

STATE OF VERMONT  
PUBLIC SERVICE BOARD

Docket No. 7627

Petition of Central Vermont Public Service )  
Corporation (“CVPS”) for Approval of )  
certain amendments to its Alternative Regulation )  
Plan Pursuant to 30 V.S.A. § 218d )

**CENTRAL VERMONT PUBLIC SERVICE CORPORATION  
ALTERNATIVE REGULATION PLAN**

Revised and Restated effective March 3, 2011

\* \* \*

PREAMBLE

This Alternative Regulation Plan is revised and restated to conform to the plan approved by the Vermont Public Service Board in Docket No. 7336 by orders entered September 30, 2008, October 23, 2008, February 12, 2009 and September 3, 2010, the order in Docket No. 7586 of October 20, 2010, and the order in Docket No. 7627 of March 3, 2011.

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**CENTRAL VERMONT PUBLIC SERVICE CORPORATION  
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**CENTRAL VERMONT PUBLIC SERVICE CORPORATION  
ALTERNATIVE REGULATION PLAN**

Revised and Restated effective March 3, 2011

This Alternative Regulation Plan (“Plan”) constitutes an alternative form of regulation under 30 V.S.A. § 218d approved by the Public Service Board (the “Board” or “PSB”) in Docket No. 7336 by Orders dated September 30, 2008, October 23, 2008, February 12, 2009, and September 3, 2010, the order in Docket No. 7586 of October 20, 2010, and the order of March 3, 2011 in Docket No. 7627. By reference, this document shall also serve as the compliance tariff that will govern the manner in which the electric rates of Central Vermont Public Service Corporation (the “Company” or “CVPS”) will be regulated by the Board during the term of the Plan.

**I. TERM**

This revised and restated Plan shall take effect January 1, 2011. The Plan shall terminate, unless extended, on December 31, 2013; provided, however, that rates incorporating adjustments relating to the Power Cost Adjustment Mechanism and the Earnings Sharing Adjustment Mechanism shall continue beyond the termination date, as provided in Section II.D, below.

- A. The Company shall have the option to petition for an extension beyond 2013, subject to review by the Department of Public Service (“Department” or “DPS”) and approval from the Board.
- B. The Plan may be terminated or modified upon request of the Company or the Department of Public Service and approval by the Board.
- C. CVPS future alternative regulation intentions, if any, must be filed by April 15, 2013.

**II. RATE ADJUSTMENTS**

No rate adjustment other than as described herein will be effective before January 1, 2014 unless provided as a temporary increase pursuant to 30 V.S.A. § 226(a). The Company may also file modified or new tariffs for new services or adjustments including service offerings enabled through the implementation of advanced metering infrastructure and smart grid technologies being developed under the CVPS SmartPower™ Program.

## A. BASE RATE ADJUSTMENTS

### 1. Effectiveness and Filing

The Company's Base Rates will be subject to revision effective on a bills-rendered basis commencing with Cycle 01 January 2011, 2012 and 2013, if supported by cost of service information filed by November 1 of the preceding year.

### 2. Notice and Process

The Company shall provide individual customer notice through normal bill mailings during December following each November 1 Base Rate filing. In addition, the Company shall provide copies of each November 1 Base Rate filing to all entities that are parties in Docket No. 7321. The filing also is subject to Board suspension and review. Any Board decision in the proceeding resulting from the Board's suspension shall be based on contested case procedures and shall be issued on or before April 30, with rates effective on a bills rendered basis May 1, of the year following the applicable November 1 Base Rate filing. This deadline shall not apply to any investigation relating to the Company's existing rates described in Section IV.D.

### 3. Cost of Service Methodology

The rate year cost of service ("COS") filing shall determine Base Rates and be calculated in a manner consistent with the traditional Vermont rate making principles (*i.e.*, exclude disallowed costs and results of unregulated operations (but business services included in cost of service)) and consistent with the provisions of this Plan.

