THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)

Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Green Mountain Power Corp	**End of** 2016/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ____________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Green Mountain Power Corp		02 Year/Period of Report End of 2016/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /		
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 163 Acorn Lane Colchester, VT 05446		
05 Name of Contact Person Dawn D. Bugbee		06 Title of Contact Person Chief Financial Officer
07 Address of Contact Person *(Street, City, State, Zip Code)* 163 Acorn Lane Colchester, VT 05446		
08 Telephone of Contact Person, *Including Area Code* (802) 655-8768	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 12/31/2016

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Dawn D. Bugbee	03 Signature Dawn D. Bugbee	04 Date Signed *(Mo, Da, Yr)* 04/13/2017
02 Title Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NA
18	Electric Plant Held for Future Use	214	NA
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	NA
24	Extraordinary Property Losses	230	NA
25	Unrecovered Plant and Regulatory Study Costs	230	NA
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	NA
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	NA
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	NA
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	NA
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NA
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [X] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Dawn Bugbee, Chief Financial Officer
163 Acorn Lane
Colchester, Vermont 05446

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Inc. in Vermont as Vergennes electric Co. on 4/8/1893. Name changed to Peoples Hydro electric Vt. Corp. on 7/30/26 and to Green Mountain Power Corp. on 8/29/28.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

The property of the respondent was not held by a receiver or a trustee at any time during 2015.

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric service in the state of Vermont.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

On April 12, 2007, Northstars Merger Subsidiary Corporation ("Merger Sub"), a wholly-owned subsidiary of NNEEC("Parent"), was merged with and into Green Mountain Power Corporation (the "Company") (the "Merger") pursuant to the Agreement and Plan of Merger, dated as of June 21, 2006 (the "Merger Agreement"), by and among Parent, Merger Sub and the Company. As a result of the Merger, which was effective as of 7:45 a.m. Eastern Daylight Time on April 12, 2007, the Company became a wholly-owned subsidiary of the Parent.
At the effective time of the Merger, each issued and outstanding share of the Company's common stock, par value $3.33 1/3 per share, subject to certain limitations, was converted into the right to receive $35.00 in cash, without interest thereon. All of the remaining unexercised stock options were converted to shares, and any remaining unvested stock grants were immediately vested. The shares were exchanged for cash, and all stock compensation plans were discontinued.

As a result of the Merger, all of the Company's issued and outstanding capital stock is held by Parent and all of the issued and outstanding capital stock of Parent is owned, directly or indirectly, by Gaz Métro Limited Partnership ("Gaz Métro"), a limited partnership organized under the laws of the Province of Québec.

The purchase price premium has not been pushed down by the parent to the Company and is not reflected in the Company's accounts. All of the purchase price paid in excess of net book value has been allocated by the parent to goodwill. Amounts allocated to goodwill are not recoverable in rates. The accompanying financial statements are presented on an original cost basis consistent with the Company's regulatory model.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	VT Yankee Nuclear Power Corp	Nuclear Generation Contract		
2	Joint Owners	Management	Ownership %	
3	Green Mountain Power Corporation		100%	
4			------------	
5			100.00%	
6			=======	
7				
8	Northern Water Resources, Inc.	Alternative Energy Developmet	100.00%	
9				
10	Vermont Electric Power Co., Inc.	Electric Power	Common Stock	
11	Joint Owners:		Owners%:	
12	Green Mountain Power Corporation		38.8%	
13	VLite		37.5%	
14	City of Burlington Electric Light Department		6.0%	
15	Vermont Electric Cooperative		7.0%	
16	Stowe Electric		0.7%	
17	Washington Electric		1.5%	
18	Ludlow Electric		1.1%	
19	Swanton Electric		1.0%	
20	Others		3.5%	
21	VT Public Power Supply Authority		2.9%	
22			----------	
23			100%	
24			======	
25	Note: The above figures represent the share	of Common Stock. The		
26	Responent also owns 30% of VELCO's Preferred	Stock.		
27				

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
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3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Transco LLC			
2	Joint Owners:			
3	Velco Electric Power Company		5.47%	
4	Burlington Electric Dept.		5.31%	
5	Green Mountain Power		70.38%	
6	Village of Stowe		4.40%	
7	Vermont Electric Cooperative		3.87%	
8	VPPSA		8.24%	
9	Other		2.33%	
10			----------	
11			100%	
12			======	
13				
14	W.F. Wyman Station	Oil fired steam	Ownership %	
15	Joint Owners:	electric generating		
16	Green Mountain Power Corporation	unit.	2.92%	
17	Exelon New England		5.89%	
18	Florida Power & Light		84.34%	
19	Lyndonville Electric Department		0.03%	
20	Massachusetts Municipal Wholesale Electric Co.		3.67%	
21	Northeast Utilites		3.14%	
22			----------	
23			100.00%	
24			======	
25				
26				
27				

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Stony Brook	352MW Oil fired, combined		
2	Joint Owners:	cycle intermediate	Ownership %	
3	Green Mountain Power Corporation	generating unit.	8.80%	
4	Lyndonville Electric Department		0.44%	
5	Massachusetts Municipal Wholesale Electric Co.		90.76%	
6			---------	
7			100.00%	
8			=====	
9	Joseph C. McNeil Plant	Wood fueled electric		
10	Joint Owners:	generating station	Ownership %	
11	Green Mountain Power Corporation		31.00%	
12	Burlington Electric Department		50.00%	
13	Vermont Public Power Supply Authority		19.00%	
14			----------	
15			100.00%	
16			======	
17	Highgate Transmission InterConnection	Converter Facility		
18	Joint Owners:		Ownership %:	
19	Green Mountain Power Corporation		82.29%	
20	Vermont Electric Co-Op.		0.22%	
21	Burlington Electric Department		7.70%	
22	Village of Johnson Water & Light Dept		0.43%	
23	Vermont Public Power Supply Authority		9.36%	
24			-----------	
25			100.00%	
26			======	
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NEHTC AND NEHTEC		Ownership %	
2	National Grid		50.43%	
3	Northeast Utilities		22.65%	
4	Boston Edison Company		11.05%	
5	Vermont Electric Power Company, Inc.	Note: Vermont Electric	4.33%	
6	Canal Electric Company	Power Co. Inc. as	3.42%	
7	New England Power Company	agent for GMP	3.27%	
8	Connecticut Municipal Electric Energy Corp	3.18% and also as	0.84%	
9	Massachusetts Municipal Wholesale Electric Co	agent for VEC 1.15%	0.59%	
10	Town of Reading		0.47%	
11	City of Taunton		0.36%	
12	City of Chicopee		0.32%	
13	City of Braintree		0.30%	
14	City of Peabody		0.27%	
15	City of Holyoke		0.27%	
16	City of Westfield		0.26%	
17	Town of Danvers		0.24%	
18	Town of Shrewsbury		0.16%	
19	Town of Hudson		0.15%	
20	Town of Wakefield		0.13%	
21	Town of Hingham		0.12%	
22	Town of Concord		0.12%	
23	Town of North Attleborough		0.11%	
24	Town of Middleborough		0.11%	
25	Town of Groton		0.03%	
26	Note: Vermont Electric Power Co., Inc.	Respondent's equity	-----------	
27	is acting agent for Respondent.	share equals 3.18%.	100.00%	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	VT Dedicated Metallic Neutral			
2	Return Conductor	DMNR Conductor		
3				
4	Joint Owners:		Ownership %	
5	Green Mountain Power Corporation		59.40%	
6	Vermont Electric Co-Op.		40.60%	
7			------------	
8			100.00%	
9			=======	
10				
11	Catamount Resources Corporation	Unregulated activities	100%	
12				
13	Millstone Unit #3	Nuclear generation	Ownership %	
14	Green Mountain Power Corporation		1.73%	
15	Dominion Nuclear CT		94.47%	
16	Mass Municipal Wholesale Elec. Co.		4.80%	
17			------------	
18			100.00%	
19			=======	
20				
21	GMP VT Solar LLC		Ownership %	
22	Green Mountain Power Corporation	Solar generation projects	96.92%	
23	Financial Services Company		3.08%	
24			------------	
25			100.00%	
26			=======	
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President & CEO	Mary Powell	562,100
2			
3	Vice President & CFO	Dawn D. Bugbee	286,432
4			
5	Senior VP - Operations	Brian Otley	310,650
6			
7	VP - Customer Care	Steve Costello	199,842
8			
9	VP - Field Operations (Retired 7/1/2016)	Greg White	115,968
10			
11	VP - General Counsel & Power Supply	Charlotte Ancel	225,030
12			
13	VP - Stakeholder Relations	Robert Dostis	194,250
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Robert Tessier	Caisse de depot et placement du Quebec
2	Chair of the Board	174 Edison Avenue
3		St. Lambert, QC J4R2P5
4		
5	Nordahl L. Brue, Esq.	8903 Oakland Hills Drive
6	Director	Delray Beach, FL 33446
7		
8	David R. Coates	474 Coates Island
9	Director	Colchester, VT 05446
10		
11	Euclid A. Irving	3 Wilkinson Way
12	Director	Princeton, NJ 08540
13		
14	Elizabeth A. Bankowski	34 Tyler St.
15	Director	Brattleboro, VT 05301
16		
17	Robert Benoit	1101 Route 139 South
18	Director	Sutton Quebec J0E2K0
19		
20	Pierre Despars	GazMetro
21	Director	1717, reu du havre
22		Montreal QC H2K 2X3
23		
24	Mary G. Powell	Green Mountain Power
25	President & CEO, Director	163 Acorn Lane, Colchester, VT 05446
26		
27	David Wolk	119 Alumni Drive
28	Director	Castleton, VT 05735
29		
30	Francis Rathke	33 Oakledge Drive
31	Director	Burlington, Vt. 05401
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

INFORMATION ON FORMULA RATES

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff No. 3 Section II - OATT	Docket EC11-117-00
2	Schedule 21 - GMP	Docket ER12-2304-000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. No changes to or purchases of franchise rights occurred.

2. There were no acquisitions of ownership in other companies by reorganization, merger, or consolidation with other companies.

3. In January 2017, GMP closed on the purchase of the 4 Vermont hydroelectric facilities. The purchase price was $7.45M, the original cost net book value was $2.26M and the acquisition adjustment was $5.19M. The Vermont hydroelectric facilities were not included in rate base and cost of service in GMP's FY 2017 base rate filing. However, GMP is allowed to defer the Vermont hydroelectric facilities FY 2017 incremental costs that will not flow through the GMP's Power Supply Adjustor and a return on the acquired assets.

4. No important leaseholds were entered into or surrendered.

5. No important extensions or reductions of the transmission or distribution system.

6. See page 123 - Notes to Financial Statements for changes in short-term and long-term debt.

7. There were no changes in articles of incorporation or amendments to charter.

8. No significant changes to the wage scale occurred.

9. See page 123 - Notes to Financial Statements for discussion of legal proceedings.

10. None

11. Reserved

12. On December 12, 2016, GMP filed a Petition with the PSB which

    a. Informed the PSB of GMP's intention to file a traditional rate case on or before April 14, 2017 which will yield rates that will go into effect on January 1, 2018;
    b. Freeze customer base rates through December 31, 2017 (regulatory asset and liability amortizations included in the FY 2017 base rate filing will continue through 12/31/17);
    c. Request a three-month extension (the Power Adjustor and the Exogenous Change Adjustment will be extended but the Earnings Sharing Adjustor will not be extended) of the currently effective Alternative Regulation Plan commencing on October 1, 2017 and extending through December 31, 2017;
    d. Informed the PSB of GMP's intention to file on or before April 14, 2017 a proposal for a new type of regulationmajor storm occurred in July 2016.

    Also, see page 123 - Notes to Financial Statements

13. None

Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,707,800,004	1,624,536,211
3	Construction Work in Progress (107)	200-201	58,131,246	52,672,225
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,765,931,250	1,677,208,436
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	614,772,734	594,685,586
6	Net Utility Plant (Enter Total of line 4 less 5)		1,151,158,516	1,082,522,850
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		1,616,100	242,274
9	Nuclear Fuel Assemblies in Reactor (120.3)		3,997,916	3,997,916
10	Spent Nuclear Fuel (120.4)		15,074,702	15,074,702
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	18,737,050	17,729,029
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		1,951,668	1,585,863
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,153,110,184	1,084,108,713
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		15,974,538	14,598,118
19	(Less) Accum. Prov. for Depr. and Amort. (122)		9,061,351	8,743,383
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	542,397,553	441,086,845
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		17,627,243	20,194,958
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		9,980,479	9,412,398
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		576,918,462	476,548,936
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,087,142	3,087,653
36	Special Deposits (132-134)		9,919	2,401,058
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		48,996,587	45,497,051
41	Other Accounts Receivable (143)		2,394,959	3,080,695
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,966,461	2,403,025
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		705,903	322,888
45	Fuel Stock (151)	227	6,578,648	7,837,177
46	Fuel Stock Expenses Undistributed (152)	227	77,042	81,602
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	17,515,133	12,743,452
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	1,176,391	844,400
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		7,917,393	7,818,603
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		2,056,645	2,094,729
61	Accrued Utility Revenues (173)		27,705,772	25,826,620
62	Miscellaneous Current and Accrued Assets (174)		3,143,917	5,832,674
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		493,062	12,235,781
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		118,892,052	127,301,358
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		4,881,428	5,294,372
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,221,975	1,806,885
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,641,144	3,364,246
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-150,088	-23,945
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	142,385,245	127,559,769
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		0	0
82	Accumulated Deferred Income Taxes (190)	234	131,135,593	128,713,013
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		282,115,297	266,714,340
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,131,035,995	1,954,673,347

Schedule Page: 110 Line No.: 57 Column: c

Amount for Prepayments includes the following:

	Beginning Balance	Ending Balance
Account 165 Prepayment		
16511~PREPAYMENTS-INS GENERAL	1,181,010	1,219,287
16512~PREPAYMENTS-EMPLOYEE MEDICAL	(1,418,175)	(440,480)
16514~PREPAYMENTS-INS LIABILITY	154,630	158,673
16516~PREPAYMENTS-EXCESS LIABILITY	915,970	1,046,989
16517~PREPAYMENTS-D.O.L.I.	309,394	194,855
16522~PREPAYMENTS-REC BROKERAGE FEES	137,688	324,152
16523~PREPAYMENT-401K MATCH	(98,194)	88,019
16524~PREPAYMENT-LTD	(6,756)	5,097
16525~PREPAYMENT-GROUP LIFE	(21,892)	(28,682)
16531~PREPAYMENT-OTHER	1,078,932	979,073
16532~PREPAYMENTS-MMWEC	16,996	(195,141)
16538~PREPAYMENTS-MCNEIL	1,198,481	764,910
16542~PREPAYMENTS-PROPERTY TAXES	4,370,517	3,800,641
Total Account 165	7,818,603	7,917,393

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	end of 2016/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	333	333
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	559,393,341	510,097,237
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	81,827,919	63,405,400
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	104,020,353	89,668,495
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		745,241,946	663,171,465
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	629,665,046	636,905,046
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		629,665,046	636,905,046
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,094,474	3,241,792
29	Accumulated Provision for Pensions and Benefits (228.3)		11,974,571	11,922,180
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		8,309,358	7,918,549
35	Total Other Noncurrent Liabilities (lines 26 through 34)		23,378,403	23,082,521
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		83,379,803	45,067,297
38	Accounts Payable (232)		49,724,376	45,520,145
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		5,164,562	8,404,194
41	Customer Deposits (235)		1,137,614	1,525,609
42	Taxes Accrued (236)	262-263	4,128,977	4,133,434
43	Interest Accrued (237)		4,418,849	3,478,367
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	end of 2016/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,365,244	1,170,338
48	Miscellaneous Current and Accrued Liabilities (242)		9,891,900	9,649,191
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		933,127	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		160,144,452	118,948,575
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		305,887	370,973
57	Accumulated Deferred Investment Tax Credits (255)	266-267	7,083,953	3,564,576
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	98,849,949	81,530,965
60	Other Regulatory Liabilities (254)	278	574,266	624,017
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		286,996,837	265,915,263
64	Accum. Deferred Income Taxes-Other (283)		178,795,256	160,559,946
65	Total Deferred Credits (lines 56 through 64)		572,606,148	512,565,740
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,131,035,995	1,954,673,347

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	652,855,260	666,639,210		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	437,404,707	468,034,905		
5	Maintenance Expenses (402)	320-323	47,586,809	44,146,328		
6	Depreciation Expense (403)	336-337	39,053,927	36,664,420		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	139,777	100,266		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	13,770,874	12,264,752		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		10,104,761	3,405,695		
13	(Less) Regulatory Credits (407.4)		9,452,179	2,988,014		
14	Taxes Other Than Income Taxes (408.1)	262-263	35,767,716	33,535,338		
15	Income Taxes - Federal (409.1)	262-263	490,851	738,435		
16	- Other (409.1)	262-263				
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	36,155,273	34,317,846		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266	-187,137	-259,796		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		238,261	228,768		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		611,073,640	630,188,943		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		41,781,620	36,450,267		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
652,855,260	666,639,210					2
						3
437,404,707	468,034,905					4
47,586,809	44,146,328					5
39,053,927	36,664,420					6
139,777	100,266					7
13,770,874	12,264,752					8
						9
						10
						11
10,104,761	3,405,695					12
9,452,179	2,988,014					13
35,767,716	33,535,338					14
490,851	738,435					15
						16
36,155,273	34,317,846					17
						18
-187,137	-259,796					19
						20
						21
						22
						23
238,261	228,768					24
611,073,640	630,188,943					25
41,781,620	36,450,267					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		41,781,620	36,450,267		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,125,954	801,449		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		846,839	629,309		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		1,157,136	1,494,775		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	63,883,891	62,312,670		
37	Interest and Dividend Income (419)		13,345	192,040		
38	Allowance for Other Funds Used During Construction (419.1)		1,122,667	1,079,444		
39	Miscellaneous Nonoperating Income (421)		1,086	1,657		
40	Gain on Disposition of Property (421.1)		400,502	309,602		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		66,857,742	65,562,328		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		62,875	-229		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		330,328	473,971		
46	Life Insurance (426.2)		-142,629	-97,635		
47	Penalties (426.3)			-221,897		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		214,686	154,104		
49	Other Deductions (426.5)		3,778,188	3,850,551		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,243,448	4,158,865		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	29,886	32,538		
53	Income Taxes-Federal (409.2)	262-263				
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		29,886	32,538		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		62,584,408	61,370,925		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		34,249,862	32,989,738		
63	Amort. of Debt Disc. and Expense (428)		463,398	447,337		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		797,857	1,187,806		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		635,958	610,777		
70	Net Interest Charges (Total of lines 62 thru 69)		34,875,159	34,014,104		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		69,490,869	63,807,088		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		69,490,869	63,807,088		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		62,617,982	42,321,596
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		69,490,869	63,807,088
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-36,716,492	(34,921,140)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-36,716,492	(34,921,140)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-14,351,858	(8,589,562)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		81,040,501	62,617,982
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		787,418	787,418
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		787,418	787,418
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		81,827,919	63,405,400
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		89,668,495	81,081,896
50	Equity in Earnings for Year (Credit) (Account 418.1)		63,883,890	62,312,669
51	(Less) Dividends Received (Debit)		49,532,032	50,142,882
52				(3,583,188)
53	Balance-End of Year (Total lines 49 thru 52)		104,020,353	89,668,495

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	69,490,869	63,807,088
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	49,715,174	46,526,298
5	Amortization of	1,316,864	7,873,460
6	Other - Non Cash	6,368,558	644,867
7	Other - Rabbi Trust	97,567	
8	Deferred Income Taxes (Net)	36,241,464	34,843,175
9	Investment Tax Credit Adjustment (Net)	-187,137	-259,796
10	Net (Increase) Decrease in Receivables	-7,689,586	12,861,440
11	Net (Increase) Decrease in Inventory	599,830	-813,159
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	9,108,307	-5,798,606
14	Net (Increase) Decrease in Other Regulatory Assets	142,511	-18,105,031
15	Net Increase (Decrease) in Other Regulatory Liabilities	463,858	760,163
16	(Less) Allowance for Other Funds Used During Construction	1,122,667	1,079,444
17	(Less) Undistributed Earnings from Subsidiary Companies	14,321,513	11,709,048
18	Other (provide details in footnote):		
19	Other Assets	5,648,408	-3,241,081
20	Other Liabilities	3,224,536	-8,872,775
21	Net (Gain) Loss on Disposal of Assets	-337,626	-309,831
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	158,759,417	117,127,720
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-116,624,153	-94,972,939
27	Gross Additions to Nuclear Fuel	-1,373,826	-269,410
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		-1,672,417
30	(Less) Allowance for Other Funds Used During Construction	-1,122,667	-1,079,444
31	Other (provide details in footnote):		
32	All Other	1,411,632	
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-115,463,680	-95,835,322
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		589,577
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-87,037,931	-3,800,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		3,500,013
43			
44	Purchase of Investment Securities (a)	-2,833,545	-2,628,373
45	Proceeds from Sales of Investment Securities (a)	2,646,938	2,551,857

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	All Other	-2,064,514	673,226
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-204,752,732	-94,949,022
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		50,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Capital Contribution from Parent	49,296,104	6,000,000
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Borrowings on Revolving Line of Credit	442,094,113	
69	Repayments on Revolving Line of Credit	-403,781,608	
70	Cash Provided by Outside Sources (Total 61 thru 69)	87,608,609	56,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-7,240,000	-8,549,344
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Revolving Line of Credit - Net		-31,890,086
78	Net Decrease in Short-Term Debt (c)		
79	Debt Issuance Costs	-50,452	-394,113
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-36,716,492	-34,921,140
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	43,601,665	-19,754,683
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-2,391,650	2,424,015
87			
88	Cash and Cash Equivalents at Beginning of Period	5,488,711	3,064,696
89			
90	Cash and Cash Equivalents at End of period	3,097,061	5,488,711

Schedule Page: 120 Line No.: 90 Column: b

Cash Balance Calculation:

	2016	2015
Account 131	3,087,142	3,087,653
Account 134	9,919	2,401,058
Total Cash & Cash Equivalents	3,097,061	5,488,711

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

The notes below are excerpts from the Company's GAAP basis consolidated financial statements as of and for the years ended September 30, 2016 and 2015. The following disclosures contain information in accordance with GAAP reporting requirements. As such, due to differences between FERC and GAAP reporting requirements, certain disclosures may not agree to balances in the FERC financial statements. In particular, the activity related to Vermont Yankee Nuclear Power Corporation may be presented in the GAAP notes, but has been eliminated in accordance with FERC reporting instructions.

(1) Nature of Operations

Green Mountain Power Corporation (the Company or GMP), a wholly owned subsidiary of Northern New England Energy Corporation (NNEEC), operates as an electric utility that purchases, generates, transmits, distributes, and sells electricity, and utility construction services, in Vermont to approximately 260,000 customer accounts. GMP was acquired by NNEEC (itself a wholly owned subsidiary of Gaz Metro Limited Partnership of Canada), on April 12, 2007. On June 27, 2012, NNEEC acquired, Central Vermont Public Service Corporation (CVPS). CVPS was then merged with and into GMP effective October 1, 2012.

The Company's primary revenues are generated from sales of its regulated electric utility operation. The Company is regulated by the Vermont Public Service Board (VPSB) and uses the Uniform System of Accounts established by the Federal Energy Regulatory Commission (FERC).

The Company's wholly owned subsidiaries include:

- **Vermont Yankee Nuclear Power Corporation (VYNPC)**: VYNPC was formed on August 4, 1966 to construct and operate a nuclear-powered electric generating plant (the Plant). The Plant was sold to Entergy Nuclear Vermont Yankee, LLC (Entergy) on July 31, 2002. As part of the sale, VYNPC was required to purchase from Entergy the entire facility product (energy, capacity and other facility product) available from the Plant at the time of the sale through March 21, 2012. The Plant was shut down on December 29, 2014. VYNPC recognizes revenue pursuant to the terms of its FERC filed rate schedule. The Sponsors, a group of seven New England utilities, are severally obligated to pay the Company their entitlement percentage of amounts equal to VYNPC's cost of service including total operating expenses and an allowed return on equity (7.5% since July 31, 2002). The Company's entitlement share is 55%. See note 16(h). VYNPC is subject to regulation by the FERC and the VPSB with respect to rates, accounting and other matters.

Central Vermont Public Service Corporation – East Barnet Hydroelectric, Inc. (East Barnet): East Barnet was formed to finance and construct a hydroelectric facility in Vermont, which became operational on September 1, 1984. The Company has leased and operated this facility since the in-service date.

- **Northern Water Resources, Inc. (NWR)**: NWR held a limited partnership interest in a California wind farm which was sold on June 28, 2016. Though there was no book value for the wind farm assets prior to the sale, a deferred tax liability of $0 and $5,283, respectively, exists at September 30, 2016 and 2015.

(2) Summary of Significant Accounting Policies

(a) Principles of Consolidation and Presentation

The accompanying consolidated financial statements include all companies in which the Company has legal or effective control. Noncontrolling interest represent the proportionate equity interest of owners in the Company's consolidated entities that are not wholly owned. See note 23. All significant intercompany transactions with consolidated affiliates have been eliminated upon consolidation.

The Company accounts for its investments in Vermont Electric Power Company, Inc. (VELCO), Vermont Transco LLC (Transco), Green Lantern Capital Solar Fund II, LP (GLC), New England Hydro-Transmission Corporation, and New England Hydro-Transmission Electric Company, Connecticut Yankee Atomic Power Company (Connecticut Yankee), Maine Yankee Atomic Power Company (Maine Yankee) and Yankee Atomic Electric Company (Yankee Atomic) using the equity method of accounting. The Company's share of the net earnings or losses of these companies is included in equity in earnings of associated companies on the consolidated statements of income.

The Company's interests in jointly owned generating and transmission facilities are accounted for on a pro rata basis using the Company's ownership percentages and are recorded in the Company's consolidated balance sheets within utility plant in service. The Company's share of operating expenses for these facilities is included in the corresponding operating accounts in the consolidated statements of income.

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. The Company believes it has taken reasonable positions where assumptions and estimates are used. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of unbilled revenue, pension and postretirement plan assumptions, contingency reserves, asset retirement obligations, regulatory assets and liabilities, the allowance for uncollectible accounts receivable, the valuation of utility plant, income tax uncertainties, deferred tax assets and derivative financial instruments. Actual results could differ from those estimates.

The Company considers events or transactions that occur after the balance sheet date, but before the consolidated financial statements are available to be issued, to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure. These consolidated financial statements were available to be issued on November 21, 2016 and subsequent events have been evaluated through that date.

(b) Regulatory Accounting

The Company's utility operations, including accounting records, rates, operations, and certain other practices, are subject to the regulatory authority of the FERC and the VPSB.

The Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit specific incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when it is probable that such costs will be recovered in customer rates. Incurred costs are deferred as regulatory assets when the Company concludes that it is probable that future revenues will be provided to permit recovery of the previously incurred cost. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence, and legal representations. A regulatory liability is recorded when amounts that have been recorded by the Company are likely to be refunded to customers through the rate-setting process. Regulatory assets and liabilities also include changes in fair value relative to derivative financial instruments that cannot be considered as income or expense for rate-making purposes until the derivative financial instrument settles.

(c) Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. Cash that is restricted for outstanding workers' compensation claims and for use under the terms of VPSB regulatory orders amounted to $347 and $391 at September 30, 2016 and 2015, respectively, and is included in cash and cash equivalents in the consolidated balance sheets. Included in cash are deposits, subject to the Company's exclusive control, provided as collateral under performance assurance requirements for certain power supply contracts amounting to $10 at September 30, 2016 and 2015.

Net book overdrafts, determined on a financial institution-specific basis, are reclassified from cash to other current liabilities in the consolidated balance sheets. Amounts reclassified as of September 30, 2016 and 2015 were $5,636 and $3,477, respectively. The Company has classified this activity on the consolidated statements of cash flows in net cash provided by operating activities.

