beyond.

Q: If some of the changes proposed by CVPS are reasonable, does this invalidate your criticisms of the Lessons Learned and Amended Cases?

A: Not at all. For reasons discussed in this testimony and in my direct testimony, CVPS has not substantiated its claims that the Lessons Learned are valid, or that its proposed modifications are reasonable or cost-effective. Both scenarios fail to include alternative strategies that would improve cost-effectiveness by raising participation, increasing savings per participant, or reducing delivery costs per installation. The Company has proposed reduced and restructured incentives in the Amended Case. The Amended Case therefore overstates benefits and understate costs, since CVPS projections do not reflect the loss of comprehensiveness or creation of lost opportunities likely to result. CVPS made all these changes without the kinds of studies that CVPS faults the Department for not making to support criticisms of CVPS amendments. DPS analysis and testimony indicates that alternative strategies for modifying programs are likely to improve net benefits beyond those projected by CVPS in both the Lessons Learned and Amended Cases.

IV. THE COMPANY HAS MISREPRESENTED ITS AVOIDED COSTS

Q: Are Mr. Bentley's defenses of his revisions to avoided costs correct?

A: No. Bentley disputes our characterizations of three CVPS errors:

- projection of very low market values for generation capacity, even in a period in which CVPS expects the current surplus to decline, evaporate, and then become a deficiency;

- omission of all avoided T&D costs for 1993–95, even though CVPS made and plans substantial load-related T&D additions in that period; and
- the abandonment of CVPS's own marginal losses, and replacement with lower, undocumented loss values.

Q: What is the substance of CVPS's response on generation capacity?

A: Bentley asserts that market values of capacity are now lower than they were in the past, which is correct. The DPS projections of avoided generation capacity costs are lower for 1994–99 than were forecasts made a few years ago.

He does not rebut our criticism of Schaeffer's "simple mathematical expression" for projecting market capacity prices over the next decade (Chernick Direct in 5270 CV-1, 3, and 5686, pp. 14–20 and associated exhibits), particularly the time trend, which Schaeffer set to phase out this particular discount of market prices from 100% in 1994 (when capacity is assumed by CVPS to be worthless) to 0% in 2003.[21] As we have previously explained, under CVPS's arbitrary model, increasing the regional capacity surplus would actually *increase* the predicted market price for capacity, and the predicted market price would remain well below replacement costs even after the surplus becomes a shortage.

Q: What is the substance of CVPS's response on T&D capacity?

A: Bentley (p. 7) admits that CVPS has expended "large sums for load-related T&D investments in the 1993–95 time period," but makes a series of claims about the avoidability of those expenditures that he does not support with any

[21] Another arbitrary CVPS discount reduces capacity cost about 20% forever.

data or analysis, either in this proceeding or in Dockets 5270 CV-1, 3, and 5686 including the following:

- "The Company and other companies have begun to notice during the recent period of no-growth or low-growth that few T&D projects were avoidable." No comparisons have been provided of T&D project plans for (say) 1994 before and after the slowdown in load growth, showing that reduced loads on lines and substations do not reduce required investments. Many T&D costs, such as secondary lines, transformers, and primary laterals, are not counted as parts of discrete "projects," in any case.
- That T&D is unavoidable is "in part a result of minimum required equipment." The Company has not shown that its investments are limited to "minimum required equipment." In fact, in normal utility practice, many additions are in parallel to other new or existing equipment; both the size and number of components installed is variable with load.
- Bentley notes that O&M and "reconfigurations for infrastructure changes" (presumably a reference to road widening and the like) "continue with or without load growth." This is correct, but irrelevant to the dispute over T&D costs in 1993–95. Future O&M and reconfiguration costs will vary with the amount of equipment installed to meet load growth today; CVPS's marginal costs (and hence the DPS's avoided costs based on CVPS's estimates) recognize this relationship for O&M, but entirely ignore the effect of load growth on future reconfiguration costs. If anything, Bentley's argument about

reconfigurations argues for raising avoided T&D costs, not setting them to zero.

- Bentley claims that recent years have been a period of slow growth for CV, suggesting that no new T&D would be needed to meet load. In fact, residential sales rose ~~33~~ 18% from 1988 to 1993,[22] or ~~5.8~~ 3.4%/yr. Commercial sales rose about 5% in the same period, while industrial sales fell 1%. T&D equipment serving residential areas is now clearly carrying much higher loads than it was a few years ago, even if the overall system peak loads are not much higher.

The most misleading portion of Bentley's response is his reliance on unspecified "work" by Central Maine Power, which he claims

> concluded that avoided T&D costs and incremental T&D costs for load growth are not symmetrical by their very nature. Thus the use of marginal T&D costs computed during growth periods is not a valid proxy for avoided T&D costs. One result of the CMP work is that near term T&D costs are probably very low even during periods of growth.

The report on which Bentley appears to rely was provided on discovery in Dockets 5270 CV-1, et al, and is attached as Exhibit____JJP/PLC-R-8. This report (by one J. D. Bouford) is riddled with unsupported and counter-factual claims, such as that all T&D equipment has sufficient capacity to serve all future load (pp. 9 and 10), distribution systems are not designed "to allow sharing of load-serving capability" (p. 10), and primary additions are sized to serve "the load that is forecast to occur within the addition's expected useful life" (p. 12).[23] The report also essentially ignores new

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[22] The FERC forms report sales of 660 GWh in 1988 and 876 GWh in 1993.

[23] Feeders are routinely transferred between substation transformers, and primary laterals are transferred between feeders, to more evenly share loads. New transformers and feeders typically pick up part of the load previously borne by each of several neighbors.

construction, and spends some effort arguing about the avoidability of service costs. These service costs seem to be important avoidable costs, based on the data in the report, but are not treated as avoidable in the CVPS or DPS avoided-costs calculations.

But the most serious error in Bouford's report is the underlying assumption that '[t]he marginal demand cost must be developed from an assumed zero-growth basis. If we are to correctly model marginal costs for load growth and avoided costs for load reduction, an assumed zero-growth investment cost must be determined and the marginal cost of load changes from this level developed" (pp. 15–16). Bouford asserts that "a negative change in the forecast, or lower than predicted growth rate, is often incorrectly perceived as a load reduction" (p. 15). This approach guarantees that "marginal cost savings will only occur at some future date and most likely will occur outside the time limit of the marginal demand analysis" (p. 14). Of course, the DSM programs at dispute in this case would reduce CVPS's growth rate, rather than actually reducing loads in absolute terms. Hence, whatever situation Bouford might have thought he was estimating costs for, his approach is irrelevant to CVPS's DSM valuation decisions.

Had Bentley simply recited Bouford's unfounded arguments, or cited Bouford as a skeptic on T&D avoidability, his testimony would have merely been wrong. But in portraying Bouford's philosophical musing as *work* (rather than argument), or as evidence that CMP had *noticed* (rather than decided) that costs were unavoidable (p. 7, line 14), or had *concluded* (rather than assumed) that costs are asymmetrical, Bentley was misleading the Board, as Schaeffer did in describing the derivation of the market generation capacity value.

Q: What is the substance of CVPS's response on line losses?

A: Bentley argues that marginal loss factors are not appropriate for load reductions on the order of 30%. We agree. But marginal loss factors are appropriate for marginal (~1%) reductions in the rate of load growth, which is what we are modeling for DSM screening and analysis.

Bentley has never offered any derivation of the loss estimates he now uses, which are about half of the marginal losses used since Docket No. 4364. The Company once claimed that losses exhibit a "deadband due to no-load losses" and that there is a "point at which reduced loads do not reduce losses" (Petition, Exhibit 7b). This justification is ludicrous, and indicates a complete lack of understanding of electrical engineering.

In a 1990 memo from Randy Hahn, CVPS claims to demonstrate that the marginal losses are too high for DSM avoided costs, but makes three erroneous assumptions: an instantaneous 13+% load reduction, that all load is served at secondary, and that all sales occur in the peak period.

The Hahn errors lead to a compromise loss value, falling between marginal and average losses. His analysis does not distinguish between rating periods or load levels, and computes average losses of 12.1%. This value is neither relevant nor applicable to avoided-cost determination. The Company does not appear to have been impressed by Hahn's arguments in 1990 or 1992, and does not appear to have reduced avoided losses until late in 1993.

Even Hahn's analysis does not derive the loss factors used in CVPS's current avoided costs. Hahn's average loss factor is 12.1%; CVPS uses period losses that average 10.4%, not 12.1%. Hahn estimates 19.2% marginal losses at peak; CVPS uses 12.94% losses in the winter peak period, which has loads close to the peak level. The Company's peak-period *avoided* energy loss estimate is much lower than the 16% *average* demand losses on peak reported in the compliance filing in Docket No. 5627.

In summary, Bentley has never provided any evidence in support of the lower loss values, and the conceptual arguments advanced on their behalf are ill-founded.

Q: Has CVPS corrected the undisputed errors in its avoided-cost computations, and used those values in rescreening DSM or in Mr. Bentley's analysis of DSM deferred?

A: No. The major undisputed corrections the DPS made to CVPS's avoided costs included

- use of capitalized energy, rather than peaking capacity, in the capitalized energy computation;
- modification of off-system sales to reflect CVPS's own estimates of market prices for energy;
- correction of CVPS's T&D costs by adding one year's escalation in O&M costs, and by dividing costs by the amount of load associated with the costs;
- adding overheads on generation, transmission, and distribution O&M costs; and
- computing externalities for realistic NEPOOL dispatch, rather than CVPS's own-load dispatch computations.[24]

The Company has not argued against any of these corrections, in Dockets 5270 CV-1&3 and 5686, or in this Docket. Indeed, Bentley's

[24] The Company did argue that these externalities should not be used in evaluating fuel switching, because end-use emissions were somehow worse than utility emissions, but did not attempt to quantify the alleged differences.

testimony in the other dockets acknowledges that the DPS modifications may be warranted.

Q: What avoided costs does CVPS present in its rebuttal testimony?

A: Chamberlin's Exhibit____JHC-R3 presents CVPS's uncorrected 1994 avoided costs, as filed by Bentley in several dockets. Bentley's rebuttal Exhibit____BWB-R-1 uses much lower costs, as illustrated in Exhibit____JJP/PLC-9. These lower avoided costs have never been sponsored or documented by CV, and exaggerate the alleged benefits of deferring DSM as explained in Section II of this testimony.

Q: What rebuttal testimony does Dr. Chamberlin offer in support of CVPS's avoided costs?

A: Chamberlin's Exhibit____JHC-R3 purports to compare CVPS's amended avoided costs to those of nine other utilities, from New York, New Hampshire, Maine, and Rhode Island. The claim that nine other utilities are represented is somewhat misleading, since (1) the four New York utilities use LRACs set by the PSC, based on statewide avoided costs and (2) Granite State and Narragansett are both NEES subsidiaries that use New England Power (NEPCo) avoided generation and transmission costs. So Chamberlin is really comparing five other sources of avoided costs to CVPS's estimate.

Chamberlin claims to have made adjustments to place the figures on a comparable footing. In fact, he did no such thing.

The avoided costs reported for the other utilities are avoided costs for non-utility generation, not DSM. NUG avoided costs are lower than DSM avoided costs, because NUG avoided costs

- are computed for a flat load shape (or a flat shape in each rating period), rather than a DSM load shape that, because it more or less follows load, saves more high-cost energy and more kW of peak load per MWh of energy;

- exclude most or all line losses;
- exclude avoided distribution costs;
- usually exclude most transmission costs; and
- exclude any credit for reserve margin on generation capacity.

Chamberlin's work papers include DSM avoided costs for the NEES subsidiaries, but he chose not to present those avoided costs.

The avoided costs Chamberlin compares to CVPS's estimates also exclude any adjustment for risk, both due to the purpose of the estimates (since NUGs do not have the risk-avoidance benefits of DSM), and due to the fact that the jurisdictions represented do not incorporate explicit risk adjustments, even for DSM.

Similarly, the comparison avoided costs do not include any environmental (or other) externalities. Externalities are not generally rolled into NUG avoided costs, since most NUGs have their own externalities; differences in environmental effects are usually reflected elsewhere in the valuation of NUG proposals. This is the case for New York, which uses externality values in screening DSM and NUGs, but does not include them in the LRACs. The other three states on which Chamberlin relies have not monetized externalities.

Oddly, while Chamberlin uses avoided costs from as far away as Rhode Island and Maine, he does not list any avoided costs from Massachusetts, which does use externalities in screening DSM and NUGs.[25] This was not

[25] Even in Massachusetts, externalities are not necessarily included in tabulations of avoided costs.

due to a lack of Massachusetts avoided costs; Chamberlin's work papers include excerpts from the avoided costs of all three NEES retail subsidiaries; Chamberlin includes in his table the Rhode Island and New Hampshire subsidiaries, but not Massachusetts Electric, which shows avoided costs including externalities.

In addition, each avoided cost may be based on a different set of fuel prices, costs of capital, inflation rates, and other assumptions. Using the avoided-cost input assumptions of NU or NEES might change CVPS's avoided costs but correspondingly change CVPS's costs of DSM, especially fuel switching.

Bentley claims that Chamberlin 'illustrates that the Company's avoided generation costs are not understated compared to other companies in the Northeast" (Rebuttal, p. 7). In fact, Chamberlin merely demonstrates that other utilities' baseline baseload generation cost forecasts are lower than CVPS's forecasts of load-shaped generation, transmission, distribution, externalities, risk, and other factors.