- a. It is CVPS's intention to participate with the DPS in the development of a standardized COS methodology that will apply to CVPS in preparation of its annual cost of service filings under the Plan.
- b. The DPS may retain at CVPS's expense an independent firm with accounting and ratemaking expertise for the purpose of determining prior to filing that CVPS's annual COS filings under the Plan conform to the standardized COS methodology.
- c. The methodology to be used to forecast loads and revenues ("Forecast Methodology") shall be determined by agreement between the Company and the Department.
- d. CVPS may petition the PSB for permission to add to the energy efficiency charge ("EEC") billed to its customers to recover on a current basis expenses associated with intensive levels of rate year expenditures on distributed resources ("DR").

To the extent DR costs are anticipated prior to the Base Rate filing (and therefore not included in an EEC), reasonable forecasts of such costs shall be considered to be known and measurable and included in the rate year COS and Base Rates.

- e. CVPS has ceased accounting for lost revenues under an Account Correcting for Efficiency (“ACE”) as of the effective date of the Plan. The forecasted COS methodology will include forecasted rate year effects expected from all planned activities by the EEU and/or by CVPS that will reduce rate year sales. If future unanticipated, large intra-year efficiency or other DR project expenditures including (but not limited to) reliability costs incurred for generation or DR are incurred and are not reflected in Base Rates or the EEC established for such a year, CVPS may in that circumstance request special ratemaking treatment from the PSB to recognize lost revenues and or defer costs not otherwise being recovered. Before making such a request, CVPS and the Department shall conduct a review on whether special ratemaking treatment may be warranted for any proposed recovery of unanticipated energy-efficiency or distributed resource costs.

#### 4. Base Rate Changes

Any change in Base Rates shall be implemented by a uniform percentage (plus or minus) change in each Base Rate element for each rate class, except it shall not apply to rates that are not subject to generally-applicable tariff changes (for instance the Voluntary Renewable Service Rider, wholesale power market rates included in the ski area service tariff (“Exempt Charges”)), Power Cost Adjustment Mechanism rates or Earnings Sharing Adjustment Mechanism charges.

- a. The percentage Base Rate change will be determined by comparison of forecasted rate year total COS to the revenues that would be raised by existing Base Rates and projected rate year sales (*i.e.*, customer days, kWh and where relevant kW as projected via the Forecast Methodology).
- b. Forecasted sales shall include the expected effects of net metering, energy efficiency, demand response, any new rate design initiatives (including new service offerings that may be enabled via the implementation of the CVPS SmartPower project) and combined heat & power activity for the rate year.

#### 5. Non-Power Cost Cap

- a. There shall be a single non-power-cost cap mechanism under the Plan that encompasses all of the Company’s non-power costs and provides for appropriate escalation that includes an inflation adjustment, a productivity factor (subject to a “Non-Power Cost Cap Benchmarking Adjustment” as described in Rider 1), a capital expense adder, an incremental ROE adjuster and a new initiatives adder.

This mechanism shall be applied in reviewing CVPS's annual base rate filings for 2011, 2012 and 2013 while the Company is under alternative regulation, provided, however, that the Non-Power Cost Cap Benchmarking Adjustment shall only apply to base rate filings for 2012 and 2013.

- i. Before adjusting for the capital expense, incremental ROE and new initiatives adders, the non-power-cost cap will be calculated for 2011, 2012 and 2013 based on the costs embedded in the base rates determined for the previous year, modified by the following adjustments.
  - (A) The non-power-cost cap will increase or decrease based on the CPI for the Northeast region ("CPI-NE") for the most recent 12 months preceding the cost-of-service filing.
  - (B) Adjust for productivity factor by subtracting the amount calculated in accordance with the Non-Power Cost Cap Benchmarking Adjustment described in Rider 1.
  - (C) By way of illustration, assume the U.S. Department of Labor reports that the CPI-NE for 12 months ending October is 2.5%. See [www.bls.gov/cpi](http://www.bls.gov/cpi) (click on the Northeast region under Regional Resources). Assuming the Non-Power Cost Cap Benchmarking Adjustment results described in Rider 1 place the Company in the 2<sup>nd</sup> quintile, the allowed increase to the previous year's non-power costs would be:  $2.5\% - (1\% - .5\%) = 2.0\%$ .
- ii. The incremental ROE adjuster shall increase (in the case of an increase in the allowed ROE) or decrease (in the case of a decrease in the allowed ROE) the non-power cost cap in an amount equal to the difference between the allowed ROE in current base rates and the allowed ROE in the proposed base rates multiplied by the proportion of common equity in the capital structure, then multiplied by the average rate base in the proposed filing, and the resulting amount shall be grossed up for income taxes.
- iii. The following methodology shall be used to calculate the capital expense adder for the non-power cost cap:
  - (A) For 2011, CVPS shall assume the 2011 estimated net-plant-in-service additions, using the format approved by the PSB. In the event that figure gives rise to any disputes about the 2011 estimated net-plant-in-service additions, the PSB will resolve the issue and then require CVPS to use the resulting figure to calculate the capital expense adder for 2011, applying the same methodology that it used to calculate the capital expense adder for 2010.

