STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 5270-CV-1

Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy In Re: Fuel-Switching Issues for CVPS

Docket No. 5270-CV-3

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

Docket No. 5686

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

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DIRECT PREFILED TESTIMONY OF PAUL L. CHERNICK ON BEHALF OF THE VERMONT DEPARTMENT OF PUBLIC SERVICE

April 4, 1994

Mr. Chernick's testimony discusses avoided costs and screening of controlled-water-heating measures.

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I. Identification and Qualifications

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

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

Q: Summarize your professional education and experience.

A: I received a 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 ___ PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over one hundred times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously before this Commission?

A: Yes. I testified twice before the Board in Docket No. 5270: in Module 6 on cost-recovery issues, on behalf of the Conservation Law Foundation (CLF), Vermont Natural Resources Council (VNRC) and Vermont Public Interest Research Group (VPIRG); and in support of a stipulation on collaborative program design principles (including the cost-benefit test for DSM and the role of externalities) and cost recovery, on behalf of CLF, VNRC, VPIRG, the Department of Public Service (DPS) and Central Vermont Public Service (CV). More recently, I testified for CLF, VNRC and VPIRG in Docket No. 5330 on the cost-effectiveness of Vermont utilities purchases from Hydro Quebec (HQ), particularly on the relative benefits of DSM and the purchase, and the conflicts between those two resources. In Docket No. 5491, I testified for CLF on the cost-effectiveness of CV's purchases from HQ, and on the effect of those purchases on the development of cost-effective DSM resources. I also testified in Docket No. 4936, on the likely cost and completion date of Millstone Unit 3.

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

A: Yes. I have been involved in utility planning issues since 1978, including load forecasting, the economic evaluation of proposed and existing power plants, and the establishment of rate for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to CLF's conservation design project in Jamaica; to CLF interventions in a number of New England rule-making and adjudicatory proceedings; to the Boston Gas Company on avoided costs and conservation program design; to the City of Chicago and Cincinnati on their utilities' resource plans; to the Maryland People's Counsel, Iowa Consumer Advocate, and South Carolina Consumer Advocate on a variety of least-cost planning issues; to environmental groups in North Carolina, Florida, Ohio and Michigan on DSM planning; and to several parties on incorporating externalities in utility planning and resource acquisition. I also assisted the DC PSC in drafting order 8974 in Formal Case 834 Phase II, which established least-cost planning requirements for the electric and gas utilities serving the District.

I am one of the principal authors of the five-volume report *From Here to Efficiency*, a comprehensive review of DSM planning, ratemaking, and implementation issues published by the Pennsylvania Energy Office.

Q: Have you testified previously on rate design issues?

A: Yes. Much of my early work for the Massachusetts Attorney General concerned retail rate design, including determination of marginal costs.

Q: Please summarize your previous work regarding CV.

A: As noted above, I testified in Docket Nos. 5270 and 5330 on DSM and resource planning issues applicable to CV and other Vermont utilities. I also testified specifically on CV's resource planning in Docket No. 5491. I was a consultant for the collaborative DSM program design effort involving CLF, VNRC, VPIRG, the Department, and CV, and testified on behalf of all those parties in my second appearance in Docket No. 5270.

My work on the collaborative concerned many of the issues addressed in this testimony: avoided cost, and the benefits and costs of CV's water-heater load controls. The effectiveness (or lack thereof) of CV's load control was an unresolved issue at the time that CV discontinued the collaborative. This docket essentially picks up those issues where they were left off in 1990.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: This testimony is filed on behalf of the Vermont Department of Public Service.

Q: What subjects do you cover in this testimony?

A: This testimony presents evidence relevant to both the fuel-switching issues in Docket No. 5270 CV-1 and CV-3, and the load-control issues in Docket 5686.

For both dockets, I review the avoided costs estimated by Central Vermont Public Service (hereafter referred to as "CV" or "the Company"), correct simple errors in CV's avoided costs, and derive more realistic estimates of avoided costs.

For Docket No. 5270 CV-1 and CV-3, I present the end-use fuel costs to be used for screening fuel-switching. I derive externality values for both avoided electric use and increased fossil-fuel use.

For Docket 5686, I analyze the available data on the performance of CV's water heater load controls, estimate the contribution of controlled and uncontrolled water heaters to CV's loads, and correct CV's economic screening of load control.

Q: What sources did you rely on for this testimony?

A: I employ information from a number of sources. In addition to testimony filed in the two proceedings in which this testimony was filed (Docket No. 5270 CV-1 and CV-3 on fuel switching and Docket No. 5686 on load control), I had access to testimony, filings, and information responses from:

- Information responses (hereafter referred to as "IR-xx") filed in either of the two proceedings (those that I cite without reference to a specific docket are from Docket No. 5270),
- Central Vermont's petition to amend its implementation plans (hereafter referred to as "the Petition"),
- the proceeding on CV's implementation of Act 250 (Docket No. 5624),
- proceedings before the Environmental Board (Bartholomae Land-Use Permit #8b0472-EB),
- the Board-initiated rate case (Docket No. 5701),
- the Company's previous rate case (Docket No. 5491),
- the examinations of CV's marginal costs (Docket 4364) and rate design (Docket 5294),

- the December 1993 stipulation between CV and the Department in Docket No. CV-4 (hereafter referred to as "the Stipulation").

III. Avoided Costs

A. Summary of Changes in CV's Estimates of Avoided Costs

Q: What are CV's current estimates of its avoided costs?

A: The Company has prepared two sets of avoided costs: one used for evaluating energy-efficiency programs and fuel switching, and a second used for valuing load control. The Company's current avoided-cost estimates were developed late in 1993, and filed (with incorrect labels) as Exhibit 7a in the Petition, as Exhibit BWB-4 in the testimony of Bruce Bentley in Docket No. 5701, and (in summary form) in the supplementary testimony of Scott Anderson in Docket No. 5686. The Company refers to these avoided costs as being of "1994 vintage," as opposed to the preceding "1992-vintage" avoided costs.

1. The Company's Current Estimates of Avoided Costs for DSM

Q: Please describe CV's current estimates of avoided costs for DSM.

A: In the Petition and Mr. Bentley's testimony in Docket No. 5701, CV provides a set of avoided costs that differ from the previous avoided costs in the following ways:

- fuel prices are lower;
- load levels are lower, resulting in lower marginal energy costs;

- demand-related generation is assumed to have no value until 1998, and the value is lower than the cost of new peaking generation until 2004;[1]
- the computation of capitalized energy and off-system sales changes;
- marginal losses are dramatically reduced;
- transmission and distribution (T&D) is assumed to have no value until 1996; and
- the default 5% externality value from Docket 5270 is replaced by externalities computed from the unit values in the Stipulation , apparently with own-load emission rates (excluding the effects of off-system sales).

The detail available on some of these items is quite limited, since CV has generally provided little information in either its filings or its discovery responses. A small amount of documentation was provided in Exhibit 7a to the Petition, and somewhat more in IR 7-6 and other parts of the seventh set, with some additional detail provided in supplemental responses and in Set 9.[2]

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[1]The projected costs of new power plants and gas supply are also assumed to be lower than in the 1992 avoided costs (IR 7-6, 7-21).

[2]This process was delayed and protracted by CV's reluctance to respond to discovery. The DPS requested the documentation of the 1994 avoided costs (based on claims made in CV's "Outline of Issues" and elsewhere) in Discovery Set 4, on 11/19/93. On December 9, CV responded to this discovery by claiming that the avoided costs were still work in process, and that the analyses necessary to support the claims had not been completed. On December 13, CV filed the 1994 avoided costs (mislabeled as 1992 avoided costs) in the Petition. Since the Petition also included screening results and other conclusions based on the 1994 avoided costs, CV must have completed the avoided cost analysis well before it claimed that the avoided costs were still in development. Discovery Set 7, on the avoided costs in the Petition, finally yielded meaningful responses at the beginning of February 1994.

All costs are assigned to five energy rating periods (three in the winter, two in the summer). Generation and transmission demand costs are allocated to energy in various time periods based on a methodology developed in Docket 4364. This methodology assigns costs to periods based on the "80% CR" allocator, which is determined by (1) the number of hours within 20% of annual or monthly peak, and (2) weighting the monthly peaks in accordance with CV's capability-responsibility proxy.[3] Externalities are allocated with generation and transmission demand costs; while Mr. Bentley describes this allocation as "more appropriate than anything else" (IR 7-25), treating these energy-related externalities as if they were demand-related is nonsensical.[4] Distribution costs are allocated using a different allocator, for which I have seen no documentation, but which reasonably allocates more costs to off-peak periods than does the 80% CR allocator.

2. *Load-Control Analysis*

Q: Please describe CV's current estimates of avoided costs for load control.

A: In Howard Spinner's testimony in Docket No. 5686, CV separates demand-related costs from energy-related costs.[5] All demand-related costs are reallocated to demand, using CV's proxy for capability responsibility (or

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[3]I.e., 70% based on annual peak and 30% based on monthly peak. The Company's proxy for capability responsibility is discussed further in §IV.B.1

[4]The Company may have allocated externalities to demand to increase the apparent attractiveness of load control. Obviously, even a perfectly controlled off-peak water heater results in air pollution; CV's allocation denies reality.

[5]This is consistent with CV's treatment of the 1992 avoided costs in the prefiled testimony of Anderson and Spinner.

CR), which is 70% of the annual peak, plus 30% of the average of monthly peaks. Both externalities and distribution are allocated to the CR proxy.[6]

B. Corrections of Internal Inconsistencies in CV Avoided Costs

Q: Have you identified any internal inconsistencies in CV's current avoided costs?

A: Yes. I have identified three apparent oversights in CV's current avoided costs. I include in this category only errors that I assume CV did not mean to make, as opposed to those instances where the Company simply disagrees with my interpretation, the demands of reason, or the laws of physics.

First, when CV allocates distribution costs to time periods, it allocates 100.4% of the total costs. I corrected this overstatement.

Second, CV assumes 4.79% inflation in T&D costs, even though its current escalation rates for general costs (the Gross Domestic Product inflator) and construction range from 4% to 4.5%. I used a 4.25% escalation rate for all costs, other than fuels and market-sensitive costs.

Third, CV's computation of capitalized energy contains an apparent programming error.[7] Capitalized energy is the difference between the fixed costs of avoided supply resources, minus the avoided demand-related

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[6]Since the CR proxy is less than coincident peak, on which the generation and transmission demand costs are computed, the dollar-per-kW values should be adjusted upward. The Company does not appear to have made any such adjustment, but CV's documentation does not allow me to determine definitively whether this is the case.

[7]Actually, I cannot tell exactly how CV made this error, since the total value of capitalized energy is an input to the spreadsheet CV provided on discovery, rather than a computation. The Company provided this type of partial documentation in response to many discovery questions.

generation costs (generally peaker costs).[8] For example, in 1998, CV estimates that the avoided supply (an oil-fired power purchase) would cost \$50.49/kW-yr., while peaking capacity would cost \$6.49/kW-yr., so capitalized energy would be \$44/kW (IR 7-6). The Company's avoided-cost computations use the peaking-capacity cost instead of the higher capitalized-energy value. Thus, CV's capitalized energy for 1998 is \$129,800, or \$6.49/kW times the 20-MW decrement.

Exhibit ___ PLC-2 contains the derivation of CV's avoided costs, with my corrections of these three errors. Exhibit ___ PLC-3 summarizes the corrected CV avoided costs used in the Department's screening of fuel switching and load control. Following CV's practice, fuel switching and other energy-efficiency measures are screened with "bundled" avoided costs (all costs are allocated to energy), and load control measures (and other measures for controlled loads) are screened with "unbundled" avoided costs (demand costs are allocated to CR or CP). Unlike CV, I do not allocate externalities to demand, but leave it in energy costs.

C. Summary of the Company's Errors

Q: Please describe the other errors you have identified in CV's current avoided cost projections.

A: Central Vermont's current avoided cost projections for DSM contain the following errors:

[8]The Company sometime uses the term "capitalized fuel savings," or "CAPFS."

- The Company assumes that generation capacity has no value until 1998, and that capacity value will remain much lower than the cost of new generation through 2003.
- The Company assumes overall energy costs (including capitalized energy and modest off-system sales revenues) that are low compared to CV's own estimates of market prices for energy.
- The Company uses avoided energy losses that are arbitrarily and incorrectly set below the marginal loss level.
- The Company assumes that no transmission or distribution costs are avoidable through 1995.
- The Company further understates T&D costs by omitting one year's escalation in O&M costs, and by dividing costs by more kW than the load associated with the costs.
- The Company omits all overheads on generation, transmission, and distribution O&M costs.
- The Company computes externalities based on its own-load dispatch computations, ignoring off-system sales.

In addition, it is not clear that CV has properly identified the mix of supply resources that would be avoided by additional DSM or fuel switching. The mix of supply resources that CV identifies as avoidable differ from the mix of resources added in the same period, as shown in Exhibit ___ PLC-4

D. Re-estimation of Avoided Costs

Q: Please describe your re-estimation of CV's avoided costs.

A: I relied primarily on CV's own data and assumptions, and modified CV's avoided costs only where they were clearly unreasonable. I used a 4.25% inflation rate and 9% discount rate in all computations.[9]

In accordance with the Decision in Docket 5270, avoided costs for efficiency and load-control measures are increased by 11.1% to reflect planning risks.[10] As CV and the DPS agreed in the Stipulation, electric avoided costs for fuel-switching to fossil fuels are increased by 8.1% to reflect risk.

This treatment of risk is likely to understate the benefits of fuel switching.[11] The Board's 10% risk adder was based on studies in the Northwest that reflected only planning risks, due to load forecast uncertainties (over- and under-capacity). The adder does not reflect the risks of

- volatility in fuel prices for electric generation,
- volatility of usage due to variability of weather,
- delays, cost overruns, and cancellation in construction of power plants,

[9]Central Vermont uses inconsistent escalation and discount rates. For example, CV uses a 9% discount rate for avoided costs, based on CV's after-tax cost of capital (IR 7-6), and generally uses a rate of 9–9.5% (IR 4-2, 5-57). However, the supplemental response to IR 7-6 computes a discount rate of 8.47%, which would yield a higher present value of avoided costs. The Company also suggests that its after-tax cost of capital varies from 8.5–9.5% (IR 4-33).

[10]This is equivalent to reducing the costs of DSM by 10%. Including these risk benefits for load control is probably inappropriate, since load control may have little or no benefits and is thus highly risky. Central Vermont apparently has some quibble with this risk valuation, but has declined to explain its concern (IR 4-111, 4-112).

[11]In addition, as discussed in §III.E, the end-use fuel prices used in the DPS-RII analyses are overstated compared to the fuel prices used in the avoided electric costs. Hence, our analysis implicitly includes an additional substantial risk adder on direct fossil fuel use.

- reliability of operating resources,
- premature retirement of plants.

Fossil fuels burned at the end use avoid these risks on the electric system, and do not generally share the same risks, except for fuel price volatility. End-use fuel prices may be more volatile than CV's average energy costs (including nuclear, CV-owned hydro, and purchases from small power producers and Hydro Quebec), but are not likely to be significantly more volatile than CV marginal costs (gas, oil, or purchases or sales based on gas and oil).

Some of the risks of potential future environmental regulations on fossil fuels are internalized in the externality values we apply to fossil fuels for both direct use and electricity generation.

Regardless of the type of fuel used, the DSM programs proposed by the Department and RII will reduce risk by reducing use (and hence the annual dollar effect of any particular change in fuel costs), and by reducing the sensitivity of total energy bills to weather.

I have prepared avoided costs in two forms, mirroring CV's practice. For efficiency and fuel-switching of uncontrolled loads, I prepare a rolled-in avoided cost, in which all demand costs are allocated to the energy periods. For load control decisions, and fuel-switching of load controlled end uses, I constructed disaggregated avoided costs, separating energy costs, generation and transmission demand costs (allocated on CV's capability responsibility proxy), and distribution cost (allocated on equivalent coincident peak, as discussed in §V.B.3 below). Except for distribution costs and externalities (which are treated as energy-related), I allocate costs to time periods and demand measures as CV does, mostly for consistency.

In addition, I have made extensive and important modifications to CV's avoided costs in generation capacity costs, off-system sales, losses, T&D, and externalities, as discussed in the following sections. Exhibit ___ PLC-5 presents the results of my derivation of CV's direct avoided costs. Exhibit ___ PLC-6 sumarizes the RII avoided costs used in measure and program screening.

1. Demand-Related Generation Capacity Costs

Q: What problems have you identified in CV's estimates of avoided demand-related generation capacity costs?

A: The Company's 1994 avoided costs include no demand-related generation costs until 1998, when CV projects that it will require additional resources for reliability purposes. Even in 1998, the avoided generation demand cost is only $6.49/kW-yr., compared to a cost of $85.48/kW-yr. for new real-levelized CT capacity. Demand costs are assume to rise slowly through 2004, when it finally reaches the cost of new CTs. Exhibit ___ PLC-7 compares CV's estimates of the costs of new peaking capacity and of the market costs of peaking capacity.

This projection is inconsistent with other CV estimates of peaking capacity costs, and with the rates for peaking capacity in recent New England power contracts.

- In his letter of 1/13/94 to Enid Gidney of the Board staff, Howard Spinner provided a "low" estimate of the "short-term marginal capacity cost" of $10/kW-yr. for 1992 capacity savings.
- Exhibit ___ PLC-8 shows the prices charged for peaking power in recent wholesale contracts. These values range from $35 to $50/kW-yr.

over the period 1994–1999, and most show steep increases in 2000, to \$70–115/kW-yr. The pure generation capacity value of these contracts is difficult to determine, since most provide some transmission services, but generation capacity is clearly priced above CV's projection.

- The Company adopts a NEPOOL estimate that the New England capacity surplus will disappear by 1998 (IR 2-3, Docket 5701).[12]
- The demands of life extension, especially in terms of compliance with the NOx requirements of the Clean Air Act Amendments, will increase the costs of maintaining capacity in operation in the late 1990s. Retirement and deactivation of older units will increase the market costs of capacity to approximate the costs of operating, maintaining, and retrofitting these units.
- The Company plans on acquiring new capacity (including new CTs) in 2000. These costs should be avoidable.

Q: Has CV offered any justification for its projection of peaking capacity costs?

A: Not in this docket.13 In Docket 5701, CV finally provided the derivation of its avoided peaking capacity costs (IR 2-3). The derivation is not a "simple mathematical expression" that summarizes historical relationships (Schaefer, Docket 5701, p. 4), but an arbitrary and illogical construct.

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[12]This estimate may understate the effect of DSM.

[13]The Company responded to a request for the source of its assertion that "capacity is almost costless" [Outline of Evidence, p. 6] by providing a newspaper article on electric loads and a graph of electric loads from the New York Power Pool (IR 8-49). The Company also avoided this issue in its responses to IR 4-86 and 7-6.

Mr. Schaefer claims in his testimony that he derived the expected market price based on two "elements," as follows: "(1) the amount of capacity in the market for sale; and (2) the lowest alternate or default price for which a purchaser would be eligible to procure capacity." (pp. 3-4) He further claims that "we examined that actual market prices, default prices, and excess megawatt levels (i.e., market supply) ... We used our forecast of the future default price and excess capacity in conjunction with the functions derived from historical experience to project the capacity price."

This discussion suggests that CV's simple mathematical expression would look like:

$$\frac{P_i}{P_{0,i}} = a \times \left[b + cE_i^f\right]^g$$

or perhaps

$$P_{0,i} - P_i = a \times \left[b + cE_i^f\right]^g,$$

where

P_i = the market price in year i,

$P_{0,\,i}$ = the default price,

E_i = the amount of excess capacity in the pool,

a, b, c, f, and g = coefficients, not all of which are likely to be used in any one formulation.

The latter formulation makes somewhat less sense, especially if it is stated in nominal dollars, since it implies that the difference between market and default prices does not vary with the level of market prices.

In fact, IR 2-3 shows that CV actually used a very different formula:

$$P_{0,i} - P_i = \left[E_0 + a - E_i\right] \times \left[m_i \times t + b_i\right],$$

where

t = time (measured in days since 12/31/88)

m_i, b_i = coefficients that vary with time

E_0 = "maximum available surplus MW," set at 1,800 MW in 1989–99, and ,3300 MW in 2000–2003, and

a = a constant that is sometime described as 0, but was actually 3,300 MW.

The Company's discovery responses do not provide any of the four coefficients, E_0, a, m, or b, from any historical data, so CV's claim that it uses historical data is simply untrue. IR 2-3 (Docket 5701) asserts, "it was observed that $\Delta P(t)/\Delta E(t)$ form a straight line using ... (1989–1994) data," where $P = P_0\text{-}P_i$ and $E = E_0\text{-}E_i$. However, the response does not demonstrate the claimed relationship and the Company's data show no such pattern.[14] Central Vermont simply selected m and b so that the market price of capacity would be near zero in 1994 and equal to the default price in 2003. The Company did not derive a price forecast; it assumed one.[15]

[14]The CV data base consists of some sort of contract price data, with prices associated with the first day of various months. The size of the contracts is not indicated, but the same price (and hence apparently the same contract) is sometimes represented for several months, and some months have more than one observation. It is not clear which data were used, since Hahn's notes refer to "items highlighted in blue," but the response shows no indication of being highlighted. The Company smoothes these monthly data for 1989–1994 market price with a third-order polynomial (which is not provided), apparently with respect to time, to produce annual values. Central Vermont does not indicate how the months were aggregated into years (prices seem to change in the spring of most years, rather than in January), given the differences between power years and calendar years. In any case, the aggregated data do not show the pattern Schaefer describes.

[15]In fact, even though Schaefer's discussion claims that m and b are constant from 1993 to 2003, the attached work papers (apparently from Randy Hahn) show the development of two arbitrary lines, changing the slope of the time trend at 2000, which is also when E_0 is assumed to change, due to "new tielines." CV does not explain what these new tielines are, or how they change the value of peaking capacity.

While the Board may reasonably be disturbed by CV's misrepresentation of its arbitrary time-trend price projection as reflecting historical relationships of price to excess capacity, the most remarkable aspect of the formula is that the sign of excess capacity is wrong. Central Vermont's formula shows the difference between market price and default price as decreasing (e.g., market price rising) as excess rises, and vice versa. A capacity shortage, such as CV projects for 1998–2003, reduces the market price; CV projects rising market prices in this period only because it phases out the time trend. The Company's modeling of market capacity value is simply preposterous.

Q: Are there any other problems in CV's analysis?

A: One additional serious problem is that Central Vermont assumes the market price of capacity will be capped at 80% of the default price, which in 2003 is the real-levelized cost of CT capacity. This assumption is based on the observation that the 1989 market price was about 80% of the $75 default price CV identified for 1989, apparently based on the NEPOOL deficiency and adjustment charges.[16] Since the NEPOOL charges are based on the nominal ratemaking costs of new CTs, they will (if regularly updated) always be higher than the real-levelized cost of CTs. While the 1989 market price was probably lower than the NEPOOL charges, it was higher than the 1989 real-levelized cost of new CTs. Hence, CV has multiplied a low market:NEPOOL ratio by the low real-levelized cost, to produce an understated adjusted default value.

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[16]The Company does not attempt to explain the 20% cost differential, or justify projecting it into the future, based on a single observation.

Central Vermont's methodology includes other peculiar adjustments and undocumented inputs, but most of these are minor. For example, CV assumes that the market cost of capacity it buys or sells will be $5/kW-yr. (nominal dollars) lower than the peaking capacity value computed by its formula. Since CV may well be buying or selling peaking capacity, this assumption is unwarranted.

Q: You have pointed out some serious problems with the formula CV used to project market prices of power, such as its domination by the time trend, and the fact that capacity surpluses increase market price. Do the results of CV's analysis make any sense?

A: No. Exhibit ___ PLC-9 shows the relationship between excess and market price in Schaefer's historical data, and in his projections. The excess peaks in 1992 and 1993 (resulting in prices of $4–13/kW), and then falls to less than 1991 levels by 1994, to less than 1990 levels by 1996, and to less than 1989 levels (the excess becomes a deficiency) by 1998. Yet Schaefer's CT price projection is lower than the actual $13/kW 1992 price through 1998.

Q: Have you corrected Schaefer's analysis?

A: Yes. Exhibit ___ PLC-10 corrects CV's analysis and shows that reasonable projections from CV's historical data and forecasts of excess capacity are much higher that CV's own projections. This table uses Schaefer's data, with the following three improvements:

- I have used the cost of a new CT as the default price, without CV's inappropriate adjustment. Since the cost of capital was higher in 1989 and 1990, I left the default price at the $60.50 CV estimated for 1989, rather than reducing it to the cost of a new CT at 1993 prices.

- Since there seems to be some lag in the effect of surplus on price (probably reflecting NEPOOL capability responsibility rules), I compute the lagged surplus in each year as the average of the current and previous year.
- I estimate the ratio of P_i/P_0 by interpolating between the historical values.

Q: What generation demand costs did you include in your estimates of avoided costs?

A: If I had seen and corrected CV's analysis prior to estimating avoided costs, I would have based my estimates of avoided costs on values similar to those in Exhibit ___ PLC-10. However, because CV did not provide its analysis in a timely fashion, I conservatively used much lower values. I assumed just $10/kW-yr. in 1994, which is about 7% lower in real terms than the value reported by Spinner. I held this estimate constant in real terms through 1999 (at which point it is slightly lower than CV's projection). These values are almost certainly too low. From 2001 onward (when CV's resource plan assumes the construction of new CT capacity), I use CV's estimate of the cost of new CT capacity, with the addition of overheads on O&M (as discussed in §D.5 below). For 2000, I use the average of 1999 and 2001 capacity costs. I also included the 21% reserve margin CV uses in its avoided costs.[17]

As discussed in §IV.B.1, I follow CV's practice of measuring generation capacity costs for load control in kilowatts of CV's capability

[17]The Company sometime uses an 18% reserve margin requirement, but appears to believe that 21% is prudent for resource planning and avoided-cost determination.

responsibility (CR) proxy. Since CR is about 5% lower than CP, I increase the dollars per kW of generation costs to restate them in dollars per kW CR.

2. Correction for Off-system Sales

Q: Please expand on your statement that the overall energy costs CV assumes are low compared to CV's own estimates of market prices for energy.

A: Central Vermont computes avoided dispatch costs and adds in some capitalized energy (after 1998) and modest off-system sales revenues. However, CV's total avoided energy costs are generally lower than its own estimates of the market prices for wholesale energy transactions. The reasons for this include the following.

The Company assumes that, when the HQ sellback ends, this excess baseload capacity will be retained by CV, rather than resold; reselling would push avoided dispatch costs down dramatically. Consequently, according to IR 7-26, CV expects that 63% of the energy freed up by the DSM decrement in 1997 will be from Vermont Yankee.

While CV assumes that excess base and intermediate energy can be resold, it assumes profits of only $5/MWH for nuclear sales (leaving the sale price at about 1¢/kWh), and $2/MWH for Merrimack and other steam units (for Merrimack, the sale price would be 2.2¢ by 1997).[18] By comparison, CV is currently selling power back to HQ at about 4.5¢/kWh, and projects that off-peak opportunity market energy prices in 1997 will range from 2.6¢ to

[18]This problem is compounded by CV's failure to include SO_2-allowance costs for Merrimack (IR 4-91).

3.1¢, depending on the season.[19] The $2/MWH is based on NEPOOL and VELCo savings shares, which usually represents the lowest-value transaction available to a seller. The $5/MWH is based on CV's average profit margin for a set of 16 GWH of "system sales" in the first 9 months of 1993 (IR 7-27).[20] These system sales appear to be only minor, short-term opportunity sales, and definitely exclude such longer-term sales as the HQ sellback. Since the system sales are not limited to nuclear sales, the assumption that the system-sale average profit would apply to nuclear sales (and only nuclear sales) is inappropriate. Since a DSM decrement to load would allow for longer-term sales of baseload capacity, CV should be assuming prices higher than short-term sales profits and NEPOOL-VELCo savings shares.

In addition, CV's estimate of the price of short-term off-system sales is inconsistent with CV's actual sales in 1992. It is not clear what IR 7-27 means by "system sales," but the profit level indicates that these are not just nuclear sales. In 1992, CV's average sale price for "daily energy sales" (excluding VELCo interchange) was $31/MWH, and the average price for "short term system sales" was $28/MWH; but for a large sale to NYPA (which is clearly too large to be included in the 1993 data), the latter average would have been $36/MWH. These prices, shown in Exhibit ___ PLC-11, would represent a profit of about $20–30/MWH for nuclear sales,

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[19]The Company previously assumed that off-system sales would split the difference between CV dispatch costs and a market proxy; that approach would provide a more reasonable estimate of the sales price of excess nuclear energy.

[20]Central Vermont provides data for November (but not October) in the same response, but does not include the higher November sale price in the "YTD" average. The sales are presented in MWH, but are labeled "GWH."

$12–20/MWH for sales from Merrimack, and $8–16/MWH for sales from Canal.[21]

Central Vermont's dispatch assumes the purchase of large amounts of energy at the opportunity purchase prices when those prices are less than CV's own resources, but does not allow for sale of energy at similar prices.

Q: How did you correct this problem?

A: I changed CV's computation of off-system sales. Rather than add in an arbitrary profit for resale of baseload energy, I based my off-system sales adjustment on the market price of energy. I computed the difference between CV's other energy costs (dispatch energy and capitalized energy) and the market value of energy, and assumed that CV would make enough short- and long-term sales to capture 80% of the difference.[22] This computation does not assume optimal planning and operation of CV's sales practices, just that CV will do a better job than it assumes.

For 1994–99, I use CV's estimate of opportunity energy purchases as the market price of energy. Since CV provides these values for on-peak and off-peak hours, and for high-load (December–March, July–August) and low-load months, I produced separate estimates for each energy rating period, as shown in Exhibit ___ PLC-12.

From the year 2000 onwards, I assume that the market value of energy is determined by combined-cycle (CC) costs. Central Vermont projects its first CC addition in 2000, and the cost of CC energy is considerably lower

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[21]These computations use fuel costs from CV's FERC Form 1: $6–8/MWH energy costs for the Yankee units, $16/MWH for Merrimack, and $20/MWH for Canal.

[22]Where CV's avoided cost is higher than the market cost of energy, I assume that CV sells into the market and reduces its avoided energy costs by 80% of the difference.

than CV's projection of opportunity purchase prices. I assumed this market value would be equal to the cost of a mix of 33% intermediate and 67% baseload CC energy, using CV's projections of CC costs (and crediting the CCs with the cost of a CT). I selected the mix of base and intermediate so that, at the load factors projected in CV's UPLAN runs (80% for base, 35% for intermediate), the mix would have the same load factor as the DSM decrement. Exhibit ___ PLC-13 presents the results of this analysis. I then allocated this average annual cost to rating periods in proportion to the period market prices assumed by CV.

Q: *How important is this correction?*

A: In many years, my off-system sales adjustment is not very different from CV's. However, in 1996 and 1997, when CV assumes a resource mix that is grossly out of balance, my adjustment produces much more reasonable and stable avoided energy costs. In 1999, my adjustment decreases CV's anomalously high avoided energy cost. In the period 2000–2003, my adjustment corrects for CV's use of cheap oil-steam purchases as capitalized energy, when combined-cycle capacity is avoidable. In various other years, my avoided costs change the relationship between rating periods; in particular, my projections of avoided energy costs do not repeat the curious pattern of CV's projections, which show summer energy costs exceeding winter energy costs, with the differential growing over time.

3. Losses

Q: What avoided energy losses has CV used prior to the current round of avoided costs?

A: The Company has used the marginal energy costs derived in a 1984 study by P. T. Zschokke (IR 4-87), and incorporated in CV's marginal-cost studies from Docket 4364 onwards. The estimates of marginal energy loss to secondary voltage (at which all residential customers are served) are shown in Exhibit ___ PLC-14.

Q: Do these losses appear to be correctly computed?

A: Yes. Given the limited data available, CV appears to have properly

- accounted for the differences in sales and losses by voltage level;
- reconciled loss estimates with observed losses;
- recognized that marginal losses increase as the square of load; and
- removed no-load losses from total losses, to derive the variable losses from which marginal losses are computed.

Indeed, the Zschokke memo is one of the cleanest and most readable loss studies I have ever had the pleasure to review.

Q: What energy losses does CV use in its current avoided costs?

A: Central Vermont uses energy losses (shown in Exhibit ___ PLC-14) that are roughly half of the marginal losses, or approximately equal to average variable losses.

Q: What is the basis for CV's new loss estimates?

A: The Company has never provided any derivation of these estimates. The original explanation for the lower losses was 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 IR 7-18, Robert Amelang, CV's Principal Engineer, disavows the explanation in the Petition, and correctly defines no-load losses. Since no-load losses are properly accounted for in the Zschokke analysis, they cannot explain CV's new estimates. While Amelang claims that recognizing no-load losses is a "refinement" in the new estimates, he does not provide any analysis that does anything with no-load losses.