Q: Was the nature and purpose of the other utilities' avoided-cost estimates obvious from the underlying documents?

A: Yes. Exhibit____JHC-3 notes that the CMP and Narragansett avoided costs, and some of the data for the New York utilities, are from *Independent Power Markets Quarterly*, which from its title appears to refer to non-utility generation, not DSM. The PSNH and Granite State avoided-cost documents are also quite clear about their purpose.

Q: Please describe the information in the Granite State document relied on by Dr. Chamberlin, demonstrating that the avoided costs are not applicable to DSM.

A: The Granite State Table I.9.3 cited by Exhibit___JHC-3 includes the following information:

- Note C states that line losses are "not applied [since line loss] depends on interconnection voltage level." Indeed, column 5 shows the same avoided costs with losses as column 4 shows without losses.
- Column 7 specifies that only generation capacity is included in the avoided costs.
- Note E notes that generation capacity costs are "converted to cents/kWh using an assumed capacity factor of 80%, which is representative of baseload units. The resulting cents/kWh values are not appropriate when evaluating non-baseload resource alternatives." Yet Chamberlin applies these avoided costs to non-baseload DSM.

The Granite State avoided costs are also based on a general inflation rate of 3% (p. I-9–10) and gas prices considerably lower than those CVPS uses, and are computed for a flat 100-MW load decrement, rather than a proportional DSM load decrement (p. I-9–4).[26] The relevant pages of the Granite State document are provided in Exhibit___DPS-JJP/PLC-R-10. The comparison of gas prices is shown in Exhibit___DPS-JJP/PLC-R-11.

[26] Other avoided-cost components, such as reserve requirements, externalities, and risk, are not mentioned in the source document and appear to be excluded from the computation, but these exclusions are not easily demonstrated by any simple reference.

Q: Please describe the information in the PSNH document relied on by Dr. Chamberlin, demonstrating that those avoided costs are not applicable to DSM.

A: On page VII-2 of the PSNH document, the avoided energy costs are clearly specified as having been estimated for "a future block of private power producer ("PPP") resources...assumed to have...an average capacity factor of 80 percent." Chamberlin's source, Table VII-1, states that the avoided costs are estimated at the "generation busbar voltage level," i.e., without line losses, transmission costs, or distribution costs. Table VII-2 further shows that the capacity value in Table VII-1 is based on the costs of a combustion turbine, and excludes T&D capacity.[27] The relevant pages of the PSNH document are provided in Exhibit____DPS-JJP/PLC-R-12.

Q: Does Chamberlin properly adjust the avoided costs reported by his sources, "to place the figures on a comparable footing," as he puts it on page 26?

A: No. For the Granite State estimates, Chamberlin's exhibit simply copied the source document values, without adjusting for the differences in input assumptions or the differences between NUG and DSM avoided costs. On discovery, Chamberlin revised these estimates to include distribution costs and modest 10% line losses, but continues to ignore transmission costs and reserves (which are included in the $85/kW-yr real-levelized NEPCo capacity charge reported in the NEES DSM avoided costs), load shape, and other differences between NUG and DSM avoided costs. Chamberlin used

[27] As is true for Granite State, many cost components are not mentioned and appear to be excluded.

losses from a Massachusetts Electric filing, but failed to include the $45–47/MWh externalities (three or four times the levelized externalities included in either CVPS's avoided-cost estimates or the DPS's) included in the same filing.

Chamberlin's adjustment to add distribution costs to the Granite State NUG avoided costs is bizarre, to say the least. Granite State's parent company, NEES, provides an estimate of $120.19/kW-yr in 1994$, which would be $21/MWh for a 65% load factor in 1994. Yet Chamberlin converts the distribution costs to $/MWh at a 100% load factor, computes the ratio of levelized distribution to non-distribution DSM avoided costs (which turns out to be 0.361), and computes distribution costs as the product of that ratio times the NUG avoided costs. In 1994, Chamberlin reports Granite State's avoided distribution costs to be $8.4/MWH, 40% of the $21/MWH indicated by NEES's estimate. The relevant pages of Chamberlin's work papers are provided in Exhibit____DPS-JJP/PLC-R-13.

For Narragansett, Chamberlin uses data from the *Independent Power Markets Quarterly*, which appear to be NUG avoided costs, as noted above. Since Chamberlin has refused to provide the source document, and since his representations have proven to be unreliable, the Board should not give his undocumented assertions any weight. He repeats the incomplete and understated adjustments that he made in Granite State's avoided costs.

Chamberlin's behavior is even stranger when he moves on to the PSNH avoided costs. He does not use the average avoided energy costs, but instead uses the on-peak avoided energy costs, which are roughly 15% higher than average.[28] This may reasonably approximate the difference between the avoided costs for a flat load shape for baseload NUGs and a load-proportional shape for DSM; prior estimates for CVPS showed a difference of roughly 20%.

Chamberlin added 7% to the NU avoided energy costs, "to account for losses." It is also odd that Chamberlin chose to add only 7% losses, since Bentley's estimated losses range from 8.6% in the summer off-peak to 12.9% in the winter peak, averaging roughly 10%, and CVPS's marginal losses are 13.8%–24.7%, averaging roughly 18%. Chamberlin increased the NU losses to 10% in his discovery response.

While Chamberlin made some upward adjustments to NU's avoided NUG energy costs, he made an offsetting downward adjustment to NU's generation capacity costs—he ignored them entirely. This adjustment places the NU avoided cost on a *less* "comparable footing." By 2015, the end of Exhibit____JHC-3, NU projects a capacity cost of $216.40/kW-yr; at a 65% DSM load factor and with 21% reserves, this is equivalent to $46/MWH.

For the four New York utilities, Chamberlin simply reports the NUG avoided costs, including transmission costs and secondary losses, and fails to adjust for the exclusion of distribution, reserve margin, DSM load shape, for externalities, or risk adjustment. The New York avoided costs do not include Clean Air Act costs (not even the costs of low-sulfur fuels or sulfur allowances), or avoidable life extensions.

For CMP, Exhibit____JHC-R3 originally used NUG avoided costs, without adjustments. The revision in discovery uses CMP avoided costs at

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[28] The NU on-peak period is much broader than CV's, as noted in Exhibit____JHC-R3.

secondary voltage (apparently including line losses) that are described as being used for screening DSM, but the notes attached to Chamberlin's work papers report that these values include "no reserve margin" and that "supply and DSM [are] treated the same," suggesting that these are NUG avoided costs that CMP improperly uses for DSM.[29] The notes also include cryptic references to T&D values in a range of $22–$120/kW; the avoided costs appear to include little if any T&D.[30] Chamberlin did not adjust for any of these errors, or externalities or risk.

The Bangor Hydro avoided costs also appear to be estimated for 100% load factor (the avoided capacity costs in $/kWh and in $/kW-yr are consistent only for a load factor over 100%). Chamberlin does not adjust for that error, or for the exclusion of all transmission and distribution costs, reserves, risk, and externalities.

Exhibit____JJP/PLC-R-14 summarizes Chamberlin's failures to adjust avoided costs to a comparable basis.

Q: If Chamberlin had actually performed the adjustment he claimed to have performed, and placed the avoided costs on a comparable basis, would the comparison avoided costs he proposed be much lower than CVPS's avoided costs?

A: No. Some of the cost components (transmission capacity, distribution capacity, line losses) for the various utilities exceed the equivalent estimates

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[29] Rather than demonstrating that other utilities *have* avoided costs lower than CV's, Chamberlin may have demonstrated that the Maine utilities *use* avoided costs for DSM that are very poorly estimated.

[30] This is hardly surprising, considering CMP's position that avoided T&D should be estimated for a base of zero load growth.

for CV, including NYSEG transmission, Granite State distribution, and Bangor Hydro line losses. Exhibit___JJP/PLC-15 combines the underlying generation (and in the case of NYSEG, transmission) costs for three of the utilities with corrected-CVPS values of reserves, peak load factor (but without correcting for the effect of load shape on avoided energy, other than Chamberlin's adjustment for PSNH), transmission, distribution, losses (Bentley's version), externalities, and risk. The NYSEG avoided costs use New York values for reserve margin (which is rolled into the NUG LRACs) and transmission. The resulting hybrid avoided costs range from virtually identical to the corrected CV estimates to substantially higher, in the case of PSNH. The Granite State avoided costs, driven by low gas prices and low inflation, gradually fall below the corrected CV estimates after 2004; using the lower gas price and inflation projections would also decrease the costs of fuel-switching and energy-efficiency investments (especially those with continuing replacement and O&M costs).

Q: Is Mr. Bentley correct in describing the Hydro Quebec–~~Vermont~~/Vermont Joint Owners commitments as being "flexible through renegotiated terms and conditions" (p. 5) with "more flexibility...than expected" (p. 6)?

A: No. Bentley testified in Docket 5330 that the HQ contract could be resold at cost or at a profit, and therefore represented a very flexible resource. In reality, the HQ purchase has been *less* flexible than expected, since CVPS could only resell its purchases back to HQ at a significant loss. When the resale ends in 1997, CVPS is projecting that the excess of HQ energy will result in nuclear and coal energy being pushed to the margin and even backed out; this seems to be the opposite of flexibility.

Q: How seriously should the Board take Mr. Bentley's complaint that DSM is less flexible than originally planned?

A: Bentley claims that "By contrast [with the HQ/VJO contract], DSM programs are less flexible than the Company anticipated." He goes on to complain that DSM programs cost CVPS flexibility because of the need to maintain "capability, to maintain comprehensiveness, to not forego any lost opportunities and to meet outstanding customer commitments." (p. 6)

The Board should disregard Bentley's complaint as unreasonable. CVPS is essentially faulting DSM programs because their acquisition costs are not totally and instantly variable.[31] The Company is holding DSM to a standard that CVPS does not apply to supply. For example, the HQ/VJO contract does not come close to Bentley's ideal, since only the energy charges are variable, and these are subject to minimum delivery provisions. not very

Moreover, Bentley's argument exaggerates the lost value of the ideal flexibility he finds looking in DSM. Compared to supply, there is minimal economic damage from continuing with DSM acquisitions while examining potential acquisition changes. The worst that will happen is that CVPS will acquire some non-cost-effective DSM during the period when implementation, design, and acquisition are being reviewed. If the reduced acquisition renders the program uneconomic in its entirety, it can be terminated. Because DSM is acquired gradually, unlike supply, CVPS will

[31] Bentley's deferral analysis in Exhibit____BWB-R-1 assumes that DSM programs meet this standard, since he assumes zero costs during the years of deferral, and no additional costs to stop or re-start the deferred DSM. This is unreasonable, as discussed above in Section II. I pointed out in my direct testimony that CVPS was imprudently planning as if all DSM program costs were variable (pp. 31-32).

not have mistakenly committed to acquisition of the entire resource due to changing circumstances, as it apparently has with its HQ commitments.

V. THE COMPANY SHOULD BE PENALIZED FOR MISMANAGING ITS DSM PLANNING RESPONSIBILITIES

Q: Mr. Plunkett, is your recommendation that CVPS be penalized for DSM mismanagement inconsistent with your testimony opposing penalties and disallowances for PEPCo before the District of Columbia Public Service Commission, as Dr. Chamberlin testifies?

A: No. My recommendations for CVPS and PEPCO are not inconsistent just because they are different. They differ because the circumstances surrounding the two utilities are different. In PEPCo, I found a utility that had done a truly outstanding, if imperfect, job in planning and acquiring DSM resources in accord with least-cost planning directives established by its regulators. Moreover, PEPCo was in the midst of enhancing and expanding its DSM programs. Accordingly, I recommended against disallowance of reasonably incurred program costs and lost revenue.

In CVPS, I find a utility that has engaged in a pattern of behavior to undermine least-cost-planning goals set by its regulators: the Company has implemented program changes that degrade cost-effectiveness, while refusing to undertake program improvements; it has seriously misrepresented its avoided costs in pursuit of its objective of reducing DSM and promoting sales; it has refused to properly evaluate and implement program strategies to acquire cost-effective fuel-switching savings, while contriving arguments to escape responsibility for all DSM market intervention; and it has refused to manage and plan its load control program properly, while misusing it to promote uneconomic sales. For this defiance and mismanagement I have recommended a penalty.

Whereas I have found that one utility can be wrong and another right, Chamberlin is consistent in his apparent belief that all utilities are always right in all DSM matters. As far as we can tell from our encounters with Chamberlin in this and other proceedings, he has never met a utility whose DSM plan is worthy of criticism.. He has testified that even utilities with practically no real DSM, such as Detroit Edison and Cincinnati Gas and Electric, are reasonable or praiseworthy. As for his testimony in this case, the Board should dismiss the kind of "consistency" Chamberlin brings to Vermont.

Q: Mr. Plunkett, do the arguments you made on PEPCo's behalf apply to CVPS, as Dr. Chamberlin testifies at p. 33 of his rebuttal?

A: No. First, I warned the D.C. Commission that imposing undeserved penalties on PEPCo would risk reversing the program enhancements and expansion then underway. In the instant proceeding, the penalty I recommend and the disallowances recommended by other Department witnesses are designed in part to reverse the Company's present course.