- (B) By November 1, 2011, CVPS shall file 2012 estimated net-plant-in-service additions, using the format approved by the PSB. CVPS shall request that the PSB provide the other parties to the Docket No. 7336 proceeding with an opportunity to comment on that figure. In the event that figure gives rise to any disputes about the 2012 estimated net-plant-in-service additions, the PSB will resolve the issue and then require CVPS to use the resulting figure to calculate the capital expense adder for 2012, applying the same methodology that it used to calculate the capital expense adder for 2011.
- (C) By November 1, 2012, CVPS shall file 2013 estimated net-plant-in-service additions, using the format approved by the PSB. CVPS shall request that the PSB provide the other parties to the Docket No. 7336 proceeding with an opportunity to comment on that figure. In the event that figure gives rise to any disputes about the 2013 estimated net-plant-in-service additions, the PSB will resolve the issue and then require CVPS to use the resulting figure to calculate the capital expense adder for 2013, applying the same methodology that it used to calculate the capital expense adder for 2012.
- (D) Additional adjustments to the capital expense adder for the non-power cost cap shall be made in accordance with the requirements of any approved new initiatives adders.

iv. For new initiatives, an adder to the non-power cost cap may be established as provided below.

- b. For the determination of the non-power cost cap in the COS filed for rates effective in 2011, CVPS shall expand its 2011 base rate filing to include sufficient non-power cost line item information to support the calculation of the non-power cost cap to be applied in 2011.
- c. For new initiatives after the effective date of the Plan that require the Company to incur incremental costs, expenses or investment an adder to the non-power cost cap otherwise applicable may be established. New initiatives will qualify for the adder only if they are authorized by an order issued by the Board. For any order issued after August 6, 2010, such order may be granted upon a showing that (i) the risk associated with implementing the new initiative is of a nature that is distinct from the ordinary business risk that CVPS assumes in discharging its public service obligation, and (ii) the costs associated with implementing the new initiative are material.

## B. EARNINGS SHARING ADJUSTMENT MECHANISM

### 1. Effectiveness and Filing

The Company's rates will be subject to an Earnings Sharing Adjustment Mechanism ("ESAM") effective on a bills-rendered basis each July for the term of the Plan and any extensions. On or before each May 1st while the ESAM is effective, the Company shall file with the Board its actual earnings for the preceding calendar year, the proposed ESAM calculation and ESAM rate effective for July 1 through the following June 30. The Company's filing shall include all spreadsheet-based data and calculations in the form of functioning electronic spreadsheets with all links and formulae intact and accessible.

### 2. ESAM Notice and Process

The Company shall provide individual customer notice through normal bill mailings of the ESAM rate change in the billing cycle following the ESAM filing described in Section II.B.1 above. The Earnings Sharing Adjustment Mechanism is not subject to Board suspension, but the Board may open an investigation and to the extent it finds, after notice and hearing, that the calculation was inaccurate or reflected costs inappropriate for inclusion in rates, it may require a modification of the associated ESAM to the extent necessary to correct deficiencies.

### 3. ESAM Methodology

Actual earnings and variances will be calculated on a regulatory basis determined by the same methodology as the earnings cap calculation reflected in the Board's Order in Docket Nos. 6946/6988 (as modified as a result of applying the order in Docket No. 7191). Actual earnings and variances shall include the earnings impact of any variance within the Power Adjustment Efficiency Band and variance in the cost of service. The ESAM Variance Amount (as defined below) shall be deferred and amortized during the ESAM period in an amount equal to the then-current year ESAM amounts actually collected or refunded.