Instead, IR 7-18 provides a 1990 memo from Randy Hahn, which attempts to correct a perceived overestimate of losses in the Zschokke analysis.[23] Hahn incorrectly believes that he has found a logical flaw in the Zschokke analysis, but this belief is based on two errors by Hahn: he assumes that all load is served at secondary, and that all sales occur in the peak period. When he applies the secondary peak-period loss factor to a very large load decrement (a 60 MW reduction in a 451 MW peak load at the generator), he finds an implausibly large reduction in total losses. In fact, only 61.2% of CV's sales are at secondary (IR 4-87) and only 19% of sales are in the winter peak and intermediate periods; this maximum loss factor is thus relevant to only about 12% of sales.[24]

Hahn's erroneous example leads him to estimate a compromise value, falling between marginal and average losses. His analysis does not distinguish between rating periods or load levels, and computes average

[23]This information was requested in IR 4-100, but not provided.

[24]The size of the decrement in Hahn's analysis is also a problem. Rather than an abrupt 13% decrease in load, loss analysis for avoided costs should consider the effect of decreasing load growth by about 1% annually. The Company acknowledges that the problems it perceives in using marginal losses are a function of the size of the DSM program (IR 4-110). In the longer term, some of the savings will be in the form of avoided loss-reducing T&D investments, rather than avoided losses. The Company does not treat those costs as avoidable (IR 4-68).

losses of 12.1%. This value is neither relevant nor applicable to avoided-cost determination. Even though Hahn's memo was written in 1990, CV does not appear to have attempted to use it until late in 1993; the 1992 avoided costs used the marginal loss factors.

Even Hahn's analysis does not derive the loss factors used in CV's current avoided costs. Hahn's average loss factor is 12.1%; CV uses period losses that average 10.4%, not 12.1%. Hahn estimates 19.2% marginal losses at peak; CV 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.

Q: What avoided energy losses did you use?

A: I used CV's marginal energy losses, as developed in 1985 and accepted by CV and the Board ever since.

Q: So far, you have discussed only energy losses. What demand losses does CV use in its avoided costs?

A: Oddly, even for the avoided costs that are computed in dollars per kW for load control, CV does not develop avoided demand losses. Instead, CV allocates demand costs to rating periods, adds energy losses, and then reallocates the demand costs (with losses) back to demand (letter from S. R. Anderson to J. F. Wallach, 2/8/94).

Q: What avoided demand losses did you use?

A: For my avoided costs, I computed average demand losses from the Zschokke memo, as shown in Exhibit ___ PLC-15.[25] Losses on demand at the 12 hours that determine capability responsibility are lower than those at peak, so I estimate CR losses to be lower than CP losses.

For CV avoided costs, I used the 16% loss factor from Docket No. 5627.

4. Transmission and Distribution Costs

Q: What is the basis for CV's estimates of avoided transmission and distribution costs?

A: The Company's avoided transmission and distribution (T&D) costs are taken from the marginal-cost study prepared during 1985–87 and presented in Docket No. 4364. The marginal-cost estimates were derived by estimating load-related additions during 1987–96, annualizing the investment, dividing the additions by load growth assumed for that period (80.1 MW of CP), and adding the average dollars-per-kW O&M costs during 1970–86 (J. C. Cater Direct, Docket No. 4364, Exhibit JCC-5; Cater Rebuttal, Docket No. 5294, Exhibit JCC-9). Central Vermont adjusts the old distribution estimates (which were stated in terms of different measures of load) to be dollars per kW of coincident peak, inflates the 1987 values to 1994 dollars, and assumes that no T&D costs are avoidable. Unfortunately, the marginal-cost estimates

[25]Demand losses are average losses, since peak demand levels determine the size of all T&D elements, causing peak losses to vary directly with peak loads. Energy losses are marginal losses, since changing energy use does not affect T&D sizing, causing losses to vary with the square of load.

were understated, and all three of CV's adjustments are performed incorrectly.

Q: How were the marginal T&D cost estimates understated?

A: From the limited documentation of this estimate available in IR 4-56, 4-68, and 9-25, it is clear that the original study included only a subset of avoidable costs, for the following reasons:

- The original study excluded many cost categories, including any capitalized costs related to maintaining the system over time or reducing losses. The Company was unable to provide any breakdown or explanation of the exclusion of various categories of costs from the marginal-cost study (IR 9-29c, 9-30c, 9-31).
- The cost of upgrading service drops appears to have been omitted from the distribution analysis, even though CV bases its depreciation rate for services on the observation that

  > People have been (and still are) finding increasing uses for electricity which often necessitates replacing their existing service line with a higher amperage service; e.g., to 100 amps, 200 amps, or even 300 amps. (Testimony of J. H. Aikman, Docket No. 5491, p. IV-11)

- The forecast of transmission additions included no additions in 1995 or 1996; but transmission additions are planned for 1994–96 (IR 4-67, 7-16, 7-11) that were not anticipated for any year in the marginal-cost study (IR 4-68), even though 1987–96 load growth turned out to be more like 30 MW than the 80 MW assumed in the marginal-cost study.
- The historical average O&M costs are treated as 1987 dollars even though the derivation of the average O&M clearly indicates that the value is in 1986 dollars. Central Vermont corrected this error in its

update of marginal costs (IR 9-25), but failed to reflect it in the avoided costs.

In addition to the errors in the marginal cost study, CV made the following three mistakes in converting the marginal T&D costs to avoided costs.

First, in converting the marginal cost estimates to dollars per kW of coincident peak. The Company divided distribution investment costs by more kW than the load growth associated with the costs.[26] CV assumed that the 80.1 MW of CP load growth would represent 80.1 MW of load growth on primary and secondary equipment. As shown in IR 4-87, CV estimates that 85% of its load is served through the primary distribution system, and only 61.2% is served at secondary. Thus, the investment in primary distribution would serve only 68.9 MW of load growth, and the secondary investment would serve only 49.6 MW of load growth.

Second, CV inflates both O&M and capital costs by 33.7%, from 1987 dollars to 1993 dollars, which is excessive.[27]

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[26]The marginal secondary costs were stated in dollars per kW of the sum of the "non-coincident peaks" (or NCP) of individual customers, while marginal primary costs were stated in dollars per kW of the sum of the "maximum diversified demands" (or MDD) of customer classes. Since these measures of load are much higher than coincident peak (CP), the dollars per kW values are lower for the less diversified loads. In the collaborative, CV was using the dollars-per-kW NCP and MDD, until I corrected the values to $/kW CP. (The Company had not provided the information necessary to determine what portion of the CP used each type of equipment.) Central Vermont now recognizes that avoided costs must be stated in terms of the same load to be applied to the avoided costs (IR 5-44), but fails to ensure the consistency both in converting from NCP and MDD to CP, and in converting from CP to CR for load-control screening.

[27]The Company's explanations of the years' dollars of the original marginal cost study, and of inflation from those dollars to 1993 (or 1994) dollars are mutually inconsistent. Compare the

Third, CV assumes that no transmission or distribution costs are avoidable in 1994 or 1995, and explains this assumption as follows.

> It is assumed that no transmission costs are avoidable until the system loads are at least as high as the historical peaks last reached in 1989. This is a conservative planning assumption since the system in 1989 may well have had many lines with additional capacity available for load growth as well as the observation that transmission energy efficiency projects are cost effective means of reducing energy costs and often provide additional system capacity which could be used for load growth.[28] (IR 7-10)

> [D]istribution costs are assumed to be unavoidable until system loads exceed historical peaks.... (IR 7-14)

Central Vermont also argues that distribution costs are harder to avoid than transmission costs:

> For example, an energy efficiency measure on one distribution circuit does not necessarily reduce capacity needs on an adjacent circuit, but does reduce capacity needs on the common transmission facilities.

> [W]hile many relatively small energy efficiency measures can cumulatively have a large impact on transmission needs, there is a threshold need for distribution facilities that must be met as long as customers are connected and there is load. Thus a 5% system-wide energy savings might have a large impact on transmission needs, but virtually no impact on distribution needs. (IR 7-14)

avoided costs in Exhibit BWB-4, Docket No. 5701, to those in IR 4-56, as explained by IR 9-25 and 9-34.

[28]This last point (which CV also makes for distribution) refers to loss-reducing transmission investments, which are clearly load-related but which CV does not treat as avoidable by reductions in either energy or demand. It is true that adding T&D reduces losses; if all load-related T&D was included in CV avoided-cost analysis, T&D avoided costs should be reduced by the amount of the energy savings associated with expanded T&D capacity. But CV does not include all T&D investments in its avoided-cost estimates. In particular, investments to reduce losses (such as 70% of voltage conversion costs) are omitted.

Despite these arguments, CV does not project transmission costs to be avoidable any sooner than distribution costs. Furthermore, none of the company's arguments are valid, for the following reasons:

- Load-related investments are planned for 1994 and 1995 (IR 4-67, 5-133, 7-11, 7-15, 7-16).
- According to IR 9-35, CV's load actually peaked in 1987, and that (as of the 1991 IRP) the 1987 load was expected to be exceeded by 1994. Since no two of CV's reported peak loads match, it is difficult to compare load forecasts, but CV's current forecast (IR 7-6) is about the same as the IRP forecast for 1994.
- While "many lines" always have "additional capacity available for load growth," the system elements that are even slightly over-stressed by load growth require large investments.[29] The marginal cost of T&D results from averaging zero costs on over-sized elements (0 kVA expansion per kVA of load growth) with the large expansions needed on the under-sized elements (perhaps 10 or 20 kVA of capacity added per kVA of load growth). The "additional capacity" on some lines results from the over-sizing of previous expansions.
- Utilities routinely re-configure distribution circuits, to move loads from an overloaded feeder or substation to an adjacent under-loaded supply, as illustrated in IR-133.
- The Company's estimate of marginal distribution costs does not include customer-related or fixed costs that are required "as long as customers

[29]The Company essentially argues that all distribution facilities are always over-built, and that all DSM will occur on the most oversized distribution facilities, so that "capacity needs" will only occur "on an adjacent circuit."

are connected and there is load." The Company attempts to subtract from marginal costs items that were never included in the estimate.

Second, CV inflates both O&M and capital costs by 33.7%, from 1987 dollars to 1993 dollars, which is excessive.

Q: What is your corrected estimate of avoided transmission and distribution costs?

A: Exhibit ___ PLC-16 and Exhibit ___ PLC-17 provide my corrected computation of CV avoided T&D costs from the 1987 marginal cost study, including overheads on O&M. My overall estimate is $98.40/kW-yr. of CP load served at secondary in 1993.[30] The value of avoided T&D costs is probably higher than this estimate, due to CV's exclusion of many cost categories, and apparent failure to anticipate some required projects late in the planning period. I hold the 1993 estimate constant in real terms, while CV escalates its T&D costs at about 0.5% more than general inflation.

5. Overhead Costs

Q: You have mentioned that you included overhead costs on O&M for generation, transmission, and distribution. What are those costs, and how did you estimate them?

A: Overhead costs include payroll taxes, pensions, benefits, administrative (e.g., personnel, accounting, financial) staff and services, legal and regulatory costs, and other costs that are not directly assigned to particular functions. Many of these costs vary directly with the levels of activity (and could be functionalized, but are not): payroll taxes, payroll services, pensions, and

[30]The transmission cost is restated in dollars per kW of CR, as is generation. See §IV.B.2.

benefits are caused by labor; legal and regulatory costs vary with the number and scale of construction and maintenance projects (for contracting, eminent domain, right of way, damage claims, permitting). Other costs, such as the number of personnel staff and the complexity of accounting services, vary more generally with the number of employees, the amount of equipment, and the number and scale of projects.

Most utilities include overheads in their estimates of marginal and avoided costs, recognizing that these costs do vary with other expenditures. Overhead expenses are usually allocated in proportion to O&M, and typically represent about 40% of functionalized O&M.

Central Vermont's overhead costs in recent years have been about 50% of functionalized O&M, as shown in Exhibit ___ PLC-18. I used overheads of 40% in the avoided costs.

6. *Environmental Externalities*

Q: How did you estimate environmental externalities?

A: I computed environmental externalities from the dollars-per-ton values adopted in the Stipulation. These values are shown in Exhibit ___ PLC-19. Only four of the air emissions — carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM) — contribute significantly to externality valuation, so I have not bothered to quantify the other four air emissions listed in the stipulation (methane, carbon monoxide, volatile organic compounds, and nitrous oxide [N_2O]).

I recognized that reductions in CV energy use would decrease the usage of existing (or committed) NEPOOL resources until CV starts to avoid the construction of new energy-producing capacity (intermediate and baseload).

Since hydro resources are not at the margin in either the long or the short term, I have not used any hydro externality value, even though one was adopted in the stipulation. Exhibit ___ PLC-20 shows the derivation of my estimate of the marginal NEPOOL energy mix and externalities. This derivation was a cooperative effort with Emily Caverhill of Resource Insight and Bruce Biewald of the Tellus Institute.

We started with Tellus's estimates of marginal generation, from Docket 5330, and modified them subjectively to accommodate changes from 1988 to 1994: more gas in boilers, less use of CTs, some combined cycle (GCC) energy on the margin. We then projected out GCC contributions to the margin, assuming that the non-GCC marginal energy would decrease by 1% per annum, and gradually increased the gas portion of the boiler margin. We separated out the CT portion of marginal energy, to see if the treatment of CTs dramatically changed the aggregate emissions; it didn't, for our assumptions. Combustion-turbine energy rises from a depressed 5% of marginal generation in 1994 to 15% in 2004 (returning to the level estimated by Tellus for the late 1980s).

The emission rates for NOx in oil and gas boilers drop abruptly in 1995 (reflecting CAA Title I Phase I compliance), and then fall gradually as (we assume) older units are retired and selective controls (SCR and SNCR) are added. We assume that CT emissions of CO_2, SO_2, and PM fall 1% annually (due to the use of more gas, more new CTs with better heat rates), and that NOx emissions fall 5% annually to 2000, and 3% thereafter (due to the use of more gas, more new burners in old CTs, more new CTs for lower heat rates and lower emissions).

These assumptions yield aggregate externality values that fall from \$24/MWH in 1994 to \$8.60/MWH in 2000 (1993 dollars). Exhibit ___ PLC-21 lists CV and RII estimates of avoided externalities per year.

Q: What uncertainties underlie these estimates?

A: Several factors may make the actual avoided emission rates and externality values higher, and the fossil fuel emission rates lower, than those used in my analysis. On the electric side, prior to 2000, I may have been overly optimistic about the rates at which gas will become the marginal fuel for existing boilers, NOx controls will be installed on existing boilers, and combined-cycle units will become the marginal source of energy supply for NEPOOL.[31] I also assumed that none of the marginal energy supply would be from coal plants, including the very high-emission coal plants in New York and Ontario.[32] Some of the combined-cycle emission factors are likely to be understated, since I assumed no oil use (which would increase emissions of NOx, SO_2, and particulates) and very low NOx emissions for the gas combustion.[33]

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[31]The Board can be quite sure that fuel switching will not displace generation from operating nuclear or hydro plants, since these resources are always fully dispatched by NEPOOL, up to their capacity and energy limits. The Company's assertion (in "Supplemental Fuel-Switching Analysis," 6/22/93, p. 11) that nuclear and hydro plants can be the marginal source of energy is untrue for any but accounting purposes.

[32]The Company does not estimate the portion of marginal energy supply from these areas (IR 5-140).

[33]On the other hand, some portion of post-2000 avoided supply may be from low-externality renewables. In this case, direct avoided costs may be higher, but the avoided externalities lower, than used in the RII avoided costs.

After the year 2000, I assume for externality purposes that all the avoided energy is from gas-fired combined-cycle plants with SCR. Some portion of the avoided energy is likely to be from existing power plants,[34] oil burned in intermediate-duty combined-cycle plants, new coal plants,[35] and oil burned in peaking combustion turbines. Each of these resources produces more emissions than the gas-fired combined-cycle plants, and avoiding them has correspondingly greater benefits.

Our externality values do not include many effects of building and of running electric power plants, and delivering power to customers. The Department and RII did not include the environmental effects of electro-magnetic fields, air toxics (primarily from coal and heavy oil), water use, thermal pollution of water, land use, visual pollution, transmission line effects, and all effects of the fuel cycle other than at the smokestack (extraction, processing, transportation).

In terms of fossil fuels at the end use, the NOx emissions are likely to be somewhat overstated. The emission data are from the 1980s, based on older studies; the pressures of the Clean Air Act will tend to encourage manufacturers to re-design burners to reduce emissions. Low-NOx burners are not intrinsically more expensive than standard burners; manufacturers may simply switch all production to the designs that are acceptable in Southern California and other high-ozone area.

The SO_2 emissions from #2 oil at the end use are also probably overstated. These values assume that the oil contains 0.3% sulfur by weight;

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[34]Both New York and Ontario may have a surplus of existing coal and oil baseload plants for much longer than New England.

[35]such as Half-Moon Bay in New York.

this is the maximum possible value. The average value is likely to be closer to 0.2%, and may fall further in the future.[36]

Q: Can you determine what effect the Department's proposed fuel-switching program would have on global, regional, and local air quality?

A: Switching from electricity to direct use of fossil fuels would generally reduce the global air effects of meeting Vermont's energy-service needs. Those effects consist primarily of global warming from CO_2 emissions, and pollution from some long-lived airborne toxics (especially mercury).

Direct fossil use will also reduce regional air pollution in New England and the Northeast, compared to using the existing generation system. The marginal electric energy sources in New England produce more NOx, particulates, SO_2, and air toxics than do direct fossil uses. If the source of electric energy at some point in the future is entirely from gas-fired combined cycle plants, avoided regional emissions would be less than the increase in emissions from direct fossil use.

The net effects of fuel switching on local air quality in Vermont generally, or at specific sites within the state, are very sensitive to the location of the power plants that are backed out by fuel switching. Some of the affected plants are likely to be upwind of Vermont, in upstate New York and Ontario, where much of the marginal generation is from old, dirty plants burning coal and heavy (#6) oil. A part of the avoided energy will be from plants within Vermont: McNeil, peakers, and NUGs. Another portion of the avoided energy would be from oil and coal plants that are sometimes upwind of Vermont, such as those in western Massachusetts and southern New York.

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[36]The sulfur content of diesel fuel is now capped at no more than 0.05%.

The remainder of reduced emissions would occur at plants generally downwind of Vermont, such as Salem Harbor and Wyman. Predicting the mix of avoided emissions by origin would be both difficult and speculative. After the year 2000, the local effects of fuel switching will depend on both the location and the technology of the avoided units.

Q: You have discussed the direct environmental effects of fuel switching, in terms of the increased use of fossil fuels at the end use and the decreased use of fossil fuels at the power plants due to the measures undertaken in the proposed programs. Would there be any other environmental effects of the programs proposed by the Department and RII?

A: Yes. The programs would have several other effects, all of which would decrease environmental costs. First, the DPS-RII high-use program would provide blower-door-guided air sealing at time of audit for all customers, regardless of the ultimate choice of fuel. This will reduce energy use and emissions for those customers who would have fuel-switched anyway.[37] Also, reduced use of fossil-fuel space heat reduces electricity that is used by heating-system auxiliaries such as fans and pumps. The air sealing, and the fact that the program designs will encourage the installation of higher-efficiency equipment, would increase the efficiency of fossil use by free riders.

[37]Most of CV's energy savings from its current high-use-residential DSM program result from recommended fuel-switches. The Company does not now provide incentives or other mechanisms to overcome market barriers to the selection of the most efficient cost-effective fossil combustion systems.

Second, the air sealing will result in increased electric savings and reduced emissions for electric space-heating customers who continue to use electricity.[38]

Third, some participants in the water-heating program who use fossil fuels for space heating will be encouraged to improve their space-heating efficiency. The Company would pay for a home energy rating, through which weatherization investments will allow homeowners to get the 4-star rating needed for an energy-efficient mortgage (a bigger mortgage that includes financing for the conservation). The Company would also provide contractor arranging, reducing some market barriers.

Fourth, the New-Construction Program would encourage builders to bring fossil-heated homes up to a 4-star-plus rating, to avoid a $350 fee for the hook-up. The hook-up fee would cover a home-energy rating, which would encourage some efficiency improvements even for those builders that chose to forego the 4-star-plus rating. The builders would also receive incentives for efficient lighting, refrigerator, and dryer choice, further reducing electric generation costs.

The fifth, and perhaps most important, indirect environmental effect of the fuel-switching program is its demonstration effect for the other New England states and for New York and Ontario.[39] Establishing fuel switching as a part of Vermont DSM programs will increase the likelihood of significant implementation of these measures throughout the Northeast. Fuel switching in other jurisdictions will decrease the amount of pollution blowing

[38]Only a minority of participants in the high-use program are likely to switch fuels.

[39]Fuel-switching in Quebec will also tend to reduce regional emissions, by freeing up Hydro Quebec energy to displace fossil generation in Ontario, New York, and New England.

in from the dirty marginal sources of electric energy, especially in New York and Ontario.

E. End-Use Fuel Prices and Externalities

Q: How did you estimate the costs of the end-use fuels required by fuel-switching measures?

A: Resource Insight used Department projections of retail prices for #2 heating oil, natural gas, propane, and kerosene, from TR 28.[40] For propane, TR 28 projects an average statewide price by averaging prices charged to large and small customers. Resource Insight developed separate prices for large and small customers to reflect differences in the volume-based margin charged by distributors. High-volume prices were set at 5¢ per gallon ($0.55/MMBtu) less than the TR-28 price in 1994, based on observations of current prices. Low-volume prices were calculated as 8.5¢ per gallon ($0.91/MMBtu) more than the TR-28 prices in 1994, based on a 1993 DPS survey price of $15.07 (in 1993 dollars). The wholesale propane "product price" from 1994 was taken from TR 28, and escalated as projected therein. The 1994 margin for each category of propane was computed on the retail price minus the product price; the margin was escalated at the margin-escalation rate in TR 28. Exhibit ___ PLC-22 compares our projections of end-use fuel prices to the end-use fuel prices used by CV in field screening.

Q: Are these fuel prices consistent with the fuel costs underlying CV's avoided costs?

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[40]Technical Report No. 28, "Projections of Fuel Prices in Vermont," was prepared for the Department by Richard Hornby, Alex Rudkevich, and Heidi Kroll of the Tellus Institute.

A: The Department's projections of utility (or wholesale) fuel costs are generally greater than CV projections; see Exhibit ___ PLC-23. Hence, the end-use fuel prices are based on higher wholesale fuel costs than are the energy costs used in the avoided costs. A fully consistent analysis would require either higher electric avoided costs, lower end-use fuel prices, or both. Thus, the DPS-RII analysis of fuel-switching is biased toward retaining electric end-uses, and away from switching those uses to alternative fuels.

Q: How did you estimate the externalities of the end-use fuels used in fuel-switching measures?

A: I applied the dollar-per-ton externality values from the Stipulation to emission rates from generally accepted sources. The emission factors and resulting externality valuations are shown in Exhibit ___ PLC-24.

Q: How do these externalities compare to the externalities from electric end-uses?

A: The relationship between the external costs of electricity and of direct fossil-fuel use is difficult to characterize, due to the range of end-use efficiencies. Exhibit ___ PLC-25 lists the external costs of each of the end-use fuels, at 70%, 80%, and 90% efficiency, and compares these to the externalities of electricity (at 100% end-use efficiency). The external costs of direct end-use fossil fuels range from 15% to 87% of electric externalities, depending on the fuel, the efficiency, and the time period for comparison.

IV. Screening of Controlled Water Heating

Q: Please describe CV's controlled water heating programs.

A: Central Vermont's controlled water-heating rates (Rate 3 for residential and Rate 14 for commercial customers) require a separate meter for the water heater load. During control periods, all heating elements are disconnected. The Company's rate schedules limit control period to no more than 9 hours per day and no more than 5 hours in any contiguous 10-hour period. The Company generally assumes that it has 30,000 controlled water heaters; the actual count reported in the 1992 FERC Form 1 and in Docket No. 5701 (IR 5-98) is 28,827.

Central Vermont uses two control schemes. First, CV has roughly 7500 ripple-controlled water heaters. These water heaters can be turned on and off by CV dispatchers, through a high-frequency signal injected into the power line. The injection equipment has only been installed in the Rutland area. All new controlled water heaters on the distribution circuits with ripple injection are ripple-controlled (IR 5-81).

All the ripple water heaters must be turned on and off simultaneously, due to the nature of the control equipment. In early 1990, CV asserted that the ripple controls were dispatched as a function of time, based on monthly load forecasts, with adjustments for daily load conditions.[41] Actual operation data from 12/91–1994 does not appear to support this assertion for current operation, but maybe it was true earlier.

The Company also reports that it has about 22,500 clock-controlled water heaters. Each water heater is controlled for a specific set of hours on its clock. Newly installed water heaters are set to be off for 3–5 hours starting at 7 a.m., and for 3–5 hours starting at 4:30 p.m. Older clocks are set to be off

[41]The Company said it caused the automatic controls to be invoked 7–9 a.m. and 11 a.m.–1 p.m. in the Winter, and 11 a.m.–3 p.m. in the Summer.

2–7 hours between the hours of 7 a.m. and noon, and between 4:30 and 9 p.m. (IR 5-80). Some of the older clocks lack a second set of "dogs," or switches, limiting them to one interruption period per day.

Newer installations use meters with integral clocks, while older installations use separate time clocks. However, none of the clocks have back-up batteries, so any power interruption results in the clocks being off schedule, by random amounts. Central Vermont does not use battery backup because the *rate* does not require the clock to be set properly (IR 5-82); CV expresses no concern with the reliability of the clocks or their ability to produce savings at specified times. Since the average CV customer suffers 2–3 power interruptions annually, for an average of 3–7 hours per year (IR 5-45), the time clocks will often be running at the wrong time.

A. Energy Use

Q: What are the potential effects of load control on water heater energy usage?

A: Controlling a water heater reduces its ability to provide hot water during and (for some time) after the periods of control. As a result, customers are likely to install larger tanks and/or increase temperature settings in the tank to avoid running out of hot water. Both larger tanks and hotter tanks will result in greater energy losses from the tank to the surrounding space. In addition, hot water will result in higher losses from hot-water pipes, since heat will flow faster from the hotter pipe and since more heat will be stranded in the pipe when flow stops. Hotter water may also result in further consumption at the end use, as users attempt to adjust shower and faucet temperatures with greater sensitivity to small changes in water mix, and as volume-dependent uses (e.g., clothes washers) use more energy.

These increases in usage are partially offset by the reduction in tank temperature during the control period. Losses from the cooler tank will be lower. In addition, energy use will tend to decrease if customers simply tolerate less hot water.[42] In some uses, such as dish-washing, reduced water temperature will be compensated for by increased energy input at the end use; CV estimates that dish-washing alone represents 15–22% of hot-water use (IR 5-136).

1. Effect of control on tank temperature

Q: Has CV offered any analysis of the effect of control on tank temperature?

A: No. In response to discovery, CV admitted that it had never studied the effect of load control on tank temperature (IR 5-76). Nonetheless, CV opined "that the kWh usage of a controlled water heater is less than the usage of an uncontrolled water heater" (IR 1-15, Docket 5224). Central Vermont argues, "A customer who switches is not going to change his total water consumption just because of the switch. Use is probably most determined by number of people in the household" (IR 5-36).

The Company also provided an article by Fanney and Dougherty on the performance of water heaters under control (IR 1-15, Docket 5624). The article is not particularly relevant, since it does not distinguish between

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[42]While the cost of lost service to customers who reduce their energy use is harder to measure than the cost of increased energy use, the cost is probably higher for reduced service than for increased energy losses. The Company acknowledges that reduced availability of hot water should be counted as a cost of control, but has no idea how to estimate this value (IR 5-90).

average load conditions (which determine the savings due to lower tank temperatures in partially-emptied controlled tanks) and peak-demand conditions (which determine the temperature setting required to maintain hot-water supply). In addition, Fanney and Dougherty assume only 64.3 gallons of water is withdrawn from a 72-gallon water heater, over a six-hour period, and that every day's water use is the same. This limited withdrawal requires little increase in temperature to maintain adequate storage. For example, the 75-gallon Marathon storage tank described in IR 9-42 has a first-hour rating of 75 gallons, of which 20.5 gallons consists of recovery from operation of the top element. Hence, storage provides about 54.5 gallons. The most stringent demand Fanney and Dougherty place on storage (Schedule C) is to withdraw 10.7 gallons/hour during a 4-hour control period (or 43 gallons) and for 2 hours thereafter. This is well within the capacity of the tank for storage during control and for recovery after the control period. The higher water temperature setting needed to maintain water temperature under these circumstances essentially offsets the savings from the lower temperature during storage with continuous withdrawals.

With a greater hot-water demand, such as 60 gallons in the control period and another 60 gallons in the first hour after control, temperature would have to be further increased to maintain hot-water supply; the increase would probably be infeasible. As a result, standby losses would increase substantially.

Q: Have you seen any other analyses of the effect of control on water heater temperature setting?

A: Yes. A study for the Burlington Electric Light Department concluded that, even with load cycling, rather than full disconnection, control would require increasing tank temperatures from 100°F to as much as 165°F.[43]

2. Effect of control on tank size

Q: Has CV expressed an opinion as to whether load control would increase the required tank size?

A: Yes. In IR 1-18 in Docket 5624, CV responded to a question on installing load control for customers with 40-gallon tanks by asserting that "the majority of Central Vermont Public Service's customers have 80 gallon electric water heaters." The Direct Testimony of Spinner and Anderson in these dockets states that "most of our uncontrolled water-heating customers already have large tanks" (p. 12), based on "conversations with residential customer service personnel" (IR 5-74).

Q: Are these characterizations correct?

A: No. Central Vermont's own data (from IR 4-5) indicates that most uncontrolled CV water-heaters are small (50 gallons or smaller) and that controlled water-heating customers use considerably larger tanks. The Company's data, which are summarized in Exhibit ___ PLC-26, suggest that control results in larger water heaters, either immediately (especially in new construction) or at the time the water heater is next replaced. The engineering analysis presented in §IV.A.3, below, support this conclusion.

Central Vermont admits that it has never studied the effect of water heater load control on tank sizing (IR 5-75).

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[43]Lottero Associates, "Water-Heater Load Management Feasibility Study by Computerized Simulation of Control," Burlington: City of Burlington, June 1982.

Q: Has CV estimated the additional energy required by the larger tank?

A: Yes. In Exhibit SRA-6, CV estimates that increasing the size of the water heater by one step (from 50 gallons to 80 gallons, or 80 gallons to 120 gallons) increases losses by about 50–100 kWh/year, for reasonably well-insulated tanks. Spinner and Anderson then conclude that a 50-kWh increase in costs would only add $2/yr. to the cost of control.

Q: Is this computation correct?

A: No. Exhibit SRA-6 contains five major errors:

1. Central Vermont interprets losses in fraction of a percent per hour (such as 0.948%) as if they were 100 times higher (such as 94.8%). This error would lead to the conclusion that standby losses were 10,000–100,000 kWh/yr., if not for CV's other errors.
2. The Company assumes that a kWh is equivalent to 294,000 BTUs. In fact, a kWh is 3,413 BTUs.
3. The Company assumes that the average water heater is set at 115°F; this is too low, especially for controlled water heaters.
4. The Company assumes that the water heater is shut off by the control such a large part of the time that the average temperature in the tank is actually only 27.5° greater than the room temperature, or 87.5°. This is absurd.
5. The Company compares a short-run annual cost of energy only (ignoring the demand effect of the larger tank) to the present value of other costs. At the roughly $0.70/kWh present value used in Exhibits SRA-3 and SRA-5, even a 50 kWh/yr. energy increase would add $35 to the costs of control.

Q: Has CV corrected any of these errors?

A: When confronted with its errors on discovery, CV corrected items 1 and 2 (IR 9-11). The Company denied that it assumed that the tank temperature would average 87.5°, but failed to provide any coherent explanation for its assumption that water temperature would be only 27.5° greater than the ambient air temperature. When asked how this low temperature was possible, CV replied:

> This element of the formula is trying to estimate the energy movement from hot water to a colder room. It is not equivalent to the examples posed in the question [i.e., the water averages 87.5°, or the water falls to 102° and the room rises to 74°]. Over time the water temperature would move towards the air temperature. But time is a factor; energy is put into the water before it gets down to room temperature. (IR 9-11 (d))

This "response" is consistent with my interpretation that CV is assuming that the tank temperature averages 87.5°F, and is lower during control periods. This temperature setting would not generally be considered to provide hot water, even as a worst case (let alone as an average water temperature). Any temperature significantly below 120° must be considered to have some lost amenity value, which CV acknowledges should be included in the social cost test (IR 5-90). Even at 120°F, standby losses would be more than twice those estimated by CV.