(d) Revenue Recognition, Accounts Receivable, and Deferred Regulatory Revenue

Operating revenues consist principally of retail sales of electricity at regulated rates. Revenue is recognized when electricity is delivered. The Company accrues utility revenues based on estimates of electric service rendered and not billed at the end of an accounting period. The unbilled revenues, which totaled $20,474 and $22,496 at September 30, 2016 and 2015, respectively, are included in trade accounts receivable in the consolidated balance sheets. Wholesale revenues represent sales of electricity to other utilities, typically for resale, and to ISO New England for amounts by which the Company's power supply resources exceed customer loads. Revenues in excess of allowed costs or earnings in excess of earnings allowed under applicable rate plans or regulatory orders are deferred, if and when applicable. See note 3. Sales taxes collected from commercial customers are accounted for as a liability until remitted to the government and are excluded from operating revenues in the consolidated statements of income.

The Company estimates the amount of accounts receivable that will not be collected and records an allowance for estimated uncollectible amounts based upon historical experience. Charge-offs against the allowance are considered after reviewing the facts of each individual account.

(e) Inventories

The Company's inventory of generation fuel is accounted for on a first in, first out basis; Materials and supplies are recorded at cost and determined on a weighted average basis. Renewable energy certificates (RECs) are recorded at cost. The Company's inventories consist of the following:

		September 30	
		2016	**2015**
Fuel	$	6,844	7,138
Materials and supplies		17,548	12,782
RECs		2,936	2,817
Total inventory	$	27,328	22,737

The Company generates and purchases RECs in the normal course of business, and sells these RECs in order to reduce net power costs for GMP's retail customers through the power supply adjustor mechanism (see note 3). The Company accounts for purchased RECs using the inventory method. During the years ended September 30, 2016 and 2015, net REC revenue was $23,528 and $23,999, respectively. The Company has $2,936 and $2,817 of RECs inventory at September 30, 2016 and 2015, respectively, which represents the cost of RECs that were acquired in connection with certain power purchase agreements. The Company's self-generated RECs have an inventory carrying cost of zero.

(f) Utility Plant and Long-Lived Assets

Utility plant is stated at cost. Major expenditures for plant additions are recorded at original cost and include all construction-related direct labor and materials, as well as indirect construction costs. The costs of renewals and improvements of significant property units are capitalized. The costs of maintenance, repairs, and replacements of minor property units are charged to maintenance expense. The costs of units of property removed from service, net of salvage value, are charged to accumulated depreciation.

Depreciation expense is recognized on a straight-line basis based on depreciation rates adopted as a result of depreciation studies approved by the VPSB. The Company amortizes nearly all of its intangible and regulatory assets using the straight-line method based on the cost and amortization period approved by the VPSB.

(g) Long-Term Investments

At September 30, 2016 and 2015, investment securities included in the Millstone decommissioning trust consist primarily of debt and equity securities and are classified as available-for-sale. Available-for-sale securities are reflected on the consolidated balance sheets at their aggregate fair values. Dividend and interest income are recorded as a regulatory liability for the Millstone trust.

A decline in the market value of any available-for-sale security below amortized cost basis that is deemed to be other-than-temporary results in an impairment to reduce the carrying amount to fair value. To determine whether an impairment of a security is other-than-temporary, the Company considers whether evidence indicating the amortized cost of the investment is recoverable outweighs evidence to the contrary. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year-end, forecasted performance of the investee, and the general market condition in the geographic area or industry the investee operates in.

The Company's assessment of the fair market value of its long-term investments is performed by fixed income investment professionals utilizing relevant performance indicators of the underlying assets in the security (including default rates, delinquency rates, and percentage of nonperforming assets, loan to collateral value ratios, third party guarantees, and current levels of subordination).

When a security impairment is considered an other-than-temporary impairment (OTTI) the amount of OTTI recognized in earnings depends on if the Company intends to sell the security, it is more likely than not the Company will be required to sell the security before recovery of its amortized cost basis or the Company does not expect to recover the entire amortized cost basis. If the Company intends to sell the security or will be required to sell the security before recovery of its amortized cost, the OTTI recognized in earnings is equal to the entire difference between the security's amortized cost and its fair value at the balance sheet date. If the Company does not intend to sell the security and it is not more likely than not that the Company will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss, the OTTI is separated into the amount representing the credit loss and the amount related to all other factors. The amount of the total OTTI related to the credit loss is recognized in earnings and the portion of the loss related to other factors is recognized in Other Comprehensive Income (OCI). The credit loss component recognized in earnings is identified as the amount of principal cash flows not expected to be received over the remaining term of the security as projected using the Company's cash flow projections using its base assumptions.

For the years ended September 30, 2016 and 2015, there were no permanent impairments or credit losses associated with investment securities.

Millstone decommissioning trust fund: All dividend and interest income, realized and unrealized gains and losses are recorded to a regulatory liability since the fair value of the Millstone decommissioning trust fund exceeds the related asset retirement obligation. For the majority of the investments, GMP owns a share of the trust fund investments.

(h) Impairment of Long-Lived Assets

The Company performs an evaluation of long-lived assets, including utility plant, regulatory assets subject to amortization, and other long-lived assets, for potential impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the carrying value of the long-lived asset is not recoverable based on undiscounted cash flows expected to be generated by the asset, an impairment charge is recognized to the extent that the carrying value exceeds its fair value, with fair value being determined based upon discounted cash flow models. Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. As of September 30, 2016 and 2015, based upon management's analysis of the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss for long-lived assets should be recorded.

(i) Environmental Liabilities

The Company is subject to federal, state, and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. Only those site investigation, characterization, and remediation costs currently known and determinable are considered probable and reasonably estimable. As costs become probable and reasonably estimable, reserves are adjusted as appropriate. As reserves are recorded, regulatory assets are recorded to the extent environmental expenditures will be recovered in future rates. Estimates are based on studies performed by third parties.

(j) Derivative Financial Instruments

There are three different ways to account for derivative instruments: (i) as an accrual agreement, if the criteria for the normal purchase normal sale exception are met and documented; (ii) as a cash flow or fair value hedge, if the specified criteria are met and documented, or (iii) as a mark to market agreement with changes in fair value recognized in current period earnings. All derivative instruments that do not qualify for the normal purchase normal sale exception are recorded at fair value in Derivative financial instrument assets and liabilities on the consolidated balance sheets.

Gains or losses resulting from changes in the fair values of derivatives are accounted for pursuant to a regulatory accounting order issued by the VPSB as discussed below. The Company uses derivative instruments primarily to hedge the cash flow effects of price fluctuations in its power supply costs. The Company is exposed to credit loss in the event of nonperformance by the other parties to the hedge agreements. The credit risk related to the hedge agreements is limited to the cost to the Company to replace the aforementioned hedge arrangements with like instruments. The Company monitors the credit standing of the counterparties and anticipates that the counterparties will be able to fully satisfy their obligations under the hedge agreements.

On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings or other comprehensive income effects relating to future periods caused by changes in the fair value of power supply arrangements that qualify as derivatives. Any changes in the fair value of the derivative financial instrument are recorded as a regulatory asset or liability, as appropriate. As these derivative contracts are settled, realized gains or losses are reclassified into earnings through electricity power supply costs.

(k) Purchased Power

The Company records the annual cost of power obtained under short-term and long-term executory contracts as operating expenses. The contracts do not convey to the Company the right to use the related property, plant, or equipment. The Company is not the sole taker of power from these sources except for the Moretown Landfill, North Hartland Hydro Unit 1, Lower Village Hydro, Woodsville Hydro, Dewey's Mills Hydro Lower Valley Hydro, Sweetwater Hydro, Solar Garden, Charter Hill Solar, Park Street Solar, Route 7 Solar, Bondville Solar and Ampersand contracts.

(l) Taxes Other than Income

Taxes other than income consist primarily of various property taxes, Vermont gross receipts taxes and certain employer payroll tax expenses. The Company recognizes the taxes in the period incurred.

(m) Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Investment tax credits are recorded as a liability and amortized as a tax expense benefit over the lives of the relevant assets.

The Company recognizes the effect of uncertain income tax positions only if those positions are more likely than not of being sustained. When recognized, income tax positions are measured and recorded at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs. The Company records interest expense related to unrecognized tax benefits in interest expense and penalties in other (expense) income, net in the consolidated statements of income.

The Company files a consolidated tax return with its Parent, NNEEC. NNEEC pays all federal and state income taxes on behalf of the Company. The Company has a tax-sharing agreement with NNEEC to pay an amount equal to the tax that would be paid if the Company filed tax returns on a separate return basis. There was no income taxes payable to or receivable from NNEEC under the tax-sharing agreement at September 30, 2016 and 2015.

(n) Pension and Other Postretirement Benefit Plans

The Company has defined benefit pension plans covering certain of its employees. The benefits are based on years of service and the employee's compensation during the five years before retirement. GMP also sponsors defined benefit postretirement health care and life insurance plans for retired employees and their dependents. Effective January 1, 2008, for GMP and April 1, 2010, for former CVPS, newly hired employees are not eligible to participate in the Company's defined benefit pension plans, but instead qualify for an enhanced 401(k) benefit.

The Company records annual amounts relating to its pension and postretirement plans based on calculations that incorporate various actuarial and other assumptions, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates, and healthcare cost trend rates. The Company reviews its assumptions on an annual basis and makes modifications to the assumptions based on current rates and trends. The effect of modifications to those assumptions is recorded as a regulatory asset or regulatory liability, as appropriate. The Company believes that the assumptions utilized in recording its obligations under its plans are reasonable based on its experience and market conditions.

The net periodic costs are recognized as employees render the services necessary to earn the postretirement benefits. Unamortized amounts that are expected to be recovered from or returned to ratepayers in future years are recorded as a regulatory asset or regulatory liability, respectively. See notes 3 and 13.

As of October 1, 2015, GMP adopted a new methodology for estimating the service cost and interest cost components of its pension and postretirement benefit plans. Prior to October 1, 2015, the methodology being applied had used a single weighted average discount rate derived from the yield curve used to determine the projected benefit obligations at the beginning of the fiscal year. Under the new methodology, specific spot rates along the yield curve will be applied to the projected cash flows in order to estimate the service cost and interest cost for each plan. The Company has accounted for this change as a change in accounting estimate applied on a prospective basis. For fiscal 2016, this change reduced pension and postretirement benefit plan costs by approximately $2 million when compared to the prior methodology. There was no significant change to the total benefit obligation resulting from adopting the new methodology.

(o) Contingencies

Liabilities for loss contingencies arising from items such as claims, assessments, litigation, fines and penalties are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

(p) Fair Value

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

The level in the fair value hierarchy within which a fair value measurement in its entirety falls is based on the lowest level input that is available for that particular financial instrument. The values of publicly traded fixed income and equity securities are based on quoted market prices and exchange rates. Nonmarketable securities include alternative investments in hedge, private equity, and other similar funds, and are valued using current estimates of fair value in the absence of readily determinable market values. The fair values are determined by management based on information provided by the investment manager and are based on appraisals or other estimates that require varying degrees of judgment, which takes into consideration, among other things, the cost of the securities, prices of recent significant placements of securities of the same issuer, and subsequent developments concerning the companies to which the securities relate.

The estimated fair value of alternative investments represents the ownership interest in the net asset value (NAV) of the respective partnership. The Company utilizes the NAV reported by the fund managers, which is based on appraisals or other estimates that require varying degrees of judgment, as a practical expedient to estimate fair value of alternative investments that (a) do not have a readily determinable fair value and (b) either have the attributes of an investment company or prepare their financial statements consistent with the measurement principles of an investment company, unless it is probable that all or a portion of the investment will be sold for an amount different from NAV. With respect to those investments reported at NAV, as a practical expedient, classification in Level 2 or 3 is based on the Company's ability to redeem its interest at or near the date of the balance sheet. If the investment can be redeemed within ninety days of the date of the balance sheet, it is classified in Level 2; if not, it is classified as Level 3.

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, prepaid expenses and other current assets, income taxes receivable (payable), accounts payable, accrued liabilities, short-term debt, long-term debt, the Millstone and Decommissioning and Trust funds, and pension assets.

(q) Government Grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grant arrangement and the grant will be received. Government grants are recognized in the consolidated statements of income over the periods in which the related costs for which the government grant is intended to compensate are recognized. When government grants are related to reimbursements of operating expenses, the grants are recognized as a reduction of the related expense in the consolidated statements of income. For government grants related to reimbursements of capital expenditures, the grants are recognized as a reduction of the basis of the asset and recognized in the consolidated statements of income over the estimated useful life of the depreciable asset as reduced depreciation expense. There were no material amounts related to grants in the current year.

(r) Reclassifications

In November of 2015, the Financial Accounting Standards Board issued ASU 2015-17 – *Income Taxes (Topic 740: Balance Sheet Classification of Deferred Taxes*. The amendments in this update require that net deferred tax liabilities and assets be classified as noncurrent in a classified balance sheet. This guidance was adopted by the Company effective October 1, 2015. A reclassification of $24,727 has been made to decrease deferred income tax assets and to decrease noncurrent deferred income tax liabilities in the consolidated balance sheets. This change was made for 2015 to conform to the 2016 presentation.

(3) Rate Regulation and Regulatory Assets and Liabilities

(a) Rate Regulation

In August 2014, the VSPB approved a Successor Alternative Regulation Plan for the Company (Plan) effective October 1, 2014 through September 30, 2017.

The Plan contains the principal elements described below:

- A power supply cost adjustment mechanism (PSA) under which the Company recovers or credits to customers 90% of energy costs that are $307 (PSA Energy Cost Dead Band) per quarter higher or lower than energy costs included in rates and the full amount of transmission and capacity costs higher or lower than included in rates. The quarterly PSA over and under collections for each 12-month period ending March 31 are accumulated and the net over/under collection is recovered from or returned to customers at the time of the next annual base rate filing adjustment.

- The allowed ROE under the Plan adjusts annually, up or down, at the rate of one-half of the change in the average 10-year Treasury Note rate, over a specified 20-day trading period.
- An annual earnings sharing mechanism (ESAM) under which the Company has the opportunity to earn up to 35 basis points above its allowed ROE, recover 50% of any earnings shortfall between 50 basis points and 200 basis points below the allowed ROE and 100% of any earnings short fall in excess of 200 basis points below the allowed ROE. Under the Plan, certain exclusions, commonly made in setting rates, are applied to determine the Company's earnings and are expected to reduce the Company's ability to earn its allowed rate of return on equity for core utility operations. The ESAM will be recovered from or returned to customers the following base rate year.
- Base rates are adjusted annually, based on the Company's cost of service.
- The VPSB retains the authority to investigate the Company's rates at any time and to modify or terminate the Plan.
- Nonpower supply cost increases are capped at the amount currently allowed in rates, increased by inflation less a productivity factor of 1%, increased by a capital spending adjustment, adjusted for exogenous changes (if any) and further adjusted for any change in ROE. For 2016 and 2015, the formula that calculates the nonpower supply cost cap was higher than the requested rate increase; therefore, there was no resulting disallowance. The productivity factor is subject to an incentive adjustment based on the Company's benchmarked performance against 20 other utility companies.
- Collect from or return to customers material cost and revenue changes (Exogenous Change Adjustment) due to exogenous events. Exogenous events consist of major storm costs (Exogenous Storm) in excess of $1,200 per measurement period and cost or revenue changes (Exogenous Non-Storm) in excess of $1,200 per measurement period due to changes in tax laws, regulations and loss of major customer, major maintenance costs and investments not related to weather. The measurement year is the 12-month period ending March 31 and the $1,200 Exogenous Storm and Non-Storm thresholds are adjusted annually by inflation. The Exogenous Change Adjustment will be collected from or returned to customers as part of the base rate adjustment in the next base rate year, unless the Department and Company agree to a longer recovery period.

Set rates for the Company's largest customer for three years.

As a condition of the VPSB's approval of the CVPS acquisition, the Company has agreed to a plan for sharing merger synergies with the following material elements:

- The Company is obligated to provide customers at least $144,000 (nominal dollars) in customer savings over 10 years: 2013 through 2022. Savings will be measured by comparing actual operating and maintenance (O&M) costs with the O&M Platform included in rates.
- In years 2013 through 2015, customer savings are fixed in the amounts of $2,500, $5,000 and $8,000, respectively.
- In 2016 through 2020, customers and the Company share synergy savings on a 50/50 basis.
- In 2021 through 2022, all synergy savings will be credited to customers.

- If total measured savings to customers are less than $144,000 after 2022, the Company shall provide the difference to retail customers by means of a Savings Guarantee Plan approved by the VPSB.

The Company has not recognized this obligation in its consolidated financial statements since it expects that the total measured savings to customers will be achieved as described above.

In August 2014, the VPSB approved a 1.46% rate decrease effective October 1, 2014 through September 30, 2015. The allowed ROE is 9.6%. The VPSB also approved an additional 1.00% decrease returning to customers $5,960 of the Entergy MOU funds. See note 19.

In September 2015, the VPSB approved a 0.73% rate increase consisting of a 0.08% base rate increase, a 0.67% exogenous adjustment increase and a 0.02% power adjustor decrease effective October 1, 2015 through September 30, 2016. The allowed ROE is 9.44%.

In September 2016, the VPSB approved a 0.93% rate increase consisting of a 0.03% base rate decrease and a 0.96% power adjustor increase effective October 1, 2015 through September 30, 2016. The allowed ROE is 9.02%.

(b) Regulatory Assets and Liabilities

Regulatory assets and liabilities at September 30, 2016 and 2015 consist of the following:

	September 30, 2016	Amortizable 2016 balances included in rates	Original amortization period
Regulatory assets:			
Unfunded pension and postretirement benefits	$ 85,278		
Deferred storm costs	5,504	5,504	2 year
CEED fund	15,954	15,954	10 years
Pine Street Barge Canal costs	10,318	7,555	20 years
Deferred PSA Costs-undercollection	11,590	11,590	1 year
Meter retirements	4,480	4,480	5 years
Deferred efficiency fund	4,505	3,821	10 years
Income taxes	4,281	—	
Deferred nuclear outage costs	883	883	2 years
Renewable Energy Due Diligence Costs	597	597	3 years
Derivative financial instrument	942		
Asset retirement obligations (ARO)	310	310	18 years
Other regulatory assets	951	951	Various
Total regulatory assets	145,593	51,645	
Regulatory liabilities:			
Accumulated nonlegal costs of removal	36,914	—	
Derivative Financial Instrument	493	—	
Electricity assistance program	3,561	3,561	1–2 years
Millstone Unit #3 ARO	7,216	—	
Contributions in aid of construction	5,300	5,300	2 years
Solar Development Fee	1,754	1,754	2 years

		September 30, 2016	Amortizable 2016 balances included in rates	Original amortization period
Synergy savings	$	2,300	2,300	1 year
Hydro production tax credits		1,236	1,236	1 year
VYNPC net unrealized gains on long-term investments		129	—	
Deferred PSA Revenues- overcollection		18	18	1 year
Other regulatory liabilities		1,585	—	
Total regulatory liabilities		60,506	14,169	
Net regulatory assets	$	85,087	37,476	
Regulatory assets classified as current	$	16,397	—	
Regulatory liabilities classified as current		9,333	—	

		September 30, 2015	Amortizable 2015 balances included in rates	Original amortization period
Regulatory assets:				
Unfunded pension and postretirement benefits	$	62,362	—	
Deferred storm costs		19,476	19,476	1 year
CEED fund		14,119	14,119	10 years
Pine Street Barge Canal costs		11,258	8,147	20 years
Deferred PSA Costs- undercollection		8,539	8,539	1 year
Meter retirements		6,721	6,721	5 years
Deferred efficiency fund		5,524	4,870	10 years
Income taxes		5,321	—	
Deferred nuclear outage costs		452	452	2 years
Asset retirement obligations (ARO)		340	340	18 years
Other regulatory assets		1,463	1,463	Various
Total regulatory assets		135,575	64,127	

		September 30, 2015	Amortizable 2015 balances included in rates	Original amortization period
Regulatory liabilities:				
Accumulated nonlegal costs of removal		36,365	—	
Power contract derivative		12,154	—	
VYNPC Revenue Sharing Agreement		8,888	8,888	1 year
Electricity assistance program		8,771	8,771	1–2 years
Millstone Unit #3 ARO		6,466	—	
DOE Settlement		2,334	2,334	1 year
Storm surcharge offset		1,731	1,731	2 years
VYNPC net unrealized gains on long-term investments		767	—	
Reserve for loss on power contract		299	299	11 years
Deferred PSA Revenues-overcollection		124	124	1 year
Other regulatory liabilities		1,085	—	
Total regulatory liabilities		78,984	22,147	
Net regulatory assets	$	56,591	41,980	
Regulatory assets classified as current	$	12,869	—	
Regulatory liabilities classified as current		16,101	—	

The table above indicates the pre-tax amount of net regulatory assets (liabilities) presently recorded. These amounts do not include the recognition of tax effects, which would be approximately 40.5%. If the accounting standards for entities subject to rate regulation were not used, the corresponding income and the subsequent amortization of these items would not be recognized.

Unfunded Pension Benefits and Postretirement Benefits

The pension and other postretirement benefit regulatory assets reflected above represent the unrecognized pension costs and other postretirement benefit costs that would normally be recorded as a component of other comprehensive loss. Since these amounts represent costs that are expected to be included in future rates, they are recorded as regulatory assets. Also included in the regulatory asset are other employee benefit costs that have been deferred for regulatory purposes. See note 13.

Deferred Storm Costs

Costs in excess of $1,200 allowed for exogenous factors, under the alternative regulation plan, may be recorded as a regulatory asset and recovered in future periods. At September 30, 2016 and 2015, deferred storm costs from major storms were $21,671 and $19,476, respectively.

These deferred storm costs are being recovered over a 2-year period beginning October 1, 2015. Exogenous storm costs have been offset by Entergy proceeds, DOE spent fuel Phase II settlement and various deferred credits that were pending approval to reclassify as a regulatory liability. At September 30, 2016 and 2015, exogenous storm costs (net of credits of $12,613 and $0) were $5,504 and $6,523, respectively. The Company amortized $3,554 and $0 of storm costs during 2016 and 2015, respectively.

Community Energy and Efficiency Fund (CEED Fund)

One of the conditions associated with the VPSB approval of the acquisition of the former CVPS was that the Company create the CEED Fund. The CEED Fund is to be capitalized with an amount equal to $21,154 (Required Investment) as of the date the VPSB approved the acquisition, June 15, 2012. Interest accrues at the rate of inflation on uninvested amounts until the Required Investment has been made. The Required Investment will be used to provide net customer benefits to customers in the former CVPS territory equal to or greater than 1.2 times the Required Investment or $25,384 (Required Benefit), plus accrued interest on unprovided benefits

The Company invested $10,000 in weatherization projects and has also invested an additional $8,894 in thermal and electric efficiency improvement projects. The remaining Required Investment must be made by June 2019. GMP has delivered approximately $28,034 in customer benefits as of September 2016. If the Company has not provided the Required Benefit by June 2019, the Company is required to file a plan for approval by the VPSB specifying how the remaining Required Benefit will be delivered. Any shortfall would be provided to the former CVPS customers on a uniform percentage basis in the form of a bill refund.

The Company's investments into the CEED fund are subject to VPSB approval and are included in rate base and recovered through rates over a 10-year period, beginning in fiscal year 2014. If additional investments in excess of the Required Investment are needed to deliver the Required Benefit such additional investments will not be recoverable through rates. The Company made total investments of $3,303 during 2016 and $1,824 during 2015 and recorded amortization of $1,468 in 2016 and $866 in 2015.

The VPSB approved the calendar year 2016 Plan authorizing investments of approximately $3,319 in primarily electric efficiency measures. The calendar year 2015 Plan authorized investments of approximately $3,470 of primarily electric efficiency measures.

Pine Street Barge Canal Costs

The Company has recorded a regulatory asset of $10,318 and $11,258 for the years ended September 30, 2016 and September 30, 2015, respectively, to reflect unrecovered past and future Pine Street Barge Canal costs, and will amortize the full amount of incurred costs over 20 years without a return. The past unrecovered costs regulatory asset of $7,555 is included in rates. The estimated future unrecovered cost regulatory asset of $2,763 has a matching liability and is not yet included in rates. The amortization of the regulatory asset is expected to be recovered in future rates. See note 17(b).

PSA over/Under-Collection

Under the Plan, a PSA under which the Company recovers or credits to customers 90% of energy costs that are $307 (per quarter) higher or lower than energy costs included in rates for 2016 and 2015, and the full amount of transmission and capacity costs higher or lower than included in rates.

As of September 30, 2016 and 2015, the Company recorded net deferred costs of $11,572 and $8,415, respectively. Deferred amounts are recovered from or credited to customers on an annual basis under the Alternative Regulation Plan.

Meter Retirements

The Company has recorded a regulatory asset of $4,480 and $6,721 for the years ended September 30, 2016 and 2015, respectively, for old meters being replaced as a result of new technology related to the SmartPower implementation. The amount is being amortized over a 5 year period, commencing in the year ended September 30, 2013.

Deferred Efficiency Fund

One of the conditions associated with VPSB approval of the 2007 acquisition of GMP by NNEEC (2007 acquisition) was that the Company agreed to create an Efficiency Fund (EF) and an income-based discount program that would be capitalized with an amount of $8,000, adjusted for inflation since 2001. As of September 30, 2016 and 2015, the total regulatory assets recorded were $4,505 and $5,524, respectively. The EF permits customers to seek reimbursement for approved projects meeting certain energy conservation requirements. The income-based discount program was available for qualified customers to help pay for utility services in 2007 through 2009. As future amounts are expended by the Company, they become eligible to be recovered in rates. Management believes that expended amounts are probable of recovery.

Income Taxes

A regulatory asset or liability is established if it is probable that a future increase or decrease in income taxes payable will be recovered from or returned to customers through future rates. Income tax regulatory assets and liabilities have been established for the equity component of the allowance for funds used during construction, federal and state changes in enacted tax rates, if any, and for federal investment tax credits. These income tax regulatory assets and liabilities are combined into a net income tax regulatory asset.

Deferred Nuclear Outage Costs

Incremental costs associated with the scheduled refueling outage at Millstone Unit#3 nuclear plant are deferred and amortized over the period between scheduled outages.

Renewable Energy Due Diligence Costs

The Company has recorded a regulatory asset of $597 for costs related to renewable energy projects which GMP has decided not to move forward with. The amount is being amortized over a 3 year period commencing in the year ended September 30, 2016.

Derivative Financial Instrument

The derivative financial instrument regulatory asset and liability represents the fair value of certain power supply derivative assets and liabilities that are expected to be recognized in future rates as the derivative contracts are settled. Settlement gains or losses related to the derivative contracts are returned to or fully recovered from customers in the rates the Company charges and are discussed in detail in note 14.

Asset Retirement Obligations

The amount represents the deferred costs expected to be recognized in future rates, associated with conditional asset retirement obligations. Conditional asset retirement obligations are legal obligations to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. The Company amortizes amounts over periods similar to associated long lived assets included in utility plant.

Other Regulatory Assets

Other regulatory assets consist of regulatory deferrals of hydro repowerment costs, costs associated with the Vermont Marble Value Sharing agreement and various other projects and deferrals that the Company expects to be recovered in future rates.

Accumulated Non-Legal Costs of Removal

Accumulated nonlegal costs of removal represent removal costs previously recovered from ratepayers for other-than-legal obligations. The Company reflects these amounts as a regulatory liability. The Company expects, over time, to recover or settle through future revenues any over – or under-collected net costs of removal.

VYNPC Revenue Sharing Agreement

GMP received its share of the Entergy MOU payment in 2015 (see note 19), and returned $5,900 to customers in 2015. GMP applied $7,900 to 2015 deferred storm costs in accordance with the approved 2016 retail rate filing. This regulatory liability accrues interest until it is returned to customers.

