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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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 2019/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Green Mountain Power Corp	End of 2019/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	06 Title of Contact Person
Mathieu Lepage	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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(802) 655-8405	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Mathieu Lepage		
02 Title		
Chief Financial Officer	Mathieu Lepage	04/16/2020

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	12/31/2019	End of 2019/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".

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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".

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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".

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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.

Mathieu Lepage, 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	12/31/2019	End of 2019/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. On November 29, 2017 Gaz Métro changed it's name to Energir Inc ("Energir").

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	12/31/2019	End of 2019/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		Management	Ownership %	
3	Green Mountain Power Corporation		100.00%	
4			=======	
5				
6	Northern Water Resources, Inc.	Alternative Energy Developmet	100.00%	
7			=======	
8				
9	Vermont Electric Power Co., Inc.	Electric Power	Common Stock	
10	Joint Owners:		Owners%:	
11	Green Mountain Power Corporation		38.8%	
12	VLite		37.5%	
13	City of Burlington Electric Light Department		6.0%	
14	Vermont Electric Cooperative		7.0%	
15	Stowe Electric		0.7%	
16	Washington Electric		1.5%	
17	Ludlow Electric		1.1%	
18	Swanton Electric		1.0%	
19	Others		3.5%	
20	VT Public Power Supply Authority		2.9%	
21			------------	
22			100.00%	
23			=======	
24	Note: The above figures represent the share	of Common Stock. The		
25	Responent also owns 30% of VELCO's Preferred	Stock.		
26				
27	Transco LLC			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Joint Owners:			
2	Velco Electric Power Company		3.94%	
3	Burlington Electric Dept.		5.28%	
4	Green Mountain Power		75.52%	
5	Vermont Electric Co-op		6.18%	
6	VPPSA		5.52%	
7	Other		3.56%	
8			------------	
9			100.00%	
10			=======	
11				
12				
13	W.F. Wyman Station	Oil fired steam	Ownership %	
14	Joint Owners:	electric generating		
15	Green Mountain Power Corporation	unit.	2.92%	
16	Exelon New England		5.89%	
17	Florida Power & Light		84.34%	
18	Lyndonville Electric Department		0.03%	
19	Massachusetts Municipal Wholesale Electric Co.		3.67%	
20	Northeast Utilites		3.14%	
21			------------	
22			100.00%	
23			=======	
24				
25				
26				
27				

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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				
18	Catamount Resources Corporation	Unregulated activities	100.00%	
19			=======	
20				
21	Millstone Unit #3	Nuclear generation	Ownership %	
22	Green Mountain Power Corporation		1.73%	
23	Dominion Nuclear CT		94.47%	
24	Mass Municipal Wholesale Elec. Co.		4.80%	
25			------------	
26			100.00%	
27			=======	

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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		22.66%	
4	Boston Edison Company		11.05%	
5	Vermont Electric Power Company, Inc.	Note: Vermont Electric	4.34%	
6	Canal Electric Company	Power Co. Inc. as	3.41%	
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 1.16%	0.59%	
10	Town of Reading		0.47%	
11	City of Taunton		0.36%	
12	City of Chicopee		0.32%	
13	City of Braintree		0.29%	
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%	