Central Vermont also refused to correct its valuation of energy losses and to restate them in terms comparable to the rest of the analysis (IR 5-78).

Q: What cost might be inferred if a customer accepts lower hot-water availability in exchange for the lower rates under Rate 3?

A: The cost to customers can be estimated from the bill savings. We may assume that some customer who elect to use controlled water heating find that it imposes no cost, given their lifestyles,[44] and would have accepted controlled water heating for even a trivial monthly bill credit. Other participants must be assumed to have barely decided in favor of accepting or retaining control at current rates, and would not accept control for any lower incentive. Hence, the implied cost of lost amenity ranges from near zero to near the incentive in Rate 3. We may assume that the average cost is the average of these extremes (which is consistent with a linear demand curve for hot water), or half of the incentive. For an average water heater, the incentive for Rate 3 is about $80/year, suggesting a lost-amenity value of about $40/yr.; see Exhibit ___ PLC-27.

3. *Summary of energy effects*

Q: What is a reasonable estimate of the effect of control on standby losses?

A: Consider a 50 gallon 4.5 kW uncontrolled tank set at 120°F, with a 50° line water supply and in a 60° ambient temperature. When fully heated, the tank contains 8.6 kWh compared to the cold water supply. Over a four-hour period, the tank can supply about $8.6 + 4 \times 4.5 = 26.6$ kWh of hot water. If the water heater is controlled during the same period, it can provide only about 8.6 kWh.[45] Increasing the temperature of the water to 160° increases energy storage to 13.4 kWh; increasing the tank size to 80 gallons provides 13.7 kWh. An 80-gallon water heater at 160° would provide 21.5 kWh.

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[44]For example, a two-person household that occupies a home with a water heater sized for the previous six-person family, and that experiences its maximum water use late at night.

[45]The performance of stored energy is not quite this good, since the bottom of the tank may not be fully warmed, and since the hot water will tend to mix with and be cooled by the incoming cold water.

Providing the full 26.6 kWh of heat storage would require a 120-gallon tank set to more than 140°. Exhibit ___ PLC-28 shows the energy-use effects of these options and others. Even the 80-gallon tank at 160° (which provides about 80% of the hot water as the uncontrolled water heater) would increase standby tank losses by about 280 kWh. Pipe and other losses would also increase.

Resource Insight's screening of controlled water heating assumes that control increases standby losses by 5%, which would be 200 kWh for a typical 4000 kWh/year water heater. This is somewhat smaller than the 13% increase in usage in the VLS data, from 3,964 kWh for uncontrolled water heaters to 4,472 kWh for controlled water heaters. The VLS sample probably had a mix of high-and low-efficiency (or wrapped and unwrapped) tanks; the low-efficiency units would suffer much higher increases in standby losses as a result of increased size and temperature.

B. Demand Levels

1. Measuring contribution to generation requirements

Q: How should CV measure the contribution of loads to its requirements for generation capability?

A: This is a surprisingly complex subject. Utilities usually assume that their capacity requirements are determined by their annual peak load, and attribute capacity savings to reductions in annual peak. As CV has recognized, utilities in NEPOOL are actually assigned capability responsibility (CR) based on the formula:

$$CR = .7 \times \frac{B}{C} + .3 \times \frac{D}{E}$$

where:

B = the utility's non-coincident annual peak,

C = the sum of B for all NEPOOL participants,

D = the average of the utility's twelve monthly non-coincident peaks, and

E = the sum of D for all NEPOOL participants.

Since the average of monthly peaks is less than the sum of annual peaks, E is lower than C. Roughly speaking, E is about 85% of C, and

$$\begin{aligned} CR &\approx .7 \times \frac{B}{C} + \frac{.3}{.85} \times \frac{D}{C} \\ &= \frac{1}{C} \times [.7 \times B + .35 \times D] \\ &\approx k \times [0.665 \times B + 0.335 \times D] \end{aligned}$$

Moreover, CV does not participate in NEPOOL as an individual participant. VELCo monthly peak loads determined VELCo's capability responsibility to NEPOOL; CV's share of VELCo's share of NEPOOL objective capability is determined by CV's non-coincident monthly peak loads as measured by VELCo. In other words:

$$CVCR = CVShare \times VTShare \times NEPOOL\,ObCp$$

The CV share of Vermont and the Vermont share of NEPOOL are each determined by the 70:30 formula

$$CVCR = \left[.7 \times \frac{B_{CV}}{C_{VT}} + .3 \times \frac{D_{CV}}{E_{VT}}\right] \times \left[.7 \times \frac{B_{VT}}{C_{NE}} + .3 \times \frac{D_{VT}}{E_{NE}}\right] \times fn\left(NECP_{weeks,hours}\right)$$

Where $fn(NECP_{weeks,hours})$ represent the determination of NEPOOL objective capability by NEPOOL coincident loads over many hours of many weeks. Since VELCo is a very small part (about 4%) of NEPOOL, only a small part of any increase in NEPOOL responsibility is allocated to Vermont; Vermont's entire contribution to NEPOOL peak loads probably only increases Vermont's CR by about 40 MW. Since CV is such a large portion of VELCo, its contribution to VELCo coincident peak has a major effect on CV's CR and generation costs. Assuming VELCo's *E* is also about 85% of *C*,[46] the previous equation simplifies to

$$CVCR = k \times [.665 \times B_{CV} + .335 \times D_{CV}] \times [.665 \times B_{VT} + .335 \times D_{VT}]$$

Further assuming that CV is about 42% of VELCo loads, CV would absorb 42% of any increase in VELCo CR. However, any increase in CV's non-coincident load would increase the Vermont *C* and *E* values, and CV would receive 42% of the resulting reduction in CR, resulting in a 1 kW increase in load increasing CV's share of the VELCo allocation by only about 0.5 kW. Hence, the incremental effect of CV load increases on CV's capability responsibility is

$$\begin{aligned}\Delta CR &= k' \times [0.58 \times [.665 \times NCP_P + .335 \times NCP_A] + 0.42 \times [.665 \times CP_P + .335 \times CP_A]] \\ &= k' \times [[.39 \times NCP_P + .19 \times NCP_A] + [.28 \times CP_P + .14 \times CP_A]]\end{aligned}$$

where

NCP_P = the effect on CV's maximum annual NCP

NCP_A = the effect on the average of CV's monthly NCPs

CP_P = the effect on VELCo's annual peak

CP_A = the effect on the average of VELCo's monthly peaks

[46]The 85% value is that same as for NEPOOL, and is roughly consistent with the limited data I have available.

The Company uses a simplified version of the CR relationship, in which its CR proxy (CRP) equals

$$CRP = c \times [0.7 \times NCP_P + 0.3 \times NCP_A]$$

Central Vermont has understated the relative importance of average monthly peaks, and neglected the important effect of VELCo peaks on CV's capability responsibility.

Q: Are VELCo's peaks usually at the same time as CV's peaks?

A: No. Exhibit ___ PLC-29 provides the time and date of each monthly CV peak for which I have data on the corresponding VELCo peak. Of the 18 months in which we have VELCo data on both the CV peak and the VELCo peak, the two peaks occurred at different times in 10 months, and on different days in 9 months. Of the 9 months for which we have both CV FERC Form-1 data on CV's NCP, and VELCo data on VELCo's peak hour, the peaks only coincide in 4 months.

Q: How should CV measure the contribution of loads to its CR?

A: Ideally, CV would use a formula that reflects both its own peaks and VELCo peaks, such as the one I developed above.

More fundamentally, the Board should consider whether it and other Vermont utilities should be striving to reduce their NCPs (which mostly shifts costs to other Vermont utilities) or to reduce VELCo's peak (which reduces total Vermont costs). The current allocation mechanism encourages each utility to reduce its own loads, while increasing Vermont's total costs.

The Board should consider encouraging the Vermont utilities to revise the VELCo CR allocation formula, to use only contribution to VELCo monthly coincident peak loads in computing each utility's share of the

VELCo capability responsibility to NEPOOL. Each utility would then have consistent incentives to reduce both its own costs and Vermont's total costs.

Q: Other than the choice of loads to use in the CR computations, and the differences between the actual CR formula and CV's CR proxy, are there any other difficulties in using the CR concept in avoided-cost computations?

A: Yes. At least three additional difficulties arise in using CR in evaluating the cost-effectiveness of DSM options.

First, the CR computation can be performed for different periods, including calendar year (in which the December peak is compared to the January peak 11 months later, and will often be higher), power year (from November to October, which compares the December peak to a later and often higher January peak), and a rolling calculation, using the previous 12 months for each month's CR computation. The Company does its analyses on a calendar-year basis.

Second, as CV recognized, by 1986 the "peak-day load curve is essentially flat from 7:00 a.m. to 10:00 p.m." (Testimony of H. M. Spinner, Docket No. 4364, p. 9). Spinner's article attached to IR 5-92 indicated that the peak had flattened further by 1990. The peak can occur any time from 8 a.m. to 9 p.m. (Spinner and Anderson, Prefiled Testimony, p. 19). As a result, the peak hour varies between months, and between years. Determining which hour(s) are most likely to be CV peak hours in future months and years is inherently difficult.

Third, applying the CR computation, like any measure of demand, to the economic screening of DSM requires that CV identify its peak hours. As discussed in §IV.D.1, CV has not properly done this.

Q: Why does CV use the CR load measure, rather than a measure for peak load, for allocating generation capacity savings?

A: I do not know. The Company's justification for using the CR analysis implies that capability responsibility somehow avoids the difficulty of predicting peak hours with CV's "shifting" peak (Spinner & Anderson, Prefiled Testimony in CV-1 & 3, 6/18/93 , p. 8). This is not true. The CR analysis originally appeared during the collaborative process when CV tried to respond to the observation of the non-utility parties that clock water heaters were increasing actual peak loads. The Company's complex and opaque CR analysis hides a number of defects, including

- justifying additional clock controls based on the *average* value of all *existing* clock control; the appropriate measurement is the *marginal* value of *new* clock control.
- assuming that clock control of water heaters has no effect on energy use,
- assuming that ripple control had no effect on VLS load data,
- assuming that no real-time load controls would have been available on alternative peak hours.

Q: How did you measure the effect of load-control measures on generation-capacity costs?

A: To minimize disputes about the measurement of capacity benefits, and to minimize the reworking required for CV's data, I used the same CR proxy that CV used: calendar year data, weighted 70:30.

2. *Measuring contribution to transmission requirements*

Q: What types of loads determine CV's transmission costs?

A: VELCo transmission costs are allocated by a complex formula that, among other things, gives equal weights to the utility's contribution to VELCo's CP and the utility's NCP. Thus, CV's annual peak and CV's contribution to VELCo annual peak are equally important for these transmission costs. The Company's transmission billing from VELCo is determined by VELCo's loads, and allocated to CV based on CV's contributions to the VELCo annual peak and CV's non-coincident annual peak loads as measured by VELCo.

Central Vermont's own transmission costs are driven by CV's annual peak, along with loads at other hours that may require additional transmission, for maintenance, local peaks, or atypical off-peak load patterns.

Q: How did CV measure contribution of loads to transmission costs?

A: The Company uses the same CR proxy it uses for generation capacity.

Q: Why did CV use the CR proxy for transmission?

A: I do not know. The Company opines that the unit used to measure transmission costs does not matter, so long as costs are restated in terms of the same units (IR 5-44). This condition is necessary (although CV does not adjust avoided costs for the difference between CP and CR), but not sufficient. No matter how a cost is restated, it will not properly measure the contribution to costs in very different hours.

Q: How did you unitize transmission costs?

A: To minimize disputes over the allocation of this relatively minor cost, I used CV's CR proxy.

3. Measuring contribution to distribution requirements

Q: What types of load contribute to distribution requirements?

A: The maximum loads on various pieces of distribution equipment are determined by the diversified loads of various numbers of customers. Secondary lines may serve from 1 to 10 single-family customers, transformers serve as many as 20 customers; distribution feeders serve hundreds or thousands of customers (not all of whom will be residential); distribution substations serve several feeders. Residential loads primarily share equipment with other residential customers, especially at lower voltage levels.

To reflect this diversity in loads, CV's marginal-cost study allocates marginal secondary costs on customer peaks (which CV calls non-coincident peak, or NCP) and primary costs on class peaks (maximum diversified demand, or MDD). The Company's bundled avoided costs cause distribution costs to be allocated to time periods very broadly: 33% of the costs are allocated to off-peak hours, and 18% to the summer peak period. Customer peak loads occur at all times of the day, and in all seasons, depending on when the maximum combination of appliances are in use. Class peaks are less diverse, but primary distribution equipment (laterals, feeders, and substations) peak at many different times. In Docket 4364, CV noted that the percentage of monitored substations peaking during CV's peak rating period had fallen from 74.5% during 1980–81 to 48.2% during 1986–87 (Exhibit HMS-2).[47] Even the substations peaking during the peak rating period may peak in different days or different hours than the system peak.

Q: How does CV measure the effects of load control on the distribution system?

[47]The Company was unable to provide any update to this analysis.

A: Central Vermont uses the same CR proxy as for generation and transmission.

Q: Why does CV assume that distribution costs vary with CR?

A: The Company does not offer any justification for assuming that either transmission or distribution varies with CR. In IR 5-44, CV asserts that the measure of demand is not important. In IR 5-86, CV responds to a request for the basis for assuming load control reduces T&D loads by saying, that the Company "is comfortable with the same avoided T&D costs used to screen all other DSM measures. There should be no double standard." It is CV that imposes a double standard by crediting load control with distribution costs that load control cannot avoid

Q: How do you measure the distribution savings of load control?

A: The Company's water heater load control is unlikely to save any distribution costs.[48] The water heaters return to service at times when residential loads (and total system loads) are still quite high. Particularly in the evening, the recovery of the water heaters is at least as likely to add to the peak load on a distribution element as the interruption of the water heater is to reduce peak load on that element. This is particularly true for the ripple-controlled water heaters, all of which must return to service simultaneously, and for any area (an apartment building, a suburban block, a feeder area) with a large number of controlled water heaters.[49]

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[48]Even transmission savings are questionable.

[49]Central Vermont has made no effort to limit, or even track, the number of controlled water heaters on each piece of distribution equipment (IR 5-47, 5-48).

I assume that a controlled water heater has the same distribution costs as an uncontrolled water heater with the same energy usage. This assumption probably slightly favors control.

C. Load Data Available for Analysis of Water Heater Load Control

Q: What sources are available for estimating the effects of load control on CV's total loads and costs?

A: No recognized external source exists for data on the effectiveness of load control. Hence, all analyses must be driven by data from CV or the Vermont Load Study (VLS).

Load shapes and the operation of load control change over time, bringing into question any analysis mixing system load data from one year with data on water-heater operation from another.

Central Vermont has been unwilling or unable to provide system load data for any periods other than those used in its analyses (provided in IR 5-32): 1982–1986 and 1988–1990. The Company has lost the system-load data for 1987, which was used in Exhibit SRA-2.

Central Vermont's metering of Rate-3 water heaters started in 12/91. Hence, there is no period for which both actual system load data and metered water heater loads are available.

The Company has not metered uncontrolled water heaters. Hence, only data from the VLS is available for these water heaters.

D. The Company Analyses of Controlled Water Heater Loads

Q: Please describe CV's analyses of water heater loads.

A: The Company has provided the following three analyses of clock-controlled water heater loads, all in the testimony of Spinner and Anderson (6/18/93, CV 1&3):

- Computation of the CR formula from system load data for 1982–88, with actual loads and with hourly loads estimated by replacing the clock-controlled water heaters with uncontrolled water heaters, using VLS load data. (Exhibit SRA-2) This analysis was updated in Exhibit SRA-2 of Anderson's Supplemental Testimony in Docket 5686, to use CV's current avoided costs.
- A similar CR computation for 1982–86 and 1988–90, using VLS load data for uncontrolled water heaters and some sort of composite load shape from 1991–93 metered data for controlled water heaters. (Exhibit SRA-4) This analysis was updated in Exhibit SRA-3 of Anderson's Supplemental Testimony, to use CV's current avoided costs.
- An analysis of the effect of clock-controlled water heaters on the 1/92 peak load (Exhibit HMS-3).

Central Vermont has not provided any analysis of the effect of ripple control on CV loads or costs. (IR 5-88)

1. Clock-Controlled-Water-Heater Contribution to Capability Responsibility

Q: Please describe CV's analyses of the CR contribution of clock-controlled water heaters.

A: In each of the three analyses, CV starts with hourly system-load data for each study year, and computes its CR proxy for the year. The Company then subtracts an estimate of clock-controlled load (22,500 times the load per water heater) from each hour's load, and adds in the load for an equal number of controlled water heaters. The Company determines the new annual and monthly peaks, and computed the CR proxy with no clock control. The peak hours may change between the actual load and the no-control load. Finally, CV averages the CR effect of removing control over the years used in each analysis.

No detail is available on these analyses. The Company refused to provide the dates, times, and magnitudes of either the actual peaks or the potential peaks used in the load control analyses in Spinner and Anderson's testimony (IR 5-54, 5-71).[50]

Q: Has Central Vermont properly analyzed the contribution of clock-controlled water heaters to its loads?

A: No. The Company makes the following four types of errors in its analyses in Exhibits SRA-2 and SRA-4 of Spinner and Anderson's testimony, and SRA-2 and SRA-3 of Anderson's supplemental testimony:

- Making unwarranted adjustments in load
- Estimating the average, not the marginal, effects of load control on system loads
- Unrealistically modeling load in potential alternative peak hours
- Using the wrong system-load data.

Q: What unwarranted adjustments does CV make in its load data?

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[50]Resource Insight was forced to undertake complex analyses to identify these peaks. In the process, we determined that many of the peaks shifted to new times and days (and that CV had failed to reflect the implication of those shifts) if all clock-controlled water heaters were decontrolled, and that CV had used load data that were inconsistent with other sources of CV load data. Both points are discussed further below.

A: First, in Exhibit SRA-2, CV assumes that ripple-controlled (or other direct-controlled) water heaters comprised 25% of the controlled water heaters in the VLS sample, but that ripple-controlled units operated like uncontrolled water heaters.[51] In other words, CV assumes that ripple provided no benefit on the actual peak. However, the Company offers no support for this assumption (IR 5-38). Thus, CV adjusts the VLS controlled water heater load data as:

clock-controlled load = VLS-controlled load +.33 × (controlled-uncontrolled load)

Central Vermont recognizes that this computation may produce negative results, and sets a minimum clock-controlled load of zero. The computation may also produce unrealistically low (but non-zero) results.

Second, CV assumes that energy use is equal for controlled and uncontrolled water heaters. The Company fails to recognize that controlling water heaters requires larger tanks and/or higher temperatures to maintain adequate hot-water supply, during and after an interruption, and that larger tanks and higher temperature increase energy usage (see §IV.A). The Company adjusts controlled water heater load downward to remove the real effect of control on energy usage.

Q: Please explain how CV estimates the average, not the marginal, effects of load control on system loads.

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[51]This is inconsistent with CV's explanation of ripple control strategies in IR 9-8b and presented to the non-utility parties in the collaborative, as described in the introduction to §IV. In the early 1980s, when the VLS data was collected, high energy costs would encourage utilities to dispatch direct load control to avoid high-cost on-peak energy; in other words, to dispatch direct controlled water heaters like clock-controlled water heaters with the clocks set right (at least on weekdays).

A: The Company has computed the average effect of shifting *all* clock-controlled water heaters to uncontrolled status. Indeed, Spinner and Anderson argue that incremental clock control should be evaluated as if there were no control at all (p. 16), and ask, "Should not the hour that *would have been* the peak... be the high-cost hour to serve rather than the actual peak hour?" p. 9, ls. 10–13.[52]

In the past, load control was helpful in flattening short-duration peak loads on the system peak day. As CV demonstrated in Docket No. 4364, its load shapes has become considerably flatter over time (Testimony of H. M. Spinner, Docket No. 4364, p. 9; Exhibit HMS-2, p. 2).[53] Even by 1986 CV found "there is little room for newly shifted load during the day without creating a new peak" (Spinner, p. 9).

In some years, decontrolling a substantial number (e.g., 10,000) of existing water heaters would reduce load; decontrolling the remainder would increase load, as the uncontrolled water heaters contributed to a new peak load. The fact that the first 5,000 or 10,000 clocks, installed decades ago, reduced peak load is not relevant to the question of whether maintaining or increasing the 22,500 existing clocks reduces load. The potential for a new peak from decontrolling electric water heaters can be avoided by switching some water heaters to another fuel.

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[52]In his letter to Ennis Gidny, attached to IR 5-52, Spinner argues that, on 1/16/92 (when loads were well below peak levels), load control saved-generation capacity costs of $10–60/kWh-yr. of control, even though the load control had no effect on CV's actual peak.

[53]I cannot determine which measure of load Spinner used to illustrate his point. The load shown in Exhibit HMS-2 appears to be at the level of the Anderson data (including wheeling loads), but shows a 1-p.m. peak (consistent with the FERC Form), rather than the 8-a.m. peak in the company's system-load data.

Q: How does CV unrealistically model load in potential alternative peak hours?

A: The Company assumes that no real-time controls would be available in hours that might become the peak hour if the clocks were removed: there is no ripple control at new peak; no ski interruptions, no corporate or public peak alert (IR 5-65).

Central Vermont has repeatedly refused or otherwise failed to provide any data whatsoever on the historic use of ripple control (IR 5-39, 5-125, 9-22). Rather than estimating the effects of dispatchable load control in Exhibits SRA-2 and SRA-4 of Spinner and Anderson, and Exhibits SRA-2 and SRA-3 in Anderson's Supplemental, CV responds that dispatch was "not contemplated for this analysis" (IR 5-65).

Q: In what respect does CV use the wrong system load data?

A: The Company's analysis uses system data that is higher than, and peaks at times different from, both CV's and VELCo's actual peaks.[54] The load data apparently includes loads of other utilities wheeled across CV (IR 9-23).

Exhibit ___ PLC-30 juxtaposes the system data that CV used in its load-control analyses to peak loads reported by CV in its FERC Form 1, Jim Cater's Rebuttal Docket 5294, and the 1991 IRP (which may exclude losses). These loads are almost always different, and the Company's load-control loads are consistently higher than the other sources. The Company based its load-control analysis on peak loads that frequently occur at different times or days than those that CV reported to FERC.

[54]The Company appears to use the same defective data for dispatching ripple control and interruptible loads, severely limiting the usefulness of those options.

Exhibit ___ PLC-31 compares CV's reported monthly peaks from the 1992 FERC Form 1 to VELCo's reported peaks for 1992. Again, peak loads are different, and the times and date of peaks are frequently different.[55]

In short, the hourly system load data that CV provided for 1982–90 (excluding the lost 1987 data), and the two hours provided for 1992, were not CV's own loads, as reported in CV's FERC Form 1 filings or as computed by VELCo. Based on a partial reconciliation and explanation of these differences CV provided in IR 9-23, the data used in CV's load analyses and in dispatch of interruptible contracts (IR 5-52) appears to be the CV area load, including the loads of other utilities within CV's control area to whom CV provides wheeling service. This load measure has no effect on CV's costs, which are determined by VELCo and CV native load peaks.

Q: Why does CV use the wrong load data?

A: I do not know. Perhaps this is the only data available to CV in real time (for dispatch) and on an hourly basis (for analysis of clock-controlled water heater loads). If so, CV's ability to use ripple control, interruptible contracts, and other load controls is limited, and the value of these resources is likely to be small.

Q: Is the analysis based on CV metered data any better?

A: This analysis shares most of the problems of the earlier analysis using only VLS data. The Company has not provided any intermediate results, including

[55]The actual 1992 peak at 1 p.m. on 1/17/92 is given as 416 MW in the FERC Form, 433 MW by VELCo, 471 MW in Spinner and Anderson's direct, and 469 MW in IR 5-53. Not only was is the data on which CV based its load-control analysis different from the other sources, but the Company could not report consistent values for the purposes of analyzing load control, even 1½ to 2 years after the fact.

the composite data used in estimating controlled loads in particular hours of earlier years,[56] or the levels or times of the actual or hypothetical monthly peaks loads. Since CV's data is specifically for clock-controlled water heaters, there would be no justification for the adjustment CV made to the VLS data, to remove assumed ripple effects. However, based on the data presented in Exhibit HMS-3, CV has apparently included Rate-14 commercial clock-controlled water heaters along with Rate 3 residential water heaters. Grange halls, stores, and churches should not be expected to exhibit the same load shapes as homes. The metered sample of residential and commercial customers is compared to the VLS residential-only uncontrolled water heater load.

2. *The Company Analysis of the January 1992 Peak*

Q: Please describe the analysis of the effect of load control on the 1/92 peak load in the direct testimony of Spinner and Anderson.

A: That analysis is very similar to CR load control analyses, except that CV appears to have manually selected two hours for analysis, and removed *all* load control from the alternative potential peak load. This analysis and the supporting discovery responses contain several inconsistencies.

Spinner and Anderson, in their direct testimony, state that, had the clock-controlled water heaters been uncontrolled, the potential peak at 6 p.m. on 1/16/92 would have been 475 MW, rather than the actual 444 MW that

[56]The metered data was provided only for the individual metered water heaters, for the actual days of metering. How CV weighted and applied these data to loads in earlier years remains a complete mystery. Since the 1991–93 metered data could have been transformed in any of a number of ways to be used in the analysis, RII cannot review or replicate CV's results.

CV says actually occurred. Yet CV's discovery response (IR 5-52) lists 45 MW of load reductions on 1/16/92, which (if taken seriously) would imply that the potential peak was 489 MW. The Company obviously did not believe its listing of load reductions, and refused to provide the computation underlying the 475 MW estimate.

The load reductions listed in IR 5-53 and 5-53, respectively, for the actual peak at 1 p.m. on 1/17 and the potential peak at 6 p.m. on 1/16 are implausible. Central Vermont assumes more than 1-kW load reduction for ripple, and about 1 kW for clock control.[57] As shown in Exhibit ___ PLC-32, the VLS data indicate that uncontrolled water heaters use only 0.64 kW at 6 p.m. on January weekdays, so the 7,500 ripple water heaters (which were controlled at that hour) would have saved 5 MW, not the 8 MW that CV claims. Both the CV metered data and the VLS data indicate that the clock-controlled water heaters use about 0.47 kW less than their uncontrolled counterparts, so their savings from 22,500 clocks is about 10 MW, not the 22 MW that CV assumes. With these corrections, the total area load on 1/16 with no controls would have been 474 MW, just 3 MW more than the actual area peak on 1/17.[58]

More important, analysis of clock control should not assume the removal of all other controls. The 20 MW in reductions due to ski

[57]This assumption is arbitrary, as the Company admitted in IR 5049 and 5050. Central Vermont suggests that savings a 8 p.m. can be estimated by comparing actual load at 6 p.m. to the maximum load during the day, rather than to uncontrolled loads (IR 5-49).

[58]All of these system loads include wheeling loads, and so are of limited relevance. All reports of CV's native peak give the time as 1 p.m. on 1/17; it is not clear when the Company's native peak would have occurred in the absence of control, or how close that load would have been to the actual peak.

interruptions, ripple control, and peak alerts can be retained, even if all clock controls are removed. Even if we discount the ski-area interruptions (because CV failed to interrupt these loads on the actual peak), just recognizing that the savings from ripple controls and alerts do not depend on clock control would reduce the reconstituted peak without clock control to 468 MW, less than the actual peak. In other words, removing all clocks (but maintaining other controls) would reduce peak load from 471 to 468 MW

Like the CR analyses, this analysis estimate the average, not marginal, load reduction due to decontrol.

E. The Company Cost-Effectiveness Analysis for Clock-Controlled Water Heaters

Q: What problems have you identified in the Company's cost-effectiveness analysis for clock-controlled water heaters?

A: In its analyses of the cost-effectiveness of load control, CV has ignored several costs of control, including:

- the increased energy (and hence demand) use of larger tanks and higher temperatures (see §IV.A),
- the cost of the larger tank, and
- the costs of meter reading, clock setting, maintenance, and billing, as estimated in CV's own marginal cost studies (as discussed in §IV.G).

Including these costs would decrease the attractiveness of controlling water heaters, even if they slightly reduced peak loads.

In its analyses of load control, CV assumes that distribution costs vary with its CR load proxy. This assumption is incorrect. Distribution costs are driven by various mixes of customer peaks and area peaks, which have little correlation with system peaks. The rapid and simultaneous recovery of water heaters after control periods may result in higher peak loads on many distribution elements. Hence, distribution costs are as likely to increase as decrease due to control. I pointed this fact out to CV in the collaborative, and have not yet seen any coherent explanation for CV's position. Central Vermont's testimony does not reveal that the cost-effectiveness results are based on this assumption, but has acknowledged it in discovery responses.

In Exhibits SRA-2 and SRA-3 in Anderson's supplemental testimony, the Company also assumes that externalities also vary with the CR proxy, and hence are decreased by load control (given CV's results). In fact, the externalities covered in the stipulation (mostly air pollution) are produced by energy use, not peak demand or CR. The Company has not presented any justification for claiming externality benefits from load control. Indeed, CV failed to disclose in its load-control testimony or in its discovery responses that it assumes that energy-related externalities are reduced by load control.

F. Resource Insight's Analysis of Controlled-DHW Contribution to Capability Responsibility

1. Clock-Controlled Water Heaters

a) Marginal Contribution to G&T Demand

Q: How did you estimate the marginal effect of clock-controlled water heaters on the need for generation and transmission?

A: I have examined the available data on the effect of CV's clock-controlled water heaters on CV's peak load. The only consistent source for hourly load data for uncontrolled and controlled water heaters is the Vermont Load Study

(VLS). I have computed the contribution of each type of water heater to the annual and monthly peak hours identified by various sources, for 1982–1993.

I conducted several analyses. In each analysis, I compared a set of system load data for each month in a time period with a set of estimates of clock-controlled and uncontrolled water heater loads at peak load for each month. The sources of system load data include

- the hourly load data for 1982–86 and 1988–90, provided by CV in response to IR 4-2, and used by Scott Anderson in Exhibits SRA-2 and SRA-4;
- the monthly peak loads reported in CV's FERC Form 1, for each year 1982-91;
- VELCo data on VELCo and CV monthly peaks for portions of 1992 and 1993;
- actual and projected peaks for 11/93–10/94, from Exhibit STAGE-1 in Docket No. 5701.

I used data on controlled and uncontrolled water-heater load shapes from the Vermont Load Study (VLS), and also compared the system data from 12/91 through 10/93 to data on clock-controlled water-heater load data from CV's metering study for the same period.[59]

Q: What were your results?

A: Exhibit ___ PLC-33 shows the results of my comparisons of various sets of system load data to the VLS water-heater data. Exhibit ___ PLC-34 provides the detailed monthly results supporting the capability responsibility values in

[59]The Company has not metered uncontrolled water heaters, so data on those loads must be taken from the VLS.

Exhibit ___ PLC-33. Unlike CV, I have provided detailed results, including the date and time of each monthly peak.

The results for CP and CR are generally similar for any one set of peak loads, although the results vary with the data set used. Both of the long-term sources of data for peak loads (CV's load-reduction-analysis data and its FERC-Form-1 data) indicate that clock-controlled water heaters have CP and CR that is 2–10% greater than those of uncontrolled water heaters.[60] Adjusting for the difference between the energy increase of controlled water heaters in the VLS data (13%) and that used in the RII/DPS analysis (5%), clock-controlled water heaters would impose demands quite close to those of uncontrolled water heaters.

Only very limited data are available on VELCo's reports of CV peaks, and on VELCo statewide loads: 18 or 19 months of actual data, plus one year of projections of CV's own loads. Since these are better approximations of the loads that actually affect CV's costs, the data limits are unfortunate.[61] For the 1992/93 power year, clocks contribute much more to CV's own load than uncontrolled water heaters (as much as 0.4 kW, or 80% of uncontrolled load, Exhibit ___ PLC-33). The Company's projection of its own loads for 1993/94 results in loads about 0.07 kW lower for clock-controlled than uncontrolled water heaters. In the full data set (Exhibit ___ PLC-34),

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[60]The missing 1987 data would probably produce results that are still less advantageous for load control, since that year produced the least favorable results in Exhibit SRA-2 in the testimony of Spinner and Anderson.

[61]The Company indicated that it had only the data contained in the VELCo reports already in the Department's possession (IR 5-131).

controlled load exceeds uncontrolled load in three of the four peak-month (December and January) CV peak hours.

The clocks perform better on VELCo state peak hours, which tend to fall in the early evening, than on CV's mid-day peak hours. Clock load exceeds uncontrolled load in only one of the three peak-month VELCo peak hours: on the January 1992 peak (the annual peak), clock load was 0.1 kW greater than uncontrolled load. On the 1992/93 power year peak (12/8 at 6 p.m.), the clocks saved 0.07 kW compared to uncontrolled; in the peak hour for January 1993 (not a very high load month), they saved 0.38 kW. It is difficult to interpret these very limited and erratic results. Overall, they suggest that the clocks are creating peaks very similar to the uncontrolled water heaters.