Electricity Assistance Program

The Vermont Legislature passed a law in 2009 authorizing the VPSB to implement low income rates. GMP implemented an Electricity Assistance Program (EAP) in 2013 that provides financial assistance to qualified low-income residential customers. The program is funded by a per meter charge to all retail customers, and incurs costs for a 25% discount to eligible customers, and incremental costs for program administration. The regulatory liability balance represents the excess of the amount collected and costs incurred to date. In August 2015 the VPSB approved GMP's proposal for use of these funds that earmarks $450 for a rolling arrearage forgiveness program, returned $6,300 to customers in October 2015 and reduces the per meter charge collected from all retail customers by 33% effective in October 2015. In June 2014, the VPSB approved GMP's proposal for use of these excess funds that earmarked $1,000 to improve enrollment in the EAP and returned $1,500 to customers by December 31, 2014.

Millstone Unit #3 ARO

The Company has legal asset retirement obligations for decommissioning related to its jointly owned nuclear plant, Millstone Unit #3, and has an external trust fund dedicated to funding its share of future costs. This regulatory liability represents the excess of the decommissioning trust fund asset balance over the asset retirement obligation for decommissioning. The plant is currently operating and the ultimate decommissioning cost is an estimate at this time. The liability balance will be decreased when the forecasted decommissioning obligation exceeds the trust fund asset, resulting in a regulatory asset or returned to customers when the plant is fully decommissioned.

Contributions in Aid of Construction (CIAC)

The Company has a regulatory liability of $5,300 at September 30, 2016 for customer advances for construction that is being returned to customers over a 2 year period beginning October 1, 2015. These funds have been previously paid to the Company for line extension projects.

Solar Development Fee

GMP has recorded a regulatory liability of $1,754 at September 30, 2016 for fees received related to the development of certain solar projects. These fees will be returned to customers over a 2 year period beginning October 1, 2016 in accordance with the 2017 base rate filing.

Synergy Savings

GMP has recorded a regulatory liability of $2,300 and $0 at September 30, 2016 and 2015, respectively for synergies that will be returned to customers in future base rate filings. 50% of any synergies in excess of the amount included in a base rate filing will be returned to customers in future years.

Hydro Production Tax Credits

GMP has recorded a regulatory liability of $1,236 at September 30, 2016 for hydro production tax credits on the output attributable to efficiency improvements and capacity additions. This regulatory liability will be returned to customers over 1 year beginning October 1, 2016.

DOE Settlements

In June 2014, GMP received $5,700 for its share of the Phase 2 DOE settlements with Yankee Atomic, Connecticut Yankee, and Maine Yankee for the government's breach of contract to take the companies' spent fuel. In September 2014, GMP received $500 for its share of the Phase 1 DOE settlement. $3,500 of the settlements offset the fiscal year 2014 second quarter PSA under-collection. The remaining balance was applied to 2015 deferred storm costs in accordance with the approved 2016 retail rate filing. This regulatory liability accrues interest until it is returned to customers in future rate filings.

Storm Surcharge Offset

The remaining balance of the 2014 third quarter PSA over-collection of $1,637 was set aside to reduce the earnings sharing adjustment for 2015 storm costs. The storm costs, net of this liability, will be collected over 24 months beginning October 1, 2015. This regulatory liability accrues interest until it is returned to customers.

Reserve for Loss on Power Contract

In 2004, the Company established a reserve for a loss on a terminated power sales agreement in connection with the sale of a subsidiary's franchise. The reserve was amortized on a straight-line basis through December 2015 as the cash was paid out under the underlying supply contracts. The amortization was credited to power supply expense.

Other Regulatory Liabilities

Other regulatory liabilities consist of amounts received from VYNPC that are subject to a regulatory deferral order, and other insignificant amounts.

(4) Investments in Associated Companies and Joint Owned Facilities

Investments in associated companies at September 30, 2016 and 2015 include the following:

	2016 Ownership interest	2016 Investment in equity
VELCO – common	38.8%	$ 10,081
VELCO – preferred	80.1	156
Total VELCO		10,237
Transco LLC	70.3	475,632
Green Lantern Capital Solar Fund II, LP	99.9	989
New England Hydro Transmission – Common	3.2	196
New England Hydro Transmission Electric – Common	3.2	543
Connecticut Yankee Atomic Power Company	2.0	35
Maine Yankee Atomic Power Company	2.0	37
Yankee Atomic Electric Company	3.5	52
Total investment in associated companies		$ 487,721

	2015 Ownership interest	2015 Investment in equity
VELCO – common	38.8%	$ 10,275
VELCO – preferred	80.1	190
Total VELCO		10,465
Transco LLC	69.1	424,859
Green Lantern Capital Solar Fund II, LP	99.9	1,037
New England Hydro Transmission – Common	3.2	174
New England Hydro Transmission Electric – Common	3.2	458
Connecticut Yankee Atomic Power Company	2.0	33
Maine Yankee Atomic Power Company	2.0	51
Yankee Atomic Electric Company	3.5	52
Total investment in associated companies		$ 437,129

(a) Vermont Electric Power Company and Vermont Transco LLC

VELCO and Transco own and operate the transmission system in Vermont over which bulk power is delivered to all electric utilities in the state. Transco owns the transmission assets comprising the system. Transco was formed by VELCO and VELCO's owners in 2006 and VELCO was appointed as the manager of Transco. On June 30, 2006, VELCO contributed substantially all of its operating assets to Transco, in exchange for 2,400 Class A Membership Units and Transco's assumption of VELCO's debt. Transco is governed by an Amended and Restated Operating Agreement (the Transco Operating Agreement) by and among VELCO, the Company and most of Vermont's other electric utilities. VELCO operates the Transco system under a Management Services Agreement with Transco. Transco is also governed by certain Amended and Restated Three-Party Agreements, assigned to Transco from VELCO, by and among the Company, VELCO and Transco, and VELCO remains subject to an Amended Four-Party Agreement among the Company and VELCO. VELCO currently has a 5.5% ownership interest in Transco. The remaining ownership interest in Transco is held by other Vermont-based utilities.

Pursuant to the merger agreement and VPSB order related to the acquisition of the former CVPS by NNEEC, CVPS transferred 38% of the total of VELCO Class B voting common stock and 31.7% of the total of VELCO Class C nonvoting common stock to Vermont Low Income Trust for Electricity, Inc. (VLITE), in June 2012. In addition, the transmission contracts, sponsor agreement and composition of the board of directors under which VELCO operates, effectively restrict the Company's ability to exercise control over VELCO.

The Company made capital investments of $38,983 and $27,221 in Transco in 2016 and 2015, respectively, to support various transmission projects. The Company receives its current rate of return (see note 3) on the investment in Transco, since the Transco investment is accounted for as a regulated business for Vermont rate-setting purposes. Capital contributions to Transco are based on the transmission cost share of the Vermont utilities. The Company and other taxable Transco owners, also receive additional earnings and distributions to compensate for differences in taxability with other nontaxable Transco owners.

Summarized unaudited financial information for Transco follows:

		Years ended September 30	
		2016	2015
Net income	$	81,060	80,688
Company's equity in net income		61,553	59,358
Total assets	$	1,098,171	1,037,394
Liabilities and long-term debt		446,129	444,718
Net assets	$	652,042	592,676
Company's equity in net assets	$	475,632	424,859

Transco provides transmission services to the Company and others pursuant to a transmission tariff known as the 1991 Transmission Agreement (the VTA), to which all Vermont electric utilities and the State of Vermont are parties. Under the VTA, the Company and all other Vermont utilities pay their pro rata share of Transco's total costs, including interest on debt and a fixed return on equity, less revenues collected by Transco under the ISO-New England Open Access Transmission Tariff and other agreements.

Transco provided transmission services to the Company (reflected as transmission expenses in the consolidated statements of income) amounting to $19,148 and $27,809 for the years ended September 30, 2016 and 2015, respectively.

In addition to its equity ownership interest in Transco, the Company also owns 38.8% of VELCO's common stock and 80.1% of its preferred stock. The Company's ownership interest in VELCO entitles it to approximately 38.8% of the dividends distributed by VELCO. The Company has recorded its equity in earnings on this basis.

The Transco Operating Agreement requires consent of the majority member (GMP) and a majority of the remaining ownership interests to remove Transco's manager (VELCO). Additionally, the structure of VELCO's board of directors prevents the Company from having a direct or indirect controlling financial interest in Transco; therefore, consolidation is not required.

Included in the Company's financial statements are construction service receipts of $185 and $723, billed to VELCO for the years ended September 30, 2016 and 2015, respectively.

Summarized unaudited financial information for VELCO (parent company only) is as follows:

		Years ended September 30	
		2016	2015
Net income	$	1,801	3,330
Company's equity in net income		719	1,203
Total assets	$	75,118	92,294
Liabilities and long-term debt		48,947	65,567
Net assets	$	26,171	26,727
Company's equity in net assets	$	10,237	10,465
Amounts due from (to) VELCO, net		1,499	(5,034)

(b) Other Investments in Associated Companies

Green Lantern Capital Solar Fund II, LP: The Company is a limited partner of Green Lantern Capital Solar Fund II, LP (GLC) and has a 99.99% equity ownership interest. GLC was formed to finance solar power generating projects. The Company does not consolidate GLC as it does not control GLC. GLC is controlled by its general partner, Green Lantern Capital, LLC.

GMP's share of income from other associated companies not discussed in detail above totaled $157 and $176 during the years ended September 30, 2016 and 2015, respectively.

(c) Joint Owned Facilities

GMP's joint-ownership interests in electric generating and transmission facilities as of September 30, 2016 and 2015 are as follows:

	2016				
	Ownership interest	Share of capacity (in MW)		Share of utility plant	Share of accumulated depreciation
Joseph C. McNeil	31.0%	16.7	$	28,614	25,255
Wyman #4	2.9	17.6		6,321	5,892
Stony Brook #1	8.8	31.0		11,598	11,145
Highgate Transmission Facility	82.3	162.6		41,873	9,336
Metallic Neutral Return	59.4	—		1,563	1,523
Millstone Unit #3	1.7	21.4		81,966	47,633

	2015			
	Ownership interest	Share of capacity (in MW)	Share of utility plant	Share of accumulated depreciation
Joseph C. McNeil	31.0%	16.7	$ 28,801	24,510
Wyman #4	2.9	17.6	6,321	5,704
Stony Brook #1	8.8	31.0	11,598	11,007
Highgate Transmission Facility	82.3	162.6	47,732	14,334
Metallic Neutral Return	59.4	—	1,563	1,501
Millstone Unit #3	1.7	21.4	81,966	46,581

Metallic Neutral Return is a neutral conductor for the NEPOOL/Hydro-Québec Interconnection.

GMP's share of expenses for these facilities is included in operating expenses in the consolidated statements of income under the caption "Power supply expenses – Company-owned generation" for the listed generation plants (Wyman, Stony Brook, McNeil, and Millstone), under the caption "Transmission expenses" for the Metallic Neutral Return and Highgate facilities, and under the caption "Depreciation and amortization expenses" for all facilities. Each participant in these facilities must provide their own financing.

(5) Long-Term Investments

(a) Millstone Decommissioning Trust Fund

GMP has decommissioning trust fund investments related to its joint-ownership interest in Millstone Unit #3. The decommissioning trust fund was established pursuant to various federal and state guidelines. Among other requirements, the fund must be managed by an independent and prudent fund manager. Any gains or losses, realized and unrealized, are expected to be refunded to or collected from ratepayers and are recorded as regulatory assets or liabilities.

Regulatory authorities limit GMP's ability to oversee the day-to-day management of its nuclear decommissioning trust fund investments; therefore, GMP lacks investing ability and decision-making authority.

For the years ended September 30, 2016 and 2015, there were minimal realized gains and no realized losses. There were also no loss impairments of debt securities in 2016.

The fair values of these investments as of September 30, 2016 and 2015 are summarized below:

		2016	
		Amortized cost	Estimated fair value
Marketable equity securities	$	3,635	8,071
Marketable debt securities:			
Corporate bonds		457	493
U.S. government issued debt securities (agency and treasury)		1,134	1,196
State and municipal		40	46
Total marketable debt securities		1,631	1,735
Cash equivalents and other		79	79
Total	$	5,345	9,885

		2015	
		Amortized cost	Estimated fair value
Marketable equity securities	$	3,524	7,307
Marketable debt securities:			
Corporate bonds		450	463
U.S. government issued debt securities (agency and treasury)		1,048	1,085
State and municipal		90	94
Total marketable debt securities		1,588	1,642
Cash equivalents and other		36	36
Total	$	5,148	8,985

The reported trust balances include net unrealized gains of $4,540 and $3,837 as of September 30, 2016 and 2015, respectively. The Company has recorded the corresponding adjustment as a regulatory liability.

Information related to the fair value and maturities of debt securities at September 30, 2016:

Within one year	$	73
One to five years		610
Five to ten years		308
Over ten years		744
	$	1,735

(6) Utility Plant

The major classes of utility plant are as follows:

	Depreciable life in years		September 30 2016	September 30 2015
Property, plant and equipment:				
Distribution	15–60	$	764,486	726,835
Generation	35–110		487,633	480,389
Transmission	50–60		211,937	213,353
Intangible, FERC licenses and software	5–40		68,909	63,009
Buildings	50		43,540	45,047
General	10–30		23,698	22,519
Electric plant acquisition adjustments	11		22,951	22,951
Transportation	14		29,682	23,571
Office equipment	5–15		23,872	18,779
Transmission capital lease asset	30		—	—
Nuclear fuel, net	1–6		2,251	1,886
Total plant in service			1,678,959	1,618,339
Accumulated depreciation and amortization			(577,655)	(547,957)
Net plant in service			1,101,304	1,070,382
Construction work in progress			113,263	40,369
Total utility plant, net		$	1,214,567	1,110,751

Depreciation and amortization expense amounted to $48,924 and $45,362 in 2016 and 2015, respectively. During the years ended September 30, 2016 and 2015, administrative and general costs of $8,340 and $7,288, respectively, were capitalized, and there were no significant retirements. The composite depreciation rate for plant in service is 2.91% and 2.80%, respectively, in 2016 and 2015. The amount of CWIP included in rate base is $8,036 and $13,877, respectively, for the years ended September 30, 2016 and 2015.

(7) Revolving Credit Facility

Effective December 15, 2014, GMP entered into a new $110,000 credit facility, with the ability to increase it by an additional $15,000, with KeyBank N.A. as the lead bank.

The purpose of the facility is to provide liquidity for general corporate purposes, in the form of funds borrowed and letters of credit. The revolver is unsecured, and allows the Company to choose a rate based on a thirty (30) day LIBOR, Overnight LIBOR or the Alternative Base Rate plus the Applicable Rate (as defined in the revolver), with a margin based upon GMP's Standard and Poor's (S&P) unsecured credit rating of A-. The Overnight LIBOR rate at September 30, 2016 and 2015 was 1.47% and 1.22%, respectively and the 30-day LIBOR was 1.48% and 1.25%, respectively. The Company had $67,788 and $71,174 in cash borrowings, and $10,151 and $6,150 in letters of credit outstanding under its credit facility at September 30, 2016 and 2015, respectively. The Revolver balance has been classified as long term debt at September 30, 2016 and 2015, as the facility has a maturity date of December 14, 2019, and no annual requirement to pay off the outstanding balance on the credit facility. The Company was in compliance with all restrictive covenants and limitations as of September 30, 2016 and 2015.

(8) Long-Term Debt

Substantially all of the property and franchises of the Company are subject to the lien of the indentures under which the First Mortgage Bonds have been issued. The First Mortgage Bonds are callable at the Company's option at any time upon payment of a make-whole premium. The Company's long-term debt consists of the following:

		September 30 2016	September 30 2015
Total first mortgage bonds outstanding	$	635,665	592,905
Revolving line of credit		67,788	71,174
Total long-term debt outstanding		703,453	664,079
Less current maturities (due within one year)		7,255	7,240
Total first mortgage bonds outstanding, less current maturities	$	696,198	656,839
Weighted average interest rate on first mortgage bonds		5.41%	5.54%
Interest rate on revolving line of credit		1.47	1.24

The current corporate unsecured credit rating by S&P is A-; and the current senior secured debt credit ratings for the Company's first mortgage bonds by S&P is A. Amortization of capitalized bond issue expenses totaled $548 and $532 for the years ended September 30, 2016 and 2015, respectively.

On December 16, 2015, the Company issued a total of $50,000 in First Mortgage Bonds under the 26th Supplemental Indenture in two series. The terms related to each series of bonds are customary and in line with the terms found within the Company's previous bond issuances. As in past bond issuances, the bonds include a provision for a "make-whole premium" which would apply if the Company called the bonds prior to maturity. Since there is a make-whole premium, there would be no detriment to the investor if the bonds were redeemed prior to maturity. Each series of bonds has a fixed interest rate, the bonds issued consisted of an $18,000 series with an interest rate of 3.31% which mature in 2027 and a $32,000 series with an interest rate of 4.26% which mature in 2045.

The Company's long-term debt indentures and credit facility contain certain financial covenants. The most restrictive financial covenants include maximum debt to capitalization of 65% under its Indentures and 60% debt to capitalization requirements under the terms of our Vermont Economic Development Authority Recovery Zone Bonds. The Company was in compliance with all restrictive covenants and limitations as of September 30, 2016 and 2015.

The future maturities of long-term debt for each of the five years subsequent to September 30, 2016 are:

		Amount
Years ending September 30:		
2017	$	7,255
2018		7,280
2019		86,300
2020		78,118
2021		31,355
Thereafter		493,145
Total	$	703,453

The First Mortgage bonds that mature beyond 2021 have maturity dates that range between 2022 and 2045.

(9) Asset Retirement Obligations

(a) General

The Company continually reviews the regulations, laws, and contractual obligations such as decommissioning and easements to which it is a party to identify situations where there are legal obligations to perform asset retirement activities. This review identified certain easements that may obligate the Company to perform asset retirement activities. There were no new obligations identified in 2016 or 2015. The present value of such obligations identified and recorded as of September 30, 2016 and 2015 was $8,212 and $7,825, respectively, with the difference attributable to accretion expense recorded in 2016. The increase in the asset retirement obligations is a result of the present value of the obligations moving closer to the retirement date.

(b) Kingdom Community Winds (KCW)

The asset retirement obligations includes the accumulated liability of $3,928 and $3,732 at September 30, 2016 and 2015, respectively, for the decommissioning of the Company's wind facilities located on leased property. Related to this obligation, the Company has a letter of credit against its credit facility for $6,150. See note 6, 7, and 16.

(c) Millstone Unit #3

The asset retirement obligations include $2,670 and $2,519 at September 30, 2016 and 2015, respectively, for decommissioning related to the Company's joint-owned nuclear plant, Millstone Unit #3. See notes 3, 5, and 15 for further information.

Changes in the carrying value of asset retirement obligations for the years ended September 30, 2016 and 2015 are as follows:

		2016	2015
Balance at beginning of period	$	7,825	7,460
Liabilities incurred		—	—
Liabilities settled		—	—
Accretion expense		387	365
Revisions in estimated cash flows		—	—
Balance at end of period	$	8,212	7,825

(10) Other Liabilities and Deferred Credits

Other current and noncurrent liabilities at September 30, 2016 and 2015 are as follows:

		2016	2015
Other current liabilities:			
Health, insurance and damage reserves	$	7,109	6,627
Accrued taxes other than income		4,142	4,298
Cash concentration account – outstanding checks		5,636	3,477
Other		1,383	1,681
Accrued capital and O&M costs		768	1,925
SERP retirement benefits		448	479
Customer credit balances		5,061	1,228
Deferred compensation		257	458
Total other current liabilities	$	24,804	20,173

		2016	2015
Other noncurrent liabilities and deferred credits:			
Accrued employee-related costs	$	1,076	1,088
Nuclear decommissioning		313	294
Other liabilities		86	380
Total other noncurrent liabilities and deferred credits	$	1,475	1,762

(a) Capital Lease – Obligations under Transmission Interconnection Support Agreement

Agreements executed in 1985 among the GMP, VELCO, and other New England Power Pool (NEPOOL) members and Hydro-Québec (HQ) provided for the construction of the second phase (Phase II) of the interconnection between the New England electric systems and that of HQ. Phase II provides 2,000 megawatts of capacity for transmission of HQ power to Sandy Pond, Massachusetts. Construction of Phase II commenced in 1988 and was completed in late 1990. The Company is entitled to 8.3% of the Phase II power supply benefits. Total construction costs for Phase II were approximately $380,000. The New England participants, including the Company, have contracted to pay monthly their proportionate share of the total cost of constructing, owning, and operating the Phase II facilities, including capital costs. As a supporting participant, the Company must make support payments under 30-year agreements. The obligation expired in 2015.

Capital lease amortization totaled $0 and $1,779 for the years ended September 30, 2016 and 2015, respectively.

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company and New England Hydro-Transmission Corporation, subsidiaries of National Grid USA. Certain of the Phase II participating utilities, including the Company, own equity interests in such companies. The Company holds approximately 3.2% of the equity of the corporations owning the Phase II facilities and accounts for its ownership under the equity method of accounting. See note 4.

(11) Stockholder's Equity

(a) Appropriated Retained Earnings

The Company had appropriated retained earnings of $787 at September 30, 2016 and 2015 relating to regulatory requirements arising from ownership of hydroelectric facilities.

(b) Dividend Restrictions

Certain restrictions on the payment of cash dividends on common stock are contained in the Company's indentures relating to long-term debt and in the Amended and Restated Articles of Incorporation. Under the most restrictive of such provisions, $129,545 and $99,593 of retained earnings were free of restrictions at September 30, 2016 and 2015, respectively.

Certain restrictions on the payment of cash dividends on common stock exist as a result of conditions of the VPSB's approval of the 2007 acquisition of the Company and the approval of the merger between the Company and CVPS. The Company is required to notify the VPSB of any changes that result in a 3% or greater change in capital structure from the structure approved in the Company's last rate proceeding. The Company is also required to provide notice within 10 days after declaring each regular common stock cash dividend and to provide 30-day advance notice before declaring any special cash dividend.

During the years ended September 30, 2016 and 2015, the Company provided notices related to regular common stock cash dividends.

(c) Capital Contributions

In the years ended September 30, 2016 and 2015, the Company received a $39,296 and $6,000, respectively, capital contribution from its parent, NNEEC. The primary purpose of the investment was to fund investments in utility plant and affiliates.

(d) Accumulated Other Comprehensive Income (Loss) (AOCI)

The after-tax components of AOCL include the Company's equity share of changes in fair value of VELCO's interest rate swap derivative instrument.

(12) Income Taxes

The provision for income taxes for the years ended September 30, 2016 and 2015 is summarized as follows:

		2016	2015
Current federal income taxes	$	(8)	44
Current state income taxes		398	102
Total current income taxes		390	146
Deferred federal income taxes		26,037	26,498
Deferred state income taxes		8,115	8,128
Total deferred income taxes		34,152	34,626
Investment tax credits-net		(200)	(280)
Income tax expense	$	34,342	34,492

The significant items that reconcile between income taxes computed by applying the U.S. federal statutory rate and the reported income tax expense (benefit), for the reporting period, include the dividends received deduction, amortization of investment tax credits, energy credits, corporate owned life insurance, AFUDC equity and state income tax.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at September 30, 2016 and 2015 are presented below:

		2016	2015
Deferred tax assets:			
Customer advances for construction	$	2,148	4,186
Net operating losses and tax credits		69,645	57,795
Asset retirement and cost of removal obligations		16,077	15,618
Deferred compensation and other benefit plans		33,624	24,285
Other liabilities and deferred credits		9,049	14,317
Derivative financial instruments		582	4,925
Total deferred tax assets	$	131,125	121,126
Deferred tax liabilities:			
Accelerated tax depreciation on property	$	280,196	249,716
Regulatory assets – pension and other postretirement benefits		34,283	25,065
Pine Street Barge Canal		4,181	14,655
Investment in associated companies		113,855	98,307
Other deferred charges and other assets		22,195	17,399
Nonutility subsidiary investment in wind farm		—	5,698
Derivative financial instrument regulatory assets		582	4,925
Total deferred tax liabilities	$	455,292	415,765
Net deferred income tax liability	$	324,167	294,639

The change in the net deferred tax liability arises from the deferred income tax expense included in the consolidated financial statements for the periods presented, primarily affected by accelerated tax depreciation, tax versus book differences in investment in affiliates, and changes in regulatory assets and liabilities.

As of September 30, 2016 GMP recorded $69,645 of deferred tax assets related to net operating loss (NOL) carryforwards and tax credit carryforwards. Federal NOLs will expire if unused starting in fiscal year 2033 and ending in fiscal year 2035. State NOLs will expire if unused starting in fiscal year 2023 and ending in fiscal year 2025. Management believes it is more likely than not that the Company will realize its deferred tax assets based upon the expected future reversals of taxable temporary differences and the generation of future taxable income. Based on these sources of future income the Company has not recorded any valuation allowances as of September 30, 2016 and 2015.

The Company records the benefits of investment tax credits through the amortization, as approved by the VPSB, of the unamortized investment tax credits, which are initially recorded as a liability. The remaining balance of unamortized investment tax credits shown separately on the consolidated balance sheets at September 30, 2016 and 2015 was $7,121 and $3,615, respectively.

While the Company believes it has adequately provided for all tax positions, amounts asserted by taxing authorities could be greater than the Company's accrued position. Accordingly, additional provisions on federal and state tax-related matters could be recorded in the future as revised estimates are made or the underlying matters are settled or otherwise resolved.

During the year ended September 30, 2016, due to the expiration of the statute of limitations, the Company reversed an unrecognized tax benefit of $272 recorded in a previous year relating to a state net operating loss

(NOL) carryforward calculation. The related $95 deferred federal tax benefit recorded for this issue was also reversed. During the year ended September 30, 2015, a charge of $54 was recorded for a reserve for unrecognized tax benefits relating to a fiscal year 2014 state income tax refund denied by the state. This issue is currently under appeal and remains as the Company's only unrecognized tax benefit at September 30, 2016. During the year ended September 30, 2015, the Company reversed the unrecognized tax benefits reserve of $85 relating to VEBA trusts that was recorded during the year ended September 30, 2014. The VEBA issue has been settled through adjustments to the fiscal year 2014 beginning net operating loss carryforward balance in accordance with the Company's representations made to the Internal Revenue Service.

The Company recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in nonoperating expenses. During the year ended September 30, 2016, the Company recognized income of approximately $64 resulting from the reversal of interest accrued on the state NOL carryforward calculation issue reversed during the year ended September 30, 2016. During the year ended September 30, 2015, the Company recognized income of approximately $389 resulting primarily from the reversal of interest and penalties accrued for the VEBA issue during the year ended September 30, 2014. The Company had approximately $0 and $64 accrued for the payment of interest and penalties at September 30, 2016 and 2015, respectively.

The Company is subject to income taxes in the United States, but no foreign jurisdictions.

At September 30, 2016, open tax years for federal and state tax returns are 2013 and forward. There were no federal tax audits during the years ended September 30, 2016 or 2015.

(13) Employee Benefit Plans

(a) Defined Benefit Pension Plan and Other Postretirement Benefit Plan

The Company has a qualified noncontributory defined benefit pension plan (the Pension Plan) covering substantially all of its employees. New employees are not eligible to participate in the defined benefit plans. The defined pension benefits are based on the employees' level of compensation and length of service. Under the terms of the Pension Plan, employees are vested after completing five years of service, and can receive a pension benefit when they are at least age 55 with a minimum of 10 years of service or when their combined years of service and age total 80 or 85 for GMP or the former CVPS plans, respectively. Normal retirement age is 65. The Company makes annual contributions to the plans up to the maximum amount that can be deducted for income tax purposes.