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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 Return	DMNR Conductor	Ownership %	
2	Green Mountain Power Corporation		59.40%	
3	Vermont Electric Co-Op.		40.60%	
4			------------	
5			100.00%	
6			=======	
7				
8	Catamount Resources Corporation	Unregulated activities	100.00%	
9			=======	
10				
11	GMP VT Solar LLC		Ownership %	
12	Green Mountain Power Corporation	Solar generation projects	67.45%	
13	Firstar		32.55%	
14			------------	
15			100.00%	
16			=======	
17				
18	GMP VT Microgrid LLC	Solar/Battery projects	Ownership %	
19	Green Mountain Power Corporation		71.02%	
20	Firstar		28.98%	
21			------------	
22			100.00%	
23			=======	
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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 - Resigned 12/31/2019	611,250
2			
3	VP, Strategic Finance - Effective 8/1/2019	Dawn D. Bugbee - Resigned	304,494
4	VP & CFO - Resigned 8/1/2019		
5			
6	Senior VP - Operations	Brian Otley	340,995
7			
8	VP - Customer Care	Steve Costello	214,032
9			
10	VP - Stakeholder Relations	Robert Dostis	206,544
11			
12	VP - Chief Innovation Officer	Josh Castonguay	200,910
13			
14	VP - Strategic & External Affairs	Kristin Carlson	202,845
15			
16	VP - Chief Talent & Support Ops	Mari McClure	296,983
17	Corporate Secretary - Effective 6/14/2019		
18	President & CEO - Effective 1/1/2020		
19			
20	VP, CFO & Treasurer - Effective 8/1/2019	Mathieu Lepage	111,538
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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	Sophie Brochu	Energir
2	Chair of the Board	1717 Rue du Havre
3		Montreal, QC H2K 2X3
4		
5	David R. Coates	474 Coates Island
6	Director	Colchester, VT 05446
7		
8	Elizabeth A. Bankowski	34 Tyler St.
9	Director	Brattleboro, VT 05301
10		
11	Mari McClure	Green Mountain Power
12	President & CEO, Director	163 Acorn Lane, Colchester, VT 05446
13		
14	Mary G. Powell - Retired effective 12/31/19	Green Mountain Power
15	President & CEO, Director	163 Acorn Lane, Colchester, VT 05446
16		
17	David Wolk	119 Alumni Drive
18	Director	Castleton, VT 05735
19		
20	Francis Rathke	33 Oakledge Drive
21	Director	Burlington, Vt. 05401
22		
23	Eric LaChance	Energir
24	Director	1717, Rue du Havre
25		Montreal QC H2K 2X3
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[ ] Yes

[X] 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 ER12-2304-0000
3		
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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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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. There were no purchases or sales of operating units or systems.
4. No important leaseholds were entered into or surrendered.
5. There were no important expansions or reductions to the transmission or distribution system.
6. Green Mountain Power Company (GMP) issued $40M of First Mortgage Bonds on December 18, 2019. $15M were issued at 3.01% and mature on December 18, 2034 and $25M were issued at 3.53% and mature on December 18, 2049.
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. Two major storms (10/17 to 10/18 and 10/31 to 11/1) hit GMP service territory. GMP has deferred $4.7M for recovery from customers (net of a $1.2M deductible).

    Also, see page 123 - Notes to Financial Statements.
13. Elizabeth Miller joined GMP on February 17, 2020 as VP, Chief Legal, Sustainable Supply & Resilient Systems Officer.
14. 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	12/31/2019	End of 2019/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	1,932,153,320	1,855,564,930
3	Construction Work in Progress (107)	200-201	47,627,950	31,615,616
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,979,781,270	1,887,180,546
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	712,088,919	670,617,907
6	Net Utility Plant (Enter Total of line 4 less 5)		1,267,692,351	1,216,562,639
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)		1,197,475	714,346
9	Nuclear Fuel Assemblies in Reactor (120.3)		3,747,596	3,747,596
10	Spent Nuclear Fuel (120.4)		18,550,611	18,550,611
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	22,049,205	20,999,072
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		1,446,477	2,013,481
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,269,138,828	1,218,576,120
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		19,112,369	18,292,550
19	(Less) Accum. Prov. for Depr. and Amort. (122)		9,956,850	9,697,288
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	735,645,499	674,497,138
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)		22,251,400	16,776,346
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		14,305,814	12,453,911
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)		781,358,232	712,322,657
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,018,972	4,325,957
36	Special Deposits (132-134)		37,746	9,546
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		52,081,354	51,271,653
41	Other Accounts Receivable (143)		1,890,724	3,244,587
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,348,383	1,016,260
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		2,565,052	442,276
45	Fuel Stock (151)	227	4,294,199	4,382,119
46	Fuel Stock Expenses Undistributed (152)	227	38,920	60,385
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	17,885,589	18,288,846
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

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	12/31/2019	End of 2019/Q4

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	550,660	1,508,153
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)		8,721,704	9,168,010
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		3,084,981	2,132,528
61	Accrued Utility Revenues (173)		32,020,139	29,535,406
62	Miscellaneous Current and Accrued Assets (174)		9,922,483	7,541,313
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)		4,802,114	5,521,985
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		139,566,254	136,416,504
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		5,265,479	4,999,525
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	2,283,228	352,118
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,830,626	6,398,805
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)		-254,690	-247,779
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	187,502,922	168,912,114
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	157,485,220	165,020,433
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		355,112,785	345,435,216
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,545,176,099	2,412,750,497