Q: Did you get similar results for the water-heater-load data from CV's metering project?

A: The general pattern is similar. In Exhibit ___ PLC-35, I compare CV's metered load data for clock-controlled water heaters to VLS data for uncontrolled water heaters, for FERC Form (12/91–12/92) and VELCo peaks (12/91–10/93).[62] Again, the data are limited and erratic.

Using the FERC Form data, the controlled water heaters perform poorly for 1992, since their load was much greater than the uncontrolled load at the peak hour (1 p.m. 1/12/92). The clocks work better at the 6 p.m. peaks reported in the FERC forms for December of 1991 and 1992; if we assume that each of the three peak months for which we have data are equally meaningful, the average peak is slightly lower with clocks than without.

[62]The CV metered data is normalized to 4,200 kWh/year.

The VELCo data for CV's own peak does not include December 1991, and it reports 12/92 and 1/93 midday peaks, at which the clock loads are considerably higher than uncontrolled. Many of the off-peak months that have 8 a.m. or 6 p.m. peaks in the FERC data also have midday peaks in the VELCo data, and again clocks perform poorly. Over any period in this data set, clock loads are much worse than uncontrolled loads.

The VELCo data for statewide peaks are dominated by evening and early-morning peaks; thus, the resulting CP and CR values resemble the FERC data.

Q: Please summarize the results of these analyses.

A: The longer data series for system load, from the Anderson data and the FERC Forms, indicate that clocks produce peak loads and CR very similar to uncontrolled loads. The VELCo load data, which is closer to the loads for which CV is actually billed, is very limited, but indicates that clocks contribute much more to peak than do uncontrolled water heaters. The clocks perform better (on average) than uncontrolled water heaters on Vermont state peak hours, at least for the limited available sample of 1992 and 1993 peaks.[63]

Q: What load effects have you assumed for clock-controlled and uncontrolled water heaters?

[63]The future performance of clock controls may be affected by the relative growth of residential (evening) load and non-residential (mid-day) load. The Company expects its commercial and industrial sales to grow faster than residential sales (IR 4-59). In general, any trends that smooth out load curves tend to decrease the value of the clocks, while increasing peakiness increases the value of the clocks.

A: For analysis of the cost-effectiveness of controlling or decontrolling clock-controlled water heaters, and to compute the benefit of fuel switching, I used the load factors shown in Exhibit ___ PLC-36. All distribution costs are estimated based on a 72% equivalent load factor. Capability responsibility is assigned a slightly higher load factor, which is essentially offset by the increased energy use.[64]

The bottom line is that clock control of water heating does not appear to be effective in reducing loads, and may well increase coincident peak. Central Vermont does not appear to be particularly concerned about whether the controls are effective, as indicated by its concentration on using Rate 3 for retaining load, rather than reducing peak, and by CV's lack of interest in the correct operation of the clocks (IR 5-82; Spinner and Anderson, p. 21).

b) Average Contribution to Demand

Q: How did you compute the average contribution to CR of clock-controlled water heaters?

A: As summarized in Exhibit ___ PLC-37, I repeated the CV analysis of hourly load effects of removing 22,500 clock-controlled water heaters from CV' system-load data, and adding 22,500 uncontrolled water heaters. I determined the date, time, and load for each monthly peak, and computed the CR proxy, for both the CV system-load data and the total system load with the hypothetical effect of decontrol. The monthly detail for Exhibit ___ PLC-37 is contained in Exhibit ___ PLC-38. The accuracy of this analysis is limited

[64]The increased energy use only is balanced by the increase in load factor because I assume all water heaters are highly efficient, and hence have low standby losses. The average installed controlled water heater probably has greater standby losses.

by my reliance on CV's system-load data, which does not identify the correct peak hours or load level.

Q: Please describe your results.

A: In four of the eight years for which I have data, uncontrolled water heaters contribute more to CR than do clock-controlled water heaters, and increase load at the actual peak hour, which remains the peak hour as load rises. In the four other years (1984, 1985, 1988, and 1990), uncontrolled water heaters impose a lower load at the actual peak hour than do clock-controlled water heaters. In each of these four years, the decontrol of all clock-controlled water heaters increases load in some other hour, so that decontrol would shift the peak. In three years, the peak with uncontrolled water heaters would exceed the peak with clock-controlled water heaters. In 1984, the decontrolled peak is still lower than the controlled peak.[65] As discussed above (§IV.D.2), the 1992 peak is also lower without control.

These results, shown in Part B of Exhibit ___ PLC-37, are only part of the story. In each of the four years with shifting peaks, the shifted peak occurs after the actual peak. The Company is unlikely to have used peak alerts on these hours (except perhaps in 1985, for which the peak shifts from February to the next December), and may well not have dispatched ripple control or interruptible loads.[66] Part C shows the reduction in the shifted peak if just one load management measure, ripple control, were available on the shifted hour. While ripple may not have been available in all these hours,

[65]The same is true for 1987 in CV's analysis (Exhibit SRA-2, Spinner and Anderson). The Company has since lost this load data, which were the data least favorable to clock-control in Anderson's original analysis.

[66]The Company has no rules for the use of alerts (IR 9-9) or ripple (IR 9-8).

additional controls (alerts and interruptibles) may have been available in some. With this adjustment, the increase in peak load with all clock-controlled water heaters decontrolled is just 0.1 kW per water heater. If the 1987 data were available, the average would apparently be zero or slightly negative.

c) Load-minimizing control level

Q: For the years with shifting peaks, how many clock-controlled water heaters can be decontrolled before the peak starts to shift?

A: Exhibit ___ PLC-39 shows this computation for each year. For 1985 and 1988, the peak shifts after 3,000 or 4,000 water heaters are decontrolled. In 1990 and 1992, more than 13,000 water heaters must be decontrolled before the peak shifts. For 1984, 21,500 water heaters (probably more than are currently clock-controlled) would have to be decontrolled before the peak would shift.

2. Ripple-Controlled Water Heaters

Q: How did you estimate the CR load benefits of ripple-controlled water heaters?

A: Central Vermont has not provided any data on the actual operation of its ripple-controlled water heaters, other than the metered end-use data from 1991–1993, despite repeated requests (IR 5-85, 9-8c, 9-22)—although the Company offered to let the Department review CV's books. The Company apparently sees no need to collect or review these data for its won use. The Board cannot even infer a usage pattern from CV's rules for dispatching ripple, since CV says it has no such rules (IR 9-8(a)).

The data available from the metering project indicates that CV has not usually turned off the ripple water heaters at the time of CV or VELCo peak loads. Exhibit ___ PLC-40 lists the average load of the metered ripple water heaters for which there were complete data, for each peak hour identified by CV FERC forms or VELCo, and with the data normalized to 4,200 kWh annually. In a few peak hours, the loads are exactly zero; in a few others they are so low that the water heaters must have been controlled for most of the hour. Ripple controls appear to have been used in 2 of 13 monthly peak hours available from FERC (including 1 of 3 December or January peaks), 4 of 18 CV peaks available from VELCo (including 1 of 3 December or January peaks), and 7 of 19 VELCo peaks (including 2 of 3 December or January peaks).

The average peak-month peak is about 0.4 kW, and the CR proxy would also be about 0.4 kW. These values are only slightly lower (if at all) than uncontrolled or clock-controlled water heaters.

It is not clear why CV does not use its ripple controls consistently at the monthly peak hours. Data availability may preclude effective use of ripple and other real-time controls. As noted above, CV's hourly system load data appears to be the CV area load, including wheeling loads of other utilities within CV's control area. The Company may be using the area load data for dispatch of ripple control, and may thus be unable to identify the proper hours for control of the ripple water heaters.

This explanation is consistent with the observation that CV did not use its interruptible contracts on the reported CV peaks in 12/89, 1/90, 1/91, or 1/92 (IR 5-85). Using the interruptible load is a more complex decision than using ripple, and the interruptible load is not always on line to be interrupted, so the analogy to ripple is not perfect.

Q: What peak loads do you assume for ripple control?

A: Given the very limited data available, I have assumed that ripple works considerably better than the data implies. I assume a CR of about 30% of a clock or uncontrolled water heater, or 0.19 kW.

3. *Summary of Water Heater Load Shapes*

Q: What water-heater load shapes did you utilize in screening DSM options?

A: The demand values are summarized in Exhibit ___ PLC-36. Assuming all water heaters are efficient models or well wrapped, clock-controlled water heaters closely resemble uncontrolled water heaters in terms of CR and CP, because the slight improvement in load factor is offset by increased energy use. Ripple-controlled water heaters have CRs about 30% of the uncontrolled levels. The load factor on the distribution system (measured in coincident-peak equivalent kWs) is the same for all water heaters, so the distribution load is slightly higher with control.

The split of energy use between periods is covered in the testimony of Mr. Wallach. Resource insight generally accepted CV's allocation of water-heater energy to time periods, but rejected CV's assumption that control shifts energy from winter to summer. The Company's asserts that the collaborative "agreed to" this assumption (IR 5-59), but my recollection is that I corrected this error during the collaborative process and CV ignored the correction.

G. Costs of Control

Q: What are the costs of load control?

A: There are several such costs, some of which have been discussed above.

- Energy use increases with control, due to higher temperature settings and larger tanks necessary to maintain storage capacity with control. Resource Insight's screening has assumed a 5% increase in energy use. This increased energy use also increases peak demands, especially for the distribution system.
- The larger tank needed for control is more expensive than the tank that would be adequate for the uncontrolled water heater. This would add perhaps $50 to the costs of control, based on the difference between 50 gallon and 80 gallon tank costs reported in IR 1-14, Docket 5624. This cost differential should be increased to reflect somewhat higher installation cost for the larger tank and the early retirement of undersized tank.[67] RII did not actually use this cost in its analyses, since modeling the timing of the replacement was complex, and since load control failed even without it.
- If customers do not raise the temperature and/or size of their tank enough to maintain hot water supply, they incur a cost of lost service value. As estimated in §IV.A.2, this cost might average $40/year for a customer who did not adapt at all. Since we had no data on the actual pattern of responses to load control, we assumed this cost was covered by our allowance for increased energy usage.

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[67]The differential in installed cost for 50 and 80 gallons was reported as $135 in New York State Electric and Gas Corporation, "Residential Demand-Side Management: Program Design Report," October 14, 1990.

- Central Vermont incurs make-ready and meter-installation costs, which it estimates to be about $150 for each category (Spinner and Anderson Exhibits SRA-3 and 5; Anderson Exhibits SRA-2 and 4). In IR 5-87, the Company estimates that the installed cost of the Rate 3 meters is $120. We accept the lower figure, and assume a utility capital cost of $270, in 1993 dollars.
- Keeping a customer on Rate 3 requires that the meter be read, reset, recalibrated, and maintained; that billing data be entered into CV's billing system; and that CV respond to customer questions and complaints about their bills. The Company's estimate of all but the customer service costs is $19.46 in 1988 dollars (testimony of J. C. Cater, Docket No. 4364, Exhibit JCC-7).[68] While CV believes for the purposes of screening load control that the incremental metering and billing costs of Rate 3 are "small" (IR 5-63) or "very small" (IR 9-32), I relied on CV's estimate of the actual costs, as prepared for rate design. To this estimate, some customer service costs should be added: the embedded cost of service study in Exhibit JCC-1, Docket No. 4364, assigns about $4.50/yr. (1987 dollars) to Rate 3. I did not explicitly include customer service costs, but I treated CV's estimate of the marginal customer charge as though it were in 1987 dollars.[69] The resulting marginal utility O&M cost (including overheads) for load control is $34 in 1993 dollars, as shown in Exhibit ___ PLC-41.

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[68]This value is restated in IR 9-32 as $20.90 in 1990 dollars.

[69]The Company said that T&D O&M costs were measured in 1987 dollars when in fact they were in 1986 dollars. I cannot determine whether CV made the same error for metering costs.

V. Conclusions and Recommendations

Q: Please summarize your conclusions from the analyses you described above.

A: First, CV's estimates of avoided costs are understated. The actual benefits of energy efficiency and fuel switching are likely to be much higher than CV's estimates.

Second, clock control of water heaters has very little, if any, benefit for reduction of CV's generation and transmission costs, and may actually increase those costs.

Third, the load reductions, if any, due to ripple control of water heaters are highly uncertain. The Company has not implemented ripple control consistently on peak hour in recent years, and CV has refused to provide any data on its use of ripple in earlier periods. Based on recent experience, ripple appears to reduce uncontrolled water-heating peak loads by roughly one third, or about 0.2 kW per water heater.

Fourth, CV's screening of load control understates the costs of control, by ignoring the increased energy costs, tank costs, and metering O&M, and overstates the benefits by assuming that load control reduces distribution costs and energy-related externalities.

Fifth, based on the screening results in Mr. Plunkett's testimony, which use realistic avoided costs and benefits, the installation or retention of existing clock controls is clearly not cost-effective, compared to either uncontrolled water heating or alternative fuels (for many combinations of loads and fuel sources). This is likely to remain true unless large number of clock-controlled water heaters are decontrolled, or some other factor causes new peak loads in the early morning or evening.

Sixth, the screening results indicate that, even if ripple is twice as effective in reducing peak loads as the recent data would indicate, installation of new ripple controls is not cost-effective, except for the very-high-use bin of customers. Retaining ripple control for existing customers (who require no make-ready or meter installation work) may be cost-effective for high- and even medium-use customers, compared to uncontrolled usage. Fuel-switching of ripple-controlled water heaters is quite cost-effective in many situations.

Q: What are the implications of your analyses for the fuel-switching issues in Dockets 5270 CV-1 and CV-3?

A: The Board should rely on the screening results derived from the avoided costs I developed above, rather than CV's understated avoided costs. These are presented in the testimony of Mr. Plunkett.

The screening results indicate that fuel-switching of uncontrolled and controlled water heaters is cost-effective for a wide range of energy consumption, cost of installation, alternative fuels, and heating systems. Clock-controlled water heaters are just as attractive targets for fuel-switching as are uncontrolled water heaters, while ripple-controlled water heaters (even with conservation measures) are attractive targets for switches to natural gas or oil (especially in homes heated with oil), but only rarely to propane or kerosene.[70] Hence, the DSM program should include fuel switches for clock-controlled and ripple-controlled water heaters.

Q: Are the avoided costs you developed suitable for field screening of fuel switching?

A: Yes, with one exception. The two sets of avoided costs used in the DPS-RII fuel-switching analyses give slightly different results. The bundled avoided costs (structured similarly to CV's avoided costs for energy efficiency) assume a load factor of 65%, while the unbundled avoided costs assume load factors (for all distribution costs and for uncontrolled and clock-controlled generation and transmission costs) of about 72%. Fuel switching is cost-effective for lower usage and higher installation costs with the bundled avoided costs than the unbundled avoided costs. Since we screen fuel switching of the uncontrolled water heaters with the bundled avoided costs, and switching controlled water heaters with the unbundled costs, fuel-switching passes the screen more readily for uncontrolled than controlled water heating, all else equal. This screening approach is adequate for the purposes of this docket, such as determining the scale and cost of cost-effective fuel-switching, but it should be refined prior to field application.

The treatment of demand costs in these two sets of avoided costs follows CV's practice of bundling all costs into energy or leaving all demand

[70]Resource Insight's comparison of electric conservation to fuel switching of controlled water heaters is somewhat biased in favor of electricity. The low differential in energy usage due to control assumes that all tanks are wrapped (in the initial audit or previously), while the conservation package computes energy savings for wrapping water heaters. Hence, we have tended to overstate the conservation potential for water heater wraps, decreasing the number of situations in which fuel switching appears to be the least-cost option.

costs unbundled. Unbundling of generation costs is desirable, since the times of system peak loads and measure contribution to those peaks can be determined (although sometimes with some difficulty, as demonstrated in §IV). As discussed above, however, distribution costs are driven by a variety of loads, which are much harder to identify and measure than the system peak hours. Hence, CV's bundled approach is a better approximation of the causation of distribution costs.

I therefore recommend that the field screening for water heater fuel switching use avoided costs that bundle distribution costs into energy, but leave generation and transmission unbundled.

Q: What are the implications of your analyses for the load control investigation in Docket 5686?

A: Switching additional uncontrolled water heaters to load control does not appear to be cost-effective, even to maintain current numbers of controlled water heaters. The discount for Rate 3 (and probably Rate 14) is not justified by the cost of serving controlled water heaters, and cannot be justified by the benefits of switching uncontrolled water heaters to control.

It is clear from CV's position in this docket that its real interest in Rate 3 is not the savings available from controlling electric water heaters, but the ability of the low rates to promote electric water heating over alternative fuels (e.g., IR 5-99, 5-108). Since heating water is less expensive with other fuels, the Rate 3 discount cannot be justified by its role in maintaining CV's competitive position in the water-heating market.

Hence, CV should be ordered to stop permanently all promotion of Rate 3 and the rate should be closed to new customers. The current discount for Rate 3 should be reduced over time, to provide rate relief to the rest of CV's customers (who have borne the excess costs of this rate for some time), and to encourage cost-effective fuel-switching.[71]

Unless CV can demonstrate some countervailing consideration, Rate 14 should also be closed and the discount reduced.

Q: For how long should Rate 3 remain closed?

A: Rate 3 might be reopened for new ripple control of large water-heating customers who are not suitable for or decline fuel switching. Before Rate 3 is reopened, even for this limited purpose, CV should be required to demonstrate that ripple control can and will be operated in a manner that is likely to be cost-effective. Unless ripple can be dispatched very reliably at actual peak hours, its benefits are unlikely to exceed the metering costs.

Clock control of water heaters is not likely to be cost-effective unless CV's peak-day load shapes become considerably less flat than they are today. Clock control is only helpful if potential peak hours are distinct and predictable.

Q: Does this conclude your testimony?

A: Yes.

[71]Spinner suggests that any rate price above (marginal) cost should remain open for new business (IR 5-98). This suggestion ignored customer responsibility for imbedded costs. Since Rate 3 is not cost effective, customers on that rate contribute less to embedded revenue requirements than do customers on Rate 1.

Derivation of CV Avoided Costs with Corrections

TABLE 1: AVOIDED FUEL AND O&M COSTS ($/MWH)

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	WINTER ON-PEAK	23.44	24.51	27.32	24.39	21.47	28.43	37.39	33.11	32.96	36.39	36.74	34.96	36.18	38.48	38.91	42.52	47.29	47.39	53.79	62.31
	SHOULDER	23.50	24.60	27.72	25.20	22.80	29.25	38.01	34.02	33.61	37.29	37.71	35.76	36.99	39.48	39.88	43.60	48.52	48.59	55.19	63.88
	OFF-PEAK	20.61	21.48	22.20	13.18	10.21	19.80	32.76	21.64	27.16	26.02	24.47	27.35	29.30	27.19	29.08	33.14	36.44	37.76	43.75	49.89
	SUMMER ON-PEAK	20.17	20.78	22.65	23.00	18.10	30.98	40.69	32.99	37.33	37.47	40.42	39.00	39.03	45.49	45.15	49.88	51.23	57.19	59.24	64.48
	OFF-PEAK	17.08	16.91	20.06	15.84	10.33	24.41	36.49	21.32	29.24	27.71	27.71	32.72	31.88	32.60	37.59	38.40	43.36	47.77	50.10	55.32
	WINTER AVERAGE	22.24	23.23	25.20	19.73	16.88	24.88	35.52	28.36	30.59	32.12	31.66	31.84	33.38	33.82	34.87	38.69	42.86	43.48	49.74	57.27
	SUMMER AVERAGE	18.46	18.64	21.22	19.04	13.80	27.34	38.36	26.53	32.85	32.08	33.38	35.52	35.07	38.35	40.96	43.52	46.87	51.98	54.18	59.41
	ANNUAL AVERAGE	19.72	20.17	22.54	19.27	14.83	26.52	37.42	27.14	32.10	32.09	32.81	34.30	34.51	36.84	38.93	41.91	45.53	49.15	52.70	58.70

TABLE 1A: AVOIDED CAPITALIZED ENERGY COSTS

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	TOTAL ($1000)																				
	$/kW-yr	0	0	0	0	0	44.00	38.13	48.52	58.02	69.68	86.17	100.03	116.65	131.82	137.58	143.57	149.83	156.37	163.19	170.30
$/MWH	WINTER ON-PEAK	0.00	0.00	0.00	0.00	0.00	8.24	6.66	10.34	10.41	13.92	16.85	17.81	21.37	24.05	24.02	25.45	27.18	26.33	29.09	31.58
	SHOULDER	0.00	0.00	0.00	0.00	0.00	8.47	6.77	10.63	10.62	14.26	17.30	18.22	21.84	24.67	24.62	26.09	27.88	26.99	29.84	32.37
	OFF-PEAK	0.00	0.00	0.00	0.00	0.00	5.74	5.83	6.76	8.58	9.95	11.22	13.93	17.30	16.99	17.95	19.83	20.94	20.98	23.66	25.28
	SUMMER ON-PEAK	0.00	0.00	0.00	0.00	0.00	8.97	7.25	10.31	11.79	14.33	18.54	19.87	23.05	28.43	27.87	29.85	29.44	31.77	32.03	32.68
	OFF-PEAK	0.00	0.00	0.00	0.00	0.00	7.07	6.50	6.66	9.24	10.60	12.71	16.67	18.83	20.37	23.20	22.98	24.92	26.54	27.09	28.03
	WINTER AVERAGE	0.00	0.00	0.00	0.00	0.00	7.21	6.32	8.86	9.66	12.28	14.52	16.22	19.71	21.13	21.52	23.16	24.63	24.15	26.90	29.02
	SUMMER AVERAGE	0.00	0.00	0.00	0.00	0.00	7.92	6.83	8.29	10.38	12.27	15.31	18.10	20.71	23.97	25.29	26.05	26.94	28.88	29.30	30.11
	ANNUAL AVERAGE	0.00	0.00	0.00	0.00	0.00	7.68	6.66	8.48	10.14	12.27	15.05	17.47	20.38	23.02	24.03	25.08	26.17	27.30	28.50	29.74

TABLE 1B: OFFSYSTEM SALES

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	WINTER ON-PEAK	0.84	1.63	0.74	2.69	5.06	0.71	0.15	0.20	0.00	0.17	0.22	0.12	0.00	0.05	0.03	-0.01	-0.01	0.02	0.00	0.01
	SHOULDER	0.84	1.63	0.75	2.78	5.38	0.73	0.16	0.20	0.00	0.17	0.22	0.12	0.00	0.05	0.03	-0.01	-0.01	0.02	0.00	0.01
	OFF-PEAK	0.74	1.42	0.60	1.45	2.41	0.50	0.13	0.13	0.00	0.12	0.15	0.09	0.00	0.04	0.02	-0.01	-0.01	0.01	0.00	0.01
	SUMMER ON-PEAK	0.72	1.38	0.61	2.54	4.27	0.77	0.17	0.20	0.00	0.17	0.24	0.13	0.00	0.06	0.03	-0.01	-0.01	0.02	0.00	0.01
	OFF-PEAK	0.61	1.12	0.54	1.75	2.44	0.61	0.15	0.13	0.00	0.13	0.16	0.11	0.00	0.04	0.03	-0.01	-0.01	0.02	0.00	0.01
	WINTER AVERAGE	0.80	1.54	0.68	2.18	3.98	0.62	0.15	0.17	0.00	0.15	0.19	0.10	0.00	0.05	0.02	-0.01	-0.01	0.01	0.00	0.01
	SUMMER AVERAGE	0.66	1.24	0.57	2.10	3.25	0.68	0.16	0.16	0.00	0.15	0.20	0.12	0.00	0.05	0.03	-0.01	-0.01	0.02	0.00	0.01
	ANNUAL AVERAGE	0.71	1.34	0.61	2.13	3.50	0.66	0.15	0.16	0.00	0.15	0.19	0.11	0.00	0.05	0.03	-0.01	-0.01	0.02	0.00	0.01
	Dispatch + Sales	20.43	21.51	23.15	21.39	18.32	27.18	37.57	27.30	32.10	32.24	33.00	34.41	34.51	36.89	38.96	41.91	45.52	49.16	52.70	58.70
	Total Energy	20.43	21.51	23.15	21.39	18.32	34.87	44.23	35.78	42.24	44.51	48.05	51.88	54.89	59.92	62.99	66.99	71.69	76.47	81.20	88.45

TABLE 2: AVOIDED GENERATION AND TRANSMISSION CAPACITY COSTS

			1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
$/kW CP	GENERATION [1]		0.00	0.00	0.00	0.00	0.00	6.49	15.44	27.43	42.13	58.87	77.84	107.13	111.75	116.57	121.59	126.84	132.31	138.01	143.96	150.17
	TRANSMISSION [1]		0.00	0.00	0.00	22.13	23.19	24.30	25.47	26.69	27.97	29.31	30.71	32.18	33.72	35.34	37.03	38.81	40.66	42.61	44.65	46.79
	SUB TOTAL		0.00	0.00	0.00	22.13	23.19	32.16	44.15	59.88	78.94	100.54	124.90	161.81	168.94	176.39	184.16	192.28	200.76	209.60	218.84	228.50
$/kW CR		0.95	0.00	0.00	0.00	23.30	24.41	33.85	46.48	63.03	83.10	105.83	131.47	170.33	177.83	185.67	193.85	202.40	211.33	220.64	230.36	240.52
$/MWH	TOTAL G & T		0.00	0.00	0.00	3.87	4.05	5.61	7.71	10.46	13.80	17.71	21.81	28.26	29.51	30.81	32.17	33.60	35.06	36.60	38.22	39.91
	Emissions		6.71	7.73	6.39	13.73	6.06	21.83	24.54	15.84	17.83	15.23	14.82	15.80	11.56	12.98	13.01	13.51	13.74	15.07	15.59	16.38
	TOTAL G & T & Emis		6.71	7.73	6.39	17.60	10.11	27.45	32.26	26.30	31.62	32.94	36.63	44.06	41.07	43.78	45.18	47.10	48.80	51.67	53.80	56.29
	WINTER ON-PEAK		20.95	24.15	19.97	55.00	31.61	85.72	100.86	82.18	98.79	102.50	114.44	137.73	128.35	136.87	141.21	147.18	152.45	161.55	168.10	176.08
	SHOULDER		16.34	18.83	15.57	42.93	24.67	66.89	78.67	64.15	77.11	79.92	89.25	107.50	100.18	106.83	110.22	114.88	118.89	126.10	131.10	137.34
[2]	OFF-PEAK		5.72	6.60	5.45	15.02	8.63	23.41	27.53	22.45	26.98	28.12	31.26	37.62	35.06	37.38	38.57	40.20	41.61	44.12	45.88	48.06
	SUMMER ON-PEAK		7.29	8.39	6.94	19.10	10.98	29.80	35.02	28.55	34.33	35.69	39.76	47.82	44.58	47.52	49.04	51.13	53.00	56.06	58.42	61.08
	OFF-PEAK		0.01	0.01	0.01	0.03	0.02	0.05	0.06	0.05	0.06	0.06	0.07	0.08	0.08	0.08	0.09	0.09	0.09	0.10	0.10	0.11

NOTES:
[1]: FROM TABLE 2a, RISES 4.79% ANNUALLY.
[3]: ALLOCATED TO PERIODS BASED ON ALLOCATION FACTORS IN Ex JCC-3, p. 4 (8/15/88 filing).

TABLE 2a: TRANSMISSION COST SUMMARY ($/kw)

$11.56	CV 1987$ CARRYING COSTS, Ex JCC-5, DOCKET 4634.		
$2.81	PLUS CV 1987$ O&M, Ex JCC-5		
$14.37	EQUALS TOTAL 1987$/kw		
$16.68	TOTAL 1990$/kw		
$19.24	TOTAL 1993$/kw	Inflates @	4.79%

TABLE 3: AVOIDED DISTRIBUTION COST

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
$/KW CP	DISTRIBUTION [1]				64.08	67.15	70.37	73.74	77.27	80.97	84.85	88.91	93.17	97.63	102.31	107.21	112.35	117.73	123.37	129.28	135.47
$/MWH	DISTRIBUTION	0.00	0.00	0.00	11.19	11.73	12.29	12.88	13.50	14.15	14.94	15.53	16.27	17.06	17.87	18.73	19.63	20.56	21.54	22.58	23.66
–	WINTER ON-PEAK	0.00	0.00	0.00	34.20	35.84	37.50	39.38	41.24	43.21	45.46	47.42	49.72	52.11	54.60	57.22	59.96	62.79	65.84	68.95	72.35
|	SHOULDER	0.00	0.00	0.00	13.17	13.80	14.44	15.16	15.88	16.65	17.49	18.25	19.15	20.07	21.03	22.04	23.10	24.17	25.36	26.54	27.85
[2]	OFF-PEAK	0.00	0.00	0.00	14.11	14.78	15.47	16.24	17.01	17.83	18.84	19.56	20.51	21.50	22.53	23.61	24.74	25.89	27.16	28.43	29.83
|	SUMMER ON-PEAK	0.00	0.00	0.00	7.52	7.88	8.26	8.66	9.07	9.51	10.02	10.43	10.93	11.46	12.00	12.58	13.19	13.82	14.47	15.17	15.89
–	OFF-PEAK	0.00	0.00	0.00	4.67	4.89	5.13	5.38	5.63	5.90	6.26	6.48	6.79	7.12	7.45	7.81	8.19	8.58	8.99	9.42	9.87

NOTES:
[1]: TOTAL FROM TABLE 3a, RISES 4.79% ANNUALLY
[2]: SEE NOTE 3, TABLE 2, ALLOCATION FROM PAGE 5, Ex JCC-3.