The Company also provides certain healthcare and life insurance benefits for retired employees and their dependents. Employees become eligible for these benefits if they reach retirement age while working for the Company. Eligibility and benefit levels vary depending on date of hire and whether or not the retiree was a CVPS employee prior to the merger with GMP. GMP employees hired after December 31, 2007 are not eligible to receive post-retirement health care benefits. The Company accrues the cost of these benefits during the service life of covered employees.

Postretirement healthcare benefits are recovered in rates. GMP amended its postretirement healthcare plan to establish a 401(h) sub account and separate Voluntary Employee Benefit Account (VEBA) trusts for its union and nonunion employees, for purposes of funding the plan benefits. The VEBA and 401(h) plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities.

At September 30, 2016 and 2015, the unfunded pension obligations totaled $68,990 and $45,980, respectively. The Company recorded an offsetting regulatory asset for the net actuarial loss in the pension plan. At September 30, 2016, the other postretirement benefit obligation totaled $990, consisting of $245 included in other current liabilities and $745 included in unfunded pension and postretirement obligations on the consolidated balance sheets. At September 30, 2015, the other postretirement benefit obligation totaled $1,386 consisting of $210 included in other current liabilities and $1,176 included in unfunded pension and postretirement obligations on the consolidated balance sheets. At September 30, 2016 and 2015, the Company recorded an offsetting regulatory asset for the net actuarial losses in the postretirement benefit plan.

The following provides a summary of activity affecting the pension and postretirement plans' benefit obligations and assets for the years ended September 30, 2016 and 2015:

		2016	
		Pension plan benefits	**Other postretirement benefits**
Fair value of plan assets	$	176,141	41,989
Projected benefit obligation		245,131	42,979
Funded status	$	(68,990)	(990)
Accumulated benefit obligation	$	222,824	42,979
Net actuarial loss recognized in regulatory assets		82,420	847

		2015	
		Pension plan benefits	**Other postretirement benefits**
Fair value of plan assets	$	172,121	39,557
Projected benefit obligation		218,101	40,943
Funded status	$	(45,980)	(1,386)
Accumulated benefit obligation	$	195,506	40,943
Net actuarial loss recognized in regulatory assets		59,869	897

The Company pays for certain postretirement healthcare and life insurance benefits and those payments are included in the determination of the projected benefit obligation.

Net periodic pension expense and other postretirement benefit costs, employer and participant contributions, and benefits paid by plan are:

	Year ended			
	2016		2015	
	Pension plan benefits	Other postretirement benefits	Pension plan benefits	Other postretirement benefits
Net periodic benefit cost	$ 5,915	(256)	5,776	(158)
Employer contributions	5,456	529	4,428	381
Participant contributions	—	1,029	—	1,035
Benefits paid	16,882	3,155	11,885	3,719

Assumptions used to determine the Company's projected benefit obligations and the net pension and other postretirement benefit costs were:

	Year ended September 30, 2016	
	Pension plan benefits	Other postretirement benefits
Weighted average assumptions:		
Discount rate for projected benefit obligation	3.63%	3.51%
Discount rate for service cost	4.63	4.60
Discount rate for interest cost	3.80	3.41
Expected return on assets	6.85	6.65
Rate of compensation increase (to determine the costs and obligation)	3.25	—
Current year healthcare cost trend	—	7.00
Ultimate year healthcare cost trend	—	5.00
Year of ultimate trend rate	—	2023

	Year ended September 30, 2015	
	Pension plan benefits	Other postretirement benefits
Weighted average assumptions:		
Discount rate for projected benefit obligation	4.45%	4.30%
Discount rate for service cost	4.35	4.20
Discount rate for interest cost	4.35	4.20
Expected return on assets	6.85	6.65
Rate of compensation increase (to determine the costs and obligation)	3.25	—
Current year healthcare cost trend	—	7.00
Ultimate year healthcare cost trend	—	5.00
Year of ultimate trend rate	—	2023

The mortality assumption utilized a RP-2014 mortality table projected back to 2006 with Scale MP-2014 then forward with full generational projection using Scale BB-2D for the years ended September 30, 2016 and 2015.

For measurement purposes, a 7.0% annual rate of increase in the per capita cost of covered medical benefits was assumed for 2016 and 2015. This rate of increase was assumed to gradually decline to 5.0% in 2023 for 2016 and 2015. The medical trend rate assumption has a significant effect on the amounts reported. For example, increasing the assumed healthcare cost trend rate by one percentage point for all future years would increase the total of the service and interest cost components of net periodic postretirement cost for the years ended September 30, 2016 and 2015 by $145 or 7.3% and $160 or 6.7%, respectively. Decreasing the trend rate by one percentage point for all future years would decrease the total of the service and interest cost components of net periodic postretirement cost for the years ended September 30, 2016 and 2015 by $114 or 5.7% and $126 or 5.3%, respectively. Increasing the assumed healthcare cost trend rate by one percentage point for all future years would increase the postretirement benefit obligation for the years ended September 30, 2016 and 2015 by $3,237 or 7.5% and $3,134 or 7.7%, respectively. Decreasing the trend rate by one percentage point for all future years would decrease the postretirement benefit obligation for the years ended September 30, 2016 and 2015 by $2,630 or 6.1% and $2,548 or 6.2%, respectively.

The Company's defined benefit plan investment policy seeks to achieve sufficient growth to enable the defined benefit plans to meet their future obligations and to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines for the pension plan combined assets specify that 40% be invested in equity securities, 43% be invested in debt securities, and the remainder be invested in alternative and other investments. Current investment guidelines for the other postretirement benefit plan combined assets specify that 53% be invested in equity securities, 40% be invested in debt securities and the remainder be invested in alternative and other investments.

For September 30, 2016 and 2015 the Company expects an annual long-term return of 6.85% for the pension plan assets and a return of 6.65% for the other postretirement plan assets based on a representative target asset allocation described above. In formulating this assumed rate of return, the Company considered historical returns by asset category and expectations for future returns by asset category based, in part, on expected capital market performance over the next 10 years.

Asset categories and weighted average allocation percentages are provided in the following table.

	Pension plan assets		Other postretirement benefit assets	
	2016	**2015**	**2016**	**2015**
Weighted average asset allocation asset category:				
Equity securities	40%	38%	65%	65%
Debt securities	47	47	35	35
Other	13	15	—	—
Total	100%	100%	100%	100%

(b) Pension and Postretirement Benefit Plans Asset Fair Values

The fair values of the pension and other postretirement benefit plan investments are presented below:

	Pension plan assets fair value measurements at September 30, 2016			
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:				
Cash equivalents	$ 4,667	4,667	—	—
Limited partnerships	22,413	—	—	22,413
Exchange traded funds	32,827	32,827	—	—
Equity securities:				
U.S. companies	17,839	17,838	1	—
International companies	3,346	2,406	940	—
Fixed income securities:				
U.S. Treasury securities	27,208	—	27,208	—
Mortgage-backed securities	7,902	—	7,902	—
Corporate bonds-U.S. companies	34,994	—	34,994	—
Corporate bonds-foreign	6,377	—	6,377	—
Municipal bonds	1,277	—	1,277	—
Mutual funds:				
Equity funds	17,291	17,291	—	—
Total	$ 176,141	75,029	78,699	22,413

	Pension plan assets fair value measurements at September 30, 2015			
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:				
Cash equivalents	$ 3,782	3,782	—	—
Limited partnerships	26,327	—	—	26,327
Exchange traded funds	31,326	31,326	—	—
Equity securities:				
U.S. companies	17,682	17,576	—	106
International companies	3,207	2,358	849	—
Fixed income securities:				
U.S. Treasury securities	23,201	—	23,201	—
Mortgage-backed securities	19,188	—	19,188	—
Corporate bonds-U.S. companies	28,299	—	28,299	—
Corporate bonds-foreign	4,876	—	4,876	—
Municipal bonds	1,913	—	1,913	—
Mutual funds:				
Equity funds	12,320	12,320	—	—
Total	$ 172,121	67,362	78,326	26,433

Other postretirement benefit plan assets fair value measurements at September 30, 2016

		Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:					
Cash equivalents	$	730	730	—	—
Exchange traded funds		8,553	8,553	—	—
Equity securities:					
U.S. companies		4,571	4,571	—	—
International companies		158	158	—	—
Fixed income securities:					
Mutual funds:					
Equity funds		14,195	14,195	—	—
Fixed-income funds		13,773	13,773	—	—
Real estate funds		9	—	—	9
Total	$	41,989	41,980	—	9

Other postretirement benefit plan assets fair value measurements at September 30, 2015

		Total		Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:						
Cash equivalents	$	820		820	—	—
Exchange traded funds		7,718		7,718	—	—
Equity securities:						
U.S. companies		4,187		4,187	—	—
International companies		142		142	—	—
Fixed income securities:						
Mutual funds:						
Equity funds		15,014		15,014	—	—
Fixed-income funds		13,686		13,686	—	—
Real estate funds		10		—	—	10
Total		41,577	$	41,567	—	10
Less payable for future reimbursement at September 30, 2016		(2,020)				
Net plan assets	$	39,557				

Investments included in Level 3 primarily consist of the Plan's ownership in alternative investments;

principally limited partnership interests in hedge, private equity, real estate, and other similar funds. Changes in the net fair value of pension and other postretirement benefit plan assets that are classified Level 3 are as follows:

		Years ended September 30	
		2016	2015
Balance at beginning of year	$	26,443	21,648
Capital contributions		158	8,275
Redemptions		(2,719)	(3,135)
Gains and losses (realized and unrealized)		(1,460)	(345)
Balance at end of year	$	22,422	26,443

(c) ***Pension and Other Postretirement Benefit Plan Cash Flow***

Projected benefits and contributions are as follows:

		Pension plan		Other postretirement benefits	
		Contributions	Benefit payments	Contributions	Benefit payments
Years ending September 30:					
2017	$	7,000	11,659	250	2,268
2018		—	12,185	—	2,294
2019		—	12,577	—	2,319
2020		—	13,704	—	2,345
2021		—	13,992	—	2,383
2022 through 2026		—	73,268	—	11,960

Pension and other postretirement contributions beyond 2017 have yet to be determined.

(d) ***Defined Contribution Plan***

The Company maintains a 401(k) Savings Plan for substantially all employees. This plan provides for employee contributions up to specified limits. The Company matches employee pretax contributions up to 4%. The Company contributes an additional 0.75% for each year of eligible compensation made on a nonmatching basis to GMP employees hired prior to January 1, 2008 and to former CVPS employees hired prior to April 1, 2010. For GMP employees hired on or after January 1, 2008 and former CVPS employees hired on or after April 1, 2010, the Company contributes an additional 3.25% each year of eligible compensation, made on a nonmatching basis. The Company's matching contribution is immediately vested. The Company's matching and nonmatching contributions for the years ended September 30, 2016 and 2015 totaled $2,391 and $2,372, respectively.

(e) ***Supplemental Executive Retirement Plan***

The Company provides a nonqualified retirement plan (SERP) for certain employees. Benefits under the SERP are funded on a cash basis. The amount of expense recognized for this plan for the years ended September 30, 2016 and 2015 was $407 and $794, respectively. As of September 30, 2016 and 2015, the

SERP benefit obligation, based on a discount rate of 2.55% and 3.4%, was $4,993 and $4,702, respectively. As of September 30, 2016 and 2015, the current and long-term portions were $335 and $4,659 and $366 and $4,335, respectively. As of September 30, 2016 and 2015 regulatory assets were recorded for the unrecognized benefit costs associated with actuarial losses in the amount of $1,300 and $1,050, respectively.

GMP has life insurance policies intended to fund nonqualified SERP and deferred compensation benefits for GMP and former CVPS executives under the terms of their employment agreements. As of September 30, 2016 and 2015, the total cash surrender value was $20,739 and $20,229, of which $7,856 and $7,695, respectively, is included in a Rabbi Trust.

(f) Deferred Compensation

The Company has a deferred compensation plan for current and past officers and past directors. Amounts deferred are at the option of the officer or director, and include annual interest on the amounts deferred. As of September 30, 2016 and 2015 the obligations were $4,036 and $4,244, respectively.

(14) Derivative Financial Instruments

The Company purchases the majority of its power supply, and uses long-term power supply contracts to mitigate rate volatility to ratepayers. The Company enters into physical power supply agreements with various counterparties to hedge against fossil fuel price increases. Many of these contracts are derivatives but because they meet the exception for a normal purchase and sale contract, they are not carried at fair value. As a result the Company records contract-specified prices for electricity as an expense in the period used, as opposed to the changes occurring in fair market values. See note 16.

The Company has recently entered into two capacity rate swap contracts to hedge a portion of its forward capacity costs. Since these contracts will settle on a net basis, they do not meet the criteria as a normal purchase and sale and they are accounted for at fair value. Additionally, the Company has determined that these capacity rate swap contracts are considered Level 3 fair value measures since the valuation technique includes a significant unobservable assumption concerning the forward capacity market pricing curve. The Company had an agreement (the 9701 Agreement) that granted HQ an option to call power from the Company's power supply contract at prices below current and estimated future market rates. HQ has exercised all remaining call options under this agreement during 2015.

Due to a regulatory order from the VPSB that requires the Company to defer recognition of any earnings or other comprehensive income effects relating to future periods from power supply arrangements that qualify as derivatives, the Company records an offsetting regulatory asset or liability for the fair value and any subsequent unrealized gains or losses, of their derivative instruments. Realized gains or losses are recorded in the Consolidated Statements of Operations in the corresponding caption they relate to. There were no realized gains or losses in the current fiscal year. The current portion of derivative assets and liabilities, if any, are presented separately in the consolidated balance sheets.

The following table shows the calculated fair value of the derivative contracts, reflecting the risk that the Company or the counterparty will not execute upon the arrangement. Actual value upon settlement may differ materially from the fair values shown below:

		September 30			
		2016		2015	
		Fair value			
Derivatives		**Assets**	**Liabilities**	**Assets**	**Liabilities**
Capacity rate swaps	$	494	941	12,154	—
Total power supply derivative asset (liability)	$	494	941	12,154	—
Current portion	$	—	—	—	—

The tables below present assumptions used to estimate the fair value of the derivative contracts at September 30, 2016 and 2015. The forward capacity prices are based on the forward capacity auction price determined by ISO New England.

	September 30, 2016				
	Valuation model	**Risk free interest rate**	**Price volatility**	**Average forward price/kW-Mo**	**Contracts expire**
Capacity rate swaps	Net present value	0.68% – 1.12%	n/a	$ 7.03	2019-2021

	September 30, 2015				
	Valuation model	**Risk free interest rate**	**Price volatility**	**Average forward price/kW-Mo**	**Contracts expire**
Capacity rate swaps	Net present value	0.88% – 1.63%	n/a	$ 9.55	2019-2021

Certain of the Company’s derivative instruments contain reciprocal provisions that require the counter parties’ and the Company’s debt to maintain an investment grade credit rating from the major credit rating agencies. The failure to maintain an investment grade rating would obligate the counterparties or Company to deposit collateral in an amount equal to the fair value adjustment to the notional amount of the contract for derivative instruments in a liability position. A failure to maintain an investment grade rating would not obligate the counterparties or Company to deposit collateral at September 30, 2016 since there are no derivative contracts in a liability position that contain collateral provisions.

The following table summarizes the counterparties to GMP’s derivative contracts together with the fair value of those contracts, if any, as of September 30, 2016 and 2015:

		2016			
		Market value			Collateral required if below investment grade
Counterparties		Risk free	With credit risk	Assets/ (liabilities)	
Next Era	$	495	494	494	—
Next Era		(971)	(941)	(941)	—
Net total	$	(476)	(447)	(447)	—

		2015			
		Market value			Collateral required if below investment grade
Counterparties		Risk free	With credit risk	Assets	
Next Era	$	12,477	12,154	12,154	—

The Company recorded corresponding regulatory liabilities and assets. Amounts due during the next fiscal year, if any, are classified in current assets and current liabilities.

(15) Fair Value of Financial Instruments

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The carrying amounts for cash and cash equivalents, accounts receivable, prepaid expenses, income tax receivable, accounts payable and accrued liabilities approximate their fair values because of their short-term maturities. The carrying amount of the spent fuel disposal fee and accrued interest obligation approximates its fair value because it represents the amount that would be required to be paid if the DOE was to begin taking delivery of spent nuclear fuel. See note 5(a). The fair value of the Company's revolving line of credit included in long-term debt approximates its carrying value due to the short-term nature of the related borrowings and the variable interest rate. Life insurance policies held by the Rabbi Trust are carried at cash surrender value.

The Company's estimates of fair value of financial assets and financial liabilities are based on the framework and hierarchy established in applicable accounting pronouncements. The framework is based on the inputs used in valuation, gives the highest priority to quoted prices in active markets and requires that observable inputs be used in the valuations when available. The disclosure of fair value estimates in the hierarchy is based on whether the significant inputs into the valuation are observable.

At September 30, 2016 and 2015, the fair value of the Company's first mortgage bonds included in long-term debt was $785,974 and $697,593 (carrying amount of $635,665 and $592,905), respectively. The fair value of the Company's first mortgage bonds are measured using quoted offered-side prices when quoted market prices are available. If quoted market prices are not available, the fair value is determined based on quoted market prices for similar issues with similar remaining time to maturity and similar credit ratings.

The following table sets forth by level the fair value hierarchy of financial assets and liabilities that are accounted for at fair value on a recurring basis. The Company's assessment of the significance of a particular input to the fair value measure requires judgment, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy:

	Fair value as of September 30, 2016			
	Level 1	**Level 2**	**Level 3**	**Total**
Spent fuel disposal and decommissioning trusts:				
Marketable equity securities	$ 3,025	5,046	—	8,071
U.S. government issued debt securities (agency and treasury)	36,648	12,120	—	48,768
Municipal obligations	—	60,724	—	60,724
Corporate and other bonds	—	36,037	—	36,037
Money market funds	1,592	73	—	1,665
Total spent fuel disposal and decommissioning trusts	41,265	114,000	—	155,265
Derivatives – Capacity rate swaps	—	—	(447)	(447)
Total	$ 41,265	114,000	(447)	154,818

		Fair value as of September 30, 2015			
		Level 1	Level 2	Level 3	Total
Spent fuel disposal and decommissioning trusts:					
Marketable equity securities	$	2,702	4,607	—	7,309
U.S. government issued debt securities (agency and treasury)		66,466	27,936	—	94,402
Municipal obligations		—	15,094	—	15,094
Corporate and other bonds		—	33,937	—	33,937
Money market funds		2,681	33	—	2,714
Total spent fuel disposal and decommissioning trusts		71,849	81,607	—	153,456
Derivatives – Capacity rate swaps		—	—	12,154	12,154
Total	$	71,849	81,607	12,154	165,610

(a) Millstone Decommissioning Trust

The Company's primary valuation technique to measure the fair value of its nuclear decommissioning trust investments is the market approach. GMP owns a share of the qualified decommissioning fund and cannot validate a publicly quoted price at the qualified fund level. However, actively traded quoted prices for the underlying securities in the fund have been obtained. Due to these observable inputs, fixed income, equity and cash equivalent securities in the qualified fund are classified as Level 2. Equity securities are held directly in GMP's nonqualified trust and actively traded quoted prices for these securities have been obtained. Due to these observable inputs, these equity securities are classified as Level 1.

(b) Derivatives – Capacity Rate Swaps

At September 30, 2016, there were no recognized gains or losses included in earnings or other comprehensive income attributable to the change in unrealized gains or losses related to derivatives still held at the reporting date. This is due to the Company's regulatory accounting treatment for all power-related derivatives. The following table is a reconciliation of the changes in net fair value of capacity rate swap contracts that are classified as Level 3 in the fair value hierarchy:

Balance at beginning of period	$	12,154
Change in fair value relating to unrealized losses		(12,601)
Balance at September 30, 2016	$	(447)

(16) Long-Term Power Purchase and Other Commitments

(a) Electricity Purchase Commitments

Purchased power expense by significant contract supplier was as follows:

		Year ended September 30	
		2016	**2015**
Hydro Québec	$	64,686	108,020
Independent Power Producers		44,589	41,282
Nextera		41,548	40,592
Cargill (formerly JP Morgan)		17,321	24,035
Granite Reliable		14,789	13,873
Citigroup		—	12,045
Exelon (formerly Constellation Energy)		6,311	—

These contracts qualify for normal purchases and sales treatment, and are not subject to fair value accounting treatment as they are for the purchase of electricity to fulfill the Company's power supply needs. The expense related to these contracts is recorded and recognized in power supply expense at the time that the contracts are settled and the Company takes delivery of the electricity.

Significant purchased power contracts in effect as of September 30, 2016, including estimates for the Company's portion of certain minimum costs, are as follows:

		Estimated payments contractually due
Years ending September 30:		
2017	$	192,122
2018		201,403
2019		212,531
2020		196,065
2021		164,710
Thereafter		2,376,538
Total	$	3,343,369

(b) Hydro-Québec Contracts

Under various contracts, the Company purchases capacity and associated energy produced by HQ. These contracts obligate the Company to pay certain fixed capacity costs whether or not energy purchases above a minimum level set forth in the contracts are made. These minimum energy purchases must be made whether or not other less expensive energy sources might be available in the short-term market. These contracts are intended to complement the other components in the Company's power supply.

The Company currently purchases power pursuant to the Vermont Joint Owners (VJO) contract with HQ entered into in December 1987. The contract contains different schedules that expire between 2016 and 2021, with GMP's obligation to purchase under these contracts ending on October 31, 2016. If any VJO contract participant fails to meet its obligation under the VJO contract with HQ, the remaining contract participants, including the Company, will assume the defaulting participant's share on a prorated basis. To date there have been no defaults under the VJO contract and due to the small remaining volumes this risk is no longer material.

On April 15, 2011, the VPSB approved a long-term power purchase and sale agreement between Hydro-Québec Energy Services (U.S.) Inc. (HQUS), a subsidiary of HQ, and a group of Vermont utilities including GMP. The Company determined that the contract qualifies for "normal purchase normal sale" accounting treatment. Under the HQUS agreement, GMP will receive a portion of a statewide total of up to 218 or 225 MW of energy, delivered in a fixed 16 hour/day (i.e., 7x16) profile, and a corresponding portion of the environmental attributes (such as, for example, credits, benefits or emissions reductions) associated with this power. Such environmental attributes must meet a requirement specifying a hydropower content of at least 90%. HQUS markets electricity from HQ's generating facilities, whose output is presently well in excess of 90% hydroelectric. The contract lays a foundation that will guarantee GMP continued access to a reliable supply of power from HQ facilities, which should help GMP to maintain its favorable carbon footprint. Deliveries under this purchase commenced on November 1, 2012 at very small volumes, and will increase substantially in 2016 (as the existing VJO contract is expiring), and end in 2038. In 2016, the energy volumes under the contract represent an estimated 18% of GMP's projected annual energy requirement, increasing to 22% in 2017 as the largest schedules under the existing VJO contract expire.

The new HQUS contract does not include capacity, which must be purchased from other parties or left open to market prices.

The Company's contracts with HQ call for the delivery of system power and are not related to any particular facilities in the HQ system. Consequently, there are no identifiable debt-service charges associated with any particular HQ facility that can be distinguished from the overall charges paid under the contracts, and there are no generation plant outage risks although there are outage risks related to the operation of the transmission system.

(c) System Energy Contracts

The Company enters into system energy purchase contracts with various counterparties in the normal course of its business. The system contracts are usually less than five years in duration and call for firm physical delivery of specified hourly quantities that are not associated with any specific generation source and not subject to outage risk. The counter-parties are responsible for acquiring and taking title to the power that is purchased by the Company. The Company presently has in place several system energy purchases for deliveries through 2020, for terms from several months to 5 years.

(d) Other Renewable Power Contracts

The Company has committed to several contracts to purchase output from new renewable power plants, some for periods of up to 25 years, on a plant-contingent basis (the Company receives and pays only for its share of quantities actually generated by the plant). These purchases typically include energy, capacity, and renewable energy certificates and are derived from wind, solar PV, or landfill gas plants. The largest such purchase is a 20-year contract with the Granite Reliable wind project in New Hampshire, which began in April 2012.

(e) Next Era Seabrook Purchase

The Company agreed to purchase long-term energy, capacity and generation attributes from the Seabrook Nuclear Power Plant in New Hampshire owned by Next Era Seabrook LLC. This contract commenced in 2012 with purchases of approximately 131,000 MWh per year of System Power that is not related to any specific facility. Beginning in 2015, all purchases will be unit contingent purchases from the Seabrook

Nuclear Power Plant beginning at 60MW, which will decrease to 50 MW over the life of the contract that ends in 2034.

(f) ***Unit Purchases***

Under a long-term contract with Massachusetts Municipal Wholesale Electric Company (MMWEC), the Company is purchasing a percentage of the electrical output of the Stony Brook production plant constructed by MMWEC. The contract obligates the Company to pay certain minimum annual amounts representing the Company's proportionate share of fixed costs, including debt service requirements, whether or not the production plant is operating, for the life of the unit. The cost of power obtained under this long-term contract, including payments required when the production plant is not operating, is included in "purchases from others" in the consolidated statements of income.

(g) ***Kingdom Community Wind***

In October 2012, the Company completed construction and began daily commercial operation of the Kingdom Community Wind project (KCW) a 63-MW wind facility in Lowell. Eight MW of the project's output is being sold to Vermont Electric Cooperative, Inc. under a long-term contract. The remainder is incorporated into the Company's power supply.

(h) ***Nuclear Decommissioning Obligations***

Millstone Unit #3: GMP is obligated to pay its share of nuclear decommissioning costs for nuclear plants in which it has an ownership interest. GMP has an external trust dedicated to funding its joint-ownership share of future Millstone Unit #3 decommissioning costs. Dominion Nuclear Connecticut has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements have been met or exceeded. GMP also suspended contributions to the Trust Fund, but could choose to renew funding at its own discretion if the minimum requirement is met or exceeded. If a need for additional decommissioning funding is necessary, GMP will be obligated to resume contributions to the Trust Fund.

Other Yankee Companies: GMP has equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down and completely decommissioned except for the spent fuel storage at each location. The Company's obligations related to these plants are described in note 4. The balance of GMP's net nuclear decommissioning cost liability was $326 at September 30, 2016. The current and long-term portions of $13 and $313 are included in accounts payable, trade and accrued liabilities and other liabilities. The balance of GMP's net nuclear decommissioning cost liability was $428 at September 30, 2015. The current and long-term portions of $133 and $295 are included in accounts payable, trade and accrued liabilities and other liabilities.

(i) ***Renewable Energy Credits***

During the years ended September 30, 2016 and 2015, the Company received $23,528 and $23,999, respectively, of net revenue from RECs. The Company's RECs for the years ended September 30, 2016 were approximately 14% from Granite Reliable, 17% from McNeil, 2% from Moretown, 36% from KCW and 31% from a variety of other sources. In the future, REC revenues may become less certain as Vermont and other states may adjust their renewable policies.

(j) ***Operating Leases***

Vehicle Leases

The former CVPS had lease agreements for new vehicles. The Company is no longer leasing vehicles under these agreements. The total acquisition cost of all leased property under this agreement is $0 and $2,039 as of September 30, 2016 and 2015, respectively.

Solar Leases

The Company has entered into solar-related operating leases, which are primarily for leased land to host the Company's solar-related utility plant for solar power production and related activities.

The most significant lease is for land at a landfill site used to host a solar farm. The total minimum lease payments under this agreement are $750. As of September 30, 2016, future minimum rental payments required under all noncancelable operating solar leases are expected to total $865, consisting of $37 per year in 2017 through 2021 and $680 for years thereafter.

Other

Other operating lease commitments are considered minimal, as most are cancelable after one year from inception or the future minimum lease payments are of a nominal amount.

Total rental expense, which includes pole attachment rents in addition to the operating lease agreements described above, amounted to $2,688 and $2,894 for the years ended September 30, 2016 and 2015, respectively. These rental expenses are included in maintenance and other operating expenses on the consolidated statements of income.