#### a. Return on Equity

i. The allowed Return on Equity ("ROE") effective for the rate year beginning January 1, 2011 shall be 9.45%.

ii. The allowed ROE under the Plan will adjust in 2012 and subsequent years at 50% of the prior year's basis-point change in 10-yr Treasury Bill yields to maturity (*i.e.*, average yield as of the last twenty trading days prior to October 15 before the filing differenced with the

average yield of the last twenty trading days prior to October 15 of the previous year).

b. The Earnings Sharing Adjustment Mechanism shall be calculated as follows:

i. Calculation of ESAM Variance Amount

(A) If actual earnings reflect a rate of return on equity that is within a range (*i.e.*, the “earnings dead band”) equal to 75 basis points below and 75 basis points above the then effective allowed annual ROE, there will be no Earnings Sharing Adjustment Mechanism rate change;

(B) If actual earnings reflect an ROE that is below the lower bound of the earnings dead band by up to 50 basis points, a 50/50 sharing of that variance (the “earnings sharing band”), will be reflected in the ESAM rate change; and

(C) If actual earnings reflect a rate of return on equity that is either above or below the ranges of earnings as determined in parts (A) and (B) above, the ESAM rate change shall reflect the entire revenue impact of the variance beyond the ranges.

c. ESAM Rate Changes

The Earnings Sharing Adjustment Rate shall be a positive or negative percentage adjustment to all Base Rate elements equal to: (1) the ESAM Variance Amount, relative to (2) the projected revenue (based on the Forecast Methodology) from Base Rate elements during the twelve month period in which the ESAM is to be collected. The ESAM percentage shall be applied to each Base Rate element other than Exempt Charges for each rate class. Over/under collections of the ESAM, due to a variance between projected and actual revenues, shall be deferred and included in the next ESAM rate change. A sample calculation of an ESAM rate change will be supplied as an attachment to the Company’s compliance filing.

d. Other ESAM Provisions

i. CVPS shall seek reconsideration of its corporate credit rating from Moody’s Investors Service at its annual reviews during the Plan.

- ii. 'Exogenous factor' cost or revenue effects on regulated return are authorized in the ESAM Variance Amount calculation. To the extent that changes in such exogenous factors do not exceed \$600,000 in a rate year, they will have no effect on rates. To the extent that the exogenous factors accumulate to more than \$600,000, then the amount above \$600,000 would be incorporated into the ESAM adjustment process as a variance that is either positive or negative, depending on the case. This \$600,000 per year dead-band for exogenous events refers to the accumulation of such costs over a year; it is not a limit on a cost associated with a particular event. In the case of unplanned costs due to storms, such costs would not qualify as exogenous costs until they exceeded the storm-damage allowance included in the Company's base rates. Such effects that are expected to recur in subsequent years shall be included in the cost of service and reflected in Base Rates in those subsequent years.

After the close of each quarter during the rate year, CVPS will file with the Board a report of exogenous factor effects. If the Board takes no action within 30 days of the filing of the last quarterly report in January subsequent to the rate-year, the exogenous factor quantification for the year, as contained in that report, will become final. If the Board investigates and issues an order on or before the third Friday of February, the Company will incorporate the effects of that order in its closing of the books and report of earnings. If the Board investigates and does not issue an order by that date in February, the Board will not issue an order any sooner than April 1 following the rate-year. The Company, in any case, will file its ESAM adjustment report by May 1 incorporating whatever the then final status of the exogenous factor quantification is in the ESAM Variance Amount and rate.

(A) Exogenous factor costs or revenue effects shall consist of the effects on the Company from the following:

- (1) changes in Generally Accepted Accounting Principles;
- (2) changes in tax laws;
- (3) changes in Federal Energy Regulatory Commission or ISO-NE rules;

- (4) extended or permanent loss or derate of major purchased power sources;
  - (5) loss of load (not due to variations in heating and or cooling temperatures); or
  - (6) major unplanned operations and maintenance or investment cost such as those incurred due to storms or major repairs to Company-owned power plants.
- iii. Actual ESAM amounts collected or refunded in rates will be trued-up in future rates relative to the ESAM Variance Amount that gave rise to an ESAM rate change.
  - iv. ESAM rate changes are not subject to the limitations of the non-power cost cap.