TABLE 3a: DISTRIBUTION COST SUMMARY ($/kw)

PRIMARY	SECONDARY	
$19.05	$2.86	BASE COST
$9.46	$0.79	O & M
$28.51	$3.65	TOTAL 1987$/kw, CV KW
$33.10	$4.24	TOTAL 1990$
91,388	209,532	CV KW, Ex JCC-5
81,010	81,010	SYSTEM PEAK kw, Ex JCC-5
$37.34	$10.96	1990 TOTAL $/KW SYSTEM PEAK
	$48.30	DISTRIBUTION TOTAL, 1990$/KW
	$55.69	DISTRIBUTION TOTAL, 1993$/KW

TABLE 4: TIME DIFFERENTIATED AVOIDED ENERGY CONSUMPTION

GIGAWATT HOURS	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
WINTER ON-PEAK	15	15	15	14.99	14.99	15.01	14.98	14.99	14.99	14.93	15	14.99	14.99	14.99	14.99	14.99	15	14.99	15	14.98
SHOULDER	6.82	6.82	6.82	6.81	6.81	6.82	6.81	6.81	6.81	6.79	6.82	6.81	6.81	6.81	6.81	6.81	6.82	6.81	6.82	6.81
OFF-PEAK	16.36	16.36	16.36	16.35	16.36	16.37	16.35	16.35	16.35	16.21	16.36	16.35	16.35	16.35	16.35	16.35	16.37	16.35	16.37	16.35
SUMMER ON-PEAK	34.06	34.07	34.06	34.08	34.08	34.09	34.07	34.07	34.06	33.86	34.09	34.09	34.08	34.09	34.08	34.07	34.07	34.11	34.08	34.1
OFF-PEAK	42.24	42.25	42.24	42.26	42.26	42.26	42.25	42.25	42.24	41.76	42.26	42.26	42.26	42.27	42.26	42.25	42.25	42.28	42.26	42.27
WINTER TOTAL	38.18	38.18	38.18	38.15	38.16	38.20	38.14	38.15	38.15	37.93	38.18	38.15	38.15	38.15	38.15	38.15	38.19	38.15	38.19	38.14
SUMMER TOTAL	76.30	76.32	76.30	76.34	76.34	76.35	76.32	76.32	76.30	75.62	76.35	76.35	76.34	76.36	76.34	76.32	76.32	76.39	76.34	76.37
ANNUAL TOTAL	114.48	114.50	114.48	114.49	114.50	114.55	114.46	114.47	114.45	113.55	114.53	114.50	114.49	114.51	114.49	114.47	114.51	114.54	114.53	114.51

TABLE 5. TOTAL DIRECT BASE-CASE AVOIDED COSTS WITH LOSSES

Rachel: This table includes demand costs: you have to take them out

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1.1294	WINTER ON-PEAK	51.09	56.79	54.24	131.32	106.14	181.38	208.31	188.69	209.37	224.12	243.57	271.44	268.80	286.92	295.21	310.70	327.18	340.09	361.32	386.62
1.1296	SHOULDER	45.96	50.90	49.75	94.98	75.29	135.32	156.75	141.06	155.87	168.46	183.82	204.18	202.30	216.96	222.29	234.57	247.89	256.49	274.12	295.34
1.1069	OFF-PEAK	29.97	32.65	31.28	48.44	39.87	71.86	91.31	75.25	89.16	91.94	95.92	110.14	114.19	115.26	120.90	130.51	138.23	143.94	156.88	169.43
1.1091	SUMMER ON-PEAK	31.25	33.89	33.50	57.85	45.73	87.38	101.79	89.96	103.10	108.34	121.32	130.59	131.01	148.07	149.37	159.76	163.57	176.91	182.86	193.13
1.0859	OFF-PEAK	19.23	19.60	22.39	24.21	19.20	40.47	52.75	36.69	48.26	48.60	51.18	61.21	62.88	65.75	74.62	75.64	83.55	90.58	94.17	101.35
	ANNUAL AVERAGE	30.11	32.45	32.77	55.92	44.77	83.03	99.40	84.17	97.93	102.84	111.55	124.88	125.74	135.27	141.14	148.75	156.88	166.42	175.23	187.26

NOTE: EACH ENTRY IS SUM OF TABLES 1, 1A, 1B, 2, AND 3 TIMES LOSS MULTIPLIER BY TIME PERIOD

TABLE 6: ADJUSTMENT FOR RISK AND EXTERNALITIES ($/MWH)																					
	EXTERNALITIES [1]	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1.1294	WINTER ON-PEAK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.1296	SHOULDER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.1069	OFF-PEAK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.1091	SUMMER ON-PEAK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.0859	OFF-PEAK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	RISK [2]	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1.1294	WINTER ON-PEAK	5.68	6.31	6.03	14.59	11.79	20.15	23.15	20.97	23.26	24.90	27.06	30.16	29.87	31.88	32.80	34.52	36.35	37.79	40.15	42.96
1.1296	SHOULDER	5.11	5.66	5.53	10.55	8.37	15.04	17.42	15.67	17.32	18.72	20.42	22.69	22.48	24.11	24.70	26.06	27.54	28.50	30.46	32.82
1.1069	OFF-PEAK	3.33	3.63	3.48	5.38	4.43	7.98	10.15	8.36	9.91	10.22	10.66	12.24	12.69	12.81	13.43	14.50	15.36	15.99	17 43	18 83
1 1091	SUMMER ON-PEAK	3.47	3.77	3.72	6.43	5.08	9.71	11 31	10 00	11.46	12.04	13.48	14.51	14.56	16 45	16.60	17.75	18.17	19.66	20 32	21 46
1 0859	OFF-PEAK	2.14	2.18	2.49	2.69	2.13	4.50	5 86	4.08	5.36	5 40	5.69	6.80	6 99	7 31	8.29	8.40	9.28	10.06	10 48	11 26
	TOTAL COSTS [3]																				
	WINTER ON-PEAK	56 76	63 10	60.27	145 91	117.94	201.53	231 45	209 65	232.63	249 02	270 64	301 60	298.67	318 80	328 01	345.22	363.53	377 88	401 47	429 57
	SHOULDER	51 06	56 56	55.28	105 53	83.66	150 35	174 16	156 74	173.18	187 18	204 25	226 86	224 78	241 06	246 99	260 64	275 44	284 98	304 58	328 15
	OFF-PEAK	33.30	36.28	34.75	53.82	44 30	79.84	101 46	83 62	99 07	102.15	106 58	122.38	126 87	128 06	134 33	145.01	153.58	159 93	174 31	188 25
	SUMMER ON-PEAK	34 73	37 65	37.23	64 28	50.81	97.09	113 10	99 96	114 56	120.37	134 81	145.11	145 56	164 52	165 97	177 51	181.74	196 57	203 18	214 58
	OFF-PEAK	21.36	21.77	24.87	26.90	21.33	44.97	58 61	40 77	53.62	54 00	56 87	68 01	69 86	73 06	82.91	84 04	92.84	100 64	104 63	112.62
	NOTES.																				
	[3]: [1] + [2] + Total avoided costs, Table 5.																				
	CV Avoided Peak Capacity	0.00	0.00	0.00	0.00	0.00	6.49	15.44	27 43	42.13	58.87	77 84	107 13	111 75	116 57	121.59	126 84	132.31	138.01	143.96	150.17
Q 7-6	Avoided Intermediate						50.49	53 57	75 95	100.15	128 55	164 01	207 16	228 4	248 39	$259.17	$270.41	$282.14	$294.38	$307 15	$320 47
	Capitalized Energy	0 00	0 00	0.00	0 00	0.00	44 00	38.13	48 52	58 02	69 68	86 17	100 03	116 65	131 82	137 58	143 57	149 83	156 37	163 19	170 30

CV Corrected Avoided Costs Used in RII Screening

Deflators		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	4.25%	1	0.9592	0.9201	0.8826	0.8466	0.8121	0.7790	0.7473	0.7168	0.6876	0.6595	0.6326	0.6069	0.5821	0.5584	0.5356	0.5138	0.4928	0.4727
	4.79%	1	0.9543	0.9107	0.8690	0.8293	0.7914	0.7552	0.7207	0.6878	0.6563	0.6263	0.5977	0.5704	0.5443	0.5194	0.4957	0.4730	0.4514	0.4308

CVPeakLoss 16.00%

Unbundled Avoided Costs With Losses (1994$)
Sum of a) Fuel & O&M, b) Capitalized Energy, and c)Off-System Sales

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Winter Peak	0.030	0.030	0.028	0.026	0.036	0.041	0.038	0.037	0.041	0.042	0.039	0.041	0.043	0.041	0.043	0.045	0.043	0.046	0.050
Winter Shoulder	0.030	0.031	0.029	0.028	0.037	0.041	0.039	0.037	0.042	0.043	0.040	0.042	0.044	0.042	0.044	0.046	0.044	0.047	0.051
Winter Off-Peak	0.025	0.024	0.015	0.012	0.024	0.035	0.025	0.030	0.029	0.027	0.030	0.033	0.030	0.030	0.033	0.034	0.033	0.037	0.039
Summer Peak	0.025	0.025	0.026	0.022	0.038	0.043	0.038	0.041	0.041	0.045	0.043	0.044	0.050	0.047	0.049	0.048	0.051	0.050	0.051
Summer Off-Peak	0.020	0.021	0.018	0.012	0.030	0.038	0.024	0.031	0.030	0.030	0.035	0.035	0.035	0.038	0.037	0.040	0.041	0.041	0.043
Generation & Transmission	0.00	0.00	24.61	24.61	31.32	39.92	50.70	63.05	76.14	89.96	110.89	110.94	110.99	111.04	111.09	111.15	111.19	111.24	111.30
Distribution w/ losses	0.00	0.00	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69	67.69

Bundled Avoided Costs With Losses (1994$/kWh)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Winter Peak	0.030	0.030	0.076	0.074	0.087	0.096	0.099	0.104	0.115	0.122	0.131	0.132	0.134	0.133	0.134	0.136	0.134	0.137	0.142
Winter Shoulder	0.030	0.031	0.052	0.051	0.063	0.071	0.073	0.076	0.086	0.092	0.098	0.099	0.101	0.100	0.101	0.104	0.101	0.105	0.109
Winter Off-Peak	0.025	0.024	0.032	0.030	0.043	0.054	0.046	0.052	0.053	0.054	0.059	0.062	0.059	0.060	0.062	0.063	0.063	0.066	0.069
Summer Peak	0.025	0.025	0.038	0.034	0.051	0.058	0.054	0.059	0.062	0.068	0.070	0.070	0.076	0.074	0.076	0.075	0.077	0.077	0.078
Summer Off-Peak	0.020	0.021	0.022	0.017	0.034	0.043	0.028	0.036	0.034	0.035	0.040	0.039	0.039	0.043	0.042	0.044	0.046	0.046	0.047

G&T Avoided Costs

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
G&T Total $/kWh (without losses)		0.000	0.000	0.004	0.004	0.004	0.006	0.007	0.009	0.011	0.013	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Winter Peak	0.4092	0.000	0.000	0.012	0.012	0.016	0.020	0.026	0.032	0.039	0.045	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056
Winter Shoulder	0.1451	0.000	0.000	0.010	0.010	0.012	0.016	0.020	0.025	0.030	0.035	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044
Winter Off-Peak	0.1219	0.000	0.000	0.003	0.003	0.004	0.005	0.007	0.009	0.010	0.012	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Summer Peak	0.3231	0.000	0.000	0.004	0.004	0.005	0.007	0.009	0.011	0.013	0.015	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Summer Off-Peak	0.0007	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Distribution Avoided Costs

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Distribution Total $/kWh (without losses)		0.000	0.000	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Winter Peak	0.4	0.000	0.000	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035
Winter Shoulder	0.07	0.000	0.000	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Winter Off-Peak	0.18	0.000	0.000	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Summer Peak	0.2	0.000	0.000	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Summer Off-Peak	0.15	0.000	0.000	0.004	0.004	0.004	0.004	0.004	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004

	Cumulative Incremental Supplies [1]				Avoided Supplies [2]		Cumulative Incremental Mix (%)				Cumulative Mix w/o GT (%)			Avoided Supplies (%)	
Year	Steam Purchase	Gas Turbine	Intermed CC	Base CC	Steam Purchase	Base CC	Steam Purchase	Gas Turbine	Intermed CC	Base CC	Steam Purchase	Intermed CC	Base CC	Steam Purchase	Base CC
2000	50	9.8		30	17.14	2.86	0.56	0.11		0.33	0.63		0.38	0.86	0.14
2001	50	54.5	20	40	14.28	5.72	0.30	0.33	0.12	0.24	0.45	0.18	0.36	0.71	0.29
2002	50	56.3	20	40	11.42	8.58	0.30	0.34	0.12	0.24	0.45	0.18	0.36	0.57	0.43
2003	50	80.3	20	40	8.56	11.44	0.26	0.42	0.11	0.21	0.45	0.18	0.36	0.43	0.57
2004	50	80.3	37.4	40	5.7	14.3	0.24	0.39	0.18	0.19	0.39	0.29	0.31	0.29	0.72
2005	50	80.3	41.9	53.6	2.84	17.16	0.22	0.36	0.19	0.24	0.34	0.29	0.37	0.14	0.86
2006		102.3	78.4	63.5		20		0.42	0.32	0.26		0.55	0.45		1.00
2007		102.3	92.8	84		20		0.37	0.33	0.30		0.52	0.48		1.00
2008		102.3	97.4	107.5		20		0.33	0.32	0.35		0.48	0.52		1.00
2009		107	115	107.5		20		0.32	0.35	0.33		0.52	0.48		1.00
2010		107	115	128.1		20		0.31	0.33	0.37		0.47	0.53		1.00
2011		112.2	115	144.1		20		0.30	0.31	0.39		0.44	0.56		1.00
2012		117.4	161.4	244.1		20		0.22	0.31	0.47		0.40	0.60		1.00

Notes:

[1] IR 7-6 Load and Resource Tables

[2] IR 7-6 Avoided Cost Tables

Derivation of RII Avoided Costs

Exhibit_(PLC-5)

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	WINTER ON-PEAK	23.44	24.51	27.32	24.39	21.47	28.43	37.39	33.11	32.96	36.39	36.74	34.96	36.18	38.48	38.91	42.52	47.29	47.39	53.79	62.31
	SHOULDER	23.50	24.60	27.72	25.20	22.80	29.25	38.01	34.02	33.61	37.29	37.71	35.76	36.99	39.48	39.88	43.60	48.52	48.59	55.19	63.88
	OFF-PEAK	20.61	21.48	22.20	13.18	10.21	19.80	32.76	21.64	27.16	26.02	24.47	27.35	29.30	27.19	29.08	33.14	38.44	37.76	43.75	49.89
	SUMMER ON-PEAK	20.17	20.78	22.65	23.00	18.10	30.98	40.69	32.99	37.33	37.47	40.42	39.00	39.03	45.49	45.15	49.88	51.23	57.19	59.24	64.48
	OFF-PEAK	17.08	16.91	20.06	15.84	10.33	24.41	36.49	21.32	29.24	27.71	27.71	32.72	31.88	32.60	37.59	38.40	43.36	47.77	50.10	55.32
	WINTER AVERAGE	22.24	23.23	25.20	19.73	16.88	24.88	35.52	28.36	30.59	32.12	31.66	31.84	33.38	33.82	34.87	38.69	42.86	43.48	49.74	57.27
	SUMMER AVERAGE	18.46	18.64	21.22	19.04	13.80	27.34	38.36	26.53	32.85	32.08	33.38	35.52	35.07	38.35	40.96	43.52	46.87	51.98	54.18	59.41
	ANNUAL AVERAGE	19.72	20.17	22.54	19.27	14.83	26.52	37.42	27.14	32.10	32.09	32.81	34.30	34.51	36.84	38.93	41.91	45.53	49.15	52.70	58.70

TABLE 1A: AVOIDED CAPITALIZED ENERGY COSTS

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
$/kW-yr	AVOIDED PEAKING CAPACITY	0.00	10.00	10.43	10.87	11.33	11.81	12.31	57.50	102.69	107.05	111.60	116.34	121.29	126.44	131.82	137.42	143.26	149.35	155.69	162.31
	AVOIDED SUPPLY MIX	0	0	0	0	0	50.49	53.57	75.95	100.15	128.55	164.01	207.16	228.40	248.39	259.17	270.41	282.14	294.38	307.15	320.47
	CAPITALIZED ENERGY	0	0	0	0	0	38.68	41.26	18.45	0.00	21.50	52.41	90.82	107.11	121.95	127.35	132.99	138.88	145.03	151.45	158.16
$/MWH	WINTER ON-PEAK	0	0	0	0	0	7.24	7.20	3.93	0.00	4.29	10.25	16.17	19.62	22.25	22.23	23.57	25.19	24.42	27.00	29.32
	SHOULDER	0	0	0	0	0	7.45	7.32	4.04	0.00	4.40	10.52	16.54	20.06	22.82	22.79	24.17	25.85	25.04	27.70	30.06
	OFF-PEAK	0	0	0	0	0	5.04	6.31	2.57	0.00	3.07	6.83	12.65	15.89	15.72	16.62	18.37	19.41	19.46	21.96	23.48
	SUMMER ON-PEAK	0	0	0	0	0	7.89	7.84	3.92	0.00	4.42	11.28	18.04	21.16	26.30	25.80	27.65	27.29	29.47	29.73	30.35
	OFF-PEAK	0	0	0	0	0	6.22	7.03	2.53	0.00	3.27	7.73	15.13	17.29	18.85	21.48	21.29	23.10	24.62	25.14	26.04
	WINTER AVERAGE	0	0	0	0	0	6.33	6.84	3.37	0.00	3.79	8.83	14.73	18.10	19.55	19.92	21.45	22.83	22.40	24.96	26.95
	SUMMER AVERAGE	0	0	0	0	0	6.96	7.39	3.15	0.00	3.79	9.31	16.43	19.02	22.17	23.41	24.13	24.97	26.78	27.19	27.96
	ANNUAL AVERAGE	0	0	0	0	0	6.75	7.21	3.22	0.00	3.79	9.15	15.86	18.71	21.30	22.25	23.24	24.26	25.32	26.45	27.62

TABLE 1B: OFFSYSTEM SALES @ 80% of rate spread

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	WINTER ON-PEAK		2.57	1.20	7.01	13.32	6.84	5.50	11.67	17.46	13.96	11.92	11.82	11.52	11.25	14.84	15.09	14.47	19.82	17.78	14.62
	SHOULDER		2.49	0.88	6.36	12.26	6.02	4.91	10.86	16.94	13.16	10.93	10.89	10.52	9.99	13.63	13.74	12.96	18.36	16.10	12.77
	OFF-PEAK		1.03	1.19	11.24	16.89	9.19	2.57	14.57	14.28	14.94	15.64	11.32	9.99	14.83	15.82	14.62	14.84	17.70	15.14	13.54
	SUMMER ON-PEAK		2.58	1.85	4.57	11.94	-0.45	-3.16	6.25	8.10	6.77	1.53	0.04	0.49	-5.61	-1.53	-3.16	-0.06	-2.40	0.21	0.30
	OFF-PEAK		2.21	0.32	6.15	13.38	0.60	-5.59	10.23	7.71	8.22	6.78	-0.87	0.52	1.30	-2.01	0.48	-1.75	-3.08	-1.71	-2.69
	WINTER AVERAGE		1.90	1.14	8.71	14.66	7.70	4.14	12.77	16.00	14.23	13.34	11.44	10.69	12.56	15.05	14.65	14.36	18.65	16.35	13.82
	SUMMER AVERAGE		2.37	1.00	5.44	12.73	0.13	-4.51	8.46	7.88	7.57	4.44	-0.46	0.50	-1.78	-1.80	-1.15	-1.00	-2.78	-0.86	-1.36
	ANNUAL AVERAGE		2.21	1.05	6.53	13.38	2.66	-1.62	9.89	10.59	9.80	7.41	3.50	3.90	3.00	3.82	4.12	4.13	4.36	4.88	3.70
	Dispatch + Sales		22.38	23.59	25.80	28.20	29.18	35.79	37.03	42.69	41.89	40.21	37.80	38.40	39.84	42.75	46.03	49.66	53.50	57.58	62.40
	Total Energy		22.38	23.59	25.80	28.20	35.93	43.00	40.26	42.69	45.68	49.37	53.66	57.12	61.14	65.00	69.27	73.92	78.83	84.03	90.02

TABLE 1C: TOTAL ENERGY w/ losses

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1.2474	WINTER ON-PEAK	29.24	33.77	35.58	39.17	43.40	53.03	62.49	60.77	62.89	68.17	73.49	78.53	83.97	89.78	94.79	101.26	108.46	114.30	122.96	132.54
1.2474	SHOULDER	29.31	33.80	35.68	39.37	43.73	53.29	62.68	61.02	63.06	68.42	73.80	78.82	84.29	90.18	95.17	101.68	108.93	114.75	123.48	133.11
1.1865	OFF-PEAK	24.45	26.71	27.75	28.98	32.15	40.38	49.41	46.01	49.17	52.24	55.69	60.89	65.47	68.50	72.99	78.47	83.88	88.89	95.93	103.12
1.2073	SUMMER ON-PEAK	24.35	28.20	29.58	33.29	36.26	46.38	54.78	52.11	54.85	58.75	64.26	68.91	73.26	79.90	83.80	89.79	94.73	101.72	107.66	114.84
1.1382	OFF-PEAK	19.44	21.76	23.19	25.03	26.98	35.55	43.17	38.79	42.06	44.62	48.06	53.48	56.55	60.04	64.94	68.48	73.65	78.88	83.69	89.54
	WINTER AVERAGE	27.20	30.75	32.24	34.84	38.64	47.65	56.92	54.49	57.04	61.40	65.92	71.02	76.10	80.73	85.51	91.57	98.01	103.49	111.46	120.03
	SUMMER AVERAGE	21.63	24.64	26.05	28.71	31.13	40.38	48.35	44.74	47.76	50.95	55.29	60.37	64.01	68.90	73.36	77.99	83.06	89.08	94.39	100.83
	ANNUAL AVERAGE	23.49	26.68	28.11	30.75	33.63	42.81	51.21	47.99	50.86	54.44	58.83	63.92	68.04	72.85	77.41	82.52	88.04	93.88	100.09	107.23

TABLE 2: AVOIDED GENERATION AND TRANSMISSION CAPACITY COSTS

			1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
$/KW CP	GENERATION [1]			10.00	10.43	10.87	11.33	11.81	12.31	98.50	102.69	107.05
	TRANSMISSION [1]		20.34	21.20	22.10	23.04	24.02	25.04	26.11	27.22	28.38	29.58
	SUB TOTAL		20.34	33.30	34.72	36.19	37.73	39.34	41.01	146.40	152.63	159.11
$/KW CR	@CR:CP ratio of	0.95	21.41	35.06	36.55	38.10	39.72	41.41	43.17	154.11	160.66	167.49
	with losses of	14.95%	24.61	40.30	42.01	43.80	45.66	47.60	49.62	177.15	184.68	192.53
$/MWH	TOTAL G & T		4.08	6.69	6.97	7.27	7.58	7.90	8.24	29.40	30.66	32.22
–	WINTER ON-PEAK		12.76	20.89	21.78	22.72	23.68	24.65	25.75	91.88	95.79	100.26
|	SHOULDER		9 95	16.29	16.98	17.73	18.48	19.24	20.09	71.72	74.76	78.17
[2]	OFF-PEAK		3.48	5.71	5.95	6.20	6.46	6.73	7 03	25.09	26.16	27.51
|	SUMMER ON-PEAK		4 44	7 26	7.57	7.89	8.22	8.57	8 94	31.92	33.29	34.91
–	OFF-PEAK		0 01	0 01	0.01	0.01	0.01	0.01	0.02	0.06	0.06	0.06
	WINTER AVERAGE		8 28	13.56	14.14	14.75	15.37	16.01	16 72	59.66	62.20	65.21
	SUMMER AVERAGE		1.98	3.25	3.39	3.53	3 68	3.84	4 00	14.28	14.89	15.66
	Annual Average		4 08	6.69	6.97	7.27	7.58	7.90	8 24	29 40	30.66	32.22
											CP loss	CR loss
	NOTES:									0 69%	1.0069	1.006598
	[1]: FROM TABLE 2a.									1.77%	1.0181	1.017134
	[3]: ALLOCATED TO PERIODS BASED ON ALLOCATION FACTORS IN Ex JCC-3, p. 4 (8/15/88 filing).									8.90%	1.0977	1.092359
										2.85%	1.0293	1.027828
											1.1583	1.1495

			2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
$/KW CP	GENERATION [1]		111.60	116.34	121.29	126.44	131.82	137.42	143.26	149.35	155.69	162.31
	TRANSMISSION [1]		30.84	32.15	33.52	34.94	36.43	37.97	39.59	41.27	43.02	44.85
	SUB TOTAL		165.87	172.92	180.27	187.93	195.92	204.25	212.93	221.98	231.41	241.25
$/KW CR	@CR:CP ratio of	0.95	174.60	182.03	189.76	197.83	206.23	215.00	224.14	233.66	243.59	253.95
	with losses of	14.95%	200.71	209.24	218.14	227.41	237.07	247.15	257.65	268.60	280.02	291.92
$/MWH	TOTAL G & T		33.30	34.72	36.20	37.73	39.34	41.02	42.75	44.56	46.45	48.44
–	WINTER ON-PEAK		104.03	108.53	113.14	117.95	122.96	128.19	133.55	139.31	145.14	151.51
|	SHOULDER		81.14	84.71	88 31	92.06	95.97	100.05	104.15	108.74	113.19	118.18
[2]	OFF-PEAK		28.42	29 64	30 90	32.21	33.58	35.01	36.45	38.05	39 62	41.35
|	SUMMER ON-PEAK		36.14	37 68	39 29	40.95	42.70	44.53	46.42	48.34	50 44	52.55
–	OFF-PEAK		0.06	0 07	0.07	0 07	0.07	0.08	0.08	0 08	0.09	0 09
	WINTER AVERAGE		67 54	70.47	73.46	76 58	79.84	83.23	86 68	90.46	94 20	98.34
	SUMMER AVERAGE		16.17	16.86	17 58	18 32	19.11	19 92	20.77	21.63	22.57	23.52
	Annual Average		33.30	34 72	36.20	37.73	39.34	41.02	42.75	44 56	46 45	48 44

TABLE 2a: TRANSMISSION COST SUMMARY ($/kw)

Capital	O&M				
$11.56	$2.81	CV 1987$ or 86$ COSTS, Ex JCC-5, DOCKET 4634.			
	$1.12	Overheads at	40%		
1.32	1.291	Inflation to 1993$			
$15.26	$5.08	1993$			
	$20.34	TOTAL 1993$/kw		Inflates @	4 25%

TABLE 3: AVOIDED DISTRIBUTION COST

			1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
$/KW	DISTRIBUTION [1]		78 06	81 38	84 84	88.45	92.20	96.12	100.21	104.47	108.91	113.53
	with losses of	15.83%	90.42	94 26	98.27	102.44	106.80	111.34	116 07	121 00	126.14	131.51
$/MWH	DISTRIBUTION		15.80	16 46	17.17	17 90	18.65	19.44	20.28	21.14	22.04	23.16
–	WINTER ON-PEAK		48 22	50 27	52.41	54 67	57.00	59 34	61 99	64 58	67.32	70.47
|	SHOULDER		18 56	19 35	20 17	21 06	21 96	22.86	23 86	24.88	25 93	27.11
[2]	OFF-PEAK		19 90	20 74	21 62	22.56	23 50	24 48	25 56	26 64	27 78	29.21
|	SUMMER ON-PEAK		10 62	11 07	11 54	12.02	12.54	13.06	13 63	14 21	14 81	15.54
–	OFF-PEAK		6 42	6 69	6 98	7.27	7 58	7 90	8 24	8 59	8.96	9.45
	WINTER AVERAGE		30 79	32.10	33 46	34 91	36.38	37 89	39 56	41 23	42.99	45.07
	SUMMER AVERAGE		8 30	8 65	9 02	9.39	9.79	10.21	10 65	11.10	11.57	12.17
	Annual		15.80	16.46	17 17	17.90	18.65	19.44				
	NOTES:											
	[1]: TOTAL FROM TABLE 3a.											
	[2]: SEE NOTE 3, TABLE 2, ALLOCATION FROM PAGE 5, Ex JCC-3.											

			2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
$/KW	DISTRIBUTION [1]		118.36	123.39	128.63	134.10	139 80	145.74	151.94	158.39	165 13	172.14
	with losses of	15.83%	137.09	142.92	149 00	155 33	161 93	168 81	175.99	183.47	191 26	199.39
$/MWH	DISTRIBUTION		23.94	24 96	26.03	27 13	28 29	29.49	30 74	32.04	33 40	34 83
–	WINTER ON-PEAK		73 12	76 28	79 52	82 90	86 42	90 09	93 86	97 91	102.01	106 48
|	SHOULDER		28.14	29 38	30 63	31 93	33 29	34 70	36 13	37 72	39 26	40 99
[2]	OFF-PEAK		30.17	31 47	32 81	34 20	35 65	37 17	38 70	40 40	42 06	43 90
|	SUMMER ON-PEAK		16 09	16.77	17 49	18 23	19 01	19 82	20 66	21 51	22.45	23 39
–	OFF-PEAK		9.73	10 15	10 58	11 02	11 50	11 99	12 50	13 02	13 58	14 15
	WINTER AVERAGE		46.68	48.70	50 77	52.93	55 18	57 52	59 91	62.52	65 11	67 96
	SUMMER AVERAGE		12.57	13 10	13 66	14 24	14 85	15.48	16.14	16.81	17 54	18 28

TABLE 3a: DISTRIBUTION COST SUMMARY ($/kw)

PRIMARY		SECONDARY					
Capital	O&M	Capital	O&M				
$19.05	$9.46	$2.86	$0.79	CV 1987$ or 86$ COSTS, Ex JCC-5, DOCKET 4634.			
	$3.78		$0.32	Overheads at	40%		GDP
1.32	1.291	1.32	1.291	Inflation to 1993$		1992	120.9
$25.15	$17.10	$3.78	$1.43	1993$		1986	96.9
91,388	91,388	209,532	209,532	CV Demand units		increase	1.2477
68,859	68,859	49,578	49,578	CP Demand units from this voltage		92-93	3.50%
$33.37	$22.70	$15.96	$6.04	1993$/CP at generation		86-93	1.2913
			$78.06	TOTAL 1993$/kw			

TABLE 4: TIME DIFFERENTIATED AVOIDED ENERGY CONSUMPTION

GIGAWATT HOURS	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
WINTER ON-PEAK	15.00	15.00	15.00	14.99	14.99	15 01	14 98	14 99	14.99	14 93	15 00	14 99	14 99	14.99	14.99	14 99	15 00	14 99	15 00	14 98
SHOULDER	6.82	6.82	6.82	6.81	6.81	6 82	6 81	6.81	6.81	6.79	6 82	6 81	6 81	6.81	6 81	6.81	6 82	6.81	6 82	6 81
OFF-PEAK	16 36	16.36	16.36	16.35	16.36	16 37	16 35	16 35	16 35	16 21	16 36	16.35	16 35	16.35	16.35	16 35	16 37	16 35	16 37	16 35
SUMMER ON-PEAK	34 06	34 07	34 06	34.08	34.08	34 09	34 07	34 07	34 06	33 86	34 09	34.09	34 08	34.09	34 08	34 07	34 07	34 11	34 08	34 10
OFF-PEAK	42.24	42.25	42.24	42.26	42.26	42.26	42.25	42.25	42.24	41 76	42.26	42.26	42.26	42.27	42.26	42.25	42.25	42.28	42.26	42.27
WINTER TOTAL	38 18	38.18	38.18	38.15	38.16	38 20	38 14	38.15	38 15	37 93	38 18	38.15	38 15	38.15	38.15	38.15	38 19	38 15	38 19	38 14
SUMMER TOTAL	76.30	76.32	76.30	76.34	76.34	76 35	76 32	76.32	76 30	75 62	76.35	76.35	76 34	76.36	76.34	76.32	76.32	76 39	76 34	76 37
ANNUAL TOTAL	114 48	114.50	114.48	114.49	114.50	114.55	114.46	114.47	114.45	113 55	114.53	114.50	114 49	114.51	114.49	114.47	114.51	114 54	114 53	114 51

TABLE 5 TOTAL DIRECT BASE-CASE AVOIDED COSTS WITH LOSSES

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
WINTER ON-PEAK	90.22	104.94	109.77	116.56	124.08	137.02	150.23	217.23	226.00	238.89	250.64	263.33	276.63	290.63	304.17	319.54	335.87	351.52	370.10	390.53
SHOULDER	57.82	69.44	72.84	78.16	84.17	95.38	106.63	157 62	163.75	173.70	183.07	192.91	203.22	214.17	224.43	236.44	249.21	261.20	275.94	292.28
OFF-PEAK	47.83	53.16	55.32	57.74	62.12	71.60	82.00	97.75	103.10	108.95	114.27	122.00	129.17	134.92	142.23	150.65	159.03	167.34	177 60	188.37
SUMMER ON-PEAK	39.41	46.53	48.70	53.20	57.02	68.02	77.35	98.24	102.95	109.19	116.49	123.36	130.04	139.08	145.51	154.14	161.81	171.58	180.55	190.78
OFF-PEAK	25.87	28.46	30.18	32.31	34.58	43.46	51.42	47 44	51.07	54.13	57.85	63.69	67 20	71.13	76.51	80.54	86.23	91.99	97 36	103.78
WINTER AVERAGE	66.27	76.41	79.84	84.49	90.39	101.55	113.20	155.38	162.22	171.69	180.14	190.19	200.33	210.25	220.53	232.32	244.59	256.46	270 77	286.33
SUMMER AVERAGE	31 91	36.53	38.45	41.64	44.60	54.43	63.00	70.12	74.23	78.78	84 04	90.33	95 25	101 47	107.32	113.40	119.97	127.53	134 50	142.63
Annual	43.37	49.83	52.25	55.92	59.86	70.14	79.72	98.53	103.56	109.82	116.07	123 60	130.27	137 71	145.04	153.03	161.53	170.47	179 94	190 49

NOTE. EACH ENTRY IS SUM OF TABLES 1C, 2, AND 3

CAPITALIZED ENERGY ($/kW)

							market	average	CT											
Avoided Peaking Capacity	0.00	10.00	10 43	10.87	11.33	11 81	12.31	57 50	102.69	107 05	111 60	116 34	121 29	126.44	131 82	137 42	143.26	149 35	155 69	162.31
Avoided Supply Mix	from IR 7-6					50 49	53.57	75 95	100 15	128.55	164 01	207 16	228 4	248 39	$259 17	$270.41	$282.14	$294 38	$307 15	$320 47
Cap Energy					0.00	38 68	41 26	18 45	0 00	21 50	52.41	90 82	107 11	121 95	127 35	132.99	138 88	145 03	151 45	158 16

[CV94APC4.XLS]

RII Avoided Costs Used in RII Screening

Exhibit_(PLC-6)