(k) Other Commitments

The Company is required to set aside $347 and $361 as of September 30, 2016 and 2015, respectively, for a rate phase-in agreement related to the acquisition of the Vermont Marble Power Division, and renewable generation development under a VPSB regulatory order. These amounts are included in the accompanying consolidated balance sheets in cash and cash equivalents.

(l) Iberdrola Renewables Agreement

In October 2015, The Company signed a twenty-five year purchase power agreement with Iberdrola Renewables to purchase 100% of the output from their 30 MW Deerfield wind facility (Deerfield) being developed in southern Vermont. This contract is unit-contingent meaning that the Company only pays for the actual output of the plant that it receives, which included energy, capacity, and renewable energy certificates. Deerfield began construction in September 2016 and GMP expects the facility to be producing electricity by the end of 2017. The Company has an option to buy Deerfield at the end of 10 years at a predetermined purchase price of $50 million.

(m) Renewable Energy Standard

GMP is subject to the State of Vermont's policy encouraging the development of renewable energy sources in the State of Vermont as well as the purchase of renewable power by the State's electricity distributors. In December 2011, the Vermont Department of Public Service published its "Comprehensive Energy Plan" setting a goal to have 90.0% of the State of Vermont's energy needs come from renewable sources by the year 2050.

Additionally, in June 2015, the Vermont General Assembly enacted a new renewable energy law establishing a mandatory renewable energy standard for Vermont utilities. This law repeals Vermont's Sustainably Priced Energy Enterprise Development Program (commonly referred to as "SPEED) from 2005 and specifically requires that retail electricity providers: (1) have a minimum amount of renewable electricity in their supply portfolios; (2) support relatively small (less than 5 MW) renewable energy projects connected to the Vermont grid; and (3) invest in projects to reduce fossil fuel use for heating and transportation. The resource requirements under the new law begin in 2017 and escalate in quantity each year until 2032. In light of the existing renewable energy sources in its long-term supply portfolio, as well as the availability of renewable energy sources in the region, GMP is well-positioned to comply with the new renewable energy law and is well poised to meet the 2017 goals with the purchase and retirement of RECs; the construction of several small GMP solar projects and capital investments in support of GMP's cold climate heat pump lease program.

(n) Hydro Dam Purchases and Power Contracts

In July 2016, GMP reached an agreement to acquire 14 small hydroelectric power generating plants located mainly in New England, with an approximate total capacity of 17 MW, and to purchase the output of two other hydroelectric power plants in accordance with 25-year power purchase agreements. This acquisition, valued at $20,300, and subject to the regulatory approval of the VPSB and FERC, should be completed in fiscal 2017. With this acquisition and the power purchase agreements, GMP will raise the renewable energy proportion of its supply portfolio. In addition, the power purchase agreements will make it possible to fix the price of a portion of this renewable supply each year.

(17) Environmental Matters

(a) General

The electric industry typically uses or generates a range of potentially hazardous products in its operations. The Company must meet various land, water, air, and aesthetic requirements as administered by local, state, and federal regulatory agencies. The Company believes that it is in substantial compliance with these requirements, and that there are no outstanding material complaints about the Company's compliance with present environmental protection regulations.

(b) Pine Street Barge Canal Superfund Site

In 1999, the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency (EPA), the State of Vermont and numerous other parties of claims relating to a federal Superfund site in Burlington, Vermont, known as the "Pine Street Barge Canal". The consent decree resolves claims by the EPA for past site costs, natural resource damage claims, and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. As of September 30, 2016 the Company has estimated total costs of the Company's future obligations under the consent decree to be approximately $2,763, net of recoveries. The estimated liability is not discounted, and it is possible that the Company's estimate of future costs could change by a material amount. As of September 30, 2016 and 2015 the Company has recorded a regulatory asset of $10,318 and $11,258, respectively, to reflect unrecovered past and future Pine Street Barge Canal costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company began to amortize and recover these costs in 2005. The Company will amortize the full amount of incurred costs over 20 years without a return. The amortization is expected to be allowed in current and future rates, without disallowance or adjustment, until fully amortized.

(c) Clean Power Plan

In August 2015, the United States Environmental Protection Agency issued a final rule for its proposed Clean Power Plan (CPP), which requires significant reductions in CO_2 emissions from existing power plants by 2030. The CPP does not require any emission reductions from Vermont power plants, and GMP's only participation in affected plants is through limited minority participation shares in the Stony Brook and Wyman plants, so GMP does not anticipate that it will incur any material direct costs as a result of the CPP or proposals to make more stringent regulations under that legislation.

(d) Catamount Indemnifications

On December 20, 2005, the former CVPS completed the sale of Catamount, its wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm. Under the terms of the agreements with Catamount and Diamond Castle Holdings, the former CVPS agreed to indemnify them, and certain of their respective affiliates, in respect of a breach of certain representations and warranties and covenants, most of which ended June 30, 2007, except certain items that customarily survive indefinitely. Environmental indemnifications are subject to a $1,500 deductible and a $15,000 cap, and such environmental representations for only two of Catamount's underlying energy projects survived beyond June 30, 2007. The Company has not recorded any liability related to these indemnifications. To management's knowledge, there is no pending or threatened litigation with the potential to cause material expense.

(18) Other Contingent Liabilities

(a) DOE Litigation – Maine Yankee, Connecticut Yankee and Yankee Atomic

All three companies have been seeking recovery of fuel storage-related costs stemming from the default of the DOE under the 1983 fuel disposal contracts that were mandated by the United States Congress under the Nuclear Waste Policy Act of 1982. Under the Act, the companies believe the DOE was required to begin removing spent nuclear fuel and greater than Class C waste from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel or greater than Class C waste has been collected by the DOE, and each company's spent fuel is stored at its own site. Maine Yankee, Connecticut Yankee and Yankee Atomic collected the funds from GMP and other wholesale utility customers, under FERC-approved wholesale rates, and GMP's share of these payments was collected from their retail customers. The DOE decided not to appeal the decision to the U.S. Supreme Court and in February 2013 the federal government reimbursed the three companies for the Phase I damages. In June 2013, FERC established the process by which the litigation proceeds are credited and approved refunds through lower wholesale rates to utility customers, effective July 2013. GMP's share of the Phase I damages totaled approximately $3,767. Phase I includes damages for Connecticut Yankee and Yankee Atomic through 2001, and for Maine Yankee through 2002.

Phase II damages were ruled upon in November of 2013, and the DOE did not appeal. GMP's share of these funds, totaling $5,700, was received in June 2014.

A complaint for Phase III damages was filed in August 2013. A trial was held from June 30 through July 2, 2015. A favorable decision awarding 98.6% of damages requested was issued in March 2016. The Government did not appeal, and Maine Yankee, Connecticut Yankee and Yankee Atomic are working toward obtaining a FERC Order approving rate schedule changes to permit any credits to sponsors to be issued in fiscal year 2017. The Company expects to receive $1,568 which will be returned to customers a part of a future rate filing.

Due to the complexity of these issues and the potential for further appeals, the three companies cannot predict the timing of the final determinations or the amount of damages that will actually be received. Each of the companies' respective FERC settlements requires that damage payments, net of taxes and further spent fuel trust funding, if any, be credited to wholesale ratepayers including GMP. The Company expects that its share of these awards, if any, would be credited to retail customers.

(b) Nuclear Insurance

The Price-Anderson Act provides a framework for immediate, no-fault insurance coverage for the public in the event of a nuclear power plant accident that is deemed an extraordinary nuclear occurrence by the NRC. The primary level provides liability insurance coverage of $375,000, or the maximum private insurance available. If this amount is not sufficient to cover claims arising from an accident, the second level applies offering additional coverage up to $12.986 billion per incident. For the second level, each operating nuclear plant must pay a retrospective premium equal to its proportionate share of the excess loss, up to a maximum of $127,300 per reactor per incident, limited to a maximum annual payout of $19,000 per reactor. These assessments will be adjusted for inflation and the U.S. Congress can modify or increase the insurance liability coverage limits at any time through legislation. Currently, based on the GMP's joint-ownership interest in Millstone Unit #3, the Company could become liable for expenses of approximately $322 of such maximum assessment per incident per year. Maine Yankee, Connecticut Yankee and Yankee Atomic maintain $100,000 in Nuclear Liability Insurance, but have received exemptions from participating in the secondary financial protection program.

(c) Other Legal Matters

The Company does not expect any litigation to result in a material adverse effect on its operating results or financial condition.

(19) Entergy MOU Payment

On August 15, 2001, Entergy and VYNPC entered into a Purchase and Sale Agreement in which VYNPC agreed to sell the Plant to Entergy. On September 4, 2001, the Board opened Docket No. 6545 to investigate the sale and on January 7, 2002, the DPS filed testimony with the Board in which the DPS cited a concern regarding the future of Entergy power sales if the Plant was renewed to operate beyond March 21, 2012.

On March 4, 2002, a Memorandum of Understanding (MOU) was executed by Entergy, VYNPC, the Company, CVPS and the DPS which addressed all of the DPS's concerns with the proposed sale. Paragraph 4 (Sharing Excess Revenue After License Extension) of the MOU provides that if Entergy extends the operation of the Plant pursuant to a license extension, Entergy agrees to pay (MOU Payment) to VYNPC 50% of the power sales revenue above a strike price of $61/MWh (as inflated) for 10 years.

On April 24, 2014, VYNPC received notice from Entergy that VYNPC was due an MOU Payment of approximately $17,900. VYNPC received the payment on August 15, 2014 and VYNPC recorded the payment as an Other Current Liability.

VYNPC returned the MOU Payment to its Sponsors in late 2014 and early 2015 in accordance with agreements VYNPC reached with its Sponsors. GMP received $14,760 of the MOU Payment. During fiscal year 2015, GMP returned $5,960 of the Entergy MOU funds to customers. In fiscal year 2016, GMP net $7,900 of the remaining MOU Payment against two exogenous (major storm) adjustments to offset expense to be collected from customers in fiscal year 2016, and returned $900 of the proceeds to our Commercial and Industrial Transmission Service Rate Customer. Any balance remaining will be trued-up and returned to customers in future rate filings.

(20) Related-Party and Associated Company Transactions

Effective April 12, 2007, GMP became related to Vermont Gas Systems (VGS) when the Company was acquired by NNEEC. The rates at which the Company buys gas for facility heating from VGS and the rates at which VGS buys electricity from the Company are regulated and required to be transacted at rates approved by the VPSB, and applicable to similar customers of similar usage, and amounts are insignificant and immaterial with respect to these regulated revenues. VGS is also a responsible party in the Pine Street Barge Canal Superfund Site and remits funds related to this matter annually to the Company. Payments totaling $55 and $78 were received for the Pine Street Barge Canal Superfund Site during the years ended September 30, 2016 and 2015, respectively, and there were no other transactions between VGS and the Company during the years ended September 30, 2016 and 2015.

The following table summarizes account receivable and payable balances from and to affiliated companies.

		Accounts receivable	Accounts payable	Net receivable (payable)
At September 30, 2016:				
NNEEC	$	—	13	(13)
Connecticut Yankee Atomic Power Company		—	—	—
Maine Yankee Atomic Power Company		—	—	—
VELCO		1,499	—	1,499
Total	$	1,499	13	1,486

		Accounts receivable	Accounts payable	Net receivable (payable)
At September 30, 2015:				
NNEEC	$	82	—	82
Connecticut Yankee Atomic Power Company		—	3	(3)
Maine Yankee Atomic Power Company		—	—	—
VELCO		71	5,105	(5,034)
Total	$	153	5,108	(4,955)

(21) Concentration Risks

(a) HQ and NextEra Power Supply Contracts

The Company's material power supply contracts are principally with HQ and NextEra. HQ contracts are expected to meet from 21% to 24% of the Company's anticipated annual demand requirements through 2035. Beginning in 2015, the NextEra contract, representing unit contingent purchases from the Seabrook Nuclear Power Plant, is at 60 MW and will decrease to 50 MW, and will meet between 7% and 12% of the Company's annual demand requirements over the life of the contract that ends in 2034. Under the Company's Alternative Regulation Plan, there is a power supply adjustment mechanism to minimize the risk of rising power supply costs.

(b) Collective Bargaining

At September 30, 2016 and 2015, GMP had 540 and 569 employees, respectively. Of these employees, at September 30, 2016 and 2015, 279 and 291, respectively, were represented by Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers. On January 14, 2013, the Company agreed to a new five-year contract with its employees represented by the union, which is effective on

January 1, 2013 and expires on December 31, 2017.

(22) Supplemental Cash Flow Information

Supplemental cash flow information for the years ended September 30, 2016 and 2015 are as follows:

		2016	2015
Cash paid for:			
Interest	$	34,246	33,957
Income taxes paid (refunded), net		(42)	32
Supplemental disclosures of noncash information:			
Increase in unfunded pension and other postretirement benefit obligations		28,817	20,061
Plant addition for allowance for equity funds used during construction		1,004	1,199
Noncash utility plant in accounts payable		10,967	2,877
Other deferred charges reclassified to construction work in progress		1,495	—

(23) Noncontrolling Equity of GMP VT Solar LLC (GMP Solar)

The Company formed GMP Solar on November 17, 2015 to construct, operate and maintain, through wholly owned limited liability companies (each, a "Project Company," together, the "Project Companies), 5 solar generating facilities located throughout Vermont. The Company expects the total cost to develop, engineer, procure and construct the solar generating facilities to be $60,100. On May 4, 2016, the Company executed an Equity Capital Contribution Agreement with a tax equity partner (the "Tax Equity Partner) to invest $60,100 in GMP Solar to fund the cost to construct the 5 facilities. The Company will invest approximately $39,600 and the Tax Equity Partner will invest approximately $20,500. The Tax Equity Partner will make its investment in installments as certain construction milestones are met. The Company will be required to fund construction costs in excess of $60,100.

The Project Companies have entered into fixed price contracts with a contractor who specializes in the engineering, procurement and construction of solar photovoltaic projects. Payments are made to the contractor as certain construction milestones are reached. As of September 30, 2016, the Project Companies have paid the contractor $32,556. The interconnection of the solar generating facilities to the utility grid is not covered by the contract. All 5 projects are under construction and will be placed in service by December 31, 2016. These projects did not generate material revenue in fiscal year 2016.

The terms and conditions of the various agreements executed in connection with this investment are customary terms and conditions for a tax equity investment. Although GMP contributes 66% of the combined capital in exchange for its share of GMP Solar, GMP will be entitled to 1% of GMP Solar's profits, losses, deductions, and credits for the first five years, and 95% of each such item for the remaining term of GMP Solar. The Tax Equity Partner will contribute the remaining 34% of required capital in exchange for its interest in 99% of GMP Solar's profits, losses, deductions, and credits for the first five years, and 5% of each such item thereafter. This change in sharing ratios is referred to as a "partnership flip" structure, because the allocations of all partnership items "flip" from 1% to 95% (with the Tax Equity Partner's allocable share flipping from 99% down to 5%).

The Company has the option to purchase at fair market value the Tax Equity Partner's ownership interest in GMP Solar. The option can be exercised during a 6-month period beginning 5 years after the last day any energy property was placed in service.

GMP Solar is taxed as a partnership, and therefore income taxes are the responsibility of GMP Solar's members.

The Company is the managing member of GMP Solar pursuant to GMP Solar's operating agreement. As managing member GMP will conduct, direct and exercise control over all activities of GMP Solar, and shall have full power and authority on behalf of GMP Solar to manage and administer the business and affairs of GMP Solar.

In consideration for the services provided by the Company to GMP Solar and the Project Companies in connection with the development, construction and installation of the solar energy facilities, the Project Companies will pay the Company a $5,600 development fee. The development fee will be paid as certain construction milestones are achieved. As of September 30, 2016, development fees of $1,800 were paid to the Company.

As of September 30, 2016, the Company and the Tax Equity Partner have invested $36,900 and $1,500 respectively, in GMP Solar.

Certain Project Companies have executed leases with various 3rd parties to lease the land upon which three solar generation facilities will be built. The remaining two leases were executed by and among the relevant Project Company, as tenant, and the Company, as the owner of the land.

The Company has executed purchase power agreements with the Project Companies. The term of each of the agreements is 25 years, and the Company will pay a fixed price per kWh and receive all power output produced by the facilities.

Certain risks exist with respect to the Company's investment in and management of GMP Solar, including exposure to operating cost risk, revenue risk created by variations in kWh produced by the projects and investment tax credit (ITC) risk associated with the projects not meeting the ITC eligibility requirements.

The Company follows Financial Accounting Standards Board ASC Subtopic 810-10, *Consolidation – Overall*, which requires certain noncontrolling interests to be classified in the consolidated statements of income as part of consolidated net earnings and to include the accumulated amount of noncontrolling interests in the consolidated balance sheets as part of capitalization.

The Company determined GMP Solar to be a VIE under ASC 810. The Company concluded it is the primary beneficiary of GMP Solar, therefore, the Company consolidates GMP Solar. The carrying amounts and classification of GMP Solar's assets and liabilities included in the consolidated balance sheets as of September 30, 2016 are as follows:

Assets:		
Construction work in progress	$	38,066
Cash and cash equivalents		293
Prepaid expenses and other current assets		164
Total assets	$	38,523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	79,010		79,010		
2	(80,919)		(80,919)		
3	1,909		1,909		
4	(79,010)		(79,010)	63,087,088	63,008,078
5					
6					
7					
8					
9				69,490,869	69,490,869
10					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,684,816,530	1,684,816,530
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	-10,573	-10,573
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,684,805,957	1,684,805,957
9	Leased to Others		
10	Held for Future Use	42,820	42,820
11	Construction Work in Progress	58,131,246	58,131,246
12	Acquisition Adjustments	22,951,227	22,951,227
13	Total Utility Plant (8 thru 12)	1,765,931,250	1,765,931,250
14	Accum Prov for Depr, Amort, & Depl	614,772,734	614,772,734
15	Net Utility Plant (13 less 14)	1,151,158,516	1,151,158,516
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	573,670,398	573,670,398
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	29,974,469	29,974,469
22	Total In Service (18 thru 21)	603,644,867	603,644,867
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	11,127,867	11,127,867
33	Total Accum Prov (equals 14) (22,26,30,31,32)	614,772,734	614,772,734

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
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					28
					29
					30
					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	242,274	1,373,826
9	In Reactor (120.3)	3,997,916	
10	SUBTOTAL (Total 8 & 9)	4,240,190	
11	Spent Nuclear Fuel (120.4)	15,074,702	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	17,729,029	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	1,585,863	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
		1,616,100	8
		3,997,916	9
		5,614,016	10
		15,074,702	11
			12
-1,008,021		18,737,050	13
		1,951,668	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	12,146	
3	(302) Franchises and Consents	11,145,408	198,356
4	(303) Miscellaneous Intangible Plant	52,291,062	8,497,549
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	63,448,616	8,695,905
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	101,483	
9	(311) Structures and Improvements	6,902,488	221,969
10	(312) Boiler Plant Equipment	20,114,116	623,945
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	5,258,144	140,901
13	(315) Accessory Electric Equipment	1,337,866	24,585
14	(316) Misc. Power Plant Equipment	632,714	15,909
15	(317) Asset Retirement Costs for Steam Production	6,624	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	34,353,435	1,027,309
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	11,720	
19	(321) Structures and Improvements	22,324,678	241,601
20	(322) Reactor Plant Equipment	35,832,315	387,783
21	(323) Turbogenerator Units	10,399,206	112,542
22	(324) Accessory Electric Equipment	9,140,806	98,924
23	(325) Misc. Power Plant Equipment	3,679,711	39,823
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	81,388,436	880,673
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	3,936,485	15,590
28	(331) Structures and Improvements	13,547,306	1,871,114
29	(332) Reservoirs, Dams, and Waterways	72,502,093	5,788,140
30	(333) Water Wheels, Turbines, and Generators	53,135,394	1,072,413
31	(334) Accessory Electric Equipment	26,981,859	3,062,062
32	(335) Misc. Power PLant Equipment	1,903,434	52,087
33	(336) Roads, Railroads, and Bridges	2,692,900	12,047
34	(337) Asset Retirement Costs for Hydraulic Production	34,327	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	174,733,798	11,873,453
36	D. Other Production Plant		
37	(340) Land and Land Rights	130,475	568,330
38	(341) Structures and Improvements	3,356,287	225,162
39	(342) Fuel Holders, Products, and Accessories	3,957,868	114,142
40	(343) Prime Movers	16,015,824	13,856
41	(344) Generators	31,009,284	1,390,639
42	(345) Accessory Electric Equipment	2,208,561	17,684
43	(346) Misc. Power Plant Equipment	132,407,043	897,027
44	(347) Asset Retirement Costs for Other Production	3,415,752	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	192,501,094	3,226,840
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	482,976,763	17,008,275

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	5,177,334	
49	(352) Structures and Improvements	8,806,832	383,348
50	(353) Station Equipment	119,597,802	3,555,605
51	(354) Towers and Fixtures	351,058	
52	(355) Poles and Fixtures	40,351,447	2,731,805
53	(356) Overhead Conductors and Devices	39,137,217	968,638
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	1,010	
57	(359.1) Asset Retirement Costs for Transmission Plant	38,091	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	213,460,791	7,639,396
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	16,969,386	
61	(361) Structures and Improvements	23,233,983	4,351,036
62	(362) Station Equipment	91,267,352	7,273,051
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	154,500,156	15,010,514
65	(365) Overhead Conductors and Devices	174,296,249	11,968,928
66	(366) Underground Conduit	17,589,954	531,441
67	(367) Underground Conductors and Devices	33,047,156	3,156,794
68	(368) Line Transformers	120,496,919	7,485,175
69	(369) Services	44,131,562	1,109,456
70	(370) Meters	38,416,596	1,197,038
71	(371) Installations on Customer Premises	1,201,855	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	15,616,130	864,284
74	(374) Asset Retirement Costs for Distribution Plant	340,709	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	731,108,007	52,947,717
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	2,447,226	921,744
87	(390) Structures and Improvements	42,669,800	2,240,906
88	(391) Office Furniture and Equipment	19,024,066	5,098,525
89	(392) Transportation Equipment	23,571,762	7,419,851
90	(393) Stores Equipment	647,940	69,520
91	(394) Tools, Shop and Garage Equipment	4,785,161	916,624
92	(395) Laboratory Equipment	2,855,304	418,694
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	12,333,662	675,809
95	(398) Miscellaneous Equipment	2,161,784	212,088
96	SUBTOTAL (Enter Total of lines 86 thru 95)	110,496,705	17,973,761
97	(399) Other Tangible Property	21,468	
98	(399.1) Asset Retirement Costs for General Plant	72,634	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	110,590,807	17,973,761
100	TOTAL (Accounts 101 and 106)	1,601,584,984	104,265,054
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	1,601,584,984	104,265,054

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			12,146		2
			11,343,764		3
2,593,609			58,195,002		4
2,593,609			69,550,912		5
					6
					7
			101,483		8
			7,124,457		9
			20,738,061		10
					11
			5,399,045		12
			1,362,451		13
			648,623		14
			6,624		15
			35,380,744		16
					17
			11,720		18
			22,566,279		19
			36,220,098		20
			10,511,748		21
			9,239,730		22
			3,719,534		23
					24
			82,269,109		25
					26
			3,952,075		27
149,881			15,268,539		28
270,614			78,019,619		29
652,921			53,554,886		30
306,557			29,737,364		31
22,366			1,933,155		32
			2,704,947		33
			34,327		34
1,402,339			185,204,912		35
					36
			698,805		37
		1,086,010	4,667,459		38
101		-3,519	4,068,390		39
14,302			16,015,378		40
		94,721,100	127,121,023		41
		4,502,911	6,729,156		42
22		-100,306,502	32,997,546		43
			3,415,752		44
14,425			195,713,509		45
1,416,764			498,568,274		46

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			5,177,334		48
10,000			9,180,180		49
6,590,551		393	116,563,249		50
			351,058		51
42,293		229,678	43,270,637		52
39,322		-243,838	39,822,695		53
					54
					55
			1,010		56
			38,091		57
6,682,166		-13,767	214,404,254		58
					59
			16,969,386		60
661,551			26,923,468		61
831,420		66,951	97,775,934		62
					63
1,064,850		3,113	168,448,933		64
1,869,266		1,890	184,397,801		65
5,532		9,157	18,125,020		66
368,922			35,835,028		67
1,396,734		-67,344	126,518,016		68
165,137			45,075,881		69
1,885			39,611,749		70
18,432			1,183,423		71
					72
260,022			16,220,392		73
			340,709		74
6,643,751		13,767	777,425,740		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
255			3,368,715		86
255,074		-2,818,659	41,836,973		87
869,988		2,499,037	25,751,640		88
1,824,267			29,167,346		89
108,396			609,064		90
125,214			5,576,571		91
21,780			3,252,218		92
					93
459,997		165,519	12,714,993		94
		154,103	2,527,975		95
3,664,971			124,805,495		96
			21,468		97
			72,634		98
3,664,971			124,899,597		99
21,001,261			1,684,848,777		100
					101
					102
					103
21,001,261			1,684,848,777		104

Schedule Page: 204 Line No.: 58 Column: b

Amounts for Electric Plant in Service include the following:

Transmission

December 2015	213,460,791
January 2016	215,807,228
February	216,889,867
March	217,104,715
April	217,277,792
May	215,879,118
June	211,730,523
July	211,840,398
August	211,812,662
September	211,936,481
October	212,335,438
November	212,635,127
December	214,404,254

Amount for Total Transmission Plant includes Highgate $41,933,287, Y-25 $ 1,645,086 and the Woodsville Tap $30,166, which are excluded from the annual revenue requirement. The Woodsville Tap is directly charged to Woodsville, NH, the sole user of this non-integrated GMP facility.