## C. POWER COST ADJUSTMENT MECHANISM

### 1. Effectiveness and Filing

The Company's rates will be subject to a Power Cost Adjustment Mechanism ("PCAM") effective on a bills-rendered basis in the first month of each calendar quarter (*i.e.*, January, April, July, and October). Within 30 days after the end of each quarter ("Measurement Quarter"), the Company shall file with the Board and Department, (1) the Company's actual power costs reflecting the provisions set forth below, (2) the variance between the actual power costs and the power costs recovered in its Base Rates, as determined by rate element level base kWh and kW charges established in its annual COS filing, (3) the proposed PCAM charge to take effect during the second quarter succeeding the Measurement Quarter ("Collection Quarter") and (4) supporting information.

### 2. PCAM Notice and Process

The Company shall provide individual customer notice through normal bill mailings of the Power Cost Adjustment Mechanism rate change in the billing cycle following the PCAM filing described in Section II(C)(1) above. The Power Cost Adjustment Mechanism is not subject to Board suspension, but the Board may open an investigation and to the extent it finds, after notice and hearing, that the calculation was inaccurate or reflected costs inappropriate for inclusion in rates, it may require a modification of the associated Power Cost Adjustment Mechanism to the extent necessary to correct the deficiencies.

### 3. PCAM Methodology

The PCAM shall reflect a positive or negative rate per kWh adjustment equal to the following:

a. Calculation of PCAM Quarterly Variance Amount:

i. Component A, which includes the dollar amount of any variation between: (1) actual Committed Costs for the Measurement Quarter and (2) the Committed Costs revenues as determined by rate element level base kWh and kW charges recovered in revenues for the corresponding quarter; plus

ii. Ninety percent (90%) of Component B, which includes the amount, if any, by which (1) the dollar amount of any variation between: (a) actual total Open Position Costs for the Measurement Quarter and (b) total Open Position revenues as determined by rate element level base kWh and kW charges recovered in revenues for the corresponding quarter, exceeds (2) \$315,000 (the "Power Efficiency Adjustment Band").

iii. Committed Costs will consist of demand charges, transmission costs, ancillary charges (net of interchange (resales)) and fixed or stable price energy purchases. Open Position Costs consist of all other power costs (net of interchange (resales)). A detailed list of the Company's current Committed Costs and Open Position Costs will be included in the compliance phase of the Board's proceeding on this Plan.

iv. Rate element level base kWh and kW charges will be determined in annual COS filing underlying the Company's Base Rates for Component A and B power costs.

b. Calculation of Power Cost Adjustment Mechanism:

i. The Power Cost Adjustment Mechanism shall be a uniform positive or negative adjustment per kWh added to kWh rate elements (other than Exempt Charges) equal to: (1) the PCAM Measurement Quarter Variance Amount divided by (2) projected kWh sales during the Collection Quarter (based on the Forecast Methodology).

ii. Over/ under collections of the Power Cost Adjustment Mechanism, due to a variance between projected and actual kWh sales, shall be deferred and included in the balance of next subsequent PCAM Variance Amount and rate change, except that deferrals relating to periods

beginning after the last quarter in which the PCAM is in effect under this Plan will be included in the following Earnings Sharing Adjustment Mechanism rate adjustment. A sample PCAM calculation will be provided in the compliance phase of the Board's process.

iii. For accounting purposes, the PCAM Quarterly Variance Amount for the Measurement Quarter shall be deferred and it shall be amortized in the Collection Quarter in an amount equal to the revenue increases or decreases recovered or repaid in PCAM rates during the Collection Quarter. The Company shall maintain separate accounts for Component A and Component B costs.

#### D. RESIDUAL ADJUSTMENTS

The Power Cost Adjustment Mechanism shall continue through the last billing cycle in June of the year following the last year of the Plan, and the Earnings Sharing Adjustment Mechanism shall continue through the last billing cycle in June, of the second year following the last year of the plan. Any unamortized ESAM or PCAM dollar balances that may exist and which have not been trued-up at the conclusion of the effectiveness of these mechanisms shall be transferred into either: (i) the initial balance of the successor, like-ratemaking mechanisms or (ii) the cost of service basis of whatever successor rates are subsequently implemented; and amortized in such rates as debits or credits, as appropriate.