Second, I was concerned in D.C. that penalizing a utility with leading-edge DSM efforts would have a chilling effect on utilities nationwide that were also pursuing or considering similar approaches. In Vermont, I am concerned that if the Board does not penalize CVPS, the Company and other utilities will be emboldened to pursue similar or even more damaging approaches to DSM.

Third, Chamberlin mischaracterizes my testimony in this case when he invokes my PEPCo testimony regarding proposed penalties for its alleged failure to meet program savings targets. Nowhere in my testimony do I propose penalizing CVPS for failing to meet its electricity savings targets. Indeed, I testified specifically that meeting savings targets is not sufficient to establish management prudence (p. 52).[32]

Q: If the Department did not notify CVPS of the faults in its program planning, should CVPS be spared penalties for imprudent management?

A: Gamble testifies, "it's important for the Board to recognize that many of the specific criticisms alleged in the Department's testimony are being raised for the first time in the context of this proceeding" (p. 4 lines 12–14). She then argues, "it is unreasonable to penalize the Company for suggestions which were never made in the ordinary course of business between CV and the Department." The Company's reasoning is simply astounding. It implies that CVPS can only be guilty of imprudent management if the Department discovers and notifies CVPS of flaws in its DSM program planning, design, and implementation. If CVPS truly believes this, then the Board should consider relieving the Company of these DSM responsibilities and transferring them to another entity. Alternatively, the Board should consider imposing close and tight supervision on the Company's conduct of DSM.

Q: Should the Company be penalized for seeking to defer DSM acquisitions?

A: In principle, no. While the Company's deferral analysis does not prove that CVPS proposed "pacing adjustments" are cost-effective or reasonable, some

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[32] This is consistent with my Pepco testimony, where I stated that falling short of savings targets did not automatically imply imprudence.

deferral of some discretionary efficiency resources may be prudent. Unfortunately, CVPS has not conducted the analysis needed to establish when deferral should take place, how much savings should be deferred, which savings should be deferred, and how such deferral should be accomplished. The Company has instead wasted time and resources on opposing changes to program design and implementation that would improve cost-effectiveness; inventing new arguments to roll back the clock on DSM; and withholding data, refusing analysis, and making excuses regarding performance and economics of its water heat load control program. In fact, CVPS should be penalized for proceeding with major DSM cutbacks that rely on faulty analysis and that fail to consider better alternatives.

Q: For what management behavior should CVPS be penalized?

A: As discussed in Plunkett's direct testimony, the Company deserves to be penalized for four types of mismanagement of its DSM responsibilities: (1) pursuing and implementing DSM program amendments that will reduce net benefits, and failing to propose and implement improvements that would increase net benefits; (2) misrepresenting its avoided costs; (3) defying Board policy on pursuing cost-effective fuel-switching savings; and (4) mismanaging and misusing its load control program for promotional purposes.

Q: What makes this behavior so serious that it warrants the penalties Mr. Plunkett recommends in his direct testimony?

A: Several aspects of the Company's behavior in these areas indicate the necessity for significant shareholder penalties. First, the pattern of behavior has been persistent and intensifying. Second, the four areas are closely intertwined and deeply rooted within the Company's management.

Unmistakably strong penalties are needed to convince the Company to recognize and rectify the deteriorating mismanagement of its DSM responsibilities.

Q: What leads you to believe that the Company's DSM mismanagement is persistent and intensifying?

A: The persistence and increasing intensity of the Company's mismanagement is evident from several aspects of its conduct in this case and in Docket Nos. 5270-CV-1&3 and 5686:

(1) Gamble suggested during cross examination in this case that CVPS is considering hiring Smart Energy Services to deliver its residential retrofit programs. She offered this possibility despite concern by the Board and the Department that SES may be undermining DSM objectives

(2) In response to the Department's recommendation that blower-door-guided air sealing be offered to electric space heat customers at the time of an energy audit, CVPS encouraged its contractors to provide it with written comments. The letter soliciting these comments was worded in a way to suggest that the recommendation would jeopardize the contractors' livelihood.[33] This irresponsible action generated strong resistance to a program modification that CVPS should have discovered, evaluated, and tested on its own. By taking its litigation strategy from the hearing room to the DSM market infrastructure, CVPS has risked

[33] The Company's request for comments and the contractors' written responses were included as Exhibit___JFG-R-4 in Gamble's rebuttal testimony in Docket Nos. 5270-CV-1&3 and 5686.

increasing the difficulty and cost of objectively developing and properly implementing this strategy with the Company's air-sealing contractors.

(3) In the fuel-switching case, CVPS has sponsored testimony by several witnesses challenging the economic foundation of the Board's policy directing utilities to intervene in the market with DSM programs. This testimony goes far beyond issues confined to the cost-effectiveness of fuel-switching measures. Despite clear and repeated Board guidance to the contrary, CVPS persists in invoking the biased and restrictive no-losers or rate-impact measure test in pressing its case for lower DSM savings in general and against fuel-switching measures in particular. This behavior demonstrates that CVPS management is pursuing a frontal attack on all DSM, not just fuel-switching.

Q: How are the four sources of DSM mismanagement you identified linked?

A: These four problems interact in a variety of ways which, taken together, indicate just how entrenched and paralyzing the Company's DSM mismanagement really is.

Imprudent program amendments and misrepresented avoided costs are inseparable. In field implementation, measures are likely to be rejected as uneconomic due to understated avoided costs. Above in Section II we demonstrated how misrepresented avoided costs have led CVPS to the false conclusion that deferring DSM will increase net benefits.

The Company's desire to promote uneconomic sales, as evinced by its positions regarding cost-effectiveness tests in Act 250 and in its promotion of Rate 3 over non-electric alternatives, may also lie at the heart of its impudent plans to cut DSM savings.

The Company's imprudent program amendments and its refusal to pursue cost-effective fuel-switching are closely connected. Both are part of same pattern of refusing to improve program cost-effectiveness with enhancements to increase installations, or to collect information that would indicate the need for such changes. Changes that cut spending and incentives are favored instead.

The Company's vigorous opposition to fuel-switching is fed by its misrepresented avoided costs and by its mismanagement of load control. By misrepresenting its avoided costs, CVPS reduces the number of fuel-switching opportunities that are cost-effective.[34] For example, witness Gamble complained in her surrebuttal in the fuel-switching case that about half of the fuel-switches projected by the Department had benefit-cost ratios under 1.4. Under CVPS avoided costs, which Chernick estimates are approximately 25% lower, half these projected installations would have benefit-cost ratios below 1.05.[35] Without Board approval, CVPS has begun to use the new cost-effectiveness test it has invoked to oppose fuel-switching in the field. The Company is using its mismanaged load control to undermine the cost-effectiveness of fuel-switching by making controlled electric water heating appear cost-effective as an alternative to fuel-switching. The Company is combining its mismanaged load control with water-heater rentals to promote electric water heat, in effect magnifying the market barriers stemming from the higher capital costs of fuel-switching, even where cost-effective under Central Vermont's biased analysis.

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[34] In Section III we noted that Central Vermont's biased avoided costs influenced its projection of feasible fuel-switching installations in the Lessons Learned Case.

[35] $(1-.25) \times 1.4 = 1.05$.

Q: Mr. Plunkett, you indicated in your direct testimony that you favor an ROE penalty instead of disallowance of excess power costs. Can you provide even a rough idea of the amount of power cost disallowances that might result from the Company's failure to aggressively pursue fuel-switching in 1993, and how this compares to the penalty you recommend?

A: Yes. Exhibit____JJP/PLC-R-16 provides an approximation of the excess power costs in 1993 that resulted from the Company's failure to improve the design of its program and obtain more cost-effective fuel-switching installations from audited customers. Had CVPS gathered the information requested by the Board and improved the design of its residential retrofit programs involving fuel-switching, the Company should have obtained an additional 263 space heat and 269 water heat fuel-switches from the 680 and 596 audited customers using electricity for these purposes for whom fuel-switching was recommended as cost-effective, respectively. The additional fuel-switches are multiplied by my approximation of the average per fuel-switch electricity savings that would result, which produces the excess electric energy requirements caused by the Company's failure. The excess power requirements are multiplied by the 1993 values for CVPS avoided costs, corrected for Central Vermont's undisputed errors, to produce my estimate of excess power costs of $291,000.[36]

This estimate is slightly more than half the magnitude of the ROE penalty I recommend in my direct testimony. The estimate would increase significantly if the fuel-switching CVPS failed to achieve in 1992 and 1994

[36] This estimate is a simpler alternative to the three methods for estimating excess power cots discussed in Plunkett's direct testimony, pp. 48-51.

were included in the analysis, or if RII avoided costs were used in place of the CVPS corrected values used here.

+ failure to fix errors, wrong A.C. decision

Q: Mr. Plunkett, do you still believe that the form and magnitude of the penalty you recommended in your direct testimony is appropriate?

A: I stand by the form of the penalty I recommended in my direct testimony. However, I am concerned that the level of the penalty may be too low to effectuate the reforms needed by CVPS management in order to reverse its present course. My concern is prompted by the deepening intransigence I observed on the part of Company management, as discussed above. The Board may want to consider as a starting place the midrange (34 basis points) of the PEPCO and BECO penalty percentages I used to develop my recommendation of a 25 basis-point reduction for CVPS.[37] As I discussed in my direct testimony, the Company's behavior may well warrant a penalty comparable to that imposed by the Massachusetts DPU on BECO in 1986.

Q: Does this complete your surrebuttal testimony?

A: Yes.

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[37] See my direct testimony, p. 44.

Exhibit__JJP/PLC-R-2

Summary of Net Benefits of DSM Deferral Under Different Avoided Costs

Deferral case	Avoided costs	Net benefits of deferral $Millions	Source pages from Exhibit JJP/PLC-R-3
5-year deferral, postpone from 1993 to 1998	CVPS reference. Used by Bentley	-1.1	3, 5
5-year deferral, postpone from 1993 to 1998	CVPS uncorrected new avoided costs. Used by Bentley	13.0	7, 9
4-year deferral, postpone from 1994 to 1998	CVPS uncorrected new avoided costs. Used by Bentley	9.1	8, 9
4-year deferral, postpone from 1994 to 1998	CVPS filed avoided costs, with externalities and risk. Used by Chamberlin	-0.6	12, 13
4-year deferral, postpone from 1994 to 1998	CVPS corrected direct avoided costs	-0.4	16, 17
4-year deferral, postpone from 1994 to 1998	CVPS corrected avoided costs, with externalities and risk	-6.1	22, 23
4-year deferral, postpone from 1994 to 1998	RII avoided costs, with externalities and risk	-7.5	32, 33

Exhibit__JJP/PLC-R-3

Alternative DSM Deferral Analysis Under Different DSM Schedules and Avoided Costs

Exhibit__JJP/PLC-R-3

Alternative DSM Deferral Analysis Under Different DSM Schedules and Avoided Costs

Exhibit__JJP/PLC-R-3

REFERENCE AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1993

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	53.00	10	4.000	-3.470	-3.183
1994	57.00	20	4.160	-3.020	-5.725
1995	64.00	40	8.653	-6.093	-10.430
1996	72.00	60	8.999	-4.679	-13.745
1997	65.00	80	9.359	-4.159	-16.448
1998	78.00	120	19.466	-10.106	-22.474
1999	92.00	160	20.245	-5.525	-25.496
2000	100.00	160	0.000	16.000	-17.466
2001	109.00	160	0.000	17.440	-9.437
2002	118.00	160	0.000	18.880	-1.461
2003	128.00	160	0.000	20.480	6.475
2004	138.00	160	0.000	22.080	14.325
2005	149.00	160	0.000	23.840	22.102
2006	161.00	160	0.000	25.760	29.810
2007	169.00	160	0.000	27.040	37.234
2008	177.00	160	0.000	28.320	44.367
2009	187.00	160	0.000	29.920	51.280
2010	196.00	160	0.000	31.360	57.928
2011	206.00	120	0.000	24.720	62.736
2012	216.00	80	0.000	17.280	65.819
2013	227.00	60	0.000	13.620	68.049
2014	238.00	40	0.000	9.520	69.479
2015	250.00	20	0.000	5.000	70.168
2016	263.00		0.000	0.000	70.168
2017	276.00		0.000	0.000	70.168
2018	288.42		0.000	0.000	70.168
2019	301.40		0.000	0.000	70.168
2020	314.96		0.000	0.000	70.168
2021	329.14		0.000	0.000	70.168
2022	343.95		0.000	0.000	70.168
2023	359.42		0.000	0.000	70.168
2024	375.60		0.000	0.000	70.168
2025	392.50		0.000	0.000	70.168

	COSTS	BENEFITS	NET BENEFIT
NPV	48.992	119.160	70.168
B/C	2.43		
Nominal Discount Rate	9%		