Schedule Page: 204 Line No.: 75 Column: b

Amounts for Electric Plant in Service include the following:

Distribution

December 2015	731,108,007
January 2016	736,604,873
February	739,922,025
March	750,364,495
April	751,857,995
May	754,490,705
June	758,454,372
July	760,088,898
August	760,195,729
September	764,481,049
October	768,208,167
November	771,341,593
December 2015	777,425,740

Schedule Page: 204 Line No.: 99 Column: b

Amounts for Electric Plant in Service include the following:

General

December 2015	110,590,807
January 2016	111,527,033
February	112,011,435
March	114,096,114
April	115,019,512
May	115,027,443
June	114,908,101
July	115,029,834
August	113,384,827
September	120,792,167
October	121,073,742
November	119,956,321
December	124,899,597

Schedule Page: 204 Line No.: 104 Column: b

Amounts for Electric Plant in Service include the following:

Total Plant in Service

December 2015	1,601,584,984
January 2016	1,611,547,577

February	1,617,710,487
March	1,632,909,282
April	1,635,685,968
May	1,637,055,303
June	1,636,898,425
July	1,639,547,448
August	1,637,834,629
September	1,653,751,717
October	1,658,373,020
November	1,662,017,557
December	1,684,848,777

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
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6					
7					
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10					
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12					
13					
14					
15					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
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42				
43				
44				
45				
46				
47	Total			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Winhall Distribution Line 53	1,073,337
2	Middlesex Hydro Unit 1 and Unit 2 Modernization	1,195,915
3	Waterbury Little River Hydro FERC Upgrades	1,046,546
4	Bolton Falls Hydro Electrical Modernization	1,741,339
5	St Albans Digester	2,621,387
6	Marble Street to Danby Transmission LIne Rebuild	1,534,625
7	Huntington Falls Unit 3 and Intake Modernization	3,605,572
8	Huntington Falls Unit 2 and Unit 3 Modernization	5,574,532
9		
10	Miscellaneous Minor Projects (under $1,000,000)	39,737,993
11		
12		
13		
14		
15		
16		
17		
18		
19		
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21		
22		
23		
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42		
43	TOTAL	58,131,246

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	561,511,110	561,511,110		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	39,053,927	39,053,927		
4	(403.1) Depreciation Expense for Asset Retirement Costs	139,777	139,777		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,462,519	1,462,519		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Non Utility Depn Adjustment offset acc	-7,412	-7,412		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	40,648,811	40,648,811		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	18,407,652	18,407,652		
13	Cost of Removal	3,112,474	3,112,474		
14	Salvage (Credit)	30,603	30,603		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	21,489,523	21,489,523		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	Cost of Removal Adj offset account 253	-7,000,000	-7,000,000		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	573,670,398	573,670,398		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	30,912,756	30,912,756		
21	Nuclear Production	47,703,133	47,703,133		
22	Hydraulic Production-Conventional	63,093,605	63,093,605		
23	Hydraulic Production-Pumped Storage				
24	Other Production	55,303,873	55,303,873		
25	Transmission	61,534,358	61,534,358		
26	Distribution	284,408,811	284,408,811		
27	Regional Transmission and Market Operation				
28	General	30,713,862	30,713,862		
29	TOTAL (Enter Total of lines 20 thru 28)	573,670,398	573,670,398		

Name of Respondent Green Mountain Power Corp	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4

FOOTNOTE DATA

Schedule Page: 219   Line No.: 25   Column: b

Amounts for Accumulated Depreciation include the following:

Transmission

December 2015	$65,689,255
January 2016	65,985,768
February	66,300,624
March	66,519,413
April	66,822,355
May	67,117,348
June	61,250,436
July	61,558,684
August	61,811,015
September	62,094,039
October	61,226,651
November	61,513,175
December	61,534,358

Schedule Page: 219   Line No.: 26   Column: b

Amounts for Accumulated Depreciation include the following:

Distribution

December 2015	$ 279,706,337
January 2016	280,002,473
February	280,908,581
March	281,795,891
April	282,590,216
May	283,226,133
June	283,628,647
July	284,111,004
August	283,696,938
September	284,032,484
October	282,379,847
November	282,983,274
December	284,408,811

Schedule Page: 219   Line No.: 28   Column: b

Amounts for Accumulated Depreciation include the following:

General

December 2015	$28,299,578
January 2016	28,789,034
February	29,133,676
March	29,629,559
April	30,140,445
May	30,650,399
June	31,160,377
July	31,658,988
August	30,461,448
September	30,933,043
October	31,417,536
November	30,170,706
December	30,713,862

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	A. VERMONT ELECTRIC POWER COMPANY, INC.			
2	Common Stock - Class B, $100 par			
3	17,715 shares			8,230,978
4	Common stock class C, $100 par 3,921 shares			499,595
5	Preferred stock Class C $100 par 30,020 shares			43,710
6	AOCI			
7	Undistributed Equity in Earnings			1,818,069
8	SUBTOTAL			10,592,352
9				
10	B. NORTHERN WATER RESOURCES, INC.			
11	Common Stock - no par value			
12	and additional paid in capital			28,062,497
13	Undistributed Equity in Earnings			-10,951,919
14	Return of Capital			-16,666,243
15	SUBTOTAL			444,335
16				
17	C. NEW ENGLAND HYDRO ELECTRIC TRANSMISSION CO.			
18	Common stock			190,874
19	Undistributed Equity in Earnings			289,771
20	SUBTOTAL			480,645
21				
22	D. NEW ENGLAND HYDRO TRANSMISSION CORP			
23	Common stock and Additional paid in capital			1,333,978
24	Return of Capital			-1,188,206
25	Undistributed Equity in Earnings			34,281
26	SUBTOTAL			180,053
27				
28	E. VERMONT TRANSCO LLC	6-30-06		
29	Membership units purchased			323,787,770
30	Undistributed Earnings			103,267,950
31				
32	SUBTOTAL			427,055,720
33				
34	F. MAINE YANKEE ATOMIC POWER CORP			
35	Common Stock			14,899
36	Equity in undistributed earnings			30,210
37	SUBTOTAL			45,109
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	441,086,845

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	G. VERMONT YANKEE NUCLEAR POWER CORP			
2	Common Stock			
3	Paid in Capital			4,258,545
4	Equity in undistributed earnings			-3,324,511
5	SUBTOTAL			934,034
6				
7	H. YANKEE ATOMIC ELECTRIC COMPANY			
8	common stock and piad in capital			26,799
9	Equity in undistributed earnings			25,427
10	SUBTOTAL			52,226
11				
12	I. CONNECTICUT YANKEE ATOMIC POWER CO.			
13	Common Stock and Paid in Capital			40,694
14	Equity in undistributed Earnings			-7,162
15	SUBTOTAL			33,532
16				
17	K. CATAMOUNT RESOURCE CORP			
18	Common Stock			-144,670
19	Equity in undistributed earnings			389,044
20	SUBTOTAL			244,374
21				
22	L. GREEN LANTERN			
23	Common Stock			1,196,123
24	Equity in undistributed earnings			-171,658
25	SUBTOTAL			1,024,465
26				
27	M. GMP VT SOLAR LLC			
28	Common Stock			
29				
30	SUBTOTAL			
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	441,086,845

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		8,230,978		3
		499,595		4
		43,710		5
				6
722,378	1,082,817	1,457,630		7
722,378	1,082,817	10,231,913		8
				9
				10
				11
		28,062,497		12
-66,923		-11,018,842		13
		-16,666,243		14
-66,923		377,412		15
				16
				17
		190,874		18
82,044		371,815		19
82,044		562,689		20
				21
				22
		1,333,978		23
		-1,188,206		24
20,950		55,231		25
20,950		201,003		26
				27
				28
41,035,850		364,823,620		29
62,989,592	48,343,803	117,913,739		30
				31
104,025,442	48,343,803	482,737,359		32
				33
				34
		14,899		35
2,479	10,000	22,689		36
2,479	10,000	37,588		37
				38
				39
				40
				41
150,921,822	49,611,114	542,397,553		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		4,258,545		3
70,053	70,053	-3,324,511		4
70,053	70,053	934,034		5
				6
				7
		26,799		8
-185		25,242		9
-185		52,041		10
				11
				12
		40,694		13
1,559		-5,603		14
1,559		35,091		15
				16
				17
		-144,670		18
		389,044		19
		244,374		20
				21
				22
		1,196,123		23
61,944	104,441	-214,155		24
61,944	104,441	981,968		25
				26
				27
46,002,081		46,002,081		28
				29
46,002,081		46,002,081		30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
150,921,822	49,611,114	542,397,553		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	7,837,177	6,578,648	
2	Fuel Stock Expenses Undistributed (Account 152)	81,602	77,042	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	9,856,353	11,647,693	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,748,821	2,873,789	
8	Transmission Plant (Estimated)	38,210	48,341	
9	Distribution Plant (Estimated)	100,067	70,000	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)		2,875,310	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	12,743,451	17,515,133	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	844,400	1,176,391	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	21,506,630	25,347,214	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2018		2019		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
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Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
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19						
20	TOTAL					

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
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12					
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20					
21	**Generation Studies**				
22	SIS - LAMOILLE RIVER	1,599	235	1,903	235
23	SFS - LAMOILLE RIVER	6,551	235		
24	SIS - HIDDEN MEADOW SOLAR LLC	3,334	235		
25	SIS - ELIZABETH COPPER MINE	18,000	235		
26	SFS - ELIZABETH COPPER MINE	3,524	235		
27	SIS - TDI CLEAN ENEGY LINK	13,072	235		
28	SIS - GRAND ISLE 400 NW ANBARIC	12,168	235		
29	SFS - OTTER CREEK SOLAR I	2,498	235		
30	SIS - OTTER CREEK SOLAR I	789	235		
31	SFS - OTTER CREEK SOLAR II	856	235		
32	SIS - OTTER CREEK SOLAR II	789	235		
33	SIS - SLANG CREEK	25,712	235		
34	SFS - SLANG CREEK	4,863	235		
35	SIS - AMPERSAND GILMAN SOLAR	25,000	235		
36	SFS - AMPERSAND GILMAN SOLAR	10,000	235	10,000	235
37	SFS - TRILAND PARTNERS LP	9,119	235		
38	SIS - SWANTON ISO	2,557	235		235
39	SIS - RYEGATE & WELLS RIVER	31,074	235	26,625	235
40	SFS - SBVT LANDFILL	1,164	235	10,000	235

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	SIS - DEERFIELD ISO	828	235	828	235
23	SIS - KIDDER HILL WIND	4,266	235		
24	SFS - HOOSIC RIVER HYDRO, LLC	2,710	235	10,000	235
25	SIS - WILDER SOLAR LLC	3,232	235	25,000	235
26	SFS - WILDER SOLAR LLC			10,000	235
27	SIS - PSVTFI BRATT LANDFILL	2,465	235	25,000	235
28	SFS - BDE SHELDON	2,935	235	10,000	235
29	SFS - SKI BOWL SOLAR	425	235	10,000	235
30	SFS - SYBAC SOLAR LLC 2.2 MW MI-G3	232	235	10,000	235
31					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Future revenue due to income taxes	113,963		282	20,166	93,797
2	Current revenue due to income taxes	25,595		282	5,429	20,166
3	Asset Retirement	332,736		108/407	30,951	301,785
4	2013 NTA Study - 2 yrs	70,889		407	70,889	
5	VMPD Value Sharing	384,446		407	139,799	244,647
6	Depreciation Study - 4 yrs	58,000		407	19,038	38,962
7	Deerfield Wind	821,257		407	298,639	522,618
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44	TOTAL	1,806,886	0		584,911	1,221,975

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Earning Sharing - 2 yr	6,725,896		407	4,154,085	2,571,811
3	Gorge Repowerment - 2 yr	415,831		407	151,211	264,620
4	Meters retired due to smartgrid	6,160,575		407	2,240,209	3,920,366
5	SFAS109 regulatory assets-amort	5,910,455		282	1,012,723	4,897,732
6	2011 Millstone outage enrgy/cap	225,802	1,389,846	530/555	953,067	662,581
7	Pine Street - 20 years	7,975,792	126,841	404	750,902	7,351,731
8	Power Suppy Adjustor	8,300,727		449	391,969	7,908,758
9	Storm Deferral - 1 year		2,197,345			2,197,345
10	JV Solar Abandoned Sites - 3 yr		123,324	407	10,277	113,047
11	Reg Asset Low Income - 3 yr	375,038		404	100,010	275,028
12	Efficiency fund payments - 10 y	4,247,871		404	948,524	3,299,347
13	FERC Relicensing	142,681	68,446			211,127
14	Pine St. Future	3,111,306		253	348,276	2,763,030
15	Evergreen	654,708	29,626			684,334
16	CEED Fund - 10 yr	15,121,480	2,299,612	404	1,545,594	15,875,498
17	Derivative Regulatory Asset		933,127			933,127
18	JT Owned Def.	1,346,319		Various	881,309	465,010
19	VTEL Prepayment - 10 yr	1,550,000	1,109,405	921	199,457	2,459,948
20	Goodwill - Not in Rate Base	1,250,000				1,250,000
21	Pension Funding Offset	60,536,489	83,093,149	253	60,536,489	83,093,149
22						
23	Other Minor Items	2,710,591			2,618,178	92,413
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46						
47	Misc. Work in Progress	798,208				1,095,244
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	127,559,769				142,385,246

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	CAFC	-28,598	1,610,891
3	Power Supply Derivative ASC815	4,958,550	577,963
4	Reg Liability - Cost of Removal		9,825,072
5	Deferred Comp./Post Ret Health ASC 715	23,339,005	33,079,664
6	Unfunded Def Income Taxes	73,184,224	66,108,067
7	Other	27,259,832	19,933,936
8	TOTAL Electric (Enter Total of lines 2 thru 7)	128,713,013	131,135,593
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	128,713,013	131,135,593

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	ACCOUNT 201			
2	* COMMON STOCK	100	3.33	
3	TOTAL_COM	100		
4				
5	See Page 102 for a discussion of control			
6	over the respondent and common stock ownership			
7	review of merger documents indicated effectiver			
8	with merger only 100 shares issued and o/s			
9	activity and balance reflect transfer to paid			
10	in capital			
11				
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22	NOTE:All treasury stock was retired subsequent			
23	to the acquistion of GMP by NNEEC.			
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
100	333					2
100	333					3
						4
100	333					5
						6
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211:	114,781,543
2		
3	Amount established under approval plan of recapitalization	
4	effective July 1951, in compliance with order of the Federal Power Com	
5	dated April 19, 1950.	
6	Additional investment by Parent in 2010	20,000,000
7	Additional investment by Parent in 2011	10,000,000
8	Additional investment by Parent in 2012	75,000,000
9	Acquired in merger with CVPS October 1, 2012	280,071,438
10	Additional investment by Parent in 2013	3,578,316
11	Additional investment by Parent in 2014	665,940
12	Additional investment by Parent in 2015	6,000,000
13	Additional investment by Parent in 2016	49,296,104
14		
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40	TOTAL	559,393,341

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	common stock	
2		
3		
4		
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21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 BONDS		
2	First Mortgage:		
3	9.64 % Bonds	9,000,000	186,729
4	8.65 % Bonds	13,000,000	214,354
5	6.70 % Bonds	15,000,000	248,000
6	6.04 % Bonds	42,000,000	462,542
7	6.53% Bonds (8/06)	30,000,000	242,645
8	6.17% Bonds	16,000,000	226,933
9	5.98% Bonds	15,000,000	191,432
10	3.00% - 5.00% Bonds	24,765,000	989,241
11	6.00% Bonds	5,000,000	
12	4.56% Bonds	50,000,000	445,942
13	4.61%Bonds	25,000,000	210,295
14	3.99% Bonds	85,000,000	487,569
15	8.91% Bonds,Series JJ	15,000,000	178,357
16	6.90% Bonds, Series OO	17,500,000	188,420
17	5.72% Bonds, Series TT-PSB Docket No. 6943 Dated May 7, 2004	55,000,000	728,848
18	6.83% Bonds, Series UU - PSB Docket No. 7421 dated April 23, 2008	60,000,000	955,339
19	5% Vermont Economic Development Authority Bonds PSB Dkt No.7620 dtd July 14 2010	30,000,000	796,059
20	5.89% Bonds Series WW - PSB Docket No. 7682 dated Jun 15, 2011	40,000,000	389,116
21	Consolidationi of bonds - merger		630,084
22	4.39% Bonds	20,000,000	209,617
23	4.89% Bonds	43,000,000	209,617
24	4.07% Bonds	12,000,000	209,617
25	3.31% Bonds	18,000,000	211,987
26	4.26% Bonds	32,000,000	211,987
27			
28			
29			
30			
31			
32			
33	TOTAL	672,265,000	8,824,730

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
090190	090120	090190	090120	9,000,000	867,600	3
031192	031122	031192	031122	10,500,000	919,062	4
110193	110118	110193	110118	15,000,000	1,005,000	5
121602	120117	121602	120117	6,000,000	694,600	6
8/1/06	8/1/36	8/1/06	8/1/36	30,000,000	1,959,000	7
12/15/07	12/1/37	12/15/07	12/1/37	16,000,000	987,200	8
4/16/2009	4/16/2019	4/16/2009	4/16/2019	15,000,000	897,000	9
4/01/2010	4/01/2035	4/01/2010	04/01/2035	25,665,046	1,214,270	10
						11
11/18/2011	11/18/2041	11/18/2011	11/18/2041	50,000,000	2,280,000	12
11/18/2011	11/18/2041	11/18/2011	11/18/2041	25,000,000	1,152,500	13
12/5/2012	12/5/2042	12/01/2012	12/01/2042	85,000,000	3,391,500	14
12/15/1991	12/15/2031	01/01/1992	12/15/2031	15,000,000	1,336,500	15
12/15/1993	12/15/2023	02/01/1994	12/15/2023	17,500,000	1,207,500	16
07/15/2004	06/15/2019	08/01/2004	06/01/2019	55,000,000	3,146,000	17
05/15/2008	05/15/2028	06/01/2008	05/01/2028	60,000,000	4,098,000	18
12/02/2010	12/15/2020	12/02/2010	12/15/2020	30,000,000	1,500,000	19
06/15/2011	06/15/2041	06/15/2011	06/15/2041	40,000,000	2,356,000	20
10/01/2012	Various	10/1/2012	10/01/2029			21
12/16/2013	12/16/2033	1/1/2014	1/1/2033	20,000,000	878,000	22
12/16/2013	12/16/2043	1/1/2014	1/1/2043	43,000,000	2,102,700	23
1/9/2014	1/9/2029	1/1/2014	1/1/2029	12,000,000	488,400	24
12/16/2015	12/15/2027	1/1/2016	1/1/2028	18,000,000	595,800	25
12/16/2015	12/15/2045	1/1/2016	1/1/2046	32,000,000	1,363,200	26
						27
						28
						29
						30
						31
						32
				629,665,046	34,439,832	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	69,490,869
2		
3		
4	Taxable Income Not Reported on Books	
5	CAFC	750,396
6	Power supply adjustor	1,006,483
7	Environmental reserve	-348,276
8	Gain/(loss) on dispositions	-12,557,225
9	Deductions Recorded on Books Not Deducted for Return	
10	Income tax accrual	36,759,197
11	Perm differences - officers life ins, meals, lobbying, etc.	-1,676,104
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Undistributed earnings in affiliate	-32,857,923
16	CEED fund	-754,017
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation and other fixed asset differences	-5,258,530
21	Retirement benefits	556,894
22	Dividend received deduction	-276,823
23	Deferred charges	20,176,314
24		
25		
26		
27	Federal Tax Net Income	75,011,255
28	Show Computation of Tax:	
29	Taxable Income $75,011,255 x 35%	26,253,939
30		
31	Reclass to net operating loss deferred tax asset	-26,160,484
32	Return to accrual adjustment etc.	697,606
33		
34	Total current federal tax expense	791,061
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Federal					
2	Income					
3	Income	-614,265		791,061		-731,229
4	Unemployment	-152		24,135	24,302	
5	Fica	296,068		3,972,923	4,052,346	
6						
7	State of VT					
8	Income	517,521		-300,210		309,791
9	Unemployment	-1,523		230,993	232,069	
10	Gross Revenue	3,935,785		6,213,854	6,207,037	
11	Hazardous Waste			10,263	10,263	
12						
13	State of MA				12,000	12,000
14	Income					
15	State of CT					
16	State of ME				475	475
17	State of NY					
18						
19						
20						
21						
22	Property Taxes					
23	Vermont		3,680,988	26,421,922	25,854,391	
24	Massachusetts		3,647	64,298	72,679	
25	Maine		6,943	42,414	20,802	
26	Connecticut		115,129	236,607	242,677	
27	New Hampshire		399,277	154,102	158,151	
28	New York		164,533	54,087	54,854	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	4,133,434	4,370,517	37,916,449	36,942,046	-408,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
-554,433		791,061				3
-320						4
216,624		2,600,054			1,627,997	5
						6
						7
527,102		-300,210				8
-2,599						9
3,942,602		6,213,854				10
		10,263				11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
	3,113,457	26,392,037			29,885	23
	12,028	64,298				24
	-14,669	42,414				25
	121,199	236,607				26
	403,326	154,102				27
	165,300	54,087				28
						29
						30
						31
						32
						33
						34
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						38
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						40
4,128,976	3,800,641	36,258,567			1,657,882	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	1,610,161			41145/42020	155,517	
6		1,355,050	190	3,706,514			
7		599,365			41146	31,620	
8	TOTAL	3,564,576		3,706,514		187,137	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
1,454,644			5
5,061,564			6
567,745			7
7,083,953			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1						
2	Minimum Pension Acct #'s	44,840,485	186	44,840,485	69,468,548	69,468,548
3	Evergreen	654,708			29,626	684,334
4	Derivative Reg Liability	12,235,781	176	11,742,719		493,062
5	VY NEIL Refunds	408,731	131	507,819	311,015	211,927
6	VMPD Rate Phase In		407	86,597	346,386	259,789
7	CIAC Reg Liability - 2 yrs	9,100,413	407	5,125,059		3,975,354
8	Customer Synergies				2,353,316	2,353,316
9	Millstone ARO	6,857,164	128/230	679,023	1,094,557	7,272,698
10	Plant Removal		407	875,000	7,000,000	6,125,000
11	Environmental reserve	3,111,306	186	348,276		2,763,030
12	Electricity Assistance Program	2,882,831	131		984,347	3,867,178
13	Production Tax Credit		407	309,048	1,236,191	927,143
14	VT Solar Development Fee		407	1,430,871	4,502,800	3,071,929
15	VT Solar Partnership		407	1,755,713		-1,755,713
16	Undistributed Payroll		Various	1,146,896		-1,146,896
17						
18						
19						
20						
21						
22						
23	Other Minor Items	1,439,546	Various	1,160,296		279,250
24						
25						
26						
27						
28						
29						
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32						
33						
34						
35						
36						
37						
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42						
43						
44						
45						
46						
47	TOTAL	81,530,965		70,007,802	87,326,786	98,849,949

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	265,267,582	22,117,990	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	265,267,582	22,117,990	
6				
7	Non-Utility	647,681		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	265,915,263	22,117,990	
10	Classification of TOTAL			
11	Federal Income Tax	228,868,746	17,854,265	
12	State Income Tax	37,046,517	4,263,725	
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		Various	1,036,416			286,349,156	2
							3
							4
			1,036,416			286,349,156	5
							6
						647,681	7
							8
			1,036,416			286,996,837	9
							10
			811,768			245,911,243	11
			224,648			41,085,594	12
							13

NOTES (Continued)

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Transco Book Tax Difference	98,940,103	12,224,911	
4	CEED Fund	6,127,980	305,565	
5	Other Deferred Charges			
6	Other	53,783,113	6,091,125	
7	Efficiency fund Reg Asset	1,721,450	-384,389	
8				
9	TOTAL Electric (Total of lines 3 thru 8)	160,572,646	18,237,212	
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Non Utility	-12,700		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	160,559,946	18,237,212	
20	Classification of TOTAL			
21	Federal Income Tax	132,753,244	14,257,052	
22	State Income Tax	27,806,702	3,980,160	
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						111,165,014	3
						6,433,545	4
							5
			1,902			59,872,336	6
						1,337,061	7
							8
			1,902			178,807,956	9
							10
							11
							12
							13
							14
							15
							16
							17
						-12,700	18
			1,902			178,795,256	19
							20
			1,503			147,008,793	21
			399			31,786,463	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Future Revenue Due to Income Taxes	558,026	190	21,651		536,375
2	Current Revenue Due to Income Taxes	65,991	190	28,100		37,891
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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36						
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39						
40						
41	TOTAL	624,017		49,751		574,266

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ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	253,782,613	256,645,931
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	219,105,956	218,039,710
5	Large (or Ind.) (See Instr. 4)	116,234,677	114,604,157
6	(444) Public Street and Highway Lighting	2,571,391	2,604,985
7	(445) Other Sales to Public Authorities	409	410
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	591,695,046	591,895,193
11	(447) Sales for Resale	12,611,391	18,743,454
12	TOTAL Sales of Electricity	604,306,437	610,638,647
13	(Less) (449.1) Provision for Rate Refunds	-3,248,671	-9,562,267
14	TOTAL Revenues Net of Prov. for Refunds	607,555,108	620,200,914
15	Other Operating Revenues		
16	(450) Forfeited Discounts	929,530	938,173
17	(451) Miscellaneous Service Revenues	1,163,837	953,017
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	27,014,140	29,219,599
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	1,579,928	1,960,360
22	(456.1) Revenues from Transmission of Electricity of Others	14,612,717	13,367,146
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(415) Business Development Revenues (Contract Work		
26	TOTAL Other Operating Revenues	45,300,152	46,438,295
27	TOTAL Electric Operating Revenues	652,855,260	666,639,209

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ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
1,493,928	1,521,795	220,851	220,553	2
				3
1,537,218	1,535,148	40,922	39,428	4
1,186,845	1,167,867	70	70	5
4,814	5,137	159	159	6
28	28	1	1	7
				8
				9
4,222,833	4,229,975	262,003	260,211	10
465,911	521,101	5	5	11
4,688,744	4,751,076	262,008	260,216	12
				13
4,688,744	4,751,076	262,008	260,216	14

Line 12, column (b) includes $ 1,815,481 of unbilled revenues.