### III. OTHER PLAN COMPONENTS

#### A. SERVICE QUALITY

The Company's existing Service Quality & Reliability Plan is hereby incorporated into and made a part of this Plan.

#### B. LOW INCOME

The Company shall contribute 10% of Earnings Dead Band earnings in excess of the Board-approved rate of return on equity to a to-be-established low income bill assistance program. In addition, the Company shall match contributions by its customers to the Company's Shareheat Program, and the amount of the Company's match shall not be included in rates.

C. RENEWABLES

The Company shall continue its existing efforts to promote Vermont-based renewable energy, including its Cow Power Voluntary Renewable Support Rider.

D. SERVICE CHOICES

The Company shall continue the work on advanced rate designs that was begun in Docket No. 7095, including the implementation of additional rate designs developed in accordance with the terms of the CVPS SmartPower Plan approved by the Board in Docket No. 7612. The Board may require the Company to restore a fixed-price-power option (i) in the event that CVPS ratepayers begin regularly experiencing greater retail price fluctuation, or (ii) after the Company has introduced real-time pricing in conjunction with implementing its CVPS SmartPower program.

E. NEW POWER SOURCES AND SPECIAL RATEMAKING

In the event that during the term of this Plan the Company proceeds with the development of a new power plant, or proceeds with commitment to major new purchased power, the Company and the Department shall meet to determine if there are special ratemaking related changes needed to this Plan in order to make such activities feasible and cost effective. Any such changes determined to be warranted will be proposed to the PSB as amendments to this Plan.

F. PLAN EVALUATION

Not later than June 30 of each year during the effectiveness of the Plan the Company shall file a report with the Board and Department evaluating the effectiveness of the Plan's performance in achieving the goals of 30 V.S.A. § 218d. In advance of filing the reports, the Company shall confer with the Department with respect to development of the measurement criteria to be used in the reports.

IV. MISCELLANEOUS

A. During the term of the Plan, the application of 30 V.S.A. §§ 218(a), 225, 226, 227 and 229 to CVPS shall be modified by the provisions of the Plan and the Board order approving the Plan.

B. Tariffs incorporating the substantive provisions of the Plan, and related forms and filing formats will be provided in the compliance phase of the Board's review of this Plan.

- C. The Company shall work with the Department in the development of customer communications and materials to be provided to customers.
- D. Nothing in the Plan will be interpreted as preventing the Department from requesting a Board investigation into the Company's rates or the Board from undertaking such an investigation. The retroactive effect of any such investigation and of any investigation pursuant to Sections II.B.2, and II.C.2, shall be consistent with 30 V.S.A. § 218d.
- E. Plan Amendment Mechanism – non-material changes to the Plan's provisions may be agreed to by the Company and DPS and filed with the PSB to take effect in 30 days if not otherwise acted upon by the Board.
- F. CVPS shall include supplier-caused outage data in its annual service quality report to the Board and the Department. The supplier-caused outage data shall include the number of retail, rather than wholesale, customers affected by each such outage, to the extent this information can be obtained from the affected wholesale customers.
- G. The Company has agreed to introduce demand/load response programs for all customer classes, as well as cost-justified dynamic pricing where appropriate and consistent with the Company's rate-design plan filed under Docket No. 7095.
- H. The Company has agreed to continue its work to advance Vermont-based renewable power generation.
- I. The Company has agreed to work with the Energy Efficiency Utility and the Department to develop and implement an EEU program to promote the installation of societally cost-effective heating systems such as solar-thermal hot-water systems, small combined-heat and- power systems and cost-effective heat pumps.

Rider 1

NON-POWER COST BENCHMARKING ADJUSTMENT

The Non-Power Cost Benchmarking Adjustment shall equal the amount set forth in the table below, based on CVPS’s quintile ranking among the Benchmarked Utilities listed below in Transmission and Distribution (“T&D”) Expense per T&D Line Mile (“T&D Expense/T&D Line Mile”), and Customer and Administrative Expense per Customer (“Customer & Administrative Expense/Customer”), as calculated from data reported in each utility’s Federal Energy Regulatory Commission (“FERC”) Form 1 and Platts’ Utility Data Institute (“UDI”) Directory of Electric Power Distributors data bases for the most-recently completed calendar year.