REFERENCE AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	53.00		0.000	0.000	0.000
1994	57.00	10	4.160	-3.590	-3.022
1995	64.00	20	4.326	-3.046	-5.374
1996	72.00	40	8.999	-6.119	-9.709
1997	65.00	60	9.359	-5.459	-13.257
1998	78.00	80	9.733	-3.493	-15.340
1999	92.00	120	20.245	-9.205	-20.375
2000	100.00	160	21.055	-5.055	-22.912
2001	109.00	160	0.000	17.440	-14.882
2002	118.00	160	0.000	18.880	-6.907
2003	128.00	160	0.000	20.480	1.030
2004	138.00	160	0.000	22.080	8.880
2005	149.00	160	0.000	23.840	16.656
2006	161.00	160	0.000	25.760	24.365
2007	169.00	160	0.000	27.040	31.788
2008	177.00	160	0.000	28.320	38.921
2009	187.00	160	0.000	29.920	45.835
2010	196.00	160	0.000	31.360	52.483
2011	206.00	160	0.000	32.960	58.893
2012	216.00	120	0.000	25.920	63.518
2013	227.00	80	0.000	18.160	66.491
2014	238.00	60	0.000	14.280	68.636
2015	250.00	40	0.000	10.000	70.013
2016	263.00	20	0.000	5.260	70.678
2017	276.00		0.000	0.000	70.678
2018	288.42		0.000	0.000	70.678
2019	301.40		0.000	0.000	70.678
2020	314.96		0.000	0.000	70.678
2021	329.14		0.000	0.000	70.678
2022	343.95		0.000	0.000	70.678
2023	359.42		0.000	0.000	70.678
2024	375.60		0.000	0.000	70.678
2025	392.50		0.000	0.000	70.678

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	117.423	70.678
B/C	2.51		
Nominal Discount Rate	9%		

REFERENCE AVOIDED COSTS:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	53.00			0.000	0.000
1994	57.00			0.000	0.000
1995	64.00			0.000	0.000
1996	72.00			0.000	0.000
1997	65.00			0.000	0.000
1998	78.00	10	4.867	-4.087	-2.437
1999	92.00	20	5.061	-3.221	-4.199
2000	100.00	40	10.527	-6.527	-7.475
2001	109.00	60	10.949	-4.409	-9.505
2002	118.00	80	11.386	-1.946	-10.327
2003	128.00	120	23.684	-8.324	-13.552
2004	138.00	160	24.631	-2.551	-14.459
2005	149.00	160		23.840	-6.683
2006	161.00	160		25.760	1.025
2007	169.00	160		27.040	8.449
2008	177.00	160		28.320	15.582
2009	187.00	160		29.920	22.495
2010	196.00	160		31.360	29.144
2011	206.00	160		32.960	35.554
2012	216.00	160		34.560	41.720
2013	227.00	160		36.320	47.666
2014	238.00	160		38.080	53.385
2015	250.00	160		40.000	58.896
2016	263.00	120		31.560	62.886
2017	276.00	80		22.080	65.446
2018	288.42	60		17.305	67.287
2019	301.40	40		12.056	68.464
2020	314.96	20		6.299	69.028
2021	329.14			0.000	69.028
2022	343.95			0.000	69.028
2023	359.42			0.000	69.028
2024	375.60			0.000	69.028
2025	392.50			0.000	69.028

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	107.768	69.028
B/C	2.78		
Nominal Discount Rate	9%		

REFERENCE AVOIDED COSTS:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	53.00			0.000	0.000
1994	57.00			0.000	0.000
1995	64.00			0.000	0.000
1996	72.00			0.000	0.000
1997	65.00			0.000	0.000
1998	78.00			0.000	0.000
1999	92.00	10	5.061	-4.141	-2.265
2000	100.00	20	5.264	-3.264	-3.903
2001	109.00	40	10.949	-6.589	-6.937
2002	118.00	60	11.386	-4.306	-8.756
2003	128.00	80	11.842	-1.602	-9.377
2004	138.00	120	24.631	-8.071	-12.246
2005	149.00	160	25.617	-1.777	-12.826
2006	161.00	160		25.760	-5.117
2007	169.00	160		27.040	2.306
2008	177.00	160		28.320	9.439
2009	187.00	160		29.920	16.353
2010	196.00	160		31.360	23.001
2011	206.00	160		32.960	29.411
2012	216.00	160		34.560	35.578
2013	227.00	160		36.320	41.523
2014	238.00	160		38.080	47.242
2015	250.00	160		40.000	52.754
2016	263.00	160		42.080	58.073
2017	276.00	120		33.120	61.914
2018	288.42	80		23.074	64.368
2019	301.40	60		18.084	66.134
2020	314.96	40		12.598	67.262
2021	329.14	20		6.583	67.803
2022	343.95			0.000	67.803
2023	359.42			0.000	67.803
2024	375.60			0.000	67.803
2025	392.50			0.000	67.803

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	104.766	67.803
B/C	2.83		
Nominal Discount Rate	9%		

NEW AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1993

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	35.00	10	4.000	-3.650	-3.349
1994	32.00	20	4.160	-3.520	-6.311
1995	36.00	40	8.653	-7.213	-11.881
1996	39.00	60	8.999	-6.659	-16.599
1997	32.00	80	9.359	-6.799	-21.017
1998	39.00	120	19.466	-14.786	-29.834
1999	51.00	160	20.245	-12.085	-36.445
2000	57.00	160	0.000	9.120	-31.868
2001	89.00	160	0.000	14.240	-25.311
2002	98.00	160	0.000	15.680	-18.688
2003	110.00	160	0.000	17.600	-11.867
2004	133.00	160	0.000	21.280	-4.301
2005	147.00	160	0.000	23.520	3.370
2006	158.00	160	0.000	25.280	10.935
2007	166.00	160	0.000	26.560	18.227
2008	174.00	160	0.000	27.840	25.239
2009	183.00	160	0.000	29.280	32.005
2010	192.00	160	0.000	30.720	38.517
2011	202.00	120	0.000	24.240	43.232
2012	212.00	80	0.000	16.960	46.258
2013	222.00	60	0.000	13.320	48.438
2014	233.00	40	0.000	9.320	49.838
2015	245.00	20	0.000	4.900	50.513
2016	257.00		0.000	0.000	50.513
2017	270.00		0.000	0.000	50.513
2018	282.15		0.000	0.000	50.513
2019	294.85		0.000	0.000	50.513
2020	308.98		0.000	0.000	50.513
2021	321.98		0.000	0.000	50.513
2022	336.47		0.000	0.000	50.513
2023	351.61		0.000	0.000	50.513
2024	367.43		0.000	0.000	50.513
2025	383.97		0.000	0.000	50.513

	COSTS	BENEFITS	NET BENEFIT
NPV	48.992	99.505	50.513
B/C	2.03		
Nominal Discount Rate	9%		

NEW AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	35.00		0.000	0.000	0.000
1994	32.00	10	4.160	-3.840	-3.232
1995	36.00	20	4.326	-3.606	-6.017
1996	39.00	40	8.999	-7.439	-11.287
1997	32.00	60	9.359	-7.439	-16.122
1998	39.00	80	9.733	-6.613	-20.065
1999	51.00	120	20.245	-14.125	-27.792
2000	57.00	160	21.055	-11.935	-33.781
2001	89.00	160	0.000	14.240	-27.225
2002	98.00	160	0.000	15.680	-20.602
2003	110.00	160	0.000	17.600	-13.781
2004	133.00	160	0.000	21.280	-6.215
2005	147.00	160	0.000	23.520	1.457
2006	158.00	160	0.000	25.280	9.022
2007	166.00	160	0.000	26.560	16.313
2008	174.00	160	0.000	27.840	23.325
2009	183.00	160	0.000	29.280	30.091
2010	192.00	160	0.000	30.720	36.604
2011	202.00	160	0.000	32.320	42.889
2012	212.00	120	0.000	25.440	47.429
2013	222.00	80	0.000	17.760	50.336
2014	233.00	60	0.000	13.980	52.436
2015	245.00	40	0.000	9.800	53.786
2016	257.00	20	0.000	5.140	54.436
2017	270.00		0.000	0.000	54.436
2018	282.15		0.000	0.000	54.436
2019	294.85		0.000	0.000	54.436
2020	308.98		0.000	0.000	54.436
2021	321.98		0.000	0.000	54.436
2022	336.47		0.000	0.000	54.436
2023	351.61		0.000	0.000	54.436
2024	367.43		0.000	0.000	54.436
2025	383.97		0.000	0.000	54.436

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	101.181	54.436
B/C	2.16		
Nominal Discount Rate	9%		

NEW AVOIDED COSTS:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	35.00			0.000	0.000
1994	32.00			0.000	0.000
1995	36.00			0.000	0.000
1996	39.00			0.000	0.000
1997	32.00			0.000	0.000
1998	39.00	10	4.867	-4.477	-2.669
1999	51.00	20	5.061	-4.041	-4.880
2000	57.00	40	10.527	-8.247	-9.019
2001	89.00	60	10.949	-5.609	-11.601
2002	98.00	80	11.386	-3.546	-13.099
2003	110.00	120	23.684	-10.484	-17.162
2004	133.00	160	24.631	-3.351	-18.354
2005	147.00	160		23.520	-10.682
2006	158.00	160		25.280	-3.117
2007	166.00	160		26.560	4.175
2008	174.00	160		27.840	11.187
2009	183.00	160		29.280	17.953
2010	192.00	160		30.720	24.465
2011	202.00	160		32.320	30.751
2012	212.00	160		33.920	36.803
2013	222.00	160		35.520	42.618
2014	233.00	160		37.280	48.217
2015	245.00	160		39.200	53.618
2016	257.00	120		30.840	57.516
2017	270.00	80		21.600	60.021
2018	282.15	60		16.929	61.822
2019	294.85	40		11.794	62.973
2020	308.98	20		6.180	63.527
2021	321.98			0.000	63.527
2022	336.47			0.000	63.527
2023	351.61			0.000	63.527
2024	367.43			0.000	63.527
2025	383.97			0.000	63.527

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	102.267	63.527
B/C	2.64		
Nominal Discount Rate	9%		

NEW AVOIDED COSTS:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	35.00			0.000	0.000
1994	32.00			0.000	0.000
1995	36.00			0.000	0.000
1996	39.00			0.000	0.000
1997	32.00			0.000	0.000
1998	39.00			0.000	0.000
1999	51.00	10	5.061	-4.551	-2.490
2000	57.00	20	5.264	-4.124	-4.559
2001	89.00	40	10.949	-7.389	-7.961
2002	98.00	60	11.386	-5.506	-10.287
2003	110.00	80	11.842	-3.042	-11.466
2004	133.00	120	24.631	-8.671	-14.549
2005	147.00	160	25.617	-2.097	-15.233
2006	158.00	160		25.280	-7.668
2007	166.00	160		26.560	-0.376
2008	174.00	160		27.840	6.636
2009	183.00	160		29.280	13.402
2010	192.00	160		30.720	19.914
2011	202.00	160		32.320	26.200
2012	212.00	160		33.920	32.252
2013	222.00	160		35.520	38.067
2014	233.00	160		37.280	43.666
2015	245.00	160		39.200	49.067
2016	257.00	160		41.120	54.265
2017	270.00	120		32.400	58.022
2018	282.15	80		22.572	60.423
2019	294.85	60		17.691	62.150
2020	308.98	40		12.359	63.257
2021	321.98	20		6.440	63.786
2022	336.47			0.000	63.786
2023	351.61			0.000	63.786
2024	367.43			0.000	63.786
2025	383.97			0.000	63.786

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	100.749	63.786
B/C	2.73		
Nominal Discount Rate	9%		

CV FILED AVOIDED COSTS WITH EXTERNALITIES AND RISK:
REFERENCE DSM BEGINNING IN 1993

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	33.45	10	4.000	-3.665	-3.363
1994	36.06	20	4.160	-3.439	-6.257
1995	36.41	40	8.653	-7.197	-11.814
1996	62.13	60	8.999	-5.271	-15.549
1997	49.74	80	9.359	-5.380	-19.045
1998	84.21	120	19.466	-9.361	-24.627
1999	105.58	160	20.245	-3.353	-26.461
2000	88.99	160	0.000	14.238	-19.315
2001	105.40	160	0.000	16.864	-11.550
2002	111.93	160	0.000	17.909	-3.985
2003	122.15	160	0.000	19.545	3.589
2004	140.28	160	0.000	22.445	11.569
2005	138.66	160	0.000	22.185	18.805
2006	147.03	160	0.000	23.525	25.845
2007	153.40	160	0.000	24.544	32.583
2008	161.69	160	0.000	25.870	39.099
2009	170.55	160	0.000	27.288	45.404
2010	180.98	160	0.000	28.957	51.543
2011	190.58	120	0.000	22.869	55.991
2012	203.75	80	0.000	16.300	58.899
2013	215.93	60	0.000	12.956	61.020
2014	228.86	40	0.000	9.154	62.395
2015	242.59	20	0.000	4.852	63.063
2016	257.16		0.000	0.000	63.063
2017	272.64		0.000	0.000	63.063
2018	289.08		0.000	0.000	63.063
2019	306.53		0.000	0.000	63.063
2020	325.07		0.000	0.000	63.063
2021	344.76		0.000	0.000	63.063
2022	365.69		0.000	0.000	63.063
2023	387.91		0.000	0.000	63.063
2024	411.53		0.000	0.000	63.063
2025	436.63		0.000	0.000	63.063

	COSTS	BENEFITS	NET BENEFIT
NPV	48.992	112.056	63.063
B/C	2.29		
Nominal Discount Rate	9%		