Line 12, column (d) includes 13,240 MWH relating to unbilled revenues

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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 440-Residential Sales					
2	Rate 01 Domestic	1,303,910	226,038,659	206,325	6,320	0.1734
3	Rate 03 Off Peak Water Heating	37,905	4,750,043	15,152	2,502	0.1253
4	Rate 11Option TOU	55,701	8,463,836	4,826	11,542	0.1520
5	Rate 13 Space Heatin/Elec Load Mg	1,690	201,952	202	8,366	0.1195
6	Rate 15 Night Only Water Heating	97	10,923	47	2,064	0.1126
7	Rate 9/14/61/62 Time of Use	18,587	2,449,380	317	58,634	0.1318
8	Low Income Non-TOU	63,428	10,878,572	9,252	6,856	0.1715
9	Low Income TOU	1,318	206,896	131	10,061	0.1570
10	Rate 16/18 Area Lighting	918	293,380	1,322	694	0.3196
11	Green Power		58,959			
12	Earnings Sharing Adj		-1,618,848			
13	Power Adjuster		389,904			
14	Total	1,483,554	252,123,656	237,574	6,245	0.1699
15	Account 442 Comm & Ind					
16	Rate 2/06 General Service	436,105	72,661,168	36,931	11,809	0.1666
17	Rate 3 Off Peak Water Heating	1,156	131,039	321	3,601	0.1134
18	Rate 4 Primary Service	63,224	7,956,640	45	1,404,978	0.1258
19	Rate 5 Transmission Service	921	108,732	1	921,000	0.1181
20	Rate 10 General Service TOU	52,272	7,852,614	170	307,482	0.1502
21	Rate 12 Optional General Service	10,394	1,274,299	20	519,700	0.1226
22	Rate 13 Space Htg Elec Load Mgmt	2,025	273,503	52	38,942	0.1351
23	Rate 15 Night Only Water Htg	7	844	4	1,750	0.1206
24	Rate 15 Cable TV	2,828	454,759	684	4,135	0.1608
25	Rate 16-Ski Area/Snowmaking	3,527	548,864	2	1,763,500	0.1556
26	Special Contracts		1,177	1		
27	Rate 20A/20B Optional TOU	109	16,004	3	36,333	0.1468
28	Rate 65 Time of Use	953,885	126,544,608	3,065	311,219	0.1327
29	Rate 7/16/18 Area Lighting	6,207	1,767,617	2,482	2,501	0.2848
30	Green Power		8,855			
31	Earnings Sharing Adj		-1,402,829			
32	Power Adjuster		380,553			
33	Total	1,532,660	218,578,447	43,781	35,007	0.1426
34	Account 443 Ind					
35	Rate TRSR Transmission Service	402,934	35,879,058	1	402,934,000	0.0890
36	Rate 63 Time of Use	489,252	52,948,552	56	8,736,643	0.1082
37	Rate 4 Primary Service	183,455	17,014,966	6	30,575,833	0.0927
38	Rate 5 Transmission Service	88,040	7,894,064	6	14,673,333	0.0897
39	Rate 16-Ski Area/Snowmaking	24,811	3,144,819	1	24,811,000	0.1268
40	Rate 7/18 Area Lighting	35	9,946	5	7,000	0.2842
41	TOTAL Billed	4,209,593	589,879,564	262,003	16,067	0.1401
42	Total Unbilled Rev.(See Instr. 6)	13,240	1,815,481	0	0	0.1371
43	TOTAL	4,222,833	591,695,045	262,003	16,117	0.1401

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Earnings Sharing Adj		-515,921			
2	Power Adjustor		233,929			
3	Total	1,188,527	116,609,413	75	15,847,027	0.0981
4	Account 444 Public St & Highway					
5	Rate 7/16/18 Area Lighting	4,824	2,584,126	159	30,340	0.5357
6	Earnings Sharing Adj		-16,487			
7	Total	4,824	2,567,639	159	30,340	0.5323
8	Account 445 Other Sales to Public					
9	Contract 19	28	409	1	28,000	0.0146
10	Total	28	409	1	28,000	0.0146
11	Unbilled Revenue	13,240	1,815,481			0.1371
12						
13						
14	Duplicate Customers					
15	- Residential			-16,723		
16	- Commercial			-2,859		
17	- Industrial			-5		
18						
19						
20						
21						
22						
23						
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41	TOTAL Billed	4,209,593	589,879,564	262,003	16,067	0.1401
42	Total Unbilled Rev.(See Instr. 6)	13,240	1,815,481	0	0	0.1371
43	TOTAL	4,222,833	591,695,045	262,003	16,117	0.1401

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Washington Elec Co-Op	RQ	1	.06	.06	.06
2	New York State Electric & Gas	RQ	29			
3	Western Massachusetts Electric	RQ	8			
4	Vermont Electric Co-Op	LU	1			
5	ISO	OS	NA			
6	CVPS Phase 1 Trans	OS	7			
7	BP Energy	OS	2			
8	ISO New England	OS	79			
9	DTE Energy Trading	SF				
10	Constellation Power Source	SF				
11	Sempra Trading Corp	SF				
12	GMP Trans Component FERC 890					
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
272	7,398	10,775	8,534	26,707	1
37	1,674	4,377		6,051	2
29	1,284	4,138		5,422	3
21,466		3,372,300		3,372,300	4
444,108		9,199,821		9,199,821	5
					6
					7
					8
					9
					10
					11
		1,089		1,089	12
					13
					14
338	10,356	19,290	8,534	38,180	
465,574	0	12,573,210	0	12,573,210	
465,912	**10,356**	**12,592,500**	**8,534**	**12,611,390**	

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	83,646	78,027
5	(501) Fuel	6,253,936	7,824,039
6	(502) Steam Expenses	369,488	383,543
7	(503) Steam from Other Sources	303,506	240,592
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	162,576	158,903
10	(506) Miscellaneous Steam Power Expenses	739,935	1,034,093
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	7,913,087	9,719,197
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	30,633	68,595
16	(511) Maintenance of Structures	23,392	21,253
17	(512) Maintenance of Boiler Plant	285,579	430,866
18	(513) Maintenance of Electric Plant	187,150	235,592
19	(514) Maintenance of Miscellaneous Steam Plant	11,900	14,258
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	538,654	770,564
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	8,451,741	10,489,761
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	1,279,627	1,193,533
25	(518) Fuel	1,155,782	1,346,597
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	1,550,679	1,385,499
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	3,986,088	3,925,629
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	563,713	492,062
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	215,677	205,073
38	(531) Maintenance of Electric Plant	369,095	440,046
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	1,148,485	1,137,181
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	5,134,573	5,062,810
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	24,193	16,419
45	(536) Water for Power	4,329	4,193
46	(537) Hydraulic Expenses	1,119,550	1,362,912
47	(538) Electric Expenses	283,290	314,044
48	(539) Miscellaneous Hydraulic Power Generation Expenses	9,549	-4,339
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,440,911	1,693,229
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		-10,917
54	(542) Maintenance of Structures	53,684	60,874
55	(543) Maintenance of Reservoirs, Dams, and Waterways	534,725	515,635
56	(544) Maintenance of Electric Plant	1,258,440	1,276,347
57	(545) Maintenance of Miscellaneous Hydraulic Plant	520,659	303,822
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	2,367,508	2,145,761
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	3,808,419	3,838,990

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	137,079	110,543
63	(547) Fuel	1,503,505	2,034,052
64	(548) Generation Expenses	459,436	275,187
65	(549) Miscellaneous Other Power Generation Expenses	1,194,786	1,600,299
66	(550) Rents	481,381	527,164
67	TOTAL Operation (Enter Total of lines 62 thru 66)	3,776,187	4,547,245
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	18,600	11,733
70	(552) Maintenance of Structures	45,068	24,016
71	(553) Maintenance of Generating and Electric Plant	90,048	150,170
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,129,863	2,607,881
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,283,579	2,793,800
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	7,059,766	7,341,045
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	276,769,576	295,657,308
77	(556) System Control and Load Dispatching	1,017,462	791,257
78	(557) Other Expenses	112,372	82,312
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	277,899,410	296,530,877
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	302,353,909	323,263,483
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	64,482	41,252
84			
85	(561.1) Load Dispatch-Reliability	193,744	144,459
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	3,417,836	2,220,328
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	603,177	601,315
93	(562) Station Expenses	628,957	827,137
94	(563) Overhead Lines Expenses	314,630	208,149
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	86,344,896	90,006,769
97	(566) Miscellaneous Transmission Expenses		
98	(567) Rents	318,937	293,777
99	TOTAL Operation (Enter Total of lines 83 thru 98)	91,886,659	94,343,186
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	10,101	34,517
102	(569) Maintenance of Structures	30,028	39,802
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	721,072	804,616
108	(571) Maintenance of Overhead Lines	2,986,408	3,065,182
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	16,088	7,464
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,763,697	3,951,581
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	95,650,356	98,294,767

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	2,612,583	2,491,792
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	2,612,583	2,491,792
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	2,612,583	2,491,792
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	667,728	489,789
135	(581) Load Dispatching	112,927	82,975
136	(582) Station Expenses	242,349	331,255
137	(583) Overhead Line Expenses	458,682	664,245
138	(584) Underground Line Expenses	53,119	49,735
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	338,323	706,205
141	(587) Customer Installations Expenses	45,863	69,211
142	(588) Miscellaneous Expenses	1,591,937	1,847,634
143	(589) Rents	2,317,594	2,289,951
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,828,522	6,531,000
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	145,531	74,021
147	(591) Maintenance of Structures		81
148	(592) Maintenance of Station Equipment	1,716,424	1,714,797
149	(593) Maintenance of Overhead Lines	26,350,531	23,111,781
150	(594) Maintenance of Underground Lines	613,638	603,060
151	(595) Maintenance of Line Transformers	1,176	1,106
152	(596) Maintenance of Street Lighting and Signal Systems	61,581	69,619
153	(597) Maintenance of Meters	273,621	173,040
154	(598) Maintenance of Miscellaneous Distribution Plant	168,315	262,821
155	TOTAL Maintenance (Total of lines 146 thru 154)	29,330,817	26,010,326
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	35,159,339	32,541,326
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	62,914	-55,910
160	(902) Meter Reading Expenses	623,000	761,469
161	(903) Customer Records and Collection Expenses	4,564,911	5,388,107
162	(904) Uncollectible Accounts	2,170,114	2,961,927
163	(905) Miscellaneous Customer Accounts Expenses	101,932	89,463
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	7,522,871	9,145,056

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	2,264,910	2,305,265
169	(909) Informational and Instructional Expenses	27,558	53,604
170	(910) Miscellaneous Customer Service and Informational Expenses	159,771	212,871
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	2,452,239	2,571,740
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	122,216	27,898
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	122,216	27,898
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	11,790,090	12,779,751
182	(921) Office Supplies and Expenses	4,177,466	4,557,546
183	(Less) (922) Administrative Expenses Transferred-Credit	8,221,458	7,414,645
184	(923) Outside Services Employed	4,518,277	3,695,035
185	(924) Property Insurance	1,776,228	1,785,646
186	(925) Injuries and Damages	3,510,433	4,358,993
187	(926) Employee Pensions and Benefits	12,756,377	15,755,096
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	235,263	285,663
190	(929) (Less) Duplicate Charges-Cr.	267,181	93,308
191	(930.1) General Advertising Expenses	82,515	140,598
192	(930.2) Miscellaneous General Expenses	982,404	630,322
193	(931) Rents	254,425	27,358
194	TOTAL Operation (Enter Total of lines 181 thru 193)	31,594,839	36,508,055
195	Maintenance		
196	(935) Maintenance of General Plant	7,518,168	7,337,117
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	39,113,007	43,845,172
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	484,986,520	512,181,234

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Stonybrook MMWEC	LU	07B-0136-000			
2	Energy Power Investment (Moretown)	LU				
3	ISO New England	OS	124			
4	NYPA (State of VT)	OS	07B-0335-009-1			
5	Boltonville Hydro	LU	na			
6	Vermont Electric Power Producer Inc.I	LU	na			
7	Entergy (Vermont Yankee)	LU	45			
8	Solar Purchased from Customers	OS				
9	Vermont ELectric Power Prod Speed	LU	na			
10	Nextera	SF				
11	Nextra Nuclear	LU				
12	HQ Energy Services	SF				
13	BP Energy	SF				
14	Cargill (J.P.Morgan)	SF				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	National Grid	OS				
2	Vermont Electric Power Co.	OS				
3	Granite Reliable	SF				
4	Millstone Amortization #3	OS				
5	Decomission Conn Maine & Yankee Atomic	LU	FPC1			
6	ENEL North America Lower Valley Hydro	LU	FPC1			
7	ENEL North America Sweetwater Hydro	LU	FPC1			
8	ENEL North America Woodsville Hydro	LU	FPC1			
9	NorthHartland Hydro	LU	NUG			
10	Ampersand Hydro	LU	NUG			
11	Dominion Energy Marketing	LU				
12	Florida Power & Light Wyman	OS				
13	Fitchburg	OS				
14	Unitil	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Constellation	SF				
2	VELCO Schedule C4	LU				
3	Vermont Electric Power Prod Ryegate	LU				
4	Amortization FAS 5 RS2	OS				
5	Brockway Mills	SF				
6	Citigroup	IF				
7	OATI	OS				
8	Gas Watts	LU				
9	Emerson Falls	SF				
10	Nextsun Energy	LU				
11	Newport	SF				
12	Green Maple	LU				
13	Shell	IF				
14	Energy New England	LF				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Dewey Mills	SF				
2	Winooski 8	SF				
3	Worcester	SF				
4	Barnet	SF				
5	Bondville Solar	SF				
6	GMP VT Solar					
7	TESLA Battery Control	OS				
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,281			1,022,129	262,324		1,284,453	1
15,632			180,000	1,378,782		1,558,782	2
575,553				24,235,211	17,960,032	42,195,243	3
5,494			34,056	27,120		61,176	4
3,683				182,385		182,385	5
76,862				9,473,666	-22,258	9,451,408	6
					-399,320	-399,320	7
71,970				15,699,137		15,699,137	8
78,920				17,199,202		17,199,202	9
285,975				13,629,569	3,195,839	16,825,408	10
512,547				24,939,423		24,939,423	11
919,312				51,013,678		51,013,678	12
203,000				13,020,290		13,020,290	13
263,780				17,485,754		17,485,754	14
4,154,536			6,167,243	251,276,080	19,326,255	276,769,578	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					4,296	4,296	1
					-711,355	-711,355	2
176,866			509,915	13,122,903		13,632,818	3
					-80,836	-80,836	4
					-1,562,231	-1,562,231	5
306				123,163		123,163	6
1,029				94,743		94,743	7
					5,000	5,000	8
10,576				332,208	158,135	490,343	9
24,131				2,306,354		2,306,354	10
					-9,796	-9,796	11
					-712,141	-712,141	12
					171,278	171,278	13
					292,560	292,560	14
4,154,536			6,167,243	251,276,080	19,326,255	276,769,578	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
181,680				6,049,944		6,049,944	1
121,652			4,421,143	4,181,157		8,602,300	2
126,707				12,710,175		12,710,175	3
					351	351	4
285				6,729		6,729	5
77,315				4,020,380		4,020,380	6
					23,768	23,768	7
122				3,251		3,251	8
135				3,614		3,614	9
5,395				956,038		956,038	10
13,193				721,681		721,681	11
2,639				439,141		439,141	12
387,115				17,043,179		17,043,179	13
					1,011,218	1,011,218	14
4,154,536			6,167,243	251,276,080	19,326,255	276,769,578	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,512				158,036		158,036	1
1,350				28,094		28,094	2
61				2,612		2,612	3
89				3,999		3,999	4
2,405				303,401		303,401	5
964				118,737		118,737	6
					1,715	1,715	7
							8
							9
							10
							11
							12
							13
							14
4,154,536			6,167,243	251,276,080	19,326,255	276,769,578	

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	WASHINGTON ELECTRIC CO-OP	VELCO	WASHINGTON ELECTRIC CO-OP	FNO
2	VERMONT ELECTRIC COOPERATIVE	VELCO	VERMONT ELECTRIC COOPERATIVE	FNO
3	VILLAGE OF HARDWICK	VELCO	VILLAGE OF HARDWICK	FNO
4	VILLAGE OF NORTHFIELD	VELCO	VILLAGE OF NORTHFIELD	FNO
5	VILLAGE OF LUDLOW	VARIOUS	VILLAGE OF LUDLOW	FNO
6	VILLAGE OF JACKSONVILLE	VELCO	VILLAGE OF JACKSONVILLE	FNO
7	BURLINGTON ELECTRIC DEPT.	GMP	BURLINGTON ELECTRIC DEPT	FNO
8	NH ELECTRIC CO-OP	GMP	NH ELECTRIC CO-OP	FNO
9	VILLAGE OF HYDE PARK	VARIOUS	VILLAGE OF HYDE PARK	FNO
10	WOODSVILLE FIRE DISTRICT WATER &	VARIOUS	WOODSVILLE FIRE DISTRICT	FNO
11	PUBLIC SERVICE OF NEW HAMPSHIRE	VARIOUS	PUBLIC SERVICE CO OF NH	FNO
12	MAG ENERGY	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
13	CARGILL	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
14	NALCOR	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
15	NALCOR	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
16	HYDRO QUEBEC	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
17	HYDRO QUEBEC	HYDRO QUEBEC	ISO-NEW ENGLAND	NF
18	BROOKFIELD ENERGY	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
19	ROYAL BANK OF CANADA	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
20	ROYAL BANK OF CANADA	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
21	ONTARIO POWER GENERATION	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
22	ONTARIO POWER GENERATION	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
23	ONTARIO POWER GENERATION	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
24	HYDRO QUEBEC MARKETING	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
25	BURLINGTON ELECTRIC	GMP	BURLINGTON ELECTRIC	LFP
26	BROOKFIELD MARKETING	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
27	CANADIAN WOOD PRODUCTS	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
28	VELCO HIGHGATE TRANSMISSION			
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
3	GMP	VARIOUS		62,786	60,899	1
3	GMP	VARIOUS		111,062	107,327	2
3	GMP	VARIOUS		33,729	32,717	3
3	GMP	VILLAGE OF NORTHFIED		30,042	29,140	4
3	GMP	VARIOUS		48,674	47,214	5
3	GMP	VILLAGE OF JACKSONVI		5,750	5,453	6
3	GMP	VARIOUS		5,237	4,964	7
3	GMP	VARIOUS		18,418	17,269	8
3	GMP	HYDE PARK		11,742	11,090	9
3	GMP	WOODSVILLE		24,833	24,088	10
3	GMP	VARIOUS		168,781	163,845	11
3	NEW ENGLAND BORDER	SANDY POND, MA		1,496	1,496	12
3	NEW ENGLAND BORDER	SANDY POND, MA		61,488	61,488	13
3	NEW ENGLAND BORDER	SANDY POND, MA		61,656	61,656	14
3	NEW ENGLAND BORDER	SANDY POND, MA		122	122	15
3	NEW ENGLAND BORDER	SANDY POND, MA		61,488	61,488	16
3	NEW ENGLAND BORDER	SANDY POND, MA		175,707	175,707	17
3	NEW ENGLAND BORDER	SANDY POND, MA		966	966	18
3	NEW ENGLAND BORDER	SANDY POND, MA		52,704	52,704	19
3	NEW ENGLAND BORDER	SANDY POND, MA		10,148	10,148	20
3	NEW ENGLAND BORDER	SANDY POND, MA		52,704	52,704	21
3	NEW ENGLAND BORDER	SANDY POND, MA		7,458	7,458	22
3	NEW ENGLAND BORDER	SANDY POND, MA		52,704	52,704	23
3	NEW ENGLAND BORDER	SANDY POND, MA		61,488	61,488	24
3	GEORGIA	BURLINGTON		25,013	25,013	25
3	NEW ENGLAND BORDER	SANDY POND, MA		662,194	662,194	26
3	NEW ENGLAND BORDER	SANDY POND, MA		20	20	27
	GEORGIA, VT	BURLINGTON, VT				28
						29
						30
						31
						32
						33
						34
			0	**1,808,410**	**1,791,362**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
368,398		-84,755	283,643	1
612,532		45,717	658,249	2
181,095		-36,473	144,622	3
145,145		-18,032	127,113	4
252,416		-4,715	247,701	5
27,721		-7,933	19,788	6
25,264		-2,397	22,867	7
106,545		17,990	124,535	8
66,245		167	66,412	9
111,659		13,252	124,911	10
835,358		135,291	970,649	11
5,623		-2,310	3,313	12
215,943		-197,948	17,995	13
215,943		-125,967	89,976	14
438		-406	32	15
215,943		-71,981	143,962	16
783,912		-75,136	708,776	17
6,395		-1,037	5,358	18
185,094		-23,216	161,878	19
36,084			36,084	20
185,094			185,094	21
25,841		-25,535	306	22
185,094			185,094	23
534,946			534,946	24
282,100			282,100	25
4,059,250			4,059,250	26
148			148	27
5,201,404			5,201,404	28
				29
				30
				31
				32
				33
				34
14,871,630	**0**	**-465,424**	**14,406,206**	

Schedule Page: 328 Line No.: 1 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 1 Column: m

Washington Electric	
Regulatory Commission expense	$12,525
Delivery point charge	6,548
Load dispatch	34,024
Phase in	(69,300)
2015 True Up	(53,119)
Specific Facility Credit	(15,432)
TOTAL	$(84,754)

Schedule Page: 328 Line No.: 2 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 2 Column: m

Vermont Electric Cooperative	
Distribution	$38,793
Regulatory Commission expense	21,779
Delivery point charge	14,432
Load dispatch	57,090
Phase in	10,543
2015 True Up	(53,324)
Specific Facility Credit	(43,596)
TOTAL	$45,717

Schedule Page: 328 Line No.: 3 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 3 Column: m

Village of Hardwick	
Regulatory Commission expense	$6,589
Delivery point charge	1,768
Load dispatch	16,315
Phase in	(28,116)
2015 True Up	(24,989)
Specific Facility Credit	(8,040)
TOTAL	$(36,473)

Schedule Page: 328 Line No.: 4 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 4 Column: m

Village of Northfield	
Regulatory Commission expense	$5,793
Delivery point charge	884
Load dispatch	13,036
2015 True Up	(14,069)
Phase in	(23,676)
TOTAL	$(18,032)

Schedule Page: 328 Line No.: 5 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 5 Column: m

Ludlow	
Regulatory Commission expense	$9,836
Delivery point charge	2,652
Load dispatch	22,069
2015 True Up	(31,120)

Phase in	(8,151)
TOTAL	$(4,714)

Schedule Page: 328 Line No.: 6 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 6 Column: m

Village of Jacksonville

Regulatory Commission expense	$1,124
Delivery point charge	884
Load dispatch	2,564
2015 True Up	(4,801)
Phase in	(7,704)
TOTAL	$(7,933)

Schedule Page: 328 Line No.: 7 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 7 Column: m

Burlington Electric

Regulatory Commission expense	$1,029
Delivery point charge	1,768
Load dispatch	2,361
2015 True Up	(3,386)
Phase in	(2,873)
Specific Facility Credit	(1,296)
TOTAL	$(2,397)

Schedule Page: 328 Line No.: 8 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 8 Column: m

New Hampshire Electric Cooperative

Regulatory Commission expense	$3,600
Load dispatch	9,427
Distribution	6,955
2015 True Up	(9,909)
Phase in	7,917
TOTAL	$17,990

Schedule Page: 328 Line No.: 9 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 9 Column: m

Hyde Park

Regulatory Commission expense	$2,301
Delivery point charge	884
Load dispatch	6,126
Phase in	377
2015 True Up	(6,713)
Specific Facility Credit	(2,808)
TOTAL	$167

Schedule Page: 328 Line No.: 10 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 10 Column: m

Woodsville

Regulatory Commission expense	$4,739
Delivery point charge	884
Load dispatch	10,330
Phase in	6,512
2015 True Up	(12,865)

Distribution	3,652
TOTAL	$13,252

Schedule Page: 328 Line No.: 11 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 11 Column: m

Public Service Company of New Hampshire

Regulatory Commission expense	$32,569
Delivery point charge	6,188
Load dispatch	76,940
Distribution	42,489
2015 True Up	(75,284)
Phase in	52,389
TOTAL	$135,291

Schedule Page: 328 Line No.: 12 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 13 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 14 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 15 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 16 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 17 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 18 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 19 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 20 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 21 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 22 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 23 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 24 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 25 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 26 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1	Green Mountain Power - (Y-25)	FNO	3	210,330	210,330
2	Green Mountain Power - (Y-25)	FNS	3	7,172	7,172
3	Green Mountain Power - (Phase II AC)	FNO	3	802,649	802,649
4	Green Mountain Power - (Phase II AC)	FNS	3	27,348	27,348
5	Green Mountain Power - (Highgate JO)	FNO	3	5,029,437	5,029,437
6	Green Mountain Power - (Highgate JO)	FNS	3	173,208	173,208
7					
8					
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39					
40	TOTAL			6,250,144	6,250,144

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Received from wheeler							
2	VELCO Spec Facilities	OLF					4,142,278	4,142,278
3	VELCO Common Use	FNS					245,092	245,092
4	VELCO VTA	FNS	3,213,003	3,190,811	12,020,112			12,020,112
5	VELCO Network	OS					169,853	169,853
6	State of Vt NYPA	OLF			90,718			90,718
7	National Grid	FNS			1,706,368			1,706,368
8	Nat Grid - Ashuelot	FNS					16,020	16,020
9	VELCO Phases I & II	LFP			2,763,258			2,763,258
10	ISO New England	FNS			64,996,489			64,996,489
11	Vermont Electric Co-op	SFP			315,941		-170,374	145,567
12	Vermont Electric Pwr Pr	SFP					-79,560	-79,560
13	Eversource (Millstone)	OS	157,281	157,281	126,807			126,807
14	FERC 890 Compliance	OS					1,089	1,089
15	Central Maine Power	OS					805	805
16	TOTAL		3,370,284	3,348,092	82,019,693		4,325,203	86,344,896
	TOTAL		3,370,284	3,348,092	82,019,693		4,325,203	86,344,896

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	222,611
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	76,776
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	A&G Expense Payroll	78,473
7	A&G Expense Trustee	146,345
8	A&G Expense Misc Communications	17,031
9	A&G Expense Other	26,647
10		
11	Directors Fees:	
12	Bankowski, E	36,250
13	Brue, N	36,250
14	Coates, D	36,250
15	Despars, P	36,250
16	Benoit, R	41,375
17	Irving, E	41,375
18	Tessier, R	96,250
19	Wolk, D	36,250
20	Rathke, R	36,250
21		
22	Directors Expenses	18,021
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46	TOTAL	982,404

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			13,770,874		13,770,874
2	Steam Production Plant	1,132,833				1,132,833
3	Nuclear Production Plant	1,000,933				1,000,933
4	Hydraulic Production Plant-Conventional	4,842,981				4,842,981
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,695,057	135,060			7,830,117
7	Transmission Plant	3,745,515				3,745,515
8	Distribution Plant	15,845,489	4,717			15,850,206
9	Regional Transmission and Market Operation					
10	General Plant	4,791,119				4,791,119
11	Common Plant-Electric					
12	TOTAL	39,053,927	139,777	13,770,874		52,964,578

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	311	7,124	33.00		3.17	SQ	
13	312	20,738	30.00		3.37	SQ	
14	314	5,399	33.00		3.16	SQ	
15	315	1,362	33.00		3.14	SQ	
16	316	649	30.00		3.40	SQ	
17	Subtotal	35,272					
18	331	15,269	48.08	0.25	2.08	R2.5	29.80
19	332	78,020	32.15	0.30	3.11	R2	28.60
20	333	53,555	39.06	0.20	2.56	R2	30.70
21	334	29,737	33.56		2.98	SO	23.70
22	335	1,933	36.76		2.72	R3	27.30
23	336	2,705	56.18		1.78	R4	30.00
24	Subtotal	181,219					
25	341	4,667	49.83	0.13	3.03	S2.5 & S2	19.20
26	342	4,068	31.35	0.15	3.19	R2	15.50
27	343	16,015	39.22	0.15	2.55	R2	18.90
28	344	127,121	39.67	0.13	3.22	S2.5 & R3	20.45
29	345	6,729	49.14		2.79	R1.5 & R2.5	21.35
30	346	32,998	24.43		4.10	R2.5 & R3	20.45
31	Subtotal	191,598					
32	352	9,180	62.89	0.05	1.59	R2.5	50.90
33	353	116,563	52.63	0.10	1.90	R1.5	40.40
34	354	351	100.00	0.25	0.09	S1.5	37.40
35	355	43,271	53.19	0.25	1.88	R2	41.10
36	356	39,823	69.44	0.20	1.44	R2.5	43.00
37	Subtotal	209,188					
38	361	26,923	60.61	0.10	1.65	S1.5	33.60
39	362	97,776	49.75	0.10	2.01	R0.5	40.20
40	364	168,449	47.39	0.10	2.11	R0.5	35.90
41	365	184,398	51.55	0.10	1.94	SO	34.60
42	366	18,125	65.36	0.10	1.53	R2.5	49.20
43	367	35,835	55.56	0.10	1.80	R2	35.20
44	368	126,518	62.11	-0.10	1.61	SO.5	29.20
45	369	45,076	50.00	0.10	2.00	R1.5	28.00
46	370	39,612	57.65	0.10	7.17	R1.5 & S2.5	16.90
47	371	1,183	22.12		4.52	LO	12.10
48	373	16,220	33.00	0.10	3.03	O1	23.40
49	Subtotal	760,115					
50	390	41,837	38.77	0.05	2.84	R2 & S1.5	22.65

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	391	25,752	14.76		9.32	SQ	6.55
13	392	29,167	16.58	-0.10	6.03	L2	10.20
14	393	609	74.07		1.35	SQ	14.80
15	394	5,577	31.15		3.21	SQ	15.60
16	395	3,252	24.69		4.05	SQ	10.30
17	397	12,715	24.65		4.06	SQ	15.15
18	398	2,528	22.52		4.44	SQ	10.90
19	Subtotal	121,437					
20	Total	1,498,829					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	STATE OF VERMONT - PUBLIC SERV BD				
2	Rate Case General		60,192	60,192	
3	Alternative Regulation Base Rate Filing		138,760	138,760	
4	Schedule 21		6,325	6,325	
5	Various less than $25,000		29,986	29,986	
6					
7					
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46	TOTAL		235,263	235,263	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:
A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection
(2) Transmission
a. Overhead
b. Underground
(3) Distribution
(4) Regional Transmission and Market Operation
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $50,000.)
(7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B4	Cust Survey & Public Opinion Strategies
2		
3		Vendors Used:
4		Public Opinion Strategies
5		Metrix Matrix Inc
6		Casey
7		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
	76,776	930	76,776		1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	2,408,395		
4	Transmission	299,032		
5	Regional Market			
6	Distribution	3,078,300		
7	Customer Accounts	2,190,760		
8	Customer Service and Informational	2,349,623		
9	Sales	116,453		
10	Administrative and General	11,991,701		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	22,434,264		
12	Maintenance			
13	Production	1,258,001		
14	Transmission	374,231		
15	Regional Market			
16	Distribution	10,022,069		
17	Administrative and General	557,752		
18	TOTAL Maintenance (Total of lines 13 thru 17)	12,212,053		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	3,666,396		
21	Transmission (Enter Total of lines 4 and 14)	673,263		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	13,100,369		
24	Customer Accounts (Transcribe from line 7)	2,190,760		
25	Customer Service and Informational (Transcribe from line 8)	2,349,623		
26	Sales (Transcribe from line 9)	116,453		
27	Administrative and General (Enter Total of lines 10 and 17)	12,549,453		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	34,646,317	2,107,721	36,754,038
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	34,646,317	2,107,721	36,754,038
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	14,002,441	852,355	14,854,796
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	14,002,441	852,355	14,854,796
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,165,313	70,935	1,236,248
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,165,313	70,935	1,236,248
77	Other Accounts (Specify, provide details in footnote):			
78				
79	Business Development	332,535	20,242	352,777
80	Other Work in Progress	1,513,061	92,103	1,605,164
81	Rental Water Heaters	49,852	3,035	52,887
82	Lobbying	16,371	997	17,368
83	Misc Payroll	5,803,748	204,421	6,008,169
84	Other Operating Revenue	297,070	18,083	315,153
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	8,012,637	338,881	8,351,518
96	TOTAL SALARIES AND WAGES	57,826,708	3,369,892	61,196,600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	6,147,047	9,820,761	15,267,211	22,680,966
3	Net Sales (Account 447)	(3,231,685)	(4,653,504)	(7,338,087)	(9,167,862)
4	Transmission Rights	(138,993)	(180,090)	(212,783)	(258,871)
5	Ancillary Services	400,816	486,616	680,755	926,697
6	Other Items (list separately)				
7	ICAP Settlement	5,224,822	10,075,888	14,427,108	18,013,258
8	RT Regulations Settlement	211,145	366,308	632,376	883,404
9					
10					
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12					
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43					
44					
45					
46	TOTAL	8,613,152	15,915,979	23,456,580	33,077,592

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			1,416,354			
2	Reactive Supply and Voltage			699,918			
3	Regulation and Frequency Response			883,404			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement			926,698			
7	Other			2,865,535			
8	Total (Lines 1 thru 7)			6,791,909			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	819	4	18	718	97	10			-6
2	February	806	14	19	700	96	10			
3	March	708	2	19	621	83	10			-6
4	Total for Quarter 1				2,039	276	30			-12
5	April	662	5	8	583	71	10			-2
6	May	664	28	21	584	71	10			-1
7	June	702	20	19	622	77	10			-7
8	Total for Quarter 2				1,789	219	30			-10
9	July	747	13	18	663	79	10			-5
10	August	783	12	14	695	78	10			
11	September	728	8	20	648	80	10			-10
12	Total for Quarter 3				2,006	237	30			-15
13	October	648	27	19	574	72	10			-7
14	November	742	21	18	644	88	10			
15	December	814	19	18	711	95	10			-2
16	Total for Quarter 4				1,929	255	30			-9
17	Total Year to Date/Year				7,763	987	120			-46

Schedule Page: 400 Line No.: 1 Column: b

Schedule Page: 400 Col b

Monthly Transmission System Peak Loads are calculated from metering data at the kw level and rounded to the nearest MW.