RII Avoided Costs for Input to Screening Tool

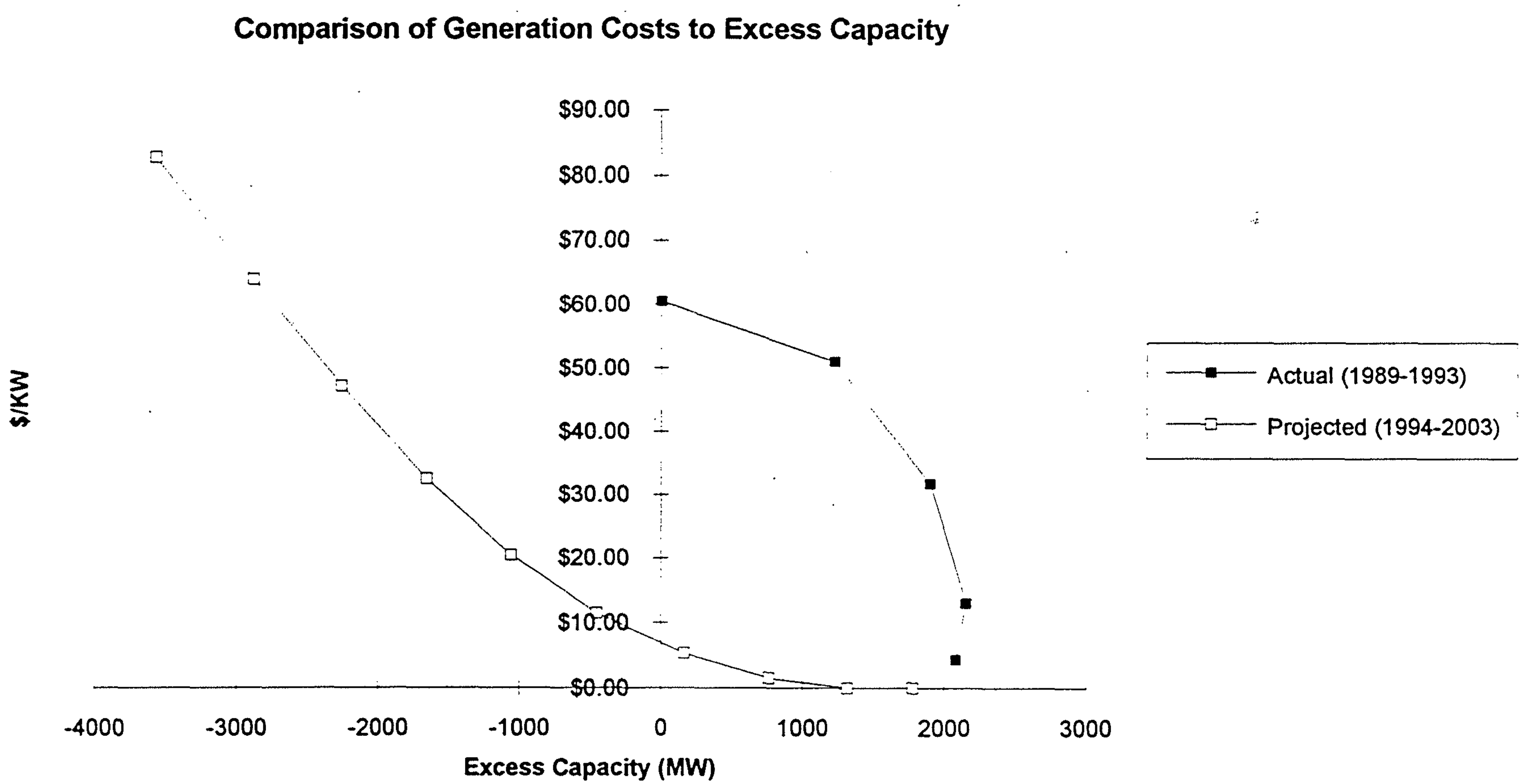
Deflator	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
4.25%	1	0.9592	0.9201	0.8826	0.8466	0.8121	0.7790	0.7473	0.7168	0.6876	0.6595	0.6326	0.6069	0.5821	0.5584	0.5356	0.5138	0.4928	0.4727

Unbundled Avoided Costs With Losses (1994$/kWh or 1994$/kW)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Winter Peak	0.034	0.034	0.036	0.038	0.045	0.051	0.047	0.047	0.049	0.051	0.052	0.053	0.054	0.055	0.057	0.058	0.059	0.061	0.063
Winter Shoulder	0.034	0.034	0.036	0.039	0.045	0.051	0.048	0.047	0.049	0.051	0.052	0.053	0.055	0.055	0.057	0.058	0.059	0.061	0.063
Winter Off-Peak	0.027	0.027	0.027	0.028	0.034	0.040	0.036	0.037	0.037	0.038	0.040	0.041	0.042	0.042	0.044	0.045	0.046	0.047	0.049
Summer Peak	0.028	0.028	0.031	0.032	0.039	0.044	0.041	0.041	0.042	0.044	0.045	0.046	0.048	0.049	0.050	0.051	0.052	0.053	0.054
Summer Off-Peak	0.022	0.022	0.023	0.024	0.030	0.035	0.030	0.031	0.032	0.033	0.035	0.036	0.036	0.038	0.038	0.039	0.041	0.041	0.042
Generation & Tran	40.299	40.299	40.299	40.299	40.299	40.299	138.004	138.004	138.004	138.004	138.004	138.004	138.004	138.004	138.004	138.004	138.004	138.004	138.004
Distribution	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262	94.262

	Year	Julian Date	Default Price	Adjusted Default Price	Base Surplus (MW)	Surplus (MW)	G.T. Cap Cost
	1989	1	$75.01	$60.50	1800	4	$60.50
	1990	32875	$76.99	$62.10	1800	1229	$51.00
	1991	33240	$78.97	$63.69	1800	1907	$31.72
	1992	33605	$80.94	$65.29	1800	2158	$13.00
	1993	33971	$82.92	$66.88	1800	2087	$4.35
	1994	34336	$84.90	$68.48	1800	1783	$0.00
	1995	34701	$86.88	$70.07	1800	1323	$0.00
	1996	35066	$88.86	$71.67	1800	769	$1.50
	1997	35432	$90.83	$73.26	1800	166	$5.26
	1998	35797	$92.81	$74.86	1800	-448	$11.49
	1999	36162	$94.79	$76.45	3300	-1058	$20.44
	2000	36527	$96.77	$78.05	3300	-1657	$32.43
	2001	36893	$98.74	$79.64	3300	-2258	$47.13
	2002	37258	$100.72	$81.24	3300	-2880	$63.87
	2003	37623	$102.70	$82.83	3300	-3565	$82.84

Seller	NEP	NU	CL&P	NU	NU
Buyer	Shrewsbury	Danvers	Bozrah L&P	Princeton	Princeton
Start date		Nov-94	Jan-93	Nov-93	Nov-93
Type of Contract	Base, intermediate and peaking	Base, intermediate and peaking	Base level, reserve req., and incremental services	Unit entitlements	Unit entitlements
Capacity	Total contract demand and mix of capacity varies over time and flexible	Total contract demand and mix of capacity varies over time and flexible	Full or partial requirements	Total contract demand and mix of capacity varies over time and flexible	Total contract demand and mix of capacity varies over time and flexible
Includes transmission?	no	yes	yes	yes, unless pool-planned	yes
Includes losses?	?	?	yes	no	no
Comments	[1]	[1]		South Meadow jets 11-14	Merrimack CT 1&2
Purchase price for peaking capacity ($/kW-yr)					
1993	$40		$36	$35	$35
1994	$40	$35	$36	$40	$40
1995	$45	$40	$36	$40	$40
1996	$45	$40	$36	$40	$40
1997	$50	$45	$36	$45	$45
1998	$50	$45	$36	$45	$45
1999	$50	$50	$36	$45	$45
2000	$110	$70	$36	$115	$115
2001	$120	$90	$36	$120	$120
2002	$130	$90	$36	$125	$125
2003	$140	$95		$130	$130
2004	$150	$100		$135	$135
Notes:					
[1]	Though available under the contract, the Buyer did not initially take any peaking capacity.				



Comparison of Generation Costs to Excess Capacity
$/KW
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
-4000
-3000
-2000
-1000
0
1000
2000
3000
Excess Capacity (MW)
Actual (1989-1993)
Projected (1994-2003)

Exhibit_(PLC-10)

Correction of CV Extrapolation of Market Price

	Default Price	Excess Capacity	Lagged Excess	Actual Prices	Actual Default Price Ratio	Interpolated Price Ratio	Projected Price	CV Projection
1989	$60.50	4	0	$60.50	100%			
1990	$60.50	1229	617	$51.00	84%			
1991	$61.87	1907	1,568	$31.72	51%			
1992	$64.54	2158	2,033	$13.00	20%			
1993	$67.33	2087	2,123	$4.35	6%			
1994	$70.23	1783	1,935			27%	$18.73	$0.00
1995	$73.26	1323	1,553			52%	$37.94	$0.00
1996	$76.42	769	1,046			69%	$53.02	$1.50
1997	$79.71	166	468			88%	$70.22	$5.26
1998	$83.15	-448	(141)			100%	$83.15	$11.49
1999	$86.74	-1058	(753)			100%	$86.74	$20.44
2000	$90.48	-1657	(1,358)			100%	$90.48	$32.43
2001	$94.38	-2258	(1,958)			100%	$94.38	$47.13
2002	$98.45	-2880	(2,569)			100%	$98.45	$63.87
2003	$102.70	-3565	(3,223)			100%	$102.70	$82.84

CV 1992 Short-Term Off-System Sales

Exhibit_(PLC-11)

Purchaser	MWH	Energy Charge	$/MWH	Total Charges $	$/MWH
	OS(a) Sales: Off-system daily sale				
VELCo	155,956	$2,719,509	$17		
NU	770	$24,220	$31		
PSNH	1,440	$38,080	$26		
GMP	240	$8,400	$35		
VtMarble	7,848	$245,024	$31		
NiMo	560	$15,680	$28		
VPPSA	113	$3,603	$32		
Burlington	810	$28,957	$36		
MMWEC	917	$29,029	$32		
Total	168,654	$3,112,502	$18		
			Average		
ex. VELCo	12,698	$392,993	$31		
	OS(d): Short-term system capacity sale				
VtMarble	6,769	$164,790	$24	$253,540	$37
Barton	1,015	$25,145	$25	$33,645	$33
Enosberg	2,036	$50,278	$25	$71,878	$35
Orleans	5,015	$121,569	$24	$179,019	$36
NYPA	72,390	$1,876,710	$26	$1,876,710	$26
			Average		Average
Total	87,225	$2,238,492	$26	$2,414,792	$28
Total ex. NYPA	14,835	$361,782	$24	538,082	$36
Source: CV 1992 FERC Form 1					

Derivation of RII Estimates of Incremental Off-System Sales Value

Exhibit_(PLC-12)

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
							Opp Pur	CC												
Market Energy Prices	WP&I	27.72	28.83	33.15	38.12	44.22	51.47	51.64	54.79	58.14	61.89	65.91	70.20	74.79	79.70	84.95	90.57	96.58	103.02	109.91
(CV Estimate of Opportunity	WOff	22.77	23.68	27.23	31.32	36.33	42.29	42.42	45.01	47.76	50.85	54.15	57.67	61.44	65.48	69.79	74.41	79.35	84.63	90.29
Purchases to 1999; CC Costs	SPeak	24.01	24.97	28.71	33.02	38.30	44.58	44.73	47.45	50.36	53.61	57.09	60.80	64.78	69.03	73.58	78.45	83.65	89.23	95.20
from 2000)	SOff	19.67	20.46	23.52	27.05	31.38	36.53	36.64	38.88	41.25	43.92	46.77	49.81	53.07	56.56	60.28	64.27	68.54	73.10	77.99
	Annual average	22.94	23.85	27.43	31.55	36.60	42.59	42.73	45.33	48.13	51.22	54.54	58.09	61.89	65.95	70.30	74.95	79.92	85.25	90.94
Fuel + Capitalized Energy	WPeak	24.51	27.32	24.39	21.47	35.67	44.59	37.04	32.96	40.68	46.99	51.13	55.80	60.73	61.14	66.09	72.48	71.81	80.79	91.63
(from Exhibit_(PLC-5)	WInt	24.60	27.72	25.20	22.80	36.70	45.33	38.06	33.61	41.69	48.23	52.30	57.05	62.30	62.67	67.77	74.37	73.63	82.89	93.94
	WOff	21.48	22.20	13.18	10.21	24.84	39.07	24.21	27.16	29.09	31.30	40.00	45.19	42.91	45.70	51.51	55.85	57.22	65.71	73.37
	SPeak	20.78	22.65	23.00	18.10	38.87	48.53	36.91	37.33	41.89	51.70	57.04	60.19	71.79	70.95	77.53	78.52	86.66	88.97	94.83
	SOff	16.91	20.06	15.84	10.33	30.63	43.52	23.85	29.24	30.98	35.44	47 85	49.17	51.45	59.07	59.69	66.46	72.39	75.24	81.36
	Annual average	20.17	22.54	19.27	14.83	33.27	44.62	30.36	32.10	35.88	41.96	50.16	53.22	58.14	61.18	65.15	69 79	74.47	79.15	86.32
Difference between	WPeak	(3.21)	(1.51)	(8.76)	(16.65)	(8.55)	(6.88)	(14.59)	(21.83)	(17.45)	(14.90)	(14 78)	(14.40)	(14.06)	(18.56)	(18.86)	(18.09)	(24.77)	(22.23)	(18.27)
Fuel + Capitalized Energy	WInt	(3.12)	(1.11)	(7.95)	(15.32)	(7.52)	(6.14)	(13.58)	(21.18)	(16 45)	(13.66)	(13.61)	(13.15)	(12.49)	(17.03)	(17.18)	(16 20)	(22.95)	(20.13)	(15 96)
and Market Price	WOff	(1.29)	(1.48)	(14.05)	(21 11)	(11.49)	(3.22)	(18.21)	(17 85)	(18.67)	(19 55)	(14.15)	(12.48)	(18.53)	(19.78)	(18 28)	(18.55)	(22.13)	(18 93)	(16 92)
	SPeak	(3.23)	(2.32)	(5.71)	(14 92)	0.57	3.95	(7.82)	(10.12)	(8.46)	(1 91)	(0 05)	(0.61)	7 01	1.92	3 95	0 07	3.01	(0 26)	(0.37)
	SOff	(2.76)	(0.40)	(7 68)	(16.72)	(0.76)	6.99	(12.79)	(9.64)	(10 28)	(8.48)	1.09	(0.65)	(1 63)	2.51	(0.59)	2.19	3.85	2.14	3.36
	Annual average	(2.77)	(1.31)	(8 16)	(16 72)	(3 32)	2.03	(12.37)	(13 24)	(12.25)	(9 26)	(4 38)	(4.87)	(3.74)	(4 77)	(5.15)	(5 16)	(5 45)	(6 10)	(4 62)

Combined-Cycle Energy Costs

Exhibit_(PLC-13)

					1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	Market Value																						
<1>	Cost of CT w/ 40% OHeads		4.25%	$73.60	$76.73	$79.99	$83.39	$86.94	$90.63	$94.48	$98.50	$102.69	$107.05	$111.60	$116.34	$121.29	$126.44	$131.82	$137.42	$143.26	$149.35	$155.69	$162.31
<2>	Base CC $/kW-yr			IR 7-6, plus 40% overheads							$203.81	$212.47	$221.50	$230.92	$240.73	$250.96	$261.63	$272.75	$284.34	$296.42	$309.02	$322.16	$335.85
<3>	+ fuel ($/MWH)			IR 7-6	Inflated from <8>						$25.13	$26.99	$28.99	$31.28	$33.75	$36.41	$39.29	$42.39	$45.74	$49.36	$53.26	$57.46	$62.00
<4>	= $/kW-yr @ CF =		80%	<2>+<3>*8.76*CF							$379.92	$401.62	$424.64	$450.11	$477.24	$506.15	$536.98	$569.85	$604.91	$642.32	$682.24	$724.86	$770.37
<5>	Int CC $/kW-yr			IR 7-6, plus 40% overheads							$155.53	$162.14	$169.03	$176.21	$183.70	$191.51	$199.65	$208.14	$216.98	$226.20	$235.82	$245.84	$256.29
<6>	+ fuel ($/MWH)			IR 7-6	Inflated from <9>						$36.29	$38.61	$41.08	$43.92	$46.95	$50.19	$53.65	$57.35	$61.31	$65.54	$70.06	$74.90	$80.07
<7>	= $/kW-yr @ CF =		35%	<5>+<6>*8.76*CF							$266.80	$280.53	$294.99	$310.87	$327.65	$345.39	$364.15	$383.98	$404.96	$427.15	$450.63	$475.48	$501.77
<8>	Fuel inflation	Base		shown lagged 1 year from CV convention								7.40%	7.40%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%
<9>		Intermediate										6.40%	6.40%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%	6.90%
<10>	Blend of CCs w/ decrement load factor of				65%	67%	BaseCC																
<11>						33%	IntCC																
<12>	Cost of Energy: <4>*<10>+<5>*<11>-<1>									$/kW-yr	244.58	259.49	275.36	293.15	312.17	332.50	354.24	377.49	402.36	428.98	457.46	487.94	520.57
										$/MWH	42.73	45.33	48.11	51.21	54.54	58.09	61.89	65.95	70.29	74.94	79.92	85.24	90.94

	Energy by Period	CV 1994 Losses	CV 1984-92 Losses (Zschokke)
Winter Peak	14.98	12.94%	24.74%
Shoulder	6.81	12.96%	24.74%
Off-Peak	16.35	10.69%	18.65%
Summer Peak	34.10	10.91%	20.73%
Off-Peak	42.27	8.59%	13.82%
Winter Total	38.14		
Summer Total	76.37		
Annual	114.51		
Weighted Avg.		10.41%	18.65%

Derivation of Demand Losses

	Loss as % of Input	CP loss	CR loss
Transmission	0.69%	1.01	1.01
Primary Substation	1.77%	1.02	1.02
Primary Distribution	8.90%	1.10	1.09
Secondary Distribution	2.85%	1.03	1.03
Total		1.16	1.15

Transmission Cost Summary ($/KW) Exhibit_(PLC-16)

Capital	O&M					
$11.56	$2.81	CV 1987$ or 86$ COSTS, Ex JCC-5, DOCKET 4634.				
	$1.12	Overheads at		40%		
1.32	1.291	Inflation to 1993$				
$15.26	$5.08	1993$				
	$20.34	TOTAL 1993$/kw			Inflates @	4.25%

[CV94APC4.XLS]

PRIMARY		SECONDARY					
Capital	O&M	Capital	O&M				
$19.05	$9.46	$2.86	$0.79	CV 1987$ or 86$ COSTS, Ex JCC-5, DOCKET 4634.			
	$3.78		$0.32	Overheads at	40%		GDP
1.32	1.291	1.32	1.291	Inflation to 1993$		1992	120.9
$25.15	$17.10	$3.78	$1.43	1993$		1986	96.9
91,388	91,388	209,532	209,532	CV Demand units		increase	1.2477
68,859	68,859	49,578	49,578	CP Demand units from this voltage		92-93	3.50%
$33.37	$22.70	$15.96	$6.04	1993$/CP at generation		86-93	1.2913
			$78.06	TOTAL 1993$/kw			

			test year ended 9/30/93	rate year ended 10/30/94	rate year ended 10/30/95	test year ended 12/31/90	rate year ended 10/30/92
				Case A	Case B		
			[1]	[1]	[1]	[2]	[2]
Non-Fuel Production		[3]	6,064	7,273	7,273	4,643	5,600
Transmission			15,673	16,477	16,477	12,142	16,028
Distribution			12,706	13,830	13,830	13,178	14,583
Customer Accounting			3,859	3,000	3,000	6,292	5,534
Customer Service and Info			3,493	7,585	8,222	1,983	5,345
Subtotal			41,795	48,165	48,802	38,238	47,090
A&G			26,096	23,358	23,358	18,887	20,441
Ratio			0.62	0.48	0.48	0.49	0.43
Payroll taxes		[4]	1,658	1,707	1,707	1,553	
A&G and payroll taxes			27,754	25,065	25,065	20,440	
Ratio			0.66	0.52	0.51	0.53	

NOTES:

[1] Cost-of-Service Schedule 1 Revised, p. 1 in Docket No. 5701

[2] Testimony of D. Doyle, Exh. DAD-1.

[3] Production expenses net of production fuel expenses of CV-owned plant (from testimony of R. de R. Stein and S.W. Page, Exh. Stage-5 in Docket No. 5701 and testimony of R. de R Stein , M. Shaufer, S.W. Page and B. W. Bentley, Exh. PABSST-5 in Docket No. 5491).

[4] Source for Cost-of-Service in Docket No. 5701: FICA tax expense from COS.WK1, Adjustment No. 12 . For test year in Docket No. 5491, FICA and unemployment taxes from 1990 FERC Form 1, pp. 262-3.

Air Emission	1992 $/ton
SO2	1000
NOx	2000
CO2	15
CO	200
TSP	400
VOCs	1500

Derivation of Estimated NEPOOL Externalities

	Share of Marginal Energy Excluding CTs %Oil	%Gas	%GCC	Emits as % Base	Oil Emits CO2	Emits as % Base	Oil Emits NOx	Emits as % Base	Oil Emits SO2	Emits as % Base	Oil Emits PM	$/MWH	Emits as % Base	Gas Emits CO2	Emits as % Base	Gas Emits NOx	$/MWH
					1.75		0.0047		0.011		0.0009			1.227		0.00541	
$/Ton					$17		$2,315		$1,158		$463						
1994	76%	19%	5%	100%	1.75	100%	0.0047	100%	0.011	100%	0.0009	27	100%	1.227	100%	0.00541	17
1995	71%	24%	6%	100%	1.75	55%	0.00259	100%	0.011	100%	0.0009	24	100%	1.227	48%	0.0026	13
1996	65%	28%	7%	100%	1.75	54%	0.00256	100%	0.011	100%	0.0009	24	100%	1.227	48%	0.00257	13
1997	60%	32%	8%	100%	1.75	54%	0.00253	100%	0.011	100%	0.0009	24	100%	1.227	47%	0.00255	13
1998	59%	32%	9%	100%	1.75	53%	0.00251	100%	0.011	100%	0.0009	24	100%	1.227	47%	0.00252	13
1999	58%	32%	10%	100%	1.75	53%	0.00248	100%	0.011	100%	0.0009	24	100%	1.227	46%	0.0025	13
2000	57%	32%	11%	100%	1.75	52%	0.00246	100%	0.011	100%	0.0009	24	100%	1.227	46%	0.00247	13
2001	56%	32%	12%	100%	1.75	52%	0.00243	100%	0.011	100%	0.0009	24	100%	1.227	45%	0.00245	13
2002	55%	32%	13%	100%	1.75	51%	0.00241	100%	0.011	100%	0.0009	24	100%	1.227	45%	0.00242	13
2003	54%	32%	13%	100%	1.75	51%	0.00239	100%	0.011	100%	0.0009	24	100%	1.227	44%	0.0024	13
2004	54%	32%	14%	100%	1.75	50%	0.00236	100%	0.011	100%	0.0009	24	100%	1.227	44%	0.00238	13
2005	53%	32%	15%	100%	1.75	50%	0.00234	100%	0.011	100%	0.0009	24	100%	1.227	43%	0.00235	13
2006	52%	32%	16%	100%	1.75	49%	0.00231	100%	0.011	100%	0.0009	24	100%	1.227	43%	0.00233	13
2007	51%	32%	17%	100%	1.75	49%	0.00229	100%	0.011	100%	0.0009	24	100%	1.227	43%	0.00231	13
2008	50%	32%	18%	100%	1.75	48%	0.00227	100%	0.011	100%	0.0009	24	100%	1.227	42%	0.00228	13
2009	49%	32%	19%	100%	1.75	48%	0.00225	100%	0.011	100%	0.0009	24	100%	1.227	42%	0.00226	13
2010	49%	32%	19%	100%	1.75	47%	0.00222	100%	0.011	100%	0.0009	24	100%	1.227	41%	0.00224	13
2011	48%	32%	20%	100%	1.75	47%	0.0022	100%	0.011	100%	0.0009	24	100%	1.227	41%	0.00221	13
2012	47%	32%	21%	100%	1.75	46%	0.00218	100%	0.011	100%	0.0009	24	100%	1.227	41%	0.00219	13
2013	46%	32%	22%	100%	1.75	46%	0.00216	100%	0.011	100%	0.0009	24	100%	1.227	40%	0.00217	13
2014	45%	32%	23%	100%	1.75	45%	0.00214	100%	0.011	100%	0.0009	24	100%	1.227	40%	0.00215	13
2015	45%	32%	23%	100%	1.75	45%	0.00211	100%	0.011	100%	0.0009	24	100%	1.227	39%	0.00213	13
2016	44%	32%	24%	100%	1.75	45%	0.00209	100%	0.011	100%	0.0009	24	100%	1.227	39%	0.00211	13
2017	43%	32%	25%	100%	1.75	44%	0.00207	100%	0.011	100%	0.0009	24	100%	1.227	39%	0.00209	13
2018	42%	32%	26%	100%	1.75	44%	0.00205	100%	0.011	100%	0.0009	24	100%	1.227	38%	0.00206	13
2019	42%	32%	26%	100%	1.75	43%	0.00203	100%	0.011	100%	0.0009	24	100%	1.227	38%	0.00204	13
2020	41%	32%	27%	100%	1.75	43%	0.00201	100%	0.011	100%	0.0009	24	100%	1.227	37%	0.00202	13

Derivation of Estimated NEPOOL Externalities

GCC Emits CO2	GCC Emits NOx	$/MWH	Composite Non-CT emissions CO2	NOx	SO2	PM	$/MWH	% CT Energy	Emits as % Base	CT CO2	Emits as % Base	CT NOx	Emits as % Base	CT SO2	Emits as % Base	CT PM	$/MWH	Overall Weighted Average
1.003	0.0001									1.89		0.006		0.001		0.0004		
1.003	0.0001	9	1.613	0.005	0.008	0.0007	24	1%	100%	1.89	100%	0.006	100%	0.001	100%	0.0004	24	24
1.003	0.0001	9	1.582	0.002	0.008	0.0006	21	2%	99%	1.87	95%	0.006	99%	0.001	99%	0.0004	23	21
1.003	0.0001	9	1.552	0.002	0.007	0.0006	20	2%	98%	1.85	90%	0.005	98%	0.001	98%	0.0004	23	20
1.003	0.0001	9	1.522	0.002	0.007	0.0005	20	3%	97%	1.83	86%	0.005	97%	0.001	97%	0.0004	22	20
1.003	0.0001	9	1.515	0.002	0.006	0.0005	19	3%	96%	1.82	81%	0.005	96%	0.001	96%	0.0004	22	19
1.003	0.0001	9	1.508	0.002	0.006	0.0005	19	4%	95%	1.80	77%	0.005	95%	0.001	95%	0.0004	21	19
1.003	0.0001	9	1.501	0.002	0.006	0.0005	19	4%	94%	1.78	74%	0.004	94%	0.001	94%	0.0004	21	19
1.003	0.0001	9	1.494	0.002	0.006	0.0005	19	5%	93%	1.76	71%	0.004	93%	0.001	93%	0.0004	21	19
1.003	0.0001	9	1.488	0.002	0.006	0.0005	19	5%	92%	1.74	69%	0.004	92%	0.001	92%	0.0004	20	19
1.003	0.0001	9	1.481	0.002	0.006	0.0005	19	6%	91%	1.73	67%	0.004	91%	0.001	91%	0.0004	20	19
1.003	0.0001	9	1.475	0.002	0.006	0.0005	18	7%	90%	1.71	65%	0.004	90%	0.001	90%	0.0004	20	19
1.003	0.0001	9	1.469	0.002	0.006	0.0005	18	8%	90%	1.69	63%	0.004	90%	0.001	90%	0.0004	19	18
1.003	0.0001	9	1.462	0.002	0.006	0.0005	18	9%	89%	1.68	61%	0.004	89%	0.001	89%	0.0004	19	18
1.003	0.0001	9	1.456	0.002	0.006	0.0005	18	10%	88%	1.66	59%	0.004	88%	0.001	88%	0.0004	19	18
1.003	0.0001	9	1.45	0.002	0.006	0.0005	18	11%	87%	1.64	58%	0.003	87%	0.001	87%	0.0004	19	18
1.003	0.0001	9	1.444	0.002	0.005	0.0004	18	12%	86%	1.63	56%	0.003	86%	0.001	86%	0.0004	18	18
1.003	0.0001	9	1.438	0.002	0.005	0.0004	18	13%	85%	1.61	54%	0.003	85%	0.001	85%	0.0004	18	18
1.003	0.0001	9	1.432	0.002	0.005	0.0004	17	14%	84%	1.59	53%	0.003	84%	0.001	84%	0.0004	18	17
1.003	0.0001	9	1.426	0.002	0.005	0.0004	17	15%	83%	1.58	51%	0.003	83%	0.001	83%	0.0004	18	17
1.003	0.0001	9	1.42	0.002	0.005	0.0004	17	15%	83%	1.56	49%	0.003	83%	0.001	83%	0.0004	17	17
1.003	0.0001	9	1.414	0.002	0.005	0.0004	17	15%	82%	1.55	48%	0.003	82%	0.001	82%	0.0004	17	17
1.003	0.0001	9	1.408	0.002	0.005	0.0004	17	15%	81%	1.53	47%	0.003	81%	0.001	81%	0.0003	17	17
1.003	0.0001	9	1.402	0.002	0.005	0.0004	17	15%	80%	1.52	45%	0.003	80%	0.001	80%	0.0003	17	17
1.003	0.0001	9	1.397	0.002	0.005	0.0004	17	15%	79%	1.50	44%	0.003	79%	0.001	79%	0.0003	16	17
1.003	0.0001	9	1.391	0.002	0.005	0.0004	16	15%	79%	1.48	42%	0.003	79%	0.001	79%	0.0003	16	16
1.003	0.0001	9	1.386	0.002	0.005	0.0004	16	15%	78%	1.47	41%	0.002	78%	0.001	78%	0.0003	16	16
1.003	0.0001	9	1.38	0.001	0.004	0.0004	16	15%	77%	1.46	40%	0.002	77%	0.001	77%	0.0003	16	16

Comparison of Electric Externality Values

Exhibit_(PLC-21)

	CV ($/kWh)	DPS ($/kWh)
1994	0.0077	0.0240
1995	0.0064	0.0209
1996	0.0137	0.0203
1997	0.0061	0.0196
1998	0.0218	0.0195
1999	0.0245	0.0193
2000	0.0158	0.0086
2001	0.0178	0.0086
2002	0.0152	0.0086
2003	0.0148	0.0086
2004	0.0158	0.0086
2005	0.0116	0.0086
2006	0.0130	0.0086
2007	0.0130	0.0086
2008	0.0135	0.0086
2009	0.0137	0.0086
2010	0.0151	0.0086
2011	0.0156	0.0086
2012	0.0164	0.0086

DPS Estimate (1994$/MMBtu)					
Year	Natural Gas	Low Use LPG	High Use LPG	Distillate	Kerosene
1995	$7.09	$14.86	$13.44	$8.31	$9.25
2000	$7.74	$15.99	$14.50	$8.95	$9.95
2005	$8.67	$17.20	$15.64	$9.65	$10.73
2010	$8.97	$18.39	$16.75	$10.32	$11.48
2015	$9.28	$19.67	$17.95	$11.03	$12.28
2020	$9.60	$21.07	$19.27	$11.80	$13.13
2025	$9.94	$22.59	$20.71	$12.61	$14.04
2030	$10.28	$24.25	$22.29	$13.49	$15.02
2035	$10.64	$26.07	$24.01	$14.42	$16.06
2040	$11.01	$28.06	$25.90	$15.42	$17.18

CV Estimate (1994$/MMBtu)					
Year	Natural Gas	Low Use LPG	High Use LPG	Distillate	Kerosene
1995	$6.52	$16.30	$13.77	$7.77	$8.95
2000	$7.12	$17.47	$14.75	$8.32	$9.59
2005	$7.77	$18.72	$15.80	$8.92	$10.28
2010	$8.49	$20.05	$16.93	$9.56	$11.01
2015	$9.27	$21.49	$18.15	$10.24	$11.80
2020	$10.12	$23.02	$19.44	$10.97	$12.64
2025	$11.05	$24.67	$20.83	$11.76	$13.55
2030	$12.07	$26.43	$22.32	$12.60	$14.52
2035	$13.17	$28.33	$23.92	$13.50	$15.56
2040	$14.39	$30.35	$25.63	$14.46	$16.67

Sources: Projections of Fuel Prices in Vermont: Summer 1993. Technical Report 28. Vermont Department of Public Service. November 1993.
Price indices from "Economic Indicators" (Gov't Printing Office, Dec. 1993)
CV Screening Tool, 1992.

Notes:

[1]: DPS estimates for years beyond 2010 extrapolated at 2005-2010 constant average growth rate

[2]: Propane prices in Technical Report 28 represent a mix of high-volume and low-volume sales. High-volume propane prices were calculated as 5 cents/gallon ($0.55/MMBtu) less than the TR 28 prices in 1994. Low-volume propane prices are about 8.5 cents/gallon ($0.91/MMBtu) hgher than the TR 28 prices, based on a 1993 DPS survy price of $15.07 (1993$). These adjustments reflect the differences in the volume-based margin charged by didtributors. The product price (the difference between the end-use and margin prices in TR 28) is assumed to be the same for low- and high-volume sales. For both price streams, the product price is escalated as implied in TR 28, while the new adjusted margin prices are escalated as the margin in TR 28.