CV FILED AVOIDED COSTS WITH EXTERNALITIES AND RISK:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	33.45		0.000	0.000	0.000
1994	36.06	10	4.160	-3.799	-3.198
1995	36.41	20	4.326	-3.598	-5.976
1996	62.13	40	8.999	-6.514	-10.591
1997	49.74	60	9.359	-6.374	-14.734
1998	84.21	80	9.733	-2.996	-16.520
1999	105.58	120	20.245	-7.576	-20.665
2000	88.99	160	21.055	-6.817	-24.086
2001	105.40	160	0.000	16.864	-16.321
2002	111.93	160	0.000	17.909	-8.756
2003	122.15	160	0.000	19.545	-1.182
2004	140.28	160	0.000	22.445	6.798
2005	138.66	160	0.000	22.185	14.034
2006	147.03	160	0.000	23.525	21.074
2007	153.40	160	0.000	24.544	27.812
2008	161.69	160	0.000	25.870	34.328
2009	170.55	160	0.000	27.288	40.633
2010	180.98	160	0.000	28.957	46.772
2011	190.58	160	0.000	30.492	52.703
2012	203.75	120	0.000	24.450	57.065
2013	215.93	80	0.000	17.274	59.893
2014	228.86	60	0.000	13.732	61.955
2015	242.59	40	0.000	9.704	63.292
2016	257.16	20	0.000	5.143	63.942
2017	272.64		0.000	0.000	63.942
2018	289.08		0.000	0.000	63.942
2019	306.53		0.000	0.000	63.942
2020	325.07		0.000	0.000	63.942
2021	344.76		0.000	0.000	63.942
2022	365.69		0.000	0.000	63.942
2023	387.91		0.000	0.000	63.942
2024	411.53		0.000	0.000	63.942
2025	436.63		0.000	0.000	63.942

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	110.687	63.942
B/C	2.37		
Nominal Discount Rate	9%		

CV FILED AVOIDED COSTS WITH EXTERNALITIES AND RISK:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	33.45			0.000	0.000
1994	36.06			0.000	0.000
1995	36.41			0.000	0.000
1996	62.13			0.000	0.000
1997	49.74			0.000	0.000
1998	84.21	10	4.867	-4.025	-2.400
1999	105.58	20	5.061	-2.949	-4.013
2000	88.99	40	10.527	-6.967	-7.510
2001	105.40	60	10.949	-4.625	-9.640
2002	111.93	80	11.386	-2.431	-10.667
2003	122.15	120	23.684	-9.026	-14.164
2004	140.28	160	24.631	-2.186	-14.942
2005	138.66	160		22.185	-7.705
2006	147.03	160		23.525	-0.666
2007	153.40	160		24.544	6.073
2008	161.69	160		25.870	12.588
2009	170.55	160		27.288	18.894
2010	180.98	160		28.957	25.033
2011	190.58	160		30.492	30.963
2012	203.75	160		32.599	36.780
2013	215.93	160		34.549	42.435
2014	228.86	160		36.618	47.935
2015	242.59	160		38.814	53.283
2016	257.16	120		30.859	57.183
2017	272.64	80		21.811	59.713
2018	289.08	60		17.345	61.558
2019	306.53	40		12.261	62.755
2020	325.07	20		6.501	63.337
2021	344.76			0.000	63.337
2022	365.69			0.000	63.337
2023	387.91			0.000	63.337
2024	411.53			0.000	63.337
2025	436.63			0.000	63.337

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	102.077	63.337
B/C	2.63		
Nominal Discount Rate	9%		

CV FILED AVOIDED COSTS WITH EXTERNALITIES AND RISK:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	33.45			0.000	0.000
1994	36.06			0.000	0.000
1995	36.41			0.000	0.000
1996	62.13			0.000	0.000
1997	49.74			0.000	0.000
1998	84.21			0.000	0.000
1999	105.58	10	5.061	-4.005	-2.191
2000	88.99	20	5.264	-3.484	-3.940
2001	105.40	40	10.949	-6.733	-7.040
2002	111.93	60	11.386	-4.671	-9.012
2003	122.15	80	11.842	-2.070	-9.814
2004	140.28	120	24.631	-7.798	-12.587
2005	138.66	160	25.617	-3.431	-13.706
2006	147.03	160		23.525	-6.666
2007	153.40	160		24.544	0.072
2008	161.69	160		25.870	6.588
2009	170.55	160		27.288	12.893
2010	180.98	160		28.957	19.032
2011	190.58	160		30.492	24.962
2012	203.75	160		32.599	30.779
2013	215.93	160		34.549	36.435
2014	228.86	160		36.618	41.934
2015	242.59	160		38.814	47.282
2016	257.16	160		41.146	52.483
2017	272.64	120		32.717	56.277
2018	289.08	80		23.126	58.738
2019	306.53	60		18.392	60.533
2020	325.07	40		13.003	61.697
2021	344.76	20		6.895	62.264
2022	365.69			0.000	62.264
2023	387.91			0.000	62.264
2024	411.53			0.000	62.264
2025	436.63			0.000	62.264

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	99.227	62.264
B/C	2.68		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1993

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	30.11	10	4.000	-3.699	-3.393
1994	32.45	20	4.160	-3.511	-6.349
1995	32.77	40	8.653	-7.342	-12.018
1996	55.92	60	8.999	-5.644	-16.017
1997	44.77	80	9.359	-5.778	-19.772
1998	83.03	120	19.466	-9.503	-25.438
1999	99.40	160	20.245	-4.341	-27.813
2000	84.17	160	0.000	13.467	-21.054
2001	97.93	160	0.000	15.668	-13.840
2002	102.84	160	0.000	16.455	-6.889
2003	111.55	160	0.000	17.848	0.027
2004	124.88	160	0.000	19.981	7.131
2005	125.74	160	0.000	20.118	13.694
2006	135.27	160	0.000	21.643	20.170
2007	141.14	160	0.000	22.583	26.370
2008	148.75	160	0.000	23.800	32.365
2009	156.88	160	0.000	25.100	38.165
2010	166.42	160	0.000	26.628	43.809
2011	175.23	120	0.000	21.027	47.899
2012	187.26	80	0.000	14.981	50.572
2013	198.35	60	0.000	11.901	52.520
2014	210.10	40	0.000	8.404	53.782
2015	222.55	20	0.000	4.451	54.396
2016	235.73		0.000	0.000	54.396
2017	249.70		0.000	0.000	54.396
2018	264.49		0.000	0.000	54.396
2019	280.16		0.000	0.000	54.396
2020	296.76		0.000	0.000	54.396
2021	314.34		0.000	0.000	54.396
2022	332.96		0.000	0.000	54.396
2023	352.69		0.000	0.000	54.396
2024	373.59		0.000	0.000	54.396
2025	395.72		0.000	0.000	54.396

	COSTS	BENEFITS	NET BENEFIT
NPV	48.992	103.388	54.396
B/C	2.11		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	30.11		0.000	0.000	0.000
1994	32.45	10	4.160	-3.835	-3.228
1995	32.77	20	4.326	-3.671	-6.063
1996	55.92	40	8.999	-6.762	-10.854
1997	44.77	60	9.359	-6.673	-15.190
1998	83.03	80	9.733	-3.091	-17.033
1999	99.40	120	20.245	-8.317	-21.583
2000	84.17	160	21.055	-7.588	-25.391
2001	97.93	160	0.000	15.668	-18.177
2002	102.84	160	0.000	16.455	-11.227
2003	111.55	160	0.000	17.848	-4.310
2004	124.88	160	0.000	19.981	2.794
2005	125.74	160	0.000	20.118	9.356
2006	135.27	160	0.000	21.643	15.833
2007	141.14	160	0.000	22.583	22.033
2008	148.75	160	0.000	23.800	28.027
2009	156.88	160	0.000	25.100	33.827
2010	166.42	160	0.000	26.628	39.472
2011	175.23	160	0.000	28.036	44.925
2012	187.26	120	0.000	22.471	48.934
2013	198.35	80	0.000	15.868	51.532
2014	210.10	60	0.000	12.606	53.425
2015	222.55	40	0.000	8.902	54.651
2016	235.73	20	0.000	4.715	55.247
2017	249.70		0.000	0.000	55.247
2018	264.49		0.000	0.000	55.247
2019	280.16		0.000	0.000	55.247
2020	296.76		0.000	0.000	55.247
2021	314.34		0.000	0.000	55.247
2022	332.96		0.000	0.000	55.247
2023	352.69		0.000	0.000	55.247
2024	373.59		0.000	0.000	55.247
2025	395.72		0.000	0.000	55.247

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	101.992	55.247
B/C	2.18		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	30.11			0.000	0.000
1994	32.45			0.000	0.000
1995	32.77			0.000	0.000
1996	55.92			0.000	0.000
1997	44.77			0.000	0.000
1998	83.03	10	4.867	-4.037	-2.407
1999	99.40	20	5.061	-3.073	-4.088
2000	84.17	40	10.527	-7.160	-7.682
2001	97.93	60	10.949	-5.073	-10.017
2002	102.84	80	11.386	-3.158	-11.352
2003	111.55	120	23.684	-10.298	-15.343
2004	124.88	160	24.631	-4.650	-16.996
2005	125.74	160		20.118	-10.434
2006	135.27	160		21.643	-3.957
2007	141.14	160		22.583	2.243
2008	148.75	160		23.800	8.237
2009	156.88	160		25.100	14.037
2010	166.42	160		26.628	19.682
2011	175.23	160		28.036	25.135
2012	187.26	160		29.961	30.481
2013	198.35	160		31.736	35.676
2014	210.10	160		33.616	40.725
2015	222.55	160		35.608	45.631
2016	235.73	120		28.288	49.207
2017	249.70	80		19.976	51.523
2018	264.49	60		15.870	53.212
2019	280.16	40		11.206	54.305
2020	296.76	20		5.935	54.837
2021	314.34			0.000	54.837
2022	332.96			0.000	54.837
2023	352.69			0.000	54.837
2024	373.59			0.000	54.837
2025	395.72			0.000	54.837

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	93.577	54.837
B/C	2.42		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	30.11			0.000	0.000
1994	32.45			0.000	0.000
1995	32.77			0.000	0.000
1996	55.92			0.000	0.000
1997	44.77			0.000	0.000
1998	83.03			0.000	0.000
1999	99.40	10	5.061	-4.067	-2.225
2000	84.17	20	5.264	-3.580	-4.022
2001	97.93	40	10.949	-7.031	-7.259
2002	102.84	60	11.386	-5.216	-9.463
2003	111.55	80	11.842	-2.918	-10.593
2004	124.88	120	24.631	-9.645	-14.023
2005	125.74	160	25.617	-5.498	-15.816
2006	135.27	160		21.643	-9.339
2007	141.14	160		22.583	-3.140
2008	148.75	160		23.800	2.855
2009	156.88	160		25.100	8.655
2010	166.42	160		26.628	14.300
2011	175.23	160		28.036	19.753
2012	187.26	160		29.961	25.099
2013	198.35	160		31.736	30.294
2014	210.10	160		33.616	35.342
2015	222.55	160		35.608	40.248
2016	235.73	160		37.717	45.016
2017	249.70	120		29.964	48.491
2018	264.49	80		21.159	50.742
2019	280.16	60		16.810	52.383
2020	296.76	40		11.870	53.446
2021	314.34	20		6.287	53.962
2022	332.96			0.000	53.962
2023	352.69			0.000	53.962
2024	373.59			0.000	53.962
2025	395.72			0.000	53.962

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	90.925	53.962
B/C	2.46		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS WITH EXTERNALITIES:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993			0.000	0.000	0.000
1994	41.11	10	4.160	-3.749	-3.155
1995	39.93	20	4.326	-3.528	-5.879
1996	71.29	40	8.999	-6.147	-10.234
1997	51.55	60	9.359	-6.266	-14.307
1998	107.48	80	9.733	-1.135	-14.983
1999	126.87	120	20.245	-5.020	-17.729
2000	101.90	160	21.055	-4.751	-20.113
2001	117.89	160	0.000	18.862	-11.429
2002	119.95	160	0.000	19.191	-3.322
2003	128.14	160	0.000	20.503	4.623
2004	142.57	160	0.000	22.812	12.733
2005	138.68	160	0.000	22.188	19.971
2006	149.80	160	0.000	23.968	27.143
2007	155.71	160	0.000	24.914	33.983
2008	163.87	160	0.000	26.219	40.587
2009	172.26	160	0.000	27.562	46.956
2010	183.29	160	0.000	29.327	53.173
2011	192.68	160	0.000	30.829	59.169
2012	205.59	120	0.000	24.671	63.571
2013	217.47	80	0.000	17.397	66.419
2014	230.03	60	0.000	13.802	68.491
2015	243.32	40	0.000	9.733	69.832
2016	257.39	20	0.000	5.148	70.483
2017	272.28		0.000	0.000	70.483
2018	288.03		0.000	0.000	70.483
2019	304.70		0.000	0.000	70.483
2020	322.34		0.000	0.000	70.483
2021	341.01		0.000	0.000	70.483
2022	360.77		0.000	0.000	70.483
2023	381.68		0.000	0.000	70.483
2024	403.80		0.000	0.000	70.483
2025	427.22		0.000	0.000	70.483