a. Non-Power Cost Cap Benchmarking Adjustment

| CVPS Ranking:            | Adjustment to the 1% Productivity Factor |
|--------------------------|------------------------------------------|
| 1 <sup>st</sup> Quintile | -100%                                    |
| 2 <sup>nd</sup> Quintile | -50%                                     |
| 3 <sup>rd</sup> Quintile | 0%                                       |
| 4 <sup>th</sup> Quintile | +50%                                     |
| 5 <sup>th</sup> Quintile | +100%                                    |

b. Methodology

To assess CVPS’s performance, each annual Base Rate filing beginning with the filing for Rate Year 2012 shall include a calculation and ranking by CVPS of its results against those of the Benchmarking Utility Group utilities regarding its T&D Expense/T&D Line Mile, and its Customer & Administrative Expense/Customer. The Customer and Administrative costs will be unitized on a per-customer basis. The T&D system operations costs will be unitized on a per-T&D-line-mile basis. The unitized Customer and Administrative costs and T&D system operations costs will then be separately compared and ranked by quintile against the other benchmarked utilities’ results. In order to calculate the adjustment to the productivity factor the T&D Expense/T&D Line Mile ranking factor and the Customer & Administrative Expense/Customer ranking factor shall be weighted based on the percentage of total non-power cost each expense category represents for that year. As used in this calculation the term “total non-power cost” refers to the sum of the costs in the T&D Expense and Customer & Administrative Expense categories, not to all non-power costs included in the non-power-cost cap. For Rate Year 2011, the CVPS calculation and ranking relative to the Benchmark Utility Group is

illustrated in Table 1(f) below.

The costs of CVPS’s major storm restoration efforts shall be excluded from the expenses listed above. Major storms shall be defined as those eligible for cost deferral under the exogenous events clause of the Plan.<sup>1</sup>

c. Benchmark Expense

The following FERC Form 1 expense accounts shall be utilized to determine the Weighted Average Cost per Customer and Cost per T&D Line Mile:

|                                                                           | FERC Form 1 |
|---------------------------------------------------------------------------|-------------|
| TOTAL Administrative & General Expenses                                   | p. 323      |
| TOTAL Customer Accounts Expenses                                          | p. 322      |
| TOTAL Customer Service and Information Expenses                           | P. 323      |
| TOTAL Sales Expenses                                                      | p. 323      |
| TOTAL Distribution Expenses                                               | p. 322      |
| TOTAL Transmission Expenses less<br>Transmission of Electricity by Others | p. 321      |
| Average Number of Customers per Year                                      | p. 301      |

d. Benchmark Utility Group

The Benchmark Utility Group shall be comprised of the following companies:

|                                               |                                      |
|-----------------------------------------------|--------------------------------------|
| Bangor Hydro-Electric                         | Unitil Energy Systems, Inc.          |
| MDU Resources                                 | Green Mountain Power Corporation     |
| Granite State Electric                        | The Empire District Electric Company |
| Western Massachusetts Electric Company        | Maine Public Service Company         |
| Public Service Company of New Hampshire       | Rochester Gas & Electric             |
| Upper Peninsula Power Company                 | Otter Tail Power Company             |
| Madison Gas & Electric                        | Fitchburg Gas & Electric             |
| CH Energy                                     | Black Hills Power, Inc.              |
| Allete (Minnesota Power, SWL&P)               | Rockland Electric Company            |
| The United Illuminating Company (UL Holdings) |                                      |

<sup>1</sup> If there are multiple types of exogenous costs (as defined in the Plan) that cumulatively are greater than \$600,000, the amount of costs associated with major storms that would be excluded from the calculation under the Non-Power Cost Benchmarking Adjustment would be proportional. For example, if there were \$400,000 in exogenous storm repair costs and \$400,000 in exogenous tax expense costs, 50 percent (50%) of the total costs above \$600,000 (or \$100,000) would be excluded when calculating the Non-Power Cost Benchmarking Adjustment.