Exhibit_(PLC-23)

Comparison of CV and DPS Wholesale Fuel Price Forecasts

Fuel Type		CV Estimate		DPS Estimate		
			Real		Real	
		1995 Price	Escalation	1995 Price	Escalation	
		$/MMBTU	1995-2010	$/MMBTU	1995-2010	
#6 oil (1%S)		$2.66	2.10%	$3.29	2.60%	CV Estimate for Canal
#2 oil		$5.40	2.11%	$4.16	2.30%	
Firm Natural Gas		$3.00	~2.50%			Includes $76.84/kW-yr for pipeline in 2000, deflated and real-levelized
	Vermont			$4.37	2.92%	
	Southern NE			$5.29	2.49%	

DPS Forecasts from Projections of Fuel Prices in Vermont: Summer 1993. Technical Report 28 .
Vermont Department of Public Service. November 1993. Inflated 15.2% from 1991$ to 1995%

CV Forecasts from IR 7-6
CV gas price includes pipeline at $0.72/MMBTU =
$76.84/kW-yr /[(8760*.85)kWh/kW-yr]*[(1,000,000/7560) kWh/MMBTU]/[1.0425^5 inflation]*[.65 nominal to real]
escalation is 3.42% for commodity and 0% for pipeline

Emission	1990$/ton	1994$/ton	Emissions (lbs/MMBtu) Gas	Propane	Oil	Kerosene
SO2	1,000	1,158	0.0006	0	0.288	0
NOx	2,000	2,315	0.095	0.094	0.12	0.107
CO2	15	17	110.0	139.3	161.3	157.3
CO	200	232	0.019	0.019	0.033	0.026
TSP	400	463	0.005	0.005	0.017	0.011
VOCs	1,500	1,736	0.005	0.005	0.005	0.005
1994$/MMBtu			$1.07	$1.33	$1.72	$1.50

Notes:

All CO2 emissions are based on carbon and heat content of fuels found in Fink & Beaty (1974), Standard Handbook for Electrical Engineers.

Emissions from natural gas, propane and oil are based on AP-42.

Kerosene emissions (except SO2 and CO2)) are the average of distillate and propane emissions.

$/ton values are based on the December 1993 stipulation in Docket No. 5270 CV4, and reflect inflation of 15.75% from 1990 to 1994.

	1994$/MMBtu Delivered		
Energy Source	@ 70% Efficiency	@ 80% Efficiency	@ 90% Efficiency
Natural Gas	$1.53	$1.34	$1.19
Propane	$1.90	$1.66	$1.48
Oil (No.2)	$2.46	$2.15	$1.91
Kerosene	$2.14	$1.88	$1.67
Electricity @ 100% Efficiency, with losses of 12%			
1994	$7.88		
2000	$2.82		

Comparison of Tank Sizes

Tank			Implied Size Switch Due to Control				
Size	% of	% of					
Gallons	UCWH	CWH	30	40	50	80	120
<= 30	34%	7%	7%	15%	12%		
40	24%	15%			6%	19%	
50	20%	17%				20%	
80	21%	58%				20%	1%
120	1%	2%					1%
			7%	15%	17%	58%	2%

Notes: From Discovery response 4-5, corrected for "don't know" responses, 1992 study

Shaded areas are switched sizes

Rate Incentive for Accepting Load Control

64 24hr ave

Annual Water Heating Loads (kWh)	Winter Peak (kWh)	Summer Off-Season (kWh)	Rate3 Bill: Winter	Rate3 Bill: Summer	Rate3 Bill: Total inc. customer charges	Rate1 Bill Base=200: Winter	Rate1 Bill Base=200: Summer	Rate1 Bill Base=200: Total	*Rate1 bill - Rate3 bill: absolute difference	*Rate1 bill - Rate3 bill: percentage difference
3000	1030.89	1969.11	$67.83	$93.85	$226.65	$128.63	$143.59	$272.22	$45.57	20.11%
3100	1065.25	2034.75	$70.09	$96.98	$232.04	$133.22	$148.12	$281.34	$49.30	21.25%
3200	1099.61	2100.39	$72.35	$100.10	$237.43	$137.81	$152.66	$290.47	$53.04	22.34%
3300	1133.98	2166.02	$74.62	$103.23	$242.82	$142.40	$157.19	$299.59	$56.77	23.38%
3400	1168.34	2231.66	$76.88	$106.36	$248.21	$146.99	$161.72	$308.71	$60.50	24.38%
3500	1202.70	2297.30	$79.14	$109.49	$253.60	$151.58	$166.25	$317.84	$64.24	25.33%
3600	1237.07	2362.93	$81.40	$112.62	$258.99	$156.17	$170.78	$326.96	$67.97	26.25%
3700	1271.43	2428.57	$83.66	$115.75	$264.38	$160.76	$175.32	$336.08	$71.71	27.12%
3800	1305.79	2494.21	$85.92	$118.87	$269.77	$165.36	$179.85	$345.20	$75.44	27.96%
3900	1340.15	2559.85	$88.18	$122.00	$275.15	$169.95	$184.38	$354.33	$79.17	28.77%
4000	1374.52	2625.48	$90.44	$125.13	$280.54	$174.54	$188.91	$363.45	$82.91	29.55%
4100	1408.88	2691.12	$92.70	$128.26	$285.93	$179.13	$193.45	$372.57	$86.64	30.30%
4200	1443.24	2756.76	$94.97	$131.39	$291.32	$183.72	$197.98	$381.70	$90.37	31.02%
4300	1477.61	2822.39	$97.23	$134.52	$296.71	$188.31	$202.51	$390.82	$94.11	31.72%
4400	1511.97	2888.03	$99.49	$137.64	$302.10	$192.90	$207.04	$399.94	$97.84	32.39%
4500	1546.33	2953.67	$101.75	$140.77	$307.49	$197.49	$211.57	$409.07	$101.58	33.03%
4600	1580.69	3019.31	$104.01	$143.90	$312.88	$202.08	$216.11	$418.19	$105.31	33.66%
4700	1615.06	3084.94	$106.27	$147.03	$318.27	$206.67	$220.64	$427.31	$109.04	34.26%
4800	1649.42	3150.58	$108.53	$150.16	$323.66	$211.26	$225.17	$436.44	$112.78	34.84%
4900	1683.78	3216.22	$110.79	$153.28	$329.05	$215.86	$229.70	$445.56	$116.51	35.41%
5000	1718.15	3281.85	$113.05	$156.41	$334.44	$220.45	$234.24	$454.68	$120.25	35.95%
5100	1752.51	3347.49	$115.32	$159.54	$339.83	$225.04	$238.77	$463.81	$123.98	36.48%
5200	1786.87	3413.13	$117.58	$162.67	$345.22	$229.63	$243.30	$472.93	$127.71	37.00%
5300	1821.24	3478.76	$119.84	$165.80	$350.61	$234.22	$247.83	$482.05	$131.45	37.49%
5400	1855.60	3544.40	$122.10	$168.93	$355.99	$238.81	$252.36	$491.17	$135.18	37.97%
5500	1889.96	3610.04	$124.36	$172.05	$361.38	$243.40	$256.90	$500.30	$138.91	38.44%
5600	1924.32	3675.68	$126.62	$175.18	$366.77	$247.99	$261.43	$509.42	$142.65	38.89%
5700	1958.69	3741.31	$128.88	$178.31	$372.16	$252.58	$265.96	$518.54	$146.38	39.33%
5800	1993.05	3806.95	$131.14	$181.44	$377.55	$257.17	$270.49	$527.67	$150.12	39.76%

Tank Size Gallons	R Value	Loss/hr	Tank Temp	Delta T Ambient Air 60°F	Standby kWh/yr	Delta T Incoming Water 50°F	kWH Inventory
50	18	0.337%	120	60	216	70	8.55
80	18	0.288%	120	60	296	70	13.68
120	18	0.252%	120	60	388	70	20.53
50	18	0.337%	130	70	252	80	9.77
50	18	0.337%	140	80	289	90	11.00
50	18	0.337%	150	90	325	100	12.22
50	18	0.337%	160	100	361	110	13.44
80	18	0.288%	130	70	345	80	15.64
80	18	0.288%	140	80	395	90	17.59
80	18	0.288%	150	90	444	100	19.55
80	18	0.288%	160	100	493	110	21.50
120	18	0.252%	130	70	453	80	23.46
120	18	0.252%	140	80	518	90	26.39
120	18	0.252%	150	90	583	100	29.32
120	18	0.252%	160	100	647	110	32.26

Comparison of CV Non-Coincident Peak with CV Contribution to VELCo Peak Exhibit_(PLC-29)

		CV Non-coincident Peaks				CV Coincident		CP Same as:	
		FERC Form 1		VELCo		Peak		FERC	VELCo
Year	Month	Date	Hour	Date	Hour	Date	Hour	NCP	NCP
1992	Jan	17	1:00 PM	17	1:00 PM	17	1:00 PM	Yes	Yes
1992	Feb	13	8:00 AM			13	8:00 AM	Yes	
1992	Mar	7	8:00 AM						
1992	Apr	12	8:00 AM						
1992	May	6	8:00 AM	6	8:00 AM	4	9:00 AM		
1992	Jun	8	1:00 PM						
1992	Jul	20	2:00 PM	27	1:00 PM	27	11:00 AM		
1992	Aug	27	2:00 PM	27	2:00 PM	27	2:00 PM	Yes	Yes
1992	Sep	18	1:00 PM	10	2:00 PM	10	2:00 PM		Yes
1992	Oct	26	6:00 PM	26	6:00 PM	27	6:00 PM		
1992	Nov	9	6:00 PM	9	6:00 PM	18	6:00 PM		
1992	Dec	8	6:00 PM	10	12:00 PM	8	6:00 PM	Yes	
1993	Jan			11	1:00 PM	19	6:00 PM		
1993	Feb			1	1:00 PM	1	7:00 PM		
1993	Mar			19	8:00 AM	19	8:00 AM		Yes
1993	Apr			1	2:00 PM	1	7:00 PM		
1993	May			25	2:00 PM	24	12:00 PM		
1993	Jun			28	1:00 PM	28	12:00 PM		
1993	Jul			8	1:00 PM	7	12:00 PM		
1993	Aug			2	2:00 PM	26	2:00 PM		
1993	Sep			15	2:00 PM	3	12:00 PM		
1993	Oct			11	9:00 AM	11	9:00 AM		Yes

					CV	Anderson			CV	Peaks at		
		FERC Form 1, p.401			Docket	(Exh.SRA-2 & SRA-4)			Sales:	same	MW Difference	
Year	Month	Date	Hour	Load	5294			Load	IRP	time?	FERC-	FERC-
				(MW)	(MW)	Date	Hour	(MW)	IR9-35	(F&A)	5294	Anderson
1982	Jan	27	8:00 AM	392	417	27	8:00 AM	430.6	362	Yes	-25	-38.6
1982	Feb	11	8:00 AM	354		26	8:00 AM	392.2				-38.2
1982	Mar	4	8:00 AM	354		1	8:00 AM	383.5				-29.5
1982	Apr	7	12:00 PM	343		8	9:00 AM	372.3				-29.3
1982	May	24	9:00 AM	281		24	12:00 PM	296.1				-15.1
1982	Jun	16	10:00 AM	273		7	9:00 AM	291.2				-18.2
1982	Jul	19	12:00 PM	281		19	11:00 AM	306.8				-25.8
1982	Aug	9	12:00 PM	284		5	11:00 AM	316.3				-32.3
1982	Sep	27	12:00 PM	280		27	12:00 PM	298.3		Yes		-18.3
1982	Oct	25	9:00 AM	301		25	9:00 AM	325.9		Yes		-24.9
1982	Nov	16	6:00 PM	313		29	6:00 PM	333.2				-20.2
1982	Dec	13	6:00 PM	372		13	6:00 PM	418.8		Yes		-46.8
1983	Jan	19	6:00 PM	373		19	8:00 AM	413.5				-40.5
1983	Feb	11	8:00 AM	371		11	8:00 AM	403.6		Yes		-32.6
1983	Mar	24	8:00 AM	321		25	8:00 AM	350.1				-29.1
1983	Apr	19	12:00 PM	318		19	12:00 PM	340.1		Yes		-22.1
1983	May	10	9:00 AM	296		9	10:00 AM	328				-32
1983	Jun	15	2:00 PM	306		15	2:00 PM	332.9		Yes		-26.9
1983	Jul	18	2:00 PM	294		20	12:00 PM	306.9				-12.9
1983	Aug	18	12:00 PM	305		19	1:00 PM	315.9				-10.9
1983	Sep	6	12:00 PM	303		6	2:00 PM	314.4				-11.4
1983	Oct	26	9:00 AM	315		21	8:00 AM	339.4				-24.4
1983	Nov	28	5:00 PM	338		18	8:00 AM	358				-20
1983	Dec	21	8:00 AM	388	413	21	8:00 AM	420.4	358	Yes	-25	-32.4
1984	Jan	12	8:00 AM	397		16	12:00 PM	423.6				-26.6
1984	Feb	2	8:00 AM	389		2	8:00 AM	417.9		Yes		-28.9
1984	Mar	13	1:00 PM	384		13	1:00 PM	415.1		Yes		-31.1
1984	Apr	10	12:00 PM	335		16	12:00 PM	348.6				-13.6
1984	May	3	8:00 AM	309		3	8:00 AM	329.1		Yes		-20.1
1984	Jun	11	12:00 PM	320		11	12:00 PM	330.4		Yes		-10.4
1984	Jul	31	12:00 PM	317		16	12:00 PM	322.9				-5.9
1984	Aug	13	12:00 PM	339		14	1:00 PM	356.3				-17.3
1984	Sep	27	9:00 AM	322		27	9:00 AM	342.5		Yes		-20.5
1984	Oct	2	9:00 AM	325		2	9:00 AM	348.6		Yes		-23.6
1984	Nov	20	6:00 PM	360		20	6:00 PM	374.1		Yes		-14.1
1984	Dec	27	1:00 PM	410	427	27	1:00 PM	431.4	379	Yes	-17	-21.4
1985	Jan	21	12:00 PM	420	436	21	12:00 PM	436.5	391	Yes	-16	-16.5
1985	Feb	8	12:00 PM	419		8	12:00 PM	441.6		Yes		-22.6
1985	Mar	4	1:00 PM	396		4	12:00 PM	411.9				-15.9
1985	Apr	1	12:00 PM	344		1	12:00 PM	355.8		Yes		-11.8
1985	May	9	8:00 AM	321		9	8:00 AM	330.6		Yes		-9.6
1985	Jun	24	2:00 PM	315		24	1:00 PM	321.3				-6.3
1985	Jul	15	2:00 PM	273		26	12:00 PM	326				-53
1985	Aug	15	2:00 PM	292		15	2:00 PM	343.5		Yes		-51.5
1985	Sep	13	8:00 AM	272		5	2:00 PM	325.2				-53.2
1985	Oct	29	6:00 PM	291		30	8:00 AM	355.1				-64.1
1985	Nov	26	6:00 PM	316		26	6:00 PM	392.6		Yes		-76.6
1985	Dec	19	8:00 AM	367		19	8:00 AM	440		Yes		-73
1986	Jan	15	1:00 PM	390	430	15	8:00 AM	464.1	397		-40	-74.1
1986	Feb	7	~~12:00 PM~~	348		7	12:00 PM	424.5		Yes		-76.5
1986	Mar	21	8:00 AM	327		21	8:00 AM	408.3		Yes		-81.3
1986	Apr	7	12:00 PM	281		7	12:00 PM	356.8		Yes		-75.8
1986	May	5	8:00 AM	253		5	8:00 AM	331.6		Yes		-78.6

1986	Jun	16	12:00 PM	272	16	2:00 PM	324.9			-52.9
1986	Jul	29	11:00 AM	275	29	12:00 PM	343.2			-68.2
1986	Aug	18	2:00 PM	283	18	2:00 PM	341.7		Yes	-58.7
1986	Sep	18	8:00 AM	269	17	8:00 AM	340.5			-71.5
1986	Oct	10	8:00 AM	291	7	8:00 AM	366.5			-75.5
1986	Nov	19	6:00 PM	334	20	12:00 PM	417.4			-83.4
1986	Dec	9	12:00 PM	360	9	12:00 PM	439.4		Yes	-79.4
1987	Jan	27	8:00 AM	361						
1987	Feb	16	12:00 PM	364						
1987	Mar	10	8:00 AM	340						
1987	Apr	1	12:00 PM	301						
1987	May	1	8:00 AM	291						
1987	Jun	25	12:00 PM	273						
1987	Jul	13	2:00 PM	295						
1987	Aug	17	12:00 PM	296						
1987	Sep	25	8:00 AM	287						
1987	Oct	14	8:00 AM	310						
1987	Nov	10	6:00 PM	331						
1987	Dec	30	12:00 PM	394				418		
1988	Jan	15	~~8:00 AM~~	400	14	10:00 PM	480.7	410		-80.7
1988	Feb	5	12:00 PM	364	12	1:00 PM	437.5			-73.5
1988	Mar	21	12:00 PM	365	21	12:00 PM	429.2		Yes	-64.2
1988	Apr	13	8:00 AM	292	13	8:00 AM	358.7		Yes	-66.7
1988	May	4	8:00 AM	290	3	8:00 AM	348.7			-58.7
1988	Jun	15	2:00 PM	300	15	2:00 PM	358.9		Yes	-58.9
1988	Jul	8	2:00 PM	296	14	10:00 PM	400.7			-104.7
1988	Aug	4	12:00 PM	326	4	12:00 PM	387.3		Yes	-61.3
1988	Sep	29	8:00 AM	309	29	8:00 AM	359.5		Yes	-50.5
1988	Oct	14	8:00 AM	322	7	8:00 AM	384.2			-62.2
1988	Nov	21	6:00 PM	325	21	6:00 PM	407.4		Yes	-82.4
1988	Dec	12	6:00 PM	384	12	8:00 AM	472.3			-88.3
1989	Jan	4	6:00 PM	380	6	1:00 PM	475.5			-95.5
1989	Feb	17	12:00 PM	377	10	8:00 AM	444.5			-67.5
1989	Mar	7	12:00 PM	377	7	12:00 PM	457		Yes	-80
1989	Apr	12	8:00 AM	320	12	8:00 AM	388.2		Yes	-68.2
1989	May	9	8:00 AM	292	9	8:00 AM	351.7		Yes	-59.7
1989	Jun	27	2:00 PM	303	27	2:00 PM	365.2		Yes	-62.2
1989	Jul	27	2:00 PM	309	26	2:00 PM	376.7			-67.7
1989	Aug	4	12:00 PM	296	16	12:00 PM	364.4			-68.4
1989	Sep	11	11:00 AM	283	28	9:00 AM	359.4			-76.4
1989	Oct	9	10:00 AM	300	9	10:00 AM	376.9		Yes	-76.9
1989	Nov	29	6:00 PM	367	29	6:00 PM	439.8		Yes	-72.8
1989	Dec	27	6:00 PM	410	27	6:00 PM	483	412	Yes	-73
1990	Jan	15	12:00 PM	386	15	12:00 PM	448.2	382	Yes	-62.2
1990	Feb	27	~~1:00 PM~~	380	27	2:00 PM	440.6			-60.6
1990	Mar	7	8:00 AM	365	7	8:00 AM	426.9		Yes	-61.9
1990	Apr	12	8:00 AM	325	12	8:00 AM	379.5		Yes	-54.5
1990	May	21	1:00 PM	311	21	1:00 PM	352.2		Yes	-41.2
1990	Jun	18	1:00 PM	321	18	3:00 PM	357			-36
1990	Jul	16	11:00 AM	323	18	2:00 PM	363.7			-40.7
1990	Aug	27	2:00 PM	337	27	2:00 PM	371.5		Yes	-34.5
1990	Sep	7	12:00 PM	314	7	1:00 PM	350.5			-36.5
1990	Oct	29	6:00 PM	331	29	6:00 PM	379.4		Yes	-48.4
1990	Nov	13	6:00 PM	359	13	6:00 PM	406.9		Yes	-47.9
1990	Dec	27	6:00 PM	380	27	6:00 PM	448.1		Yes	-68.1

Year	Month	FERC Form 1, p.401				VELCo - CV NC Peak				Same date	MW
		Date	Hour	Load (MW)		Date	Hour	Load (MW)		& hour?	Difference
1992	Jan	17	1:00 PM	416		17	1:00 PM	433		Yes	-17
1992	Feb	13	8:00 AM	391							
1992	Mar	7	8:00 AM	374							
1992	Apr	12	8:00 AM	337							
1992	May	6	8:00 AM	305		6	8:00 AM	318		Yes	-13
1992	Jun	8	1:00 PM	315							
1992	Jul	20	2:00 PM	323		27	1:00 PM	339			-16
1992	Aug	27	2:00 PM	346		27	2:00 PM	362		Yes	-16
1992	Sep	18	1:00 PM	322		10	2:00 PM	343			-21
1992	Oct	26	6:00 PM	330		26	6:00 PM	344		Yes	-14
1992	Nov	9	6:00 PM	369		9	6:00 PM	373		Yes	-4
1992	Dec	8	6:00 PM	398		10	12:00 PM	411			-13

Exhibit_(PLC-32)

Correction of Reconstituted Peak - 1/16/92, 6 pm

	CV Estimate IR 5-52 (MW)	Correction (MW)	Comments
Actual load	444		
Ski area interruption	12		On 1/16/92 at 6 pm
Ripple control	8	5	Assuming 7500 units with load like VLS UCWH (0.64 kW)
Peak alert (Company)	0.5		
Peak alert (Public)	2.5		
Time clock control	22	10	Using VLS CWH (0.18 kW) or CV CWH (0.16 kW, from DR4-7) & UCWH (0.64kW)
Total	489	474	CV claims load of 475 MW in HMS-3

[TABLL2-5.XLS]

Clock-Controlled DHW Marginal Contribution to Peaks, VLS Data for Waters
Annual Summary

Year	FERC Form 1 Peaks							Anderson System Load Data					
	Date	Hour	CCWH Load		UCWH			Date	Hour	CWH Load		UCWH	
			CP (KW)	CR (KW)	CP (KW)	CR (KW)				CP (KW)	CR (KW)	CP (KW)	CR (KW)
1982	27-Jan	8:00 AM	0.51	0.55	0.78	0.75		27-Jan	8:00 AM	0.51	0.53	0.78	0.75
1983	21-Dec	8:00 AM	0.64	0.63	0.75	0.72		21-Dec	8:00 AM	0.64	0.66	0.75	0.72
1984	27-Dec	1:00 PM	0.64	0.66	0.53	0.56		27-Dec	1:00 PM	0.64	0.67	0.53	0.55
1985	21-Jan	12:00 PM	0.82	0.79	0.53	0.55		8-Feb	12:00 PM	0.90	0.86	0.65	0.63
1986	15-Jan	1:00 PM	0.60	0.65	0.53	0.56		15-Jan	8:00 AM	0.51	0.60	0.78	0.74
1987	30-Dec	12:00 PM	0.98	0.92	0.52	0.56							
1988	15-Jan	8:00 AM	0.51	0.57	0.78	0.74		14-Jan	10:00 PM	0.59	0.64	0.46	0.51
1989	27-Dec	6:00 PM	0.52	0.56	0.59	0.60		27-Dec	6:00 PM	0.52	0.57	0.59	0.60
1990	15-Jan	12:00 PM	0.82	0.77	0.53	0.56		15-Jan	12:00 PM	0.82	0.76	0.53	0.56
1991	11-Jan	1:00 PM	0.60	0.61	0.53	0.57							
1992	17-Jan	1:00 PM	0.60	0.61	0.53	0.57							
1993													
1994													
		Average	0.66	0.67	0.60	0.61			Average	0.64	0.66	0.63	0.63

Clock-Controlled DHW Marginal Contribution to Peaks, VLS Data for Waters
Annual Summary

VELCo CV System Load		CWH Load		UCWH		
Date	Hour	CP (KW)	CR (KW)	CP (KW)	CR (KW)	
10-Dec	12:00 PM	0.98	0.89	0.52	0.54	[1]
12-Dec	6:00 PM	0.52	0.54	0.59	0.61	[2]
	Average	0.75	0.72	0.56	0.57	

VELCo Total State Load		CWH Load		UCWH		
Date	Hour	CP (KW)	CR (KW)	CP (KW)	CR (KW)	
8-Dec	6:00 PM	0.52	0.52	0.59	0.61	[1]
	Average	0.52	0.52	0.59	0.61	

[1] 1993 VELCo data is for 11/92-10/93

[2] For year 1994: 11/93-12/93 are actual, 1/94-10/94 are projected, from Exhibit STAGE-1, Docket 5701.

FERC Form 1 System Load Data							
		Date	Hour	Peak (MW)	CP CCWH(KW) (from VLS)	CP UCWH(KW) (from VLS)	
1982	Jan	27	8:00 AM	392	0.51	0.78	
1982	Feb	11	8:00 AM	354	0.63	0.92	
1982	Mar	4	8:00 AM	354	0.72	1.11	
1982	Apr	7	12:00 PM	343	1.15	0.53	
1982	May	24	9:00 AM	281	0.50	0.62	
1982	Jun	16	10:00 AM	273	0.42	0.47	
1982	Jul	19	12:00 PM	281	0.93	0.53	
1982	Aug	9	12:00 PM	284	0.80	0.60	
1982	Sep	27	12:00 PM	280	0.46	0.56	
1982	Oct	25	9:00 AM	301	0.69	0.71	
1982	Nov	16	6:00 PM	313	0.47	0.60	
1982	Dec	13	6:00 PM	372	0.52	0.59	
1983	Jan	19	6:00 PM	373	0.18	0.64	
1983	Feb	11	8:00 AM	371	0.63	0.92	
1983	Mar	24	8:00 AM	321	0.72	1.11	
1983	Apr	19	12:00 PM	318	1.15	0.53	
1983	May	10	9:00 AM	296	0.50	0.62	
1983	Jun	15	2:00 PM	306	0.63	0.44	
1983	Jul	18	2:00 PM	294	0.55	0.50	
1983	Aug	18	12:00 PM	305	0.80	0.60	
1983	Sep	6	12:00 PM	303	0.46	0.56	
1983	Oct	26	9:00 AM	315	0.69	0.71	
1983	Nov	28	5:00 PM	338	0.43	0.52	
1983	Dec	21	8:00 AM	388	0.64	0.75	
1984	Jan	12	8:00 AM	397	0.51	0.78	
1984	Feb	2	8:00 AM	389	0.63	0.92	
1984	Mar	13	1:00 PM	384	0.63	0.57	
1984	Apr	10	12:00 PM	335	1.15	0.53	
1984	May	3	8:00 AM	309	0.79	0.70	
1984	Jun	11	12:00 PM	320	0.73	0.46	
1984	Jul	31	12:00 PM	317	0.93	0.53	
1984	Aug	13	12:00 PM	339	0.80	0.60	
1984	Sep	27	9:00 AM	322	0.69	0.51	
1984	Oct	2	9:00 AM	325	0.69	0.71	
1984	Nov	20	6:00 PM	360	0.47	0.60	
1984	Dec	27	1:00 PM	410	0.64	0.53	
1985	Jan	21	12:00 PM	420	0.82	0.53	
1985	Feb	8	12:00 PM	419	0.90	0.65	
1985	Mar	4	1:00 PM	396	0.63	0.57	
1985	Apr	1	12:00 PM	344	1.15	0.53	
1985	May	9	8:00 AM	321	0.79	0.70	
1985	Jun	24	2:00 PM	315	0.63	0.44	
1985	Jul	15	2:00 PM	273	0.55	0.50	
1985	Aug	15	2:00 PM	292	0.56	0.50	
1985	Sep	13	8:00 AM	272	0.83	0.70	
1985	Oct	29	6:00 PM	291	0.55	0.58	
1985	Nov	26	6:00 PM	316	0.47	0.60	

1985	Dec	19	8:00 AM	367	0.64	0.75	
1986	Jan	15	1:00 PM	390	0.60	0.53	
1986	Feb	7	12:00 PM	348	0.90	0.65	
1986	Mar	21	8:00 AM	327	0.72	1.11	
1986	Apr	7	12:00 PM	281	1.15	0.53	
1986	May	5	8:00 AM	253	0.79	0.70	
1986	Jun	16	12:00 PM	272	0.73	0.46	
1986	Jul	29	11:00 AM	275	0.63	0.61	
1986	Aug	18	2:00 PM	283	0.56	0.50	
1986	Sep	18	8:00 AM	269	0.83	0.70	
1986	Oct	10	8:00 AM	291	0.78	0.67	
1986	Nov	19	6:00 PM	334	0.47	0.60	
1986	Dec	9	12:00 PM	360	0.98	0.52	
1987	Jan	27	8:00 AM	361	0.51	0.78	
1987	Feb	16	12:00 PM	364	0.90	0.65	
1987	Mar	10	8:00 AM	340	0.72	1.11	
1987	Apr	1	12:00 PM	301	1.15	0.53	
1987	May	1	8:00 AM	291	0.79	0.70	
1987	Jun	25	12:00 PM	273	0.73	0.46	
1987	Jul	13	2:00 PM	295	0.55	0.50	
1987	Aug	17	12:00 PM	296	0.80	0.60	
1987	Sep	25	8:00 AM	287	0.83	0.70	
1987	Oct	14	8:00 AM	310	0.78	0.67	
1987	Nov	10	6:00 PM	331	0.47	0.60	
1987	Dec	30	12:00 PM	394	0.98	0.52	
1988	Jan	15	8:00 AM	400	0.51	0.78	
1988	Feb	5	12:00 PM	364	0.90	0.65	
1988	Mar	21	12:00 PM	365	1.03	0.58	
1988	Apr	13	8:00 AM	292	0.74	0.91	
1988	May	4	8:00 AM	290	0.79	0.70	
1988	Jun	15	2:00 PM	300	0.63	0.44	
1988	Jul	8	2:00 PM	296	0.55	0.50	
1988	Aug	4	12:00 PM	326	0.80	0.60	
1988	Sep	29	8:00 AM	309	0.83	0.70	
1988	Oct	14	8:00 AM	322	0.78	0.67	
1988	Nov	21	6:00 PM	325	0.47	0.60	
1988	Dec	12	6:00 PM	384	0.52	0.59	
1989	Jan	4	6:00 PM	380	0.18	0.64	
1989	Feb	17	12:00 PM	377	0.90	0.65	
1989	Mar	7	12:00 PM	377	1.03	0.58	
1989	Apr	12	8:00 AM	320	0.74	0.91	
1989	May	9	8:00 AM	292	0.79	0.70	
1989	Jun	27	2:00 PM	303	0.63	0.44	
1989	Jul	27	2:00 PM	309	0.55	0.50	
1989	Aug	4	12:00 PM	296	0.80	0.60	
1989	Sep	11	11:00 AM	283	0.46	0.52	
1989	Oct	9	10:00 AM	300	0.67	0.66	
1989	Nov	29	6:00 PM	367	0.47	0.60	
1989	Dec	27	6:00 PM	410	0.52	0.59	
1990	Jan	15	12:00 PM	386	0.82	0.53	
1990	Feb	27	1:00 PM	380	0.72	0.73	

1990	Mar	7	8:00 AM	365	0.72	1.11	
1990	Apr	12	8:00 AM	325	0.74	0.91	
1990	May	21	1:00 PM	311	0.90	0.48	
1990	Jun	18	1:00 PM	321	0.83	0.44	
1990	Jul	16	11:00 AM	323	0.63	0.61	
1990	Aug	27	2:00 PM	337	0.56	0.50	
1990	Sep	7	12:00 PM	314	0.46	0.56	
1990	Oct	29	6:00 PM	331	0.55	0.58	
1990	Nov	13	6:00 PM	359	0.47	0.60	
1990	Dec	27	6:00 PM	380	0.52	0.59	
1991	Jan	11	1:00 PM	399	0.60	0.53	
1991	Feb	12	8:00 AM	374	0.63	0.92	
1991	Mar	7	8:00 AM	352	0.72	1.11	
1991	Apr	12	8:00 AM	317	0.74	0.91	
1991	May	21	1:00 PM	306	0.90	0.48	
1991	Jun	18	1:00 PM	320	0.83	0.44	
1991	Jul	20	11:00 AM	339	0.63	0.61	
1991	Aug	27	2:00 PM	332	0.56	0.50	
1991	Sep	7	12:00 PM	310	0.46	0.56	
1991	Oct	29	6:00 PM	321	0.55	0.58	
1991	Nov	13	6:00 PM	347	0.47	0.60	
1991	Dec	27	6:00 PM	390	0.52	0.59	
1992	Jan	17	1:00 PM	416	0.60	0.53	
1992	Feb	13	8:00 AM	391	0.63	0.92	
1992	Mar	7	8:00 AM	374	0.72	1.11	
1992	Apr	12	8:00 AM	337	0.74	0.91	
1992	May	6	8:00 AM	305	0.79	0.70	
1992	Jun	8	1:00 PM	315	0.83	0.44	
1992	Jul	20	2:00 PM	323	0.55	0.50	
1992	Aug	27	2:00 PM	346	0.56	0.50	
1992	Sep	18	1:00 PM	322	0.53	0.52	
1992	Oct	26	6:00 PM	330	0.55	0.58	
1992	Nov	9	6:00 PM	369	0.47	0.60	
1992	Dec	8	6:00 PM	398	0.52	0.59	
		Avg. of Dec. & Jan.		389.41	0.58	0.62	
		Avg. all months:		333.08	0.68	0.64	