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	117.228	70.483
B/C	2.51		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS WITH EXTERNALITIES:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	41.11			0.000	0.000
1995	39.93			0.000	0.000
1996	71.29			0.000	0.000
1997	51.55			0.000	0.000
1998	107.48	10	4.867	-3.792	-2.261
1999	126.87	20	5.061	-2.524	-3.642
2000	101.90	40	10.527	-6.451	-6.879
2001	117.89	60	10.949	-3.876	-8.664
2002	119.95	80	11.386	-1.790	-9.420
2003	128.14	120	23.684	-8.307	-12.639
2004	142.57	160	24.631	-1.819	-13.286
2005	138.68	160		22.188	-6.049
2006	149.80	160		23.968	1.124
2007	155.71	160		24.914	7.964
2008	163.87	160		26.219	14.567
2009	172.26	160		27.562	20.936
2010	183.29	160		29.327	27.153
2011	192.68	160		30.829	33.149
2012	205.59	160		32.895	39.019
2013	217.47	160		34.795	44.715
2014	230.03	160		36.805	50.242
2015	243.32	160		38.932	55.606
2016	257.39	120		30.887	59.510
2017	272.28	80		21.782	62.036
2018	288.03	60		17.282	63.875
2019	304.70	40		12.188	65.065
2020	322.34	20		6.447	65.642
2021	341.01			0.000	65.642
2022	360.77			0.000	65.642
2023	381.68			0.000	65.642
2024	403.80			0.000	65.642
2025	427.22			0.000	65.642

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	104.382	65.642
B/C	2.69		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS WITH EXTERNALITIES:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	41.11			0.000	0.000
1995	39.93			0.000	0.000
1996	71.29			0.000	0.000
1997	51.55			0.000	0.000
1998	107.48			0.000	0.000
1999	126.87	10	5.061	-3.793	-2.075
2000	101.90	20	5.264	-3.226	-3.694
2001	117.89	40	10.949	-6.233	-6.563
2002	119.95	60	11.386	-4.190	-8.333
2003	128.14	80	11.842	-1.591	-8.950
2004	142.57	120	24.631	-7.523	-11.624
2005	138.68	160	25.617	-3.428	-12.742
2006	149.80	160		23.968	-5.570
2007	155.71	160		24.914	1.270
2008	163.87	160		26.219	7.874
2009	172.26	160		27.562	14.243
2010	183.29	160		29.327	20.460
2011	192.68	160		30.829	26.455
2012	205.59	160		32.895	32.325
2013	217.47	160		34.795	38.021
2014	230.03	160		36.805	43.548
2015	243.32	160		38.932	48.912
2016	257.39	160		41.183	54.118
2017	272.28	120		32.673	57.907
2018	288.03	80		23.043	60.359
2019	304.70	60		18.282	62.143
2020	322.34	40		12.894	63.298
2021	341.01	20		6.820	63.858
2022	360.77			0.000	63.858
2023	381.68			0.000	63.858
2024	403.80			0.000	63.858
2025	427.22			0.000	63.858

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	100.821	63.858
B/C	2.73		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS WITH EXTERNALITIES AND RISK ADD
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993			0.000	0.000	0.000
1994	45.06	10	4.160	-3.709	-3.122
1995	43.77	20	4.326	-3.451	-5.787
1996	78.14	40	8.999	-5.873	-9.948
1997	56.51	60	9.359	-5.968	-13.827
1998	117.81	80	9.733	-0.308	-14.011
1999	139.07	120	20.245	-3.557	-15.956
2000	111.69	160	21.055	-3.184	-17.554
2001	129.22	160	0.000	20.675	-8.035
2002	131.47	160	0.000	21.035	0.850
2003	140.46	160	0.000	22.473	9.559
2004	156.27	160	0.000	25.004	18.449
2005	152.00	160	0.000	24.320	26.382
2006	164.19	160	0.000	26.271	34.243
2007	170.68	160	0.000	27.308	41.741
2008	179.62	160	0.000	28.739	48.979
2009	188.82	160	0.000	30.211	55.960
2010	200.90	160	0.000	32.145	62.774
2011	211.20	160	0.000	33.792	69.347
2012	225.35	120	0.000	27.042	74.172
2013	238.36	80	0.000	19.069	77.293
2014	252.14	60	0.000	15.128	79.565
2015	266.71	40	0.000	10.668	81.035
2016	282.13	20	0.000	5.643	81.748
2017	298.44		0.000	0.000	81.748
2018	315.71		0.000	0.000	81.748
2019	333.98		0.000	0.000	81.748
2020	353.32		0.000	0.000	81.748
2021	373.78		0.000	0.000	81.748
2022	395.44		0.000	0.000	81.748
2023	418.35		0.000	0.000	81.748
2024	442.61		0.000	0.000	81.748
2025	468.27		0.000	0.000	81.748

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	128.493	81.748
B/C	2.75		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS WITH EXTERNALITIES AND RISK ADDE
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	45.06			0.000	0.000
1995	43.77			0.000	0.000
1996	78.14			0.000	0.000
1997	56.51			0.000	0.000
1998	117.81	10	4.867	-3.689	-2.200
1999	139.07	20	5.061	-2.280	-3.447
2000	111.69	40	10.527	-6.059	-6.488
2001	129.22	60	10.949	-3.196	-7.959
2002	131.47	80	11.386	-0.868	-8.326
2003	140.46	120	23.684	-6.829	-10.972
2004	156.27	160	24.631	0.373	-10.840
2005	152.00	160		24.320	-2.907
2006	164.19	160		26.271	4.954
2007	170.68	160		27.308	12.452
2008	179.62	160		28.739	19.690
2009	188.82	160		30.211	26.671
2010	200.90	160		32.145	33.485
2011	211.20	160		33.792	40.057
2012	225.35	160		36.056	46.491
2013	238.36	160		38.138	52.734
2014	252.14	160		40.342	58.793
2015	266.71	160		42.673	64.672
2016	282.13	120		33.855	68.952
2017	298.44	80		23.876	71.721
2018	315.71	60		18.943	73.736
2019	333.98	40		13.359	75.040
2020	353.32	20		7.066	75.673
2021	373.78			0.000	75.673
2022	395.44			0.000	75.673
2023	418.35			0.000	75.673
2024	442.61			0.000	75.673
2025	468.27			0.000	75.673

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	114.413	75.673
B/C	2.95		
Nominal Discount Rate	9%		

CV Corrected AVOIDED COSTS WITH EXTERNALITIES AND RISK ADDE
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	DSM PROGRAMS COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	45.06			0.000	0.000
1995	43.77			0.000	0.000
1996	78.14			0.000	0.000
1997	56.51			0.000	0.000
1998	117.81			0.000	0.000
1999	139.07	10	5.061	-3.671	-2.008
2000	111.69	20	5.264	-3.030	-3.529
2001	129.22	40	10.949	-5.780	-6.190
2002	131.47	60	11.386	-3.498	-7.667
2003	140.46	80	11.842	-0.606	-7.902
2004	156.27	120	24.631	-5.879	-9.992
2005	152.00	160	25.617	-1.296	-10.415
2006	164.19	160		26.271	-2.553
2007	170.68	160		27.308	4.944
2008	179.62	160		28.739	12.182
2009	188.82	160		30.211	19.163
2010	200.90	160		32.145	25.978
2011	211.20	160		33.792	32.550
2012	225.35	160		36.056	38.983
2013	238.36	160		38.138	45.226
2014	252.14	160		40.342	51.285
2015	266.71	160		42.673	57.165
2016	282.13	160		45.140	62.871
2017	298.44	120		35.813	67.024
2018	315.71	80		25.257	69.711
2019	333.98	60		20.039	71.667
2020	353.32	40		14.133	72.932
2021	373.78	20		7.476	73.547
2022	395.44			0.000	73.547
2023	418.35			0.000	73.547
2024	442.61			0.000	73.547
2025	468.27			0.000	73.547

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	110.510	73.547
B/C	2.99		
Nominal Discount Rate	9%		

RII AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1993

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	43.37	10	4.000	-3.566	-3.272
1994	49.83	20	4.160	-3.163	-5.934
1995	52.25	40	8.653	-6.563	-11.002
1996	55.92	60	8.999	-5.644	-15.001
1997	59.86	80	9.359	-4.570	-17.971
1998	70.14	120	19.466	-11.049	-24.559
1999	79.72	160	20.245	-7.489	-28.656
2000	98.53	160	0.000	15.765	-20.744
2001	103.56	160	0.000	16.569	-13.115
2002	109.82	160	0.000	17.571	-5.693
2003	116.07	160	0.000	18.572	1.505
2004	123.60	160	0.000	19.776	8.536
2005	130.27	160	0.000	20.843	15.334
2006	137.71	160	0.000	22.033	21.928
2007	145.04	160	0.000	23.207	28.299
2008	153.03	160	0.000	24.485	34.466
2009	161.53	160	0.000	25.845	40.438
2010	170.47	160	0.000	27.275	46.220
2011	179.94	120	0.000	21.593	50.420
2012	190.49	80	0.000	15.239	53.139
2013	201.28	60	0.000	12.077	55.116
2014	212.72	40	0.000	8.509	56.394
2015	224.84	20	0.000	4.497	57.013
2016	237.68		0.000	0.000	57.013
2017	251.30		0.000	0.000	57.013
2018	265.73		0.000	0.000	57.013
2019	281.03		0.000	0.000	57.013
2020	297.26		0.000	0.000	57.013
2021	314.46		0.000	0.000	57.013
2022	332.71		0.000	0.000	57.013
2023	352.07		0.000	0.000	57.013
2024	372.60		0.000	0.000	57.013
2025	394.39		0.000	0.000	57.013

	COSTS	BENEFITS	NET BENEFIT
NPV	48.992	106.005	57.013
B/C	2.16		
Nominal Discount Rate	9%		

Exhibit__JJP/PLC-R-3

RII AVOIDED COSTS:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	43.37		0.000	0.000	0.000
1994	49.83	10	4.160	-3.662	-3.082
1995	52.25	20	4.326	-3.281	-5.616
1996	55.92	40	8.999	-6.762	-10.406
1997	59.86	60	9.359	-5.767	-14.155
1998	70.14	80	9.733	-4.122	-16.612
1999	79.72	120	20.245	-10.678	-22.454
2000	98.53	160	21.055	-5.289	-25.108
2001	103.56	160	0.000	16.569	-17.479
2002	109.82	160	0.000	17.571	-10.057
2003	116.07	160	0.000	18.572	-2.860
2004	123.60	160	0.000	19.776	4.171
2005	130.27	160	0.000	20.843	10.970
2006	137.71	160	0.000	22.033	17.563
2007	145.04	160	0.000	23.207	23.934
2008	153.03	160	0.000	24.485	30.101
2009	161.53	160	0.000	25.845	36.073
2010	170.47	160	0.000	27.275	41.855
2011	179.94	160	0.000	28.790	47.455
2012	190.49	120	0.000	22.859	51.533
2013	201.28	80	0.000	16.103	54.169
2014	212.72	60	0.000	12.763	56.086
2015	224.84	40	0.000	8.994	57.325
2016	237.68	20	0.000	4.754	57.926
2017	251.30		0.000	0.000	57.926
2018	265.73		0.000	0.000	57.926
2019	281.03		0.000	0.000	57.926
2020	297.26		0.000	0.000	57.926
2021	314.46		0.000	0.000	57.926
2022	332.71		0.000	0.000	57.926
2023	352.07		0.000	0.000	57.926
2024	372.60		0.000	0.000	57.926
2025	394.39		0.000	0.000	57.926

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	104.671	57.926
B/C	2.24		
Nominal Discount Rate	9%		

RII AVOIDED COSTS:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	DSM PROGRAMS COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	43.37			0.000	0.000
1994	49.83			0.000	0.000
1995	52.25			0.000	0.000
1996	55.92			0.000	0.000
1997	59.86			0.000	0.000
1998	70.14	10	4.867	-4.166	-2.484
1999	79.72	20	5.061	-3.467	-4.380
2000	98.53	40	10.527	-6.586	-7.685
2001	103.56	60	10.949	-4.735	-9.866
2002	109.82	80	11.386	-2.601	-10.964
2003	116.07	120	23.684	-9.755	-14.745
2004	123.60	160	24.631	-4.855	-16.471
2005	130.27	160		20.843	-9.672
2006	137.71	160		22.033	-3.079
2007	145.04	160		23.207	3.292
2008	153.03	160		24.485	9.459
2009	161.53	160		25.845	15.432
2010	170.47	160		27.275	21.214
2011	179.94	160		28.790	26.813
2012	190.49	160		30.478	32.251
2013	201.28	160		32.205	37.523
2014	212.72	160		34.035	42.635
2015	224.84	160		35.974	47.591
2016	237.68	120		28.522	51.197
2017	251.30	80		20.104	53.528
2018	265.73	60		15.944	55.224
2019	281.03	40		11.241	56.322
2020	297.26	20		5.945	56.854
2021	314.46			0.000	56.854
2022	332.71			0.000	56.854
2023	352.07			0.000	56.854
2024	372.60			0.000	56.854
2025	394.39			0.000	56.854

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	95.594	56.854
B/C	2.47		
Nominal Discount Rate	9%		