In the event any Benchmark Utility ceases to exist as a separate investor-owned electric distribution utility filing an annual FERC Form 1, or in the event that such utility ceases to publish T&D Line Mile data, or in the event that it ceases to be an appropriate benchmark as agreed by both the Company and the Department, said utility shall be replaced by a mutually agreed upon investor-owned electric distribution utility with relevant attributes similar to the Company. In the event the Department and the Company are unable to agree on a replacement, they shall submit the issue to the Board for resolution.

e. An Illustration of Non-Power Cost Benchmarking Adjustment

The Company's 2011 benchmark utilizing reported 2009 data is described in the following table:

Table 1(f): Illustration of Adjustment Calculation

| Productivity<br>Factor Adj | Company                           | State       | 43% Weighting             |      | 57% Weighting                     |           | rank |    |
|----------------------------|-----------------------------------|-------------|---------------------------|------|-----------------------------------|-----------|------|----|
|                            |                                   |             | T&D Exp/ T&D<br>Line Mile | rank | Cust & Admin<br>Exp/ Cust         | rank      |      |    |
| 0.00                       | Unitil Energy Systems, Inc.*      | NH          | 2,034                     | 1    | Bangor Hydro-Electric             | Maine     | 124  | 1  |
| 0.00                       | Maine Public Service Co.          | Maine       | 2,216                     | 2    | Unitil Energy Systems, Inc.*      | NH        | 161  | 2  |
| 0.00                       | MDU Resources                     | Mont/Dak/WY | 2,239                     | 3    | MDU Resources                     | Mont/Dak  | 172  | 3  |
| 0.00                       | Black Hills Power, Inc.           | SD          | 2,381                     | 4    | Green Mountain Power              | VT        | 189  | 4  |
| 0.50                       | Bangor Hydro-Electric             | Maine       | 2,448                     | 5    | Granite State Electric Company    | NH        | 203  | 5  |
| 0.50                       | Otter Tail                        | Minn, Dak   | 2,589                     | 6    | The Empire District Electric Co.  | Ark       | 237  | 6  |
| 0.50                       | Fitchburg Gas & Electric          | Mass        | 3,025                     | 7    | Western Massachusetts Electric Co | Mass      | 270  | 7  |
| 0.50                       | Upper Peninsula Power Company     | Mich        | 3,438                     | 8    | Maine Public Service Co.          | Maine     | 297  | 8  |
| 1.00                       | Rochester Gas & Electric          | NY          | 3,528                     | 9    | CVPS                              | VT        | 301  | 9  |
| 1.00                       | The Empire District Electric Co.  | Ark         | 3,684                     | 10   | PSNH                              | NH        | 313  | 10 |
| 1.00                       | Green Mountain Power              | VT          | 3,744                     | 11   | Rochester Gas & Electric          | NY        | 346  | 11 |
| 1.00                       | Allete                            | Minn        | 3,750                     | 12   | Upper Peninsula Power Company     | Mich      | 355  | 12 |
| 1.50                       | Western Massachusetts Electric Co | Mass        | 3,846                     | 13   | Madison Gas & Electric            | Wis       | 357  | 13 |
| 1.50                       | PSNH                              | NH          | 4,229                     | 14   | Fitchburg Gas & Electric          | Mass      | 368  | 14 |
| 1.50                       | CVPS                              | VT          | 4,268                     | 15   | Otter Tail                        | Minn, Dak | 392  | 15 |
| 1.50                       | CH Energy                         | NY          | 4,375                     | 16   | CH Energy                         | NY        | 399  | 16 |
| 2.00                       | Madison Gas & Electric            | Wis         | 5,127                     | 17   | Black Hills Power, Inc.           | SD        | 422  | 17 |
| 2.00                       | Rockland Electric Company         | NJ          | 5,305                     | 18   | Allete                            | Minn      | 479  | 18 |
| 2.00                       | Granite State Electric Company    | NH          | 6,071                     | 19   | Rockland Electric Company         | NJ        | 515  | 19 |
| 2.00                       | The United Illuminating Co        | CT          | 11,320                    | 20   | The United Illuminating Co        | CT        | 519  | 20 |
|                            |                                   | Median      | 3,714                     |      |                                   |           | 330  |    |
|                            |                                   | Average     | 3,981                     |      |                                   |           | 321  |    |

|                 |                        |
|-----------------|------------------------|
|                 | Productivity<br>Factor |
| CVPS Adjustment | 1.215                  |

Note: CVPS major storm costs should be excluded if such costs qualify for deferral