Anderson System Load Data						
		Date	Hour	Peak	CP	CP
				(MW)	CCWH(KW)	UCWH(KW)
					(from VLS)	(from VLS)
1982	Jan	27	8:00 AM	430.6	0.51	0.78
1982	Feb	26	8:00 AM	392.2	0.63	0.92
1982	Mar	1	8:00 AM	383.5	0.72	0.56
1982	Apr	8	9:00 AM	372.3	0.46	0.91
1982	May	24	12:00 PM	296.1	0.70	0.51
1982	Jun	7	9:00 AM	291.2	0.51	0.57
1982	Jul	19	11:00 AM	306.8	0.63	0.61
1982	Aug	5	11:00 AM	316.3	0.70	0.71
1982	Sep	27	12:00 PM	298.3	0.46	0.56
1982	Oct	25	9:00 AM	325.9	0.69	0.71
1982	Nov	29	6:00 PM	333.2	0.47	0.60
1982	Dec	13	6:00 PM	418.8	0.52	0.59
1983	Jan	19	8:00 AM	413.5	0.51	0.78
1983	Feb	11	8:00 AM	403.6	0.63	0.92
1983	Mar	25	8:00 AM	350.1	0.72	1.11
1983	Apr	19	12:00 PM	340.1	1.15	0.53
1983	May	9	10:00 AM	328.0	0.34	0.51
1983	Jun	15	2:00 PM	332.9	0.63	0.44
1983	Jul	20	12:00 PM	306.9	0.93	0.53
1983	Aug	19	1:00 PM	315.9	0.79	0.60
1983	Sep	6	2:00 PM	314.4	0.49	0.50
1983	Oct	21	8:00 AM	339.4	0.78	0.67
1983	Nov	18	8:00 AM	358.0	0.67	0.57
1983	Dec	21	8:00 AM	420.4	0.64	0.75
1984	Jan	16	12:00 PM	423.6	0.82	0.53
1984	Feb	2	8:00 AM	417.9	0.63	0.92
1984	Mar	13	1:00 PM	415.1	0.63	0.57
1984	Apr	16	12:00 PM	348.6	1.15	0.53
1984	May	3	8:00 AM	329.1	0.79	0.70
1984	Jun	11	12:00 PM	330.4	0.73	0.46
1984	Jul	16	12:00 PM	322.9	0.93	0.53
1984	Aug	14	1:00 PM	356.3	0.79	0.60
1984	Sep	27	9:00 AM	342.5	0.69	0.51
1984	Oct	2	9:00 AM	348.6	0.69	0.71
1984	Nov	20	6:00 PM	374.1	0.47	0.60
1984	Dec	27	1:00 PM	431.4	0.64	0.53
1985	Jan	21	12:00 PM	436.5	0.82	0.53
1985	Feb	8	12:00 PM	441.6	0.90	0.65
1985	Mar	4	12:00 PM	411.9	1.03	0.58
1985	Apr	1	12:00 PM	355.8	1.15	0.53
1985	May	9	8:00 AM	330.6	0.79	0.70
1985	Jun	24	1:00 PM	321.3	0.83	0.44
1985	Jul	26	12:00 PM	326.0	0.93	0.53
1985	Aug	15	2:00 PM	343.5	0.56	0.50
1985	Sep	5	2:00 PM	325.2	0.49	0.50
1985	Oct	30	8:00 AM	355.1	0.78	0.67
1985	Nov	26	6:00 PM	392.6	0.47	0.60

1985	Dec	19	8:00 AM	440.0	0.64	0.75	
1986	Jan	15	8:00 AM	464.1	0.51	0.78	
1986	Feb	7	12:00 PM	424.5	0.90	0.65	
1986	Mar	21	8:00 AM	408.3	0.72	1.11	
1986	Apr	7	12:00 PM	356.8	1.15	0.53	
1986	May	5	8:00 AM	331.6	0.79	0.70	
1986	Jun	16	2:00 PM	324.9	0.63	0.44	
1986	Jul	29	12:00 PM	343.2	0.93	0.53	
1986	Aug	18	2:00 PM	341.7	0.56	0.50	
1986	Sep	17	8:00 AM	340.5	0.83	0.70	
1986	Oct	7	8:00 AM	366.5	0.78	0.67	
1986	Nov	20	12:00 PM	417.4	0.87	0.56	
1986	Dec	9	12:00 PM	439.4	0.98	0.52	
1987	Jan						
1987	Feb						
1987	Mar						
1987	Apr						
1987	May						
1987	Jun						
1987	Jul						
1987	Aug						
1987	Sep						
1987	Oct						
1987	Nov						
1987	Dec						
1988	Jan	14	10:00 PM	480.7	0.59	0.46	
1988	Feb	12	1:00 PM	437.5	0.72	0.73	
1988	Mar	21	12:00 PM	429.2	1.03	0.58	
1988	Apr	13	8:00 AM	358.7	0.74	0.91	
1988	May	3	8:00 AM	348.7	0.79	0.70	
1988	Jun	15	2:00 PM	358.9	0.63	0.44	
1988	Jul	14	10:00 PM	400.7	0.92	0.48	
1988	Aug	4	12:00 PM	387.3	0.80	0.60	
1988	Sep	29	8:00 AM	359.5	0.83	0.70	
1988	Oct	7	8:00 AM	384.2	0.78	0.67	
1988	Nov	21	6:00 PM	407.4	0.47	0.60	
1988	Dec	12	8:00 AM	472.3	0.64	0.75	
1989	Jan	6	1:00 PM	475.5	0.60	0.53	
1989	Feb	10	8:00 AM	444.5	0.63	0.92	
1989	Mar	7	12:00 PM	457.0	1.03	0.58	
1989	Apr	12	8:00 AM	388.2	0.74	0.91	
1989	May	9	8:00 AM	351.7	0.79	0.70	
1989	Jun	27	2:00 PM	365.2	0.63	0.44	
1989	Jul	26	2:00 PM	376.7	0.55	0.50	
1989	Aug	16	12:00 PM	364.4	0.80	0.60	
1989	Sep	28	9:00 AM	359.4	0.69	0.51	
1989	Oct	9	10:00 AM	376.9	0.67	0.66	
1989	Nov	29	6:00 PM	439.8	0.47	0.60	
1989	Dec	27	6:00 PM	483.0	0.52	0.59	
1990	Jan	15	12:00 PM	448.2	0.82	0.53	
1990	Feb	27	2:00 PM	440.6	0.61	0.68	

1990	Mar	7	8:00 AM	426.9	0.72	1.11	
1990	Apr	12	8:00 AM	379.5	0.74	0.91	
1990	May	21	1:00 PM	352.2	0.90	0.48	
1990	Jun	18	3:00 PM	357.0	0.44	0.37	
1990	Jul	18	2:00 PM	363.7	0.55	0.50	
1990	Aug	27	2:00 PM	371.5	0.56	0.50	
1990	Sep	7	1:00 PM	350.5	0.53	0.52	
1990	Oct	29	6:00 PM	379.4	0.55	0.58	
1990	Nov	13	6:00 PM	406.9	0.47	0.60	
1990	Dec	27	6:00 PM	448.1	0.52	0.59	
		Avg. of Dec. & Jan.		445.38	0.64	0.62	
		Avg. all months:		378.12	0.71	0.63	

VELCo CV System Load Data						
		Date	Hour	CV NC Peak (MW)	CP CCWH(KW) (from VLS)	CP UCWH(KW) (from VLS)
1992	Jan	17	1:00 PM	433	0.60	0.53
1992	Feb					
1992	Mar					
1992	Apr					
1992	May	6	8:00 AM	318	0.79	0.70
1992	Jun					
1992	Jul	27	1:00 PM	339	0.83	0.49
1992	Aug	27	2:00 PM	362	0.56	0.50
1992	Sep	10	2:00 PM	343	0.49	0.50
1992	Oct	26	6:00 PM	344	0.55	0.58
1992	Nov	9	6:00 PM	373	0.47	0.60
1992	Dec	10	12:00 PM	411	0.98	0.52
1993	Jan	11	1:00 PM	404	0.60	0.53
1993	Feb	1	1:00 PM	397	0.72	0.73
1993	Mar	19	8:00 AM	394	0.72	1.11
1993	Apr	1	2:00 PM	348	0.67	0.50
1993	May	25	2:00 PM	316	0.71	0.39
1993	Jun	28	1:00 PM	334	0.83	0.44
1993	Jul	8	1:00 PM	351	0.83	0.49
1993	Aug	2	2:00 PM	356	0.56	0.50
1993	Sep	15	2:00 PM	334	0.49	0.50
1993	Oct	11	9:00 AM	354	0.69	0.71
1993	Nov	21	6:00 PM	372	0.47	0.60
1993	Dec	12	6:00 PM	404	0.52	0.59
1994	Jan	1	12:00 PM	390	0.82	0.53
1994	Feb	1	6:00 PM	390	0.15	0.73
1994	Mar	18	8:00 AM	391	0.72	1.11
1994	Apr	1	9:00 AM	336	0.46	0.82
1994	May	24	11:00 AM	308	0.36	0.55
1994	Jun	18	2:00 PM	328	0.63	0.44
1994	Jul	7	12:00 PM	350	0.93	0.53
1994	Aug	25	12:00 PM	353	0.80	0.60
1994	Sep	3	11:00 AM	334	0.64	0.52
1994	Oct	11	9:00 AM	342	0.69	0.71
		Avg. of Dec. & Jan.		408.40	0.70	0.54
		Avg. all months:		360.30	0.64	0.60

Note: 11/92-10/93 considered 1993 calendar year and
11/93-10/94 considered 1994 calendar year.
For year 1994: 11/93-12/93 are actual, 1/94-10/94 are projected,
from Exhibit STAGE-1, Docket 5701.

VELCo Total State Load						
		Date	Hour	CV - Coin. Peak (MW)	CP CCWH(K (from VLS	CP UCWH(KW) (from VLS)
1992	Jan	17	1:00 PM	433	0.63	0.53
1992	Feb	13	8:00 AM	407	0.72	0.73
1992	Mar					
1992	Apr					
1992	May	4	9:00 AM	310	0.50	0.62
1992	Jun					
1992	Jul	27	11:00 AM	332	0.63	0.61
1992	Aug	27	2:00 PM	362	0.56	0.50
1992	Sep	10	2:00 PM	343	0.49	0.50
1992	Oct	27	6:00 PM	339	0.55	0.58
1992	Nov	18	6:00 PM	370	0.47	0.60
1992	Dec	8	6:00 PM	408	0.52	0.59
1993	Jan	19	6:00 PM	397	0.18	0.64
1993	Feb	1	7:00 PM	394	0.08	0.90
1993	Mar	19	8:00 AM	394	0.72	1.11
1993	Apr	1	7:00 PM	345	0.24	0.68
1993	May	24	12:00 PM	313	0.70	0.51
1993	Jun	28	12:00 PM	329	0.73	0.46
1993	Jul	7	12:00 PM	347	0.93	0.53
1993	Aug	26	2:00 PM	356	0.56	0.50
1993	Sep	3	12:00 PM	331	0.46	0.56
1993	Oct	11	9:00 AM	354	0.69	0.71
		Avg. of Dec. & Jan.		412.67	0.44	0.59
		Avg. all months:		361.26	0.55	0.62

	FERC Form 1							VELCo - CV NCP				
	Date	Hour	CV Clock Load (KW)	VLS Unc. Load (KW)	Delta			Date	Hour	CV Clock Load (KW)	VLS Unc. Load (KW)	Delta
Dec-91	27	6:00 PM	0.38	0.59	-0.22		Dec-91					
Jan-92	17	1:00 PM	0.89	0.53	0.36		Jan-92	17	1:00 PM	0.89	0.53	0.36
Feb-92	13	8:00 AM	0.30	0.92	-0.62		Feb-92					
Mar-92	7	8:00 AM	0.28	1.11	-0.83		Mar-92					
Apr-92	12	8:00 AM	0.55	0.91	-0.36		Apr-92					
May-92	6	8:00 AM	0.59	0.70	-0.11		May-92	6	8:00 AM	0.61	0.70	-0.09
Jun-92	8	1:00 PM	0.51	0.44	0.07		Jun-92					
Jul-92	20	2:00 PM	0.53	0.50	0.03		Jul-92	27	1:00 PM	0.90	0.49	0.41
Aug-92	27	2:00 PM	0.73	0.50	0.23		Aug-92	27	2:00 PM	0.73	0.50	0.23
Sep-92	18	1:00 PM	0.84	0.52	0.32		Sep-92	10	2:00 PM	0.51	0.50	0.01
Oct-92	26	6:00 PM	0.26	0.58	-0.33		Oct-92	26	6:00 PM	0.27	0.58	-0.31
Nov-92	9	6:00 PM	0.13	0.60	-0.47		Nov-92	9	6:00 PM	0.14	0.60	-0.47
Dec-92	8	6:00 PM	0.20	0.59	-0.39		Dec-92	10	12:00 PM	1.12	0.52	0.60
Jan-93							Jan-93	11	1:00 PM	0.90	0.53	0.37
Feb-93							Feb-93	1	1:00 PM	0.57	0.73	-0.16
Mar-93							Mar-93	19	8:00 AM	0.46	1.11	-0.65
Apr-93							Apr-93	1	2:00 PM	0.76	0.50	0.26
May-93							May-93	25	2:00 PM	0.65	0.39	0.26
Jun-93							Jun-93	28	1:00 PM	0.87	0.44	0.43
Jul-93							Jul-93	8	1:00 PM	1.08	0.49	0.59
Aug-93							Aug-93	2	2:00 PM	1.08	0.50	0.58
Sep-93							Sep-93	15	2:00 PM	0.66	0.50	0.16
Oct-93							Oct-93	11	9:00 AM	0.36	0.71	-0.35
	Avg. of Dec.& Jan.		0.49	0.57	-0.08			Avg. of Dec.& Jan.		0.97	0.53	0.44
	Avg. all months		0.48	0.65	-0.18			Avg. all months		0.70	0.57	0.12
	CR		0.48	0.59	-0.11			CR		0.62	0.37	0.26

Contribution of Clock-Controlled Water Heaters to CV Peak Loads (CV Metered Data)

	VELCo - State CP				
	Date	Hour	CV Clock Load (KW)	VLS Unc. Load (KW)	Delta
Dec-91					
Jan-92	17	1:00 PM	0.89	0.53	0.36
Feb-92	12	1:00 PM	0.76	0.73	0.03
Mar-92					
Apr-92					
May-92	4	9:00 AM	0.39	0.62	-0.23
Jun-92					
Jul-92	27	11:00 AM	0.14	0.61	-0.47
Aug-92	27	2:00 PM	0.73	0.50	0.23
Sep-92	10	2:00 PM	0.49	0.50	-0.01
Oct-92	27	6:00 PM	0.17	0.58	-0.41
Nov-92	18	6:00 PM	0.10	0.60	-0.50
Dec-92	8	6:00 PM	0.20	0.59	-0.39
Jan-93	19	6:00 PM	0.17	0.64	-0.47
Feb-93	1	7:00 PM	0.12	0.90	-0.78
Mar-93	19	8:00 AM	0.51	1.11	-0.60
Apr-93	1	7:00 PM	0.07	0.68	-0.61
May-93	24	12:00 PM	0.34	0.51	-0.17
Jun-93	28	12:00 PM	0.42	0.46	-0.04
Jul-93	7	12:00 PM	0.94	0.53	0.41
Aug-93	26	2:00 PM	0.47	0.50	-0.03
Sep-93	3	12:00 PM	0.75	0.56	0.19
Oct-93	11	9:00 AM	0.36	0.71	-0.35
	Avg. of Dec.& Jan.		0.42	0.59	-0.17
	Avg. all months		0.42	0.62	-0.20
	CR		0.42	0.60	-0.18

Contribution of Clock-Controlled Water Heaters to CV Peak Loads (CV Metered Data)

	VELCo - State CP				
	Date	Hour	CV Clock Load (KW)	VLS Unc. Load (KW)	Delta
Dec-91					
Jan-92	17	1:00 PM	0.89	0.53	0.36
Feb-92	12	1:00 PM	0.76	0.73	0.03
Mar-92					
Apr-92					
May-92	4	9:00 AM	0.39	0.62	-0.23
Jun-92					
Jul-92	27	11:00 AM	0.14	0.61	-0.47
Aug-92	27	2:00 PM	0.73	0.50	0.23
Sep-92	10	2:00 PM	0.49	0.50	-0.01
Oct-92	27	6:00 PM	0.17	0.58	-0.41
Nov-92	18	6:00 PM	0.10	0.60	-0.50
Dec-92	8	6:00 PM	0.20	0.59	-0.39
Jan-93	19	6:00 PM	0.17	0.64	-0.47
Feb-93	1	7:00 PM	0.12	0.90	-0.78
Mar-93	19	8:00 AM	0.51	1.11	-0.60
Apr-93	1	7:00 PM	0.07	0.68	-0.61
May-93	24	12:00 PM	0.34	0.51	-0.17
Jun-93	28	12:00 PM	0.42	0.46	-0.04
Jul-93	7	12:00 PM	0.94	0.53	0.41
Aug-93	26	2:00 PM	0.47	0.50	-0.03
Sep-93	3	12:00 PM	0.75	0.56	0.19
Oct-93	11	9:00 AM	0.36	0.71	-0.35
	Avg. of Dec.& Jan.		0.42	0.59	-0.17
	Avg. all months		0.42	0.62	-0.20
	CR		0.42	0.60	-0.18

Summary of Water Heater Load Shapes

Annual kWh Load Factor	Annual kWh UCWH Load 4000	Annual kWh CWH Load 4200	Uses:
0.717	**0.64**		Uncontrolled CR
0.720	**0.63**	**0.67**	Distribution, uncontrolled CP
0.754	0.61	**0.64**	Clock CR
0.769	0.59	**0.62**	Clock CP
2.493	0.18	**0.19**	Ripple CR, CP

	Actual Peak Date	Hour	Load (MW)	CWH (KW)	UCWH (KW)		Potential Peak Date	Hour	Actual Load (MW)	Pot. Load (MW)	CWH (KW)	UCWH (KW)		Min. Load MW	#Decntrlld
1984	27-Dec	1:00 PM	431.40	0.64	0.53		27-Dec	5:00 PM	427.10	429.13	0.49	0.58		429.04	21500.00
1985	8-Feb	12:00 PM	441.60	0.90	0.65		19-Dec	8:00 AM	440.00	442.48	0.64	0.75		440.49	4444.44
1988	14-Jan	10:00 PM	480.70	0.59	0.46		15-Jan	8:00 AM	479.40	485.48	0.51	0.78		480.28	3250.00
1990	15-Jan	12:00 PM	448.20	0.82	0.53		20-Feb	7:00 PM	433.60	452.05	0.08	0.90		444.39	13153.15
1992	17-Jan	1:00 PM	471.00	1.15	0.53		16-Jan	6:00 PM	456	466.8	0.16	0.64		462.55	13636.36

Notes: 1992 actual load at the potential peak hour increased by 12 MW, to remove ski interruptions. Actual peak had no interruptions.

11/26/85	3	6:00 PM	392.6		11/26/85	3	6:00 PM	395.53	391.03	
12/19/85	5	8:00 AM	440		12/19/85	5	8:00 AM	442.48	436.85	
1/15/86	4	8:00 AM	464.1		1/15/86	4	8:00 AM	470.18	464.33	
2/7/86	6	12:00 PM	424.5		2/7/86	6	8:00 AM	428.13	421.23	
3/21/86	6	8:00 AM	408.3		3/21/86	6	8:00 AM	417.08	408.75	
4/7/86	2	12:00 PM	356.8		4/7/86	2	10:00 AM	351.45	346.20	
5/5/86	2	8:00 AM	331.6		5/5/86	2	9:00 AM	333.30	328.65	
6/16/86	2	2:00 PM	324.9		6/23/86	2	11:00 AM	321.03	317.50	
7/29/86	3	12:00 PM	343.2		7/29/86	3	12:00 PM	334.20	330.23	
8/18/86	2	2:00 PM	341.7		8/18/86	2	2:00 PM	340.31	336.56	
9/17/86	4	8:00 AM	340.5		9/17/86	4	8:00 AM	337.58	332.33	
10/7/86	3	8:00 AM	366.5		10/7/86	3	8:00 AM	364.03	359.00	
11/20/86	5	12:00 PM	417.4		11/20/86	5	2:00 PM	413.93	409.80	
12/9/86	3	12:00 PM	439.4		12/9/86	3	1:00 PM	432.13	428.15	
1/14/88	5	10:00 PM	480.7		1/15/88	6	8:00 AM	485.48	479.63	
2/12/88	6	1:00 PM	437.5		2/5/88	6	8:00 AM	439.23	432.33	
3/21/88	2	12:00 PM	429.2		3/2/88	4	8:00 AM	434.58	426.25	
4/13/88	4	8:00 AM	358.7		4/13/88	4	8:00 AM	362.53	355.70	
5/3/88	3	8:00 AM	348.7		5/3/88	3	8:00 AM	346.68	341.43	
6/15/88	4	2:00 PM	358.9		6/15/88	4	2:00 PM	354.63	351.33	
7/14/88	5	10:00 PM	400.7		7/14/88	5	10:00 PM	390.80	387.20	
8/4/88	5	12:00 PM	387.3		8/4/88	5	2:00 PM	385.81	382.06	
9/29/88	5	8:00 AM	359.5		9/29/88	5	8:00 AM	356.58	351.33	
10/7/88	6	8:00 AM	384.2		10/7/88	6	8:00 AM	381.73	376.70	
11/21/88	2	6:00 PM	407.4		11/21/88	2	6:00 PM	410.33	405.83	
12/12/88	2	8:00 AM	472.3		12/12/88	2	8:00 AM	474.78	469.15	
1/6/89	6	1:00 PM	475.5		1/4/89	4	6:00 PM	484.25	479.45	
2/10/89	6	8:00 AM	444.5		2/9/89	5	7:00 PM	452.35	445.60	
3/7/89	3	12:00 PM	457		3/8/89	4	8:00 AM	452.48	444.15	
4/12/89	4	8:00 AM	388.2		4/12/89	4	8:00 AM	392.03	385.20	
5/9/89	3	8:00 AM	351.7		5/9/89	3	8:00 AM	349.68	344.43	
6/27/89	3	2:00 PM	365.2		6/27/89	3	2:00 PM	360.93	357.63	
7/26/89	4	2:00 PM	376.7		7/26/89	4	2:00 PM	375.58	371.83	
8/16/89	4	12:00 PM	364.4		8/16/89	4	2:00 PM	362.81	359.06	
9/28/89	5	9:00 AM	359.4		9/28/89	5	9:00 AM	355.35	351.53	
10/9/89	2	10:00 AM	376.9		10/9/89	2	10:00 AM	376.68	371.73	
11/29/89	4	6:00 PM	439.8		11/29/89	4	6:00 PM	442.73	438.23	
12/27/89	4	6:00 PM	483		12/27/89	4	6:00 PM	484.58	480.15	
1/15/90	2	12:00 PM	448.2		1/15/90	2	1:00 PM	442.83	438.85	
2/27/90	3	2:00 PM	440.6		2/20/90	3	7:00 PM	452.05	445.30	
3/7/90	4	8:00 AM	426.9		3/7/90	4	8:00 AM	435.68	427.35	
4/12/90	5	8:00 AM	379.5		4/12/90	5	8:00 AM	383.33	376.50	
5/21/90	2	1:00 PM	352.2		5/21/90	2	11:00 AM	354.18	350.05	
6/18/90	2	3:00 PM	357		6/18/90	2	11:00 AM	356.33	352.80	
7/18/90	4	2:00 PM	363.7		7/18/90	4	2:00 PM	362.58	358.83	
8/27/90	2	2:00 PM	371.5		8/27/90	2	2:00 PM	370.11	366.36	
9/7/90	6	1:00 PM	350.5		9/7/90	6	12:00 PM	352.45	348.25	
10/29/90	2	6:00 PM	379.4		10/29/90	2	6:00 PM	380.08	375.73	
11/13/90	3	6:00 PM	406.9		11/13/90	3	6:00 PM	409.83	405.33	
12/27/90	5	6:00 PM	448.1		12/27/90	5	6:00 PM	449.68	445.25	

Max Actual CVPS System Loads by Month					Decontrolled Load = CVPS System Load -VLS Controlled WH(22500) + VLS Uncontrolled WH(22500)					
Date	Day	Hour	Peak Load		Date	Day	Hour	Peak Load	Peak Load - Ripple(Uncntrld*7500)	
1/27/82	3	8:00 AM	430.6		1/27/82	3	8:00 AM	436.68	430.83	
2/26/82	5	8:00 AM	392.2		2/26/82	5	8:00 AM	398.73	391.83	
3/1/82	1	8:00 AM	383.5		3/4/82	4	8:00 AM	391.08	382.75	
4/8/82	4	9:00 AM	372.3		4/8/82	4	9:00 AM	380.40	374.25	
5/24/82	2	12:00 PM	296.1		5/24/82	2	10:00 AM	299.23	295.40	
6/7/82	2	9:00 AM	291.2		6/8/82	3	11:00 AM	293.43	289.90	
7/19/82	2	11:00 AM	306.8		7/19/82	2	11:00 AM	306.35	301.78	
8/5/82	5	11:00 AM	316.3		8/5/82	5	11:00 AM	316.47	311.15	
9/27/82	2	12:00 PM	298.3		9/27/82	2	12:00 PM	300.55	296.35	
10/25/82	2	9:00 AM	325.9		10/25/82	2	9:00 AM	326.35	321.03	
11/29/82	2	6:00 PM	333.2		11/29/82	2	6:00 PM	336.13	331.63	
12/13/82	2	6:00 PM	418.8		12/13/82	2	6:00 PM	420.38	415.95	
1/19/83	4	8:00 AM	413.5		1/19/83	4	8:00 AM	419.58	413.73	
2/11/83	6	8:00 AM	403.6		2/11/83	6	8:00 AM	410.13	403.23	
3/25/83	6	8:00 AM	350.1		3/25/83	6	8:00 AM	358.88	350.55	
4/19/83	3	12:00 PM	340.1		4/19/83	3	10:00 AM	329.25	324.00	
5/9/83	2	10:00 AM	328		5/9/83	2	10:00 AM	331.83	328.00	
6/15/83	4	2:00 PM	332.9		6/15/83	4	2:00 PM	328.63	325.33	
7/20/83	4	12:00 PM	306.9		7/20/83	4	2:00 PM	304.28	300.53	
8/19/83	6	1:00 PM	315.9		8/19/83	6	11:00 AM	315.57	310.25	
9/6/83	3	2:00 PM	314.4		9/6/83	3	12:00 PM	315.05	310.85	
10/21/83	6	8:00 AM	339.4		10/21/83	6	9:00 AM	337.05	331.73	
11/18/83	6	8:00 AM	358		11/28/83	2	6:00 PM	358.33	353.83	
12/21/83	4	8:00 AM	420.4		12/21/83	4	8:00 AM	422.88	417.25	
1/16/84	2	12:00 PM	423.6		1/16/84	2	8:00 AM	429.08	423.23	
2/2/84	5	8:00 AM	417.9		2/2/84	5	8:00 AM	424.43	417.53	
3/13/84	3	1:00 PM	415.1		3/12/84	2	8:00 AM	419.68	411.35	
4/16/84	2	12:00 PM	348.6		4/10/84	3	8:00 AM	348.03	341.20	
5/3/84	5	8:00 AM	329.1		5/3/84	5	8:00 AM	327.08	321.83	
6/11/84	2	12:00 PM	330.4		6/11/84	2	12:00 PM	324.33	320.88	
7/16/84	2	12:00 PM	322.9		7/16/84	2	2:00 PM	319.68	315.93	
8/14/84	3	1:00 PM	356.3		8/8/84	4	4:00 PM	354.19	350.96	
9/27/84	5	9:00 AM	342.5		9/27/84	5	9:00 AM	338.45	334.63	
10/2/84	3	9:00 AM	348.6		10/2/84	3	9:00 AM	349.05	343.73	
11/20/84	3	6:00 PM	374.1		11/20/84	3	6:00 PM	377.03	372.53	
12/27/84	5	1:00 PM	431.4		12/27/84	5	5:00 PM	429.13	424.78	
1/21/85	2	12:00 PM	436.5		1/16/85	4	6:00 PM	435.65	430.85	
2/8/85	6	12:00 PM	441.6		2/8/85	6	7:00 PM	441.65	434.90	
3/4/85	2	12:00 PM	411.9		3/4/85	2	1:00 PM	409.95	405.68	
4/1/85	2	12:00 PM	355.8		4/10/85	4	8:00 AM	354.83	348.00	
5/9/85	5	8:00 AM	330.6		5/9/85	5	8:00 AM	328.58	323.33	
6/24/85	2	1:00 PM	321.3		6/24/85	2	2:00 PM	314.33	311.03	
7/26/85	6	12:00 PM	326		7/26/85	6	9:00 AM	320.90	314.75	
8/15/85	5	2:00 PM	343.5		8/15/85	5	2:00 PM	342.11	338.36	
9/5/85	5	2:00 PM	325.2		9/5/85	5	2:00 PM	325.43	321.68	
10/30/85	4	8:00 AM	355.1		10/29/85	3	6:00 PM	354.38	350.03	

Aggregate Effect of Clock Control on System Load

	Date	Day	Hour	Max.Peak	CR							
				(MW)	(MW)							
Part A: Actual Load												
	1/27/82	3	8:00 AM	430.6	405.55							
	12/21/83	4	8:00 AM	420.4	399.86							
	12/27/84	5	1:00 PM	431.4	412.99							
	2/8/85	6	12:00 PM	441.6	421.12							
	1/15/86	4	8:00 AM	464.1	438.84							
	1/14/88	5	10:00 PM	480.7	457.12							
	12/27/89	4	6:00 PM	483	460.16							
	1/15/90	2	12:00 PM	448.2	431.85			Change in			Change in	
								System Load:			Load/WH	
Part B: Decontrolled Load = CVPS System Load - VLS Controlled								Peak	CR		Peak	CR
	WH(22500) + VLS Uncontrolled WH(22500)							(MW)	(MW)		(KW)	(KW)
	1/27/82	3	8:00 AM	436.68	410.82			6.07	5.27		0.27	0.23
	12/21/83	4	8:00 AM	422.88	401.80			2.48	1.94		0.11	0.09
	12/27/84	5	5:00 PM	429.13	411.39			-2.27	-1.60		-0.10	-0.07
	12/19/85	5	8:00 AM	442.48	421.38			0.88	0.25		0.04	0.01
	1/15/86	4	8:00 AM	470.18	442.71			6.07	3.86		0.27	0.17
	1/15/88	6	8:00 AM	485.48	460.41			4.78	3.29		0.21	0.15
	12/27/89	4	6:00 PM	484.58	461.44			1.57	1.28		0.07	0.06
	2/20/90	3	7:00 PM	452.05	435.16			3.85	3.31		0.17	0.15
							Average	2.93	2.20		0.13	0.10
Part C: Decontrolled Load - Ripple(Uncontrolld WH*7500)								Change in Systm Load			Change in Load/WH	
	1/27/82	3	8:00 AM	436.68	410.82			6.07	5.27		0.27	0.23
	12/21/83	4	8:00 AM	422.88	401.80			2.48	1.94		0.11	0.09
	12/27/84	5	5:00 PM	424.78	406.81			-6.63	-6.19		-0.29	-0.27
	12/19/85	5	8:00 AM	436.85	415.96			-4.75	-5.17		-0.21	-0.23
	1/15/86	4	8:00 AM	470.18	442.71			6.07	3.86		0.27	0.17
	1/15/88	6	8:00 AM	479.63	454.71			-1.07	-2.41		-0.05	-0.11
	12/27/89	4	6:00 PM	484.58	461.44			1.57	1.28		0.07	0.06
	2/20/90	3	7:00 PM	445.30	428.97			-2.90	-2.88		-0.13	-0.13
							Average	0.11	-0.54		0.00	-0.02