Day	Hour	kw
1/4/2016	18	818,984
2/14/2016	19	805,922
3/2/2016	19	708,461
4/5/2016	8	662,108
5/28/2016	21	664,183
6/20/2016	19	702,402
7/13/2016	18	746,730
8/12/2016	14	783,354
9/8/2016	20	727,846
10/27/2016	19	648,371
11/21/2016	18	741,932
12/19/2016	18	814,539

Schedule Page: 400 Col f and b

These monthly loads (relative to the peaks shown) represent the energy wheeled for the Schedule 21-GMP customers as adjusted per that Schedule.

	2016 Total Transmission Billing Loads	
	(f) Customers w/o GMP kwh	(b) Customers with GMP kwh
January	51,977,642	466,916,724
February	46,307,716	421,899,574
March	45,117,945	406,653,087
April	39,138,339	363,088,087
May	38,466,499	371,010,544
June	39,633,964	381,591,708
July	44,192,717	423,286,178
August	44,908,325	433,047,069
September	38,922,993	376,447,898
October	38,778,692	376,005,537
November	42,578,238	398,097,594
December	51,985,792	460,770,225
	522,008,862	4,878,814,225

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	4,222,833
3	Steam	96,841			
4	Nuclear	157,281	23	Requirements Sales for Resale (See instruction 4, page 311.)	338
5	Hydro-Conventional	297,504			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	465,573
7	Other	191,645			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	743,271	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	6,562
10	Purchases	4,154,537	27	Total Energy Losses	219,547
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	4,914,853
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,808,408			
17	Delivered	1,791,363			
18	Net Transmission for Other (Line 16 minus line 17)	17,045			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	4,914,853			

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	459,313	41,356	640	4	18
30	February	436,900	54,965	616	14	19
31	March	434,705	67,732	555	2	19
32	April	398,916	67,627	524	4	21
33	May	372,730	28,758	538	28	21
34	June	388,430	34,907	573	20	21
35	July	426,599	37,389	604	13	19
36	August	431,016	27,642	634	11	21
37	September	378,405	30,761	598	8	20
38	October	369,625	23,612	520	26	19
39	November	371,049	19,890	579	21	18
40	December	447,165	30,934	636	19	19
41	TOTAL	4,914,853	465,573			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Colchester #16 (b)			Plant Name: Berlin #5 (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Steel Encl.			Outdoor Steel Encl.		
3	Year Originally Constructed	1965			1972		
4	Year Last Unit was Installed	1965			1972		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	18.00			41.90		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	1			1		
12	Net Generation, Exclusive of Plant Use - KWh	363400			1559700		
13	Cost of Plant: Land and Land Rights	2439			48218		
14	Structures and Improvements	495681			592677		
15	Equipment Costs	4551886			12133140		
16	Asset Retirement Costs	0			0		
17	Total Cost	5050006			12774035		
18	Cost per KW of Installed Capacity (line 17/5) Including	280.5559			304.8696		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	130590			522604		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	20356			43717		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	43493			47634		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	4002			4045		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	3477			3867		
33	Maintenance of Misc Steam (or Nuclear) Plant	121347			6344		
34	Total Production Expenses	323265			628211		
35	Expenses per Net KWh	0.8896			0.4028		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Rutland #201* (b)			Plant Name: *Ascutney #200* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	GasTurbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Fuel Outdoor			Fuel Outdoor		
3	Year Originally Constructed	1962			1961		
4	Year Last Unit was Installed	1962			1961		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	13.20			13.30		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	812200			194200		
13	Cost of Plant: Land and Land Rights	0			1810		
14	Structures and Improvements	1957			12116		
15	Equipment Costs	3088415			2823255		
16	Asset Retirement Costs	0			0		
17	Total Cost	3090372			2837181		
18	Cost per KW of Installed Capacity (line 17/5) Including	234.1191			213.3219		
19	Production Expenses: Oper, Supv, & Engr	468			941		
20	Fuel	381842			119203		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			436		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	27486			58227		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	467			2311		
33	Maintenance of Misc Steam (or Nuclear) Plant	16930			8811		
34	Total Production Expenses	427193			189929		
35	Expenses per Net KWh	0.5260			0.9780		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Wyman #95* (d)	Plant Name: *Stony Brook Int. #96* (e)	Plant Name: *McNeil #24* (f)	Line No.
Steam	Gas / Steam	Steam	1
Conventional	Comb. Cycle Indoor	Conventional	2
1978	1981	1984	3
1978	1981	1984	4
18.00	30.20	16.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
92	32	38	11
2363300	9375280	94477400	12
5738	738	85746	13
836247	2158780	6288209	14
5405396	10090192	22742784	15
0	0	0	16
6247381	12249710	29116739	17
347.0767	405.6195	1819.7962	18
0	0	83646	19
263523	266588	5990412	20
0	0	0	21
303506	422513	369488	22
0	0	0	23
0	0	0	24
0	181059	162576	25
0	0	739935	26
0	0	0	27
0	0	0	28
0	18600	30633	29
0	42506	23392	30
0	0	285579	31
0	77309	187150	32
0	4441	11900	33
567029	1013016	7884711	34
0.2399	0.1081	0.0835	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
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0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Kingdom Commun Wind (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	2012
3	Year Last Unit was Installed	2012
4	Total installed cap (Gen name plate Rating in MW)	63
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	1
9	Generation, Exclusive of Plant Use - Kwh	166,215,000
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	166,215,000
12	Cost of Plant	
13	Land and Land Rights	568,330
14	Structures and Improvements	1,272,511
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	132,978,997
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	134,819,838
22	Cost per KW of installed cap (line 21 / 4)	2,139.9974
23	Production Expenses	
24	Operation Supervision and Engineering	125,263
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	576,819
28	Misc Pumped Storage Power generation Expenses	
29	Rents	481,381
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	2,693,848
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	3,877,311
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	3,877,311
38	Expenses per KWh (line 37 / 9)	0.0233

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	HYDRO					
2	Middlesex Station # 2	1928	3.20		6,938	5,824,497
3	Marshfield Station # 6	1927	5.00		7,316	14,391,899
4	Vergennes Station # 9 License# 2674	1912	2.40		9,905	10,480,734
5	W, Danville Station # 15	1917	1.00		2,567	5,583,383
6	Gorge Station # 18	1928	3.00		14,321	9,248,018
7	Essex station # 19 License# 2531	1917	7.20		29,873	15,142,829
8	Waterbury Station # 22 A License# 2090	1953	5.52		13,683	2,431,386
9	DeForge station # 1 D License# 2879	1986	7.50		18,132	14,557,828
10	Huntington Falls #203	1911	5.50		6,981	7,064,961
11	Beldens #204	1913	5.85		11,824	7,803,390
12	Proctor #205	1905	6.93		24,855	24,312,768
13	Center Rutland #206	1898	0.28		422	687,623
14	Pittsford #207	1941	3.60		7,715	6,143,893
15	Glen #208	1920	2.00		4,445	8,560,468
16	Patch #209	1921	0.40		535	699,560
17	Carver Falls #210	1894	2.55		5,428	4,329,397
18	Cavendish #211	1907	1.44		3,831	2,371,457
19	Salisbury #212	1917	1.30		1,980	1,831,085
20	Silver Lake #213	1917	2.20		4,137	3,336,466
21	Middlebury Lower #214	1917	2.25		5,443	3,265,530
22	Weybridge #215	1951	3.00		10,754	3,671,582
23	Taftsville #216	1910	0.50		769	684,860
24	Smith #217	1982	1.50		3,316	5,011,260
25	Pierce Mills #218	1928	0.25		884	384,920
26	Arnold Falls #219	1928	0.35		1,290	2,368,978
27	Gage #220	1921	0.70		2,216	950,522
28	Passumpsic #221	1929	0.70		1,598	487,732
29	East Barnet #222	1984	2.20		5,899	6,375,571
30	Fairfax #223	1919	4.20		17,949	4,426,763
31	Clark Falls #224	1937	3.00		13,330	5,352,192
32	Milton #225	1929	7.50		34,804	5,426,070
33	Peterson #226	1948	6.35		24,366	1,921,333
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	DIESEL					
2	Vergennes Station #9C	1963	4.00		294	2,299,852
3	Essex Station #19B	1947	4.00		192	963,753
4						
5						
6	OTHER					
7	Millstone Nuclear #227		21.00		157,281	82,269,109
8	Searsburg Wind #92	1997	6.90		12,585	4,491,519
9	Post Road Solar #232				55	46,345
10	CSJ Solar #107*	2015				332,451
11	RRMC Solar #108*	2015				587,732
12	Ferrisburg Wind #112*	2015				580,603
13	EIC Building #234*	2015				216,930
14	Stafford Hill Solar #113*	2015				13,528,121
15	Milton Solar #117*	2016				73,915
16	Peterson Solar #118*	2016				66,783
17						
18	* Generation is recorded as company use					
19						
20						
21						
22						
23						
24						
25						
26	TOTAL		137.27		467,910	290,586,067
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,820,155	57,327		109,985			2
2,878,380	65,870		95,552			3
4,366,972	43,026		92,103			4
5,583,383	37,819		32,685			5
3,082,673	40,485		62,058			6
2,103,171	68,314		246,032			7
440,469	28,889		55,825			8
1,941,044	56,365		125,975			9
1,284,538	33,835		75,192			10
1,333,913	61,312		184,542			11
3,508,336	68,245		46,232			12
2,455,795	23,239		54,858			13
1,706,637	34,424		63,561			14
4,280,234	44,076		214,460			15
1,748,900	23,945		39,060			16
1,697,803	34,026		118,015			17
1,646,845	47,202		70,013			18
1,408,527	28,015		15,865			19
1,516,576	35,051		84,890			20
1,451,347	57,919		66,874			21
1,223,861	36,277		52,003			22
1,369,721	40,451		14,485			23
3,340,840	37,527		29,093			24
1,539,679	29,013		38,229			25
6,768,508	27,770		51,670			26
1,357,889	42,494		26,181			27
696,760	34,019		24,521			28
2,897,987	39,155		79,096			29
1,053,991	61,881		63,732			30
1,784,064	51,014		69,705			31
723,476	92,961		23,189			32
302,572	58,965		43,674			33
						34
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						45
						46

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
574,963	51,414	54,625	8,905	# 2 OIL		2
240,245	60,906	26,030	6,744	# 2 OIL		3
						4
						5
						6
3,917,577	1,648,722	1,155,782	2,330,069			7
650,945	4,879		285,682			8
						9
	195					10
	1,222					11
	2,025					12
						13
6,764,061	107,639					14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
	3,317,914	1,236,438	5,000,758			26
						27
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	VT/NH Border	Canadian Border						
2		Metallic Neutral Return	450.00	450.00	H-frame steel	35.00		1
3								
4			115.00		H-frame wood	2.58		4
5			69.00		Single Pole	11.35		5
6			34.50		Single Pole	248.58		35
7			46.00		Single Pole	16.00		1
8			13.80		Single Pole	2.44		1
9			34.50		Underground	0.35		
10								
11	Marble Street#2	Center Rutland	11.00	11.00	Wood Pole	2.75		1
12								
13	Various	Various	34.50	34.50	Wood Pole	126.22	1.67	24
14					(H. Frame)	3.72		
15					(Steel Tower)	0.16		
16								
17	Various	Various	34.50	34.50	H. Frame	3.79		1
18					(Wood Pole)	3.28		
19								
20	Various	Various	46.00	46.00	Wood Pole	506.81	2.92	98
21					(H. Frame)	23.22		
22					(Steel Tower)	1.26		
23								
24	Woodford Rd.	East Pownal	46.00	46.00	H. Frame		5.51	1
25								
26								
27	Various	Various	69.00	69.00	Wood Pole	0.92		3
28					(H. Frame)	0.27		
29								
30	Bennington	Searsburg	69.00	69.00	H. Frame	10.91		1
31								
32								
33	Ladder Hill	Vernon Road	115.00	115.00	Wood Pole	0.61		1
34								
35	Canadian Boarder	Highgate Converter	120.00	120.00	H. Frame	7.58		1
36					TOTAL	1,007.80	10.10	178

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1								
2								
3	Total	Group	115.00			1,007.80	10.10	178
4	Total	Group	69.00					
5	Total	Group	34.50					
6	Total	Group	13.80					
7								
8	Total	Group	34.50		Sh/Wd			
9								
10								
11								
12								
13								
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26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,007.80	10.10	178

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2839.8MCM								1
ACSR		1,563,276	1,563,276					2
								3
ACSR	244,699	652,669	897,368					4
								5
								6
								7
								8
750 MCMCU								9
								10
#2AL		44,734	44,734					11
								12
Various	358,753	16,055,799	16,414,552					13
								14
								15
								16
								17
								18
								19
Various	3,376,860	59,351,040	62,727,900					20
								21
								22
								23
								24
								25
								26
Various	13,430	1,705,369	1,718,799					27
								28
								29
								30
								31
								32
795 ACRS	19,819	52,653	72,472					33
								34
954 ACRS	347,006	959,291	1,306,297					35
	4,360,567	80,384,831	84,745,398					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
	4,360,567	80,384,831	84,745,398					3
								4
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								34
								35
	4,360,567	80,384,831	84,745,398					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	L108 P101X	Whiter River #70	2.45	Wood Pole	36.00		1
2							
3							
4							
5							
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40							
41							
42							
43							
44	TOTAL		2.45		36.00		1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
477	AAC	Hendrx	46						1
									2
									3
									4
									5
									6
									7
									8
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Montpelier #3/Montpelier	Dist./Unattended	34.50	12.47	
2	Berlin Gas Turbine #5/Berlin	Trans./Unattended	13.20	34.50	
3	Vergennes #9/Vergennes	Trans./Unattended	2.40	34.50	
4	Vergennes #9/Vergennes	Dist./Unattended	34.50	12.47	
5	Gorge Hydro#18/Colchester	Trans./Unattended	13.80	34.50	
6	Gorge #16/Colchester	Dist./Unattd.	34.40	12.47	
7	Essex #19/Essex	Trans./Unattended	2.40	34.50	
8	Essex #19/Essex	Trans./Unattended	13.20	34.50	
9	Essex #19/Hill Top/Essex	Dist./Unatt.	34.50	12.47	
10	Mountain View #27/Montpelier	Dist./Unattended	34.50	4.16	
11	Mountain View #27/Montpelier	Dist./Unattended	34.50	12.47	
12	Queen City #32/So. Burlington	Dist./Unattended	34.50	12.47	
13	Sand Road #33/Essex	Dist/Unattended	34.50	12.47	
14	Mallets Bay #34/Colchester	Dist./Unattended	34.50	12.47	
15	So. End #37/Barre	Dist./Unattended	34.50	2.40	
16	So. End #37/Barre City	Dist./Unattended	34.50	4.16	
17	So. End #37/Barre City	Dist./Unattended	34.50	12.47	
18	Madubush #38/Warren	Dist./Unattended	34.50	12.47	
19	Irasville #39/Fayston	Dist./Unattended	34.50	12.47	
20	Bolton #41/Bolton	Dist./Unattended	34.50	12.47	
21	Digital #43/So. Burlington	Dist./Unattended	34.50	12.47	
22	Shelburne #53/Shelburne	Dist./Unattended	115.00	12.47	
23	Wilmington #56/Wilmington	Dist./Unattended	67.00	12.47	
24	Websterville #61Barre Town	Dist./Unattended	34.50	12.47	
25	Barre North End #63/Barre City	Dist./Unattended	34.50	4.16	
26	Barre North End #63/Barre City	Dist./Unattended	34.50	12.47	
27	Berlin #40/Berlin	Dist./Unattended	34.50	4.16	
28	Berlin #40/Berlin	Dist./Unattended	34.50	12.47	
29	Richmond #51/Richmond (Jt Owned VEC)	Dist./Unattended	34.50	12.47	
30	Wilder #71/Hartford	Dist./Unattended	4.60	12.47	
31	Dorset St. #78/So. Burlington	Dist./Unattended	34.50	12.47	
32	Dover #90/Dover	Dist./Unattended	67.00	12.47	
33	Dover #90/Dover	Dist./Unattended	67.00	12.47	
34	Bolton Falls #1/Duxbury	Trans/Unattended	4.16	34.50	
35	Charlotte #28/Charlotte	Dist./Unattended	115.00	13.20	
36	Waterbury/Waterbury	Dist./Unattended	34.50	12.47	
37	Town Line #44/Williston	Dist./Unattended	34.40	13.20	
38	Putney #69/Putney	Dist./Unattended	67.00	8.32	
39	Sleeply Hollow #92/Searsburg	Trans/Unattended	13.20	67.00	
40	Tafts Corners #73/Williston	Dist/Unattened	115.00	13.20	

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Barnet #14/Barnet	Dist/Unattended	34.50	13.20	
2	West Danville #15/Danville	Dist/Unattended	34.50	7.20	
3	Middlesex #2/Moretown	Dist/Unattended	34.50	2.40	
4	Little River #22/Waterbury	Dist/Unattended	34.50	4.16	
5	Barre #26/Barre City	Dist/Unattended	34.50	2.40	
6	Ethan Allen #36/Colchester	Dist/Unattended	34.50	12.47	
7	North Ferrisburgh #45/Ferrisburgh	Dist/Unattended	115.00	12.47	
8	Marshfield #6/Marshfield	Dist/Unattended	34.50	4.16	
9	Riverton #62/Berlin	Dist/Unattended	34.50	4.16	
10	Waterford #65/Waterford	Dist/Unattended	34.50	4.16	
11	Moretown #66/Moretown	Dist/Unattended	34.50	4.16	
12	Bridge St #67/Bellows Falls	Dist/Unattended	46.00	13.20	
13	White River #70/Hartford	Dist/Unattended	46.00	12.47	
14	Westminster #74/Westminster	Dist/Unattended	67.00	8.32	
15	Airport#79/So. Burlington	Dist/Unattended	34.50	4.16	
16	Iroquois #81/Colchester	Dist/Unattended	34.50	12.47	
17	Legare #83/Ryegate	Dist/Unattended	34.50	12.47	
18	Woodford Road -Bennington VT	Dist/Unattended	44.00	12.50	
19	No. Brattleboro-Brattleboro VT	Dist/ Unattended	67.00	44.00	
20	No. Brattleboro-Brattleboro VT	Dist/Unattended	44.00	12.50	
21	Brudies Road - Brattleboro VT	Dist/Unattended	69.00	12.50	
22	Vernon Road - Brattleboro VT	Transmission U	115.00	46.00	
23	Vernon Road - Brattleboro VT	Dist/Unattended	44.00	12.50	
24	Fair Haven Village - Fair Haven VT	Dist/Unattended	44.00	4.00	
25	Ely - Fairlee VT	Dist/Unattended	44.00	12.50	
26	Mendon - Mendon VT	Dist/Unattended	44.00	34.50	
27	Wells River - Newbury VT	Dist/Unattended	44.00	12.50	
28	Newbury - Newbury VT	Dist/Unattended	46.00	12.50	
29	Rochester - Rochester VT	Dist/Unattended	44.00	12.50	
30	East Rutland - Rutland City VT	Dist/Unattended	44.00	12.50	
31	North Rutland - Rutland Town VT	Dist/Unattended	44.00	12.50	
32	Mill Street - Bennington VT	Dist/Unattended	44.00	12.50	
33	Georgia - Georgia VT	Dist/Unattended	34.50	12.50	
34	Quechee - Hartford VT	Dist/Unattended	44.00	12.50	
35	Pleasant Street - Randolph VT	Dist/Unattended	44.00	12.50	
36	Bay Street - St. Johnsbury VT	Dist/Unattended	34.50	12.50	
37	South Street - Springfield VT	Dist/Unattended	44.00	12.50	
38	Riverside - Springfield VT	Dist/Unattended	46.00	12.50	
39	Windsor - Windsor VT	Dist/Unattended	44.00	12.50	
40	Gas Turbine - Rutland VT	Combination U	44.00	12.50	

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	 Secondary (d)	 Tertiary (e)
1	Gas Turbine - Ascutney VT	Combination U	44.00	13.20	
2	North Hyde Park - Johnson VT	Dist/Unattended	34.50	4.00	
3	Lowell - Lowell VT	Transmission U	44.00	34.50	
4	East Thetford - Thetford VT	Dist/Unattended	44.00	12.50	
5	South Rutland - Rutland VT	Dist/Unattended	44.00	12.50	
6	Lalor Avenue - Rutland VT	Dist/Unattended	46.00	12.50	
7	Weybridge - Weybridge VT	Combination U	44.00	12.50	
8	Milton - Milton VT	Combination U	34.50	2.30	
9	Milton - Milton VT	Dist/Unattended	34.50	12.50	
10	Nason Street - St Albans VT	Dist/Unattended	34.50	12.50	
11	Rawsonville - Jamaica VT	Dist/Unattended	44.00	12.50	
12	East Barnard - Barnard VT	Dist/Unattended	44.00	34.50	
13	Silk Road - Bennington VT	Dist/Unattended	44.00	12.50	
14	South Brattleboro - Brattleboro VT	Dist/Unattended	69.00	12.50	
15	Manchester - Manchester VT	Dist/Unattended	44.00	12.50	
16	Sheldon Springs - Sheldon VT	Dist/Unattended	34.50	12.50	
17	Underhill - Jericho VT	Dist/Unattended	34.50	12.50	
18	Ryegate - Ryegate VT	Transmission U	46.00	34.50	
19	Stratton Mountain - Winhall VT	Dist/Unattended	46.00	12.50	
20	Bromley - Winhall VT	Dist/Unattended	44.00	12.50	
21	Woodstock - Woodstock VT	Dist/Unattended	44.00	12.50	
22	Snowshed - Sherburne VT	Dist/Unattended	34.50	12.50	
23	Middlebury #2 - Middlebury VT	Dist/Unattended	44.00	12.50	
24	East Middlebury - Middlebury VT	Dist/Unattended	44.00	12.50	
25	Sherburne - Sherburne VT	Dist/Unattended	44.00	12.50	
26	North Bennington - Bennington VT	Dist/Unattended	44.00	12.50	
27	Pittsford Village - Pittsford VT	Dist/Unattended	44.00	12.50	
28	East - St Albans VT	Dist/Unattended	34.50	12.50	
29	Lyons Street - Bennington VT	Dist/Unattended	44.00	12.50	
30	North Springfield - Springfield VT	Dist/Unattended	44.00	12.50	
31	Bethel - Royalton VT	Dist/Unattended	44.00	12.50	
32	Londonderry - Londonderry VT	Dist/Unattended	44.00	12.50	
33	West Milton - Milton VT	Dist/Unattended	34.50	12.50	
34	North Elm Street - St Albans VT	Dist/Unattended	34.50	12.50	
35	Kendall Farm - Winhall VT	Transmission U	46.00	13.80	
36	Proctor - Proctor VT	Dist/Unattended	46.00	4.16	
37	Ballard Road - Georgia	Transmission U	46.00	12.47	
38	Wallingford - Wallaingford VT	Dist/Unattended	46.00	12.47	
39					
40	Total		4996.76	1656.17	

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Miscellaneous - Various (78)	Dist/Unattended			
2	Miscellaneous - Various (31)	Transmission U			
3	Miscellaneous - Various (10)	Combination U			
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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21					
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29					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
56	1					2
7	1					3
14	1					4
18	1					5
5	1					6
9	1					7
14	1					8
36	2					9
7	1					10
20	1					11
22	1					12
11	1					13
14	1					14
5	1					15
5	1					16
11	1					17
22	1					18
11	1					19
11	1					20
22	1					21
20	1					22
14	3					23
11	1					24
3	3					25
11	1					26
11	1					27
11	1					28
11	1					29
14	1					30
22	1					31
23	1					32
14	1					33
11	1					34
20	1					35
28	1					36
14	1					37
14	1					38
7	1					39
56	1					40

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
7	1					1
1	3					2
4	1					3
8	1					4
6	2					5
14	1					6
10	1					7
6	3					8
9	3					9
1	3					10
2	1					11
14	1					12
28	1					13
14	1					14
2	1					15
11	1					16
4	1					17
13	1					18
13	1					19
13	1					20
13	1					21
72	2					22
13	1					23
6	1					24
4	1					25
31	2	1				26
4	1					27
6	1					28
4	1					29
13	1					30
11	1					31
13	1					32
13	1					33
13	1					34
13	1					35
9	1					36
13	1					37
13	1					38
13	1					39
18	3					40

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
1	3					2
20	1					3
6	1					4
25	2					5
13	1					6
13	2					7
9	1					8
11	1					9
13	1	1				10
6	1					11
20	1					12
13	1					13
13	2					14
22	2					15
9	1					16
10	2					17
19	1					18
56	2	1				19
13	1					20
9	1					21
13	1					22
21	2					23
13	1					24
25	2					25
13	1					26
13	1					27
13	1					28
13	1					29
13	1					30
13	1					31
9	1					32
9	1					33
12	1					34
32	2		Condenser	2	32	35
7	1					36
						37
10	1					38
						39
1662	146	3		2	32	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
241	78					1
52	31					2
23	10					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
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						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Construction - Various	VELCO	107	499,714
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Construction - Various	VELCO	173/146	627,473
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
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39				
40				
41				
42				

Schedule	Page No.