RII AVOIDED COSTS:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993	43.37			0.000	0.000
1994	49.83			0.000	0.000
1995	52.25			0.000	0.000
1996	55.92			0.000	0.000
1997	59.86			0.000	0.000
1998	70.14			0.000	0.000
1999	79.72	10	5.061	-4.264	-2.333
2000	98.53	20	5.264	-3.293	-3.985
2001	103.56	40	10.949	-6.806	-7.119
2002	109.82	60	11.386	-4.797	-9.145
2003	116.07	80	11.842	-2.556	-10.136
2004	123.60	120	24.631	-9.799	-13.620
2005	130.27	160	25.617	-4.774	-15.177
2006	137.71	160		22.033	-8.584
2007	145.04	160		23.207	-2.213
2008	153.03	160		24.485	3.954
2009	161.53	160		25.845	9.927
2010	170.47	160		27.275	15.709
2011	179.94	160		28.790	21.308
2012	190.49	160		30.478	26.746
2013	201.28	160		32.205	32.018
2014	212.72	160		34.035	37.130
2015	224.84	160		35.974	42.086
2016	237.68	160		38.029	46.894
2017	251.30	120		30.156	50.391
2018	265.73	80		21.258	52.652
2019	281.03	60		16.862	54.298
2020	297.26	40		11.890	55.363
2021	314.46	20		6.289	55.880
2022	332.71			0.000	55.880
2023	352.07			0.000	55.880
2024	372.60			0.000	55.880
2025	394.39			0.000	55.880

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	92.843	55.880
B/C	2.51		
Nominal Discount Rate	9%		

RII AVOIDED COSTS WITH EXTERNALITIES:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993			0.000	0.000	0.000
1994	78.35	10	4.160	-3.377	-2.842
1995	78.16	20	4.326	-2.763	-4.976
1996	82.08	40	8.999	-5.716	-9.025
1997	86.27	60	9.359	-4.182	-11.743
1998	97.43	80	9.733	-1.939	-12.899
1999	107.93	120	20.245	-7.293	-16.888
2000	111.69	160	21.055	-3.184	-18.486
2001	117.28	160	0.000	18.765	-9.846
2002	124.12	160	0.000	19.860	-1.458
2003	130.98	160	0.000	20.957	6.664
2004	139.15	160	0.000	22.264	14.580
2005	146.47	160	0.000	23.436	22.224
2006	154.60	160	0.000	24.736	29.626
2007	162.65	160	0.000	26.025	36.771
2008	171.39	160	0.000	27.423	43.678
2009	180.67	160	0.000	28.908	50.358
2010	190.43	160	0.000	30.468	56.817
2011	200.74	160	0.000	32.119	63.063
2012	212.18	120	0.000	25.461	67.606
2013	223.89	80	0.000	17.911	70.538
2014	236.29	60	0.000	14.177	72.668
2015	249.41	40	0.000	9.976	74.042
2016	263.30	20	0.000	5.266	74.708
2017	278.00		0.000	0.000	74.708
2018	293.57		0.000	0.000	74.708
2019	310.05		0.000	0.000	74.708
2020	327.51		0.000	0.000	74.708
2021	346.00		0.000	0.000	74.708
2022	365.59		0.000	0.000	74.708
2023	386.35		0.000	0.000	74.708
2024	408.34		0.000	0.000	74.708
2025	431.65		0.000	0.000	74.708

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	121.453	74.708
B/C	2.60		
Nominal Discount Rate	9%		

RII AVOIDED COSTS WITH EXTERNALITIES:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	78.35			0.000	0.000
1995	78.16			0.000	0.000
1996	82.08			0.000	0.000
1997	86.27			0.000	0.000
1998	97.43	10	4.867	-3.893	-2.321
1999	107.93	20	5.061	-2.902	-3.909
2000	111.69	40	10.527	-6.059	-6.950
2001	117.28	60	10.949	-3.912	-8.751
2002	124.12	80	11.386	-1.456	-9.366
2003	130.98	120	23.684	-7.966	-12.453
2004	139.15	160	24.631	-2.367	-13.295
2005	146.47	160		23.436	-5.651
2006	154.60	160		24.736	1.752
2007	162.65	160		26.025	8.896
2008	171.39	160		27.423	15.803
2009	180.67	160		28.908	22.483
2010	190.43	160		30.468	28.942
2011	200.74	160		32.119	35.189
2012	212.18	160		33.948	41.246
2013	223.89	160		35.823	47.110
2014	236.29	160		37.806	52.788
2015	249.41	160		39.906	58.287
2016	263.30	120		31.596	62.280
2017	278.00	80		22.240	64.860
2018	293.57	60		17.614	66.734
2019	310.05	40		12.402	67.944
2020	327.51	20		6.550	68.531
2021	346.00			0.000	68.531
2022	365.59			0.000	68.531
2023	386.35			0.000	68.531
2024	408.34			0.000	68.531
2025	431.65			0.000	68.531

	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	107.271	68.531
B/C	2.77		
Nominal Discount Rate	9%		

RII AVOIDED COSTS WITH EXTERNALITIES:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	78.35			0.000	0.000
1995	78.16			0.000	0.000
1996	82.08			0.000	0.000
1997	86.27			0.000	0.000
1998	97.43			0.000	0.000
1999	107.93	10	5.061	-3.982	-2.178
2000	111.69	20	5.264	-3.030	-3.699
2001	117.28	40	10.949	-6.257	-6.580
2002	124.12	60	11.386	-3.939	-8.244
2003	130.98	80	11.842	-1.363	-8.772
2004	139.15	120	24.631	-7.934	-11.593
2005	146.47	160	25.617	-2.181	-12.304
2006	154.60	160		24.736	-4.902
2007	162.65	160		26.025	2.243
2008	171.39	160		27.423	9.150
2009	180.67	160		28.908	15.830
2010	190.43	160		30.468	22.289
2011	200.74	160		32.119	28.535
2012	212.18	160		33.948	34.593
2013	223.89	160		35.823	40.457
2014	236.29	160		37.806	46.135
2015	249.41	160		39.906	51.633
2016	263.30	160		42.128	56.958
2017	278.00	120		33.360	60.827
2018	293.57	80		23.486	63.326
2019	310.05	60		18.603	65.141
2020	327.51	40		13.100	66.315
2021	346.00	20		6.920	66.883
2022	365.59			0.000	66.883
2023	386.35			0.000	66.883
2024	408.34			0.000	66.883
2025	431.65			0.000	66.883

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	103.846	66.883
B/C	2.81		
Nominal Discount Rate	9%		

RII AVOIDED COSTS WITH EXTERNALITIES AND RISK ADDER:
REFERENCE DSM BEGINNING IN 1994

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993			0.000	0.000	0.000
1994	85.88	10	4.160	-3.301	-2.779
1995	85.67	20	4.326	-2.613	-4.796
1996	89.97	40	8.999	-5.400	-8.622
1997	94.57	60	9.359	-3.685	-11.017
1998	106.80	80	9.733	-1.190	-11.726
1999	118.31	120	20.245	-6.048	-15.035
2000	122.43	160	21.055	-1.466	-15.771
2001	128.55	160	0.000	20.568	-6.301
2002	136.05	160	0.000	21.768	2.894
2003	143.57	160	0.000	22.971	11.796
2004	152.52	160	0.000	24.403	20.473
2005	160.55	160	0.000	25.688	28.851
2006	169.46	160	0.000	27.113	36.965
2007	178.29	160	0.000	28.526	44.796
2008	187.86	160	0.000	30.058	52.367
2009	198.04	160	0.000	31.686	59.689
2010	208.72	160	0.000	33.396	66.768
2011	220.03	160	0.000	35.205	73.615
2012	232.56	120	0.000	27.908	78.595
2013	245.41	80	0.000	19.633	81.809
2014	259.00	60	0.000	15.540	84.143
2015	273.38	40	0.000	10.935	85.649
2016	288.60	20	0.000	5.772	86.379
2017	304.72		0.000	0.000	86.379
2018	321.78		0.000	0.000	86.379
2019	339.85		0.000	0.000	86.379
2020	358.98		0.000	0.000	86.379
2021	379.25		0.000	0.000	86.379
2022	400.72		0.000	0.000	86.379
2023	423.47		0.000	0.000	86.379
2024	447.58		0.000	0.000	86.379
2025	473.12		0.000	0.000	86.379

	COSTS	BENEFITS	NET BENEFIT
NPV	46.745	133.124	86.379
B/C	2.85		
Nominal Discount Rate	9%		

RII AVOIDED COSTS WITH EXTERNALITIES AND RISK ADDER:
DEFERRED DSM TO 1998

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	85.88			0.000	0.000
1995	85.67			0.000	0.000
1996	89.97			0.000	0.000
1997	94.57			0.000	0.000
1998	106.80	10	4.867	-3.799	-2.265
1999	118.31	20	5.061	-2.695	-3.739
2000	122.43	40	10.527	-5.630	-6.565
2001	128.55	60	10.949	-3.236	-8.055
2002	136.05	80	11.386	-0.502	-8.267
2003	143.57	120	23.684	-6.456	-10.769
2004	152.52	160	24.631	-0.228	-10.850
2005	160.55	160		25.688	-2.471
2006	169.46	160		27.113	5.643
2007	178.29	160		28.526	13.474
2008	187.86	160		30.058	21.045
2009	198.04	160		31.686	28.366
2010	208.72	160		33.396	35.446
2011	220.03	160		35.205	42.293
2012	232.56	160		37.210	48.933
2013	245.41	160		39.265	55.360
2014	259.00	160		41.439	61.584
2015	273.38	160		43.741	67.610
2016	288.60	120		34.632	71.988
2017	304.72	80		24.377	74.815
2018	321.78	60		19.307	76.869
2019	339.85	40		13.594	78.196
2020	358.98	20		7.180	78.839
2021	379.25			0.000	78.839
2022	400.72			0.000	78.839
2023	423.47			0.000	78.839
2024	447.58			0.000	78.839
2025	473.12			0.000	78.839

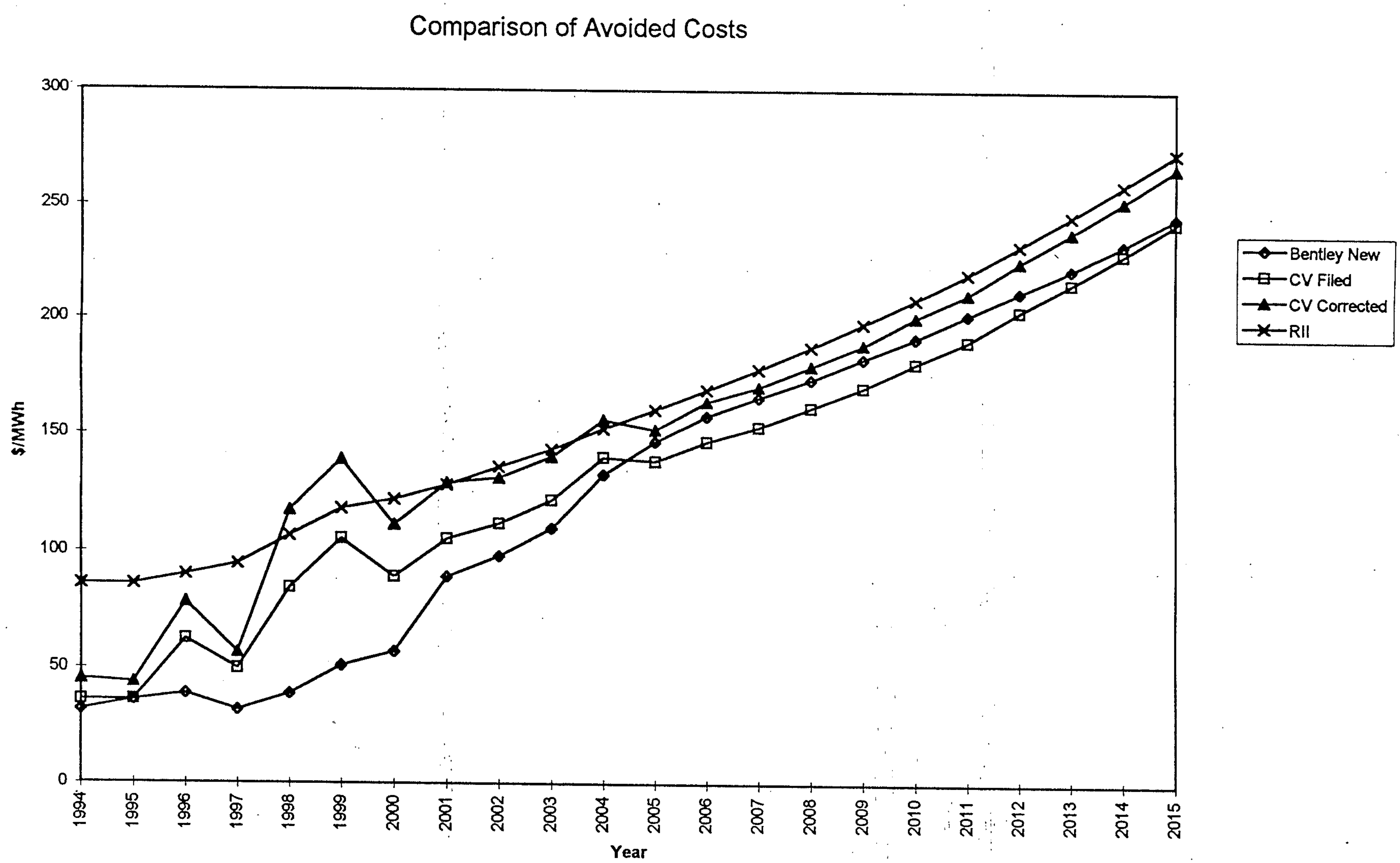
	COSTS	BENEFITS	NET BENEFIT
NPV	38.740	117.579	78.839
B/C	3.04		
Nominal Discount Rate	9%		

RII AVOIDED COSTS WITH EXTERNALITIES AND RISK ADDER:
DEFERRED DSM TO 1999

YEAR	AVOIDED COST ($/MWH)	DSM PROGRAMS SAVINGS (GWH)	COST ($M)	NET BENEFITS ($M) ANNUAL	NET BENEFITS (1992 $M) CUMULATIVE
1993				0.000	0.000
1994	85.88			0.000	0.000
1995	85.67			0.000	0.000
1996	89.97			0.000	0.000
1997	94.57			0.000	0.000
1998	106.80			0.000	0.000
1999	118.31	10	5.061	-3.878	-2.122
2000	122.43	20	5.264	-2.815	-3.534
2001	128.55	40	10.949	-5.807	-6.208
2002	136.05	60	11.386	-3.224	-7.570
2003	143.57	80	11.842	-0.356	-7.708
2004	152.52	120	24.631	-6.329	-9.958
2005	160.55	160	25.617	0.071	-9.935
2006	169.46	160		27.113	-1.821
2007	178.29	160		28.526	6.010
2008	187.86	160		30.058	13.581
2009	198.04	160		31.686	20.903
2010	208.72	160		33.396	27.983
2011	220.03	160		35.205	34.830
2012	232.56	160		37.210	41.469
2013	245.41	160		39.265	47.897
2014	259.00	160		41.439	54.120
2015	273.38	160		43.741	60.147
2016	288.60	160		46.176	65.984
2017	304.72	120		36.566	70.224
2018	321.78	80		25.742	72.963
2019	339.85	60		20.391	74.953
2020	358.98	40		14.359	76.239
2021	379.25	20		7.585	76.862
2022	400.72			0.000	76.862
2023	423.47			0.000	76.862
2024	447.58			0.000	76.862
2025	473.12			0.000	76.862

	COSTS	BENEFITS	NET BENEFIT
NPV	36.963	113.825	76.862
B/C	3.08		
Nominal Discount Rate	9%		

Exhibit__JJP/PLC-R-4



*AC Compare Chart 1

Exhibit__JJP/PLC-R-4

Comparison of Avoided Costs ($/MWh)

	Bentley New	CV Filed	CV Corrected	RII
1994	32.00	36.06	45.06	85.88
1995	36.00	36.41	43.77	85.67
1996	39.00	62.13	78.14	89.97
1997	32.00	49.74	56.51	94.57
1998	39.00	84.21	117.81	106.80
1999	51.00	105.58	139.07	118.31
2000	57.00	88.99	111.69	122.43
2001	89.00	105.40	129.22	128.55
2002	98.00	111.93	131.47	136.05
2003	110.00	122.15	140.46	143.57
2004	133.00	140.28	156.27	152.52
2005	147.00	138.66	152.00	160.55
2006	158.00	147.03	164.19	169.46
2007	166.00	153.40	170.68	178.29
2008	174.00	161.69	179.62	187.86
2009	183.00	170.55	188.82	198.04
2010	192.00	180.98	200.90	208.72
2011	202.00	190.58	211.20	220.03
2012	212.00	203.75	225.35	232.56
2013	222.00	215.93	238.36	245.41
2014	233.00	228.86	252.14	259.00
2015	245.00	242.59	266.71	273.38

Exhibit____JJP/PLC-R-5
Small C/I Retrofit Program
Actual vs. Gamble Reported Participation Rate

kW Bin	1993 Program Participants	Eligible Population	Actual Participation Rate	Gamble Reported Participation Rate
(1)	(2)	(3)	(4)	(5)
0-25	42	6,143	0.7%	47%
26-50	15	1,233	1.2%	16%
51-100	24	500	4.8%	24%
>100	15	172	8.7%	13%

Sources
2 CVPS Response to DPS Data Request 16, Question 5, part b)
3 CVPS Response to DPS Data Request 16, Question 5, part c)
4 Column 2 / Column 3
5 CVPS Response to DPS Data Request 16, Question 5, part a)

Exhibit___JJP/PLC-R-6
Small Commercial Program Screening

Summary of Program Screening Results

Social Cost Test
Small C/I Retrofit Program

	PV	¢/kWh
Benefits	33,950,898	10.7
Costs	18,280,965	5.8

Benefit-Cost Ratio	1.9
PV of Net Benefits	15,669,933
Outcome	PASS

Utilty Cost Test
Small C/I Retrofit Program

	PV	¢/kWh
Benefits	26,998,252	8.5
Costs	14,808,539	4.7

Benefit-Cost Ratio	1.8
PV of Net Benefits	12,189,714
Outcome	PASS

Notes:
(1) Costs, savings, lifetime and participant inputs extracted from Exhibit JJP-3 from Direct Prefiled Testimony of John J. Plunkett, Docket 5724, May 27, 1994. See electronic workpaper file SMCI4.XLW for specific cell references to Exhibit JJP-3.
(2) The load profile used is the average of the office and retail lighting load profiles from page 16 of Central Vermont Public Service, Small Commercial Program Reference Manual, November 1993.
(3) The 8% free-rider rate used for program screening came from page 59 of CVPS 1993 C&LM Annual Report.

EXHIBIT ___ JJP/PLC-R-8

STANDARDIZED COMPONENT METHOD FOR THE DETERMINATION OF MARGINAL AND AVOIDED DEMAND COST AT THE DISTRIBUTION LEVEL

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INTRODUCTION

Marginal costs have been used by utilities and regulatory commissions since the early 1970's to allocate costs between end use classes of customers and to allocate costs within each class of customers. Most of the emphasis in developing the theory and method of application of marginal costs to utility systems was on the generation investment. This was only natural since generation additions required extremely large lump sum capital investments that overshadowed the multitude of smaller investments in other areas of utility operations. Generation plant additions require much longer lead times than other utility plant for planning, design and construction and are affected by availability and price of fuels. Plant outages, fuel shortages or fuel price increases, and regulatory constraints, all have a direct and nearly immediate effect on customers. These factors all contributed to the greater emphasis on generation plant costs by regulators, economists, intervenors and utility staffs.

When applied to generation plant, the marginal cost can be easily determined. Each kilowatt of demand added or subtracted can be applied to the total generation mix as if all generation plant were aggregated in one entity. This is a valid approach since the utility system is fully interconnected and networked at the generation level. Each load change has a direct effect on the operation of each generation source. The marginal cost model for the generation system can be understood because of the direct load/cost relationships and this apparent linear characteristic.

This easily understood, and simple to apply model has been applied to determine the marginal costs of the distribution system. It is inappropriate and inaccurate. The distribution system is not fully interconnected and networked. In fact, the closer one moves through the system to the customer the more disassociative that plant becomes from the rest of the system. This is due to the more radial nature of the distribution system.

NON-LINEAR DISTRIBUTION INVESTMENT

The investment versus load curve at the generation level is modeled as a linear function, in fact, as a straight line relationship (see Figure #1). At the distribution level, however, the plant additions are discrete and non-linear. Loads will increase until a threshold level is reached that will trigger a major investment addition. This is due to the economic advantage of utilizing a limited number of standardized materials to construct distribution plant. Quantum increases therefore take place when the alternative of adding small plant additions to meet service limitations can no longer satisfy the deficiencies caused by load additions. This non-linear step function (see Figure #2), which of necessity causes the system to have greater load serving capability than the load impressed by the customer, is incorrectly identified as "suboptimal construction." In effect, it is the logical result of applying life cycle economic analysis to the available choices of plant additions. Much effort goes into explaining how this "excess" capacity in distribution plant is handled in determining the correct marginal costs. Emphasis is placed on the ability of a long term approach to smooth out the "lumpiness" of distribution investment.

This might be more easily understood by looking at the "services" portion of distribution plant. Services are defined as the low voltage conductor that extends from the service drop pole, either directly from a transformer or a secondary conductor, to the customer's premises. Service entrance cable usually is of one or two standard sizes, or is installed as multiples of these two sizes, which will meet the needs of the customer's loads. Since no service entrance cable is installed until a customer is present, the investment versus load curve is a discrete vertical line (see Figure #3). This characteristic has caused this investment to be incorrectly labeled as a "customer" cost rather than a "demand" cost. While it is true that no investment would be made unless a customer were present, it is also true that, 1) no investment would be made if a load were not present; and, 2) the amount of initial investment increases as the customer's forecasted load increases.

DEMAND RELATED SERVICES INVESTMENT

Marginal demand costs have been based upon linear relationships, represented as straight sloping lines, that produce the same result when load is decreasing as when it is increasing. It is assumed that investments made in any portion of the system can be "smoothed" by use of long term trends and the use of suboptiomal capacity by new customers or new loads. This model requires an integrated system with the ability to share responsibility for load changes.

Services are the ultimate example of a spatially dependent, demand related investment. Services, feeding only one customer and having no interconnectivity to each other, do not fit the above noted characteristics that allow the traditional determination of marginal demand costs. Therefore, they are incorrectly relegated to the customer cost category.

Investment in services is demand related. As the customer's proposed load is increased beyond a threshold, the size of service entrance cable is increased or the cable is installed as multiple units. The capacity of the service entrance cable will not match the load served, it must of necessity be larger than any expected load to avoid customer service problems. This, however, is not suboptiomal construction, but the result of optimizing the total construction and O & M process. These discrete investments are referred to as being "lumpy". It must be understood that, although each service investment is discrete and "lumpy" by itself, since the individual services investment is demand related the aggregate of all services investments will be demand related. This aggregated services investment, when viewed over a long term, may be utilized to determine a marginal demand cost for services.

If one plots the investment of each type and size of service versus the average maximum load that it would serve, a graph such as seen in Figure #4 will be produced. By plotting against demand, the demand relationship as well as the customer relationship of the plant investment can be shown (see Figure #5). As can be seen, this is a variation of the zero intercept method of determining customer related costs of plant. It is the use of the customer demand served, instead of the rating or size of the material, that allows the determination of both the customer and demand related component. The demand relationship is found by a straight line curve fit to the maximum load points for each size or type of material. The customer component, or that value that does not vary with load, is shown as the amount between this curve fit and a parallel line through the x-y intercept.

Another feature of services that has been difficult to explain with traditional marginal demand cost determination methods is that a load reduction does not yield the same marginal cost value as a load increase. Once a service is installed to a customer, there is no financial gain in replacing it with a smaller cable if the customer's load decreases. The cable has virtually no salvage value and the labor cost to replace the cable would exceed any investment savings. Wire and cable do not "wear out" because of load, as long as the load is below the rated capacity of the cable. The expected life of service cable is in excess of the timeframe for marginal cost studies. No costs are avoided when the load is decreased.

This dissimilar result, positive marginal cost with load increases and zero, or reduced, marginal cost with load decreases, can be modeled as an economic hysteresis effect (see Figure #6). The hysteresis effect occurs at all levels of the system. However, as one moves from the customer to the generator, the hysteresis effect is reduced so that at the generation level it can be ignored. The network nature of the system at the generation level allows load reductions in one area to be utilized some place else. The service cable is installed with the capability to serve anticipated load growth. Load reduction on a service cannot be utilized by any customer other than the customer who had the load reduction. Any load growth by this customer is already anticipated in the original installation. Therefore, the load reduction makes no capacity available that did not already exist.

THE LOW VOLTAGE SYSTEM

Secondaries are defined as those low voltage conductors that extend from the transformer to the service drop pole. They are not always used, and in a rural utility service area, they are seldom used. Great effort is expended to allocate secondaries cost to customers and a portion of pole cost to secondaries. Also, distribution transformers are added to secondaries cost to provide an easy method of allocating costs between primary and secondary customers.

Secondaries, like service drop cables, are of one or two standard sizes. They are sized to meet the proposed loads in the area. As estimated customer load reaches the customer service threshold of the smaller cable, the larger size cable, requiring increased investment, is used. A unique feature of secondaries, however, is that as the proposed load reaches the threshold of the larger conductor, the secondary is replaced by a transformer installed on the service drop pole. In fact, secondaries are no more than services extensions to reach a transformer located more than one pole away. It is this effect that could allow secondaries and services to be aggregated as one category for marginal cost determination. Transformers could also be added to this category for the above noted reason of ease in allocating costs, as well as the fact that they are also added in discrete sizes based upon the customer's proposed load. (See Figure #7). It can be seen, from this graph of transformer investment by size versus the average maximum load that it would serve, that transformers also have a readily apparent customer related and demand related component of costs. Meters also have a customer and demand related component as seen in Figure #8. This combination of services, secondaries, transformers and meters could more accurately be called the "low voltage system" for cost determination purposes.

It has been argued that transformer, secondary, services and meter capacity can be freed up by one customer's load reduction so that it can be used to serve other loads. This is only correct if the facilities are sized to serve existing load instead of proposed load. Since services, secondaries, transformers and meters are installed in a limited number of discrete sizes, and all reasonably anticipated customer loads must be served, the load capability of the low voltage system must exceed the customer load needs. Therefore, the argument of using freed up capacity to serve future load is not applicable. Capacity to serve future load was available before the load reduction.

While the plant investment of an individual low voltage system serving one customer or group of customers is a discrete, non-linear function with respect to load level, the summation of all such plant additions may be utilized for determining the marginal demand cost. This sum of the parts method eliminates the individual step functions of each installation. This smoothing effect has been utilized to support the belief that all parts of the system can be modeled like generation, a straight line cost to load relationship that results in the same value for either load increases or decreases. Although the summation smoothes out