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

	2019	2018
16511 PREPAYMENTS-INS GENERAL	1,214,318	1,077,906
16512 PREPAYMENTS-EMPLOYEE MEDICAL	(222,160)	(147,778)
16514 PREPAYMENTS-INS LIABILITY	230,599	166,976
16515 PREPAYMENTS-WORKER'S COMP	257,370	-
16516 PREPAYMENTS-EXCESS LIABILITY	(128,469)	924,418
16517 PREPAYMENTS-D.O.L.I.	29,283	27,557
16518 PREPAYMENTS-PANTON SITE LEASE	844	844
16521 PREPAYMENTS-PURCHASE POWER	352,648	-
16522 PREPAYMENTS-REC BROKERAGE FEES	516,788	461,548
16523 PREPAYMENT-401K MATCH	(25,460)	(23,590)
16524 PREPAYMENT-LTD	(68,779)	(31,084)
16525 PREPAYMENT-GROUP LIFE	(105,418)	(66,508)
16531 PREPAYMENT-IT MAINT	2,110,736	2,316,191
16532 PREPAYMENTS-MMWEC	(393,209)	(365,498)
16538 PREPAYMENTS-MCNEIL	948,438	1,036,099
16542 PREPAYMENTS-PROPERTY TAXES	3,658,128	3,659,513
16541 PREPAYMENTS - MISC	346,047	131,416
	8,721,704	9,168,010

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	12/31/2019	end of 2019/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	569,393,341	559,393,341
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	119,346,383	104,692,825
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	170,318,275	152,240,873
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)		859,058,332	816,327,372
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	789,830,046	731,130,046
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)		789,830,046	731,130,046
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)		3,143,094	2,963,280
29	Accumulated Provision for Pensions and Benefits (228.3)		9,551,272	9,544,376
30	Accumulated Miscellaneous Operating Provisions (228.4)		3,472,617	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)		9,602,992	9,149,052
35	Total Other Noncurrent Liabilities (lines 26 through 34)		25,769,975	21,656,708
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		117,372,156	89,369,201
38	Accounts Payable (232)		47,552,339	59,122,373
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		5,486,171	3,963,756
41	Customer Deposits (235)		1,242,795	1,082,596
42	Taxes Accrued (236)	262-263	3,927,679	3,582,804
43	Interest Accrued (237)		4,653,417	4,741,180
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	12/31/2019	end of 2019/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)		1,087,258	959,969
48	Miscellaneous Current and Accrued Liabilities (242)		12,435,309	12,954,113
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)		18,276,779	21,229,677
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		212,033,903	197,005,669
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		144,257	192,058
57	Accumulated Deferred Investment Tax Credits (255)	266-267	7,273,036	7,342,534
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	104,866,727	88,410,004
60	Other Regulatory Liabilities (254)	278	147,835,275	177,865,760
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)		212,528,216	206,805,424
64	Accum. Deferred Income Taxes-Other (283)		185,836,332	166,014,922
65	Total Deferred Credits (lines 56 through 64)		658,483,843	646,630,702
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,545,176,099	2,412,750,497

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	698,081,517	713,198,777		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	518,573,466	513,339,876		
5	Maintenance Expenses (402)	320-323	54,240,086	49,599,081		
6	Depreciation Expense (403)	336-337	45,656,758	43,154,826		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	135,060	135,060		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	12,967,960	11,380,540		
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)		11,601,183	15,264,038		
13	(Less) Regulatory Credits (407.4)		21,771,606	17,979,732		
14	Taxes Other Than Income Taxes (408.1)	262-263	37,908,394	36,166,946		
15	Income Taxes - Federal (409.1)	262-263	23,264	23,943		
16	- Other (409.1)	262-263				
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	2,893,027	16,868,987		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266	-137,321	-139,414		
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)		272,686	258,742		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		662,362,957	668,072,893		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		35,718,560	45,125,884		

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
698,081,517	713,198,777					2
						3
518,573,466	513,339,876					4
54,240,086	49,599,081					5
45,656,758	43,154,826					6
135,060	135,060					7
12,967,960	11,380,540					8
						9
						10
						11
11,601,183	15,264,038					12
21,771,606	17,979,732					13
37,908,394	36,166,946					14
23,264	23,943					15
						16
2,893,027	16,868,987					17
						18
-137,321	-139,414					19
						20
						21
						22
						23
272,686	258,742					24
662,362,957	668,072,893					25
35,718,560	45,125,884					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	12/31/2019	End of 2019/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)		35,718,560	45,125,884		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		844,399	1,135,667		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		593,160	840,653		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		484,351	873,676		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	86,284,106	77,237,061		
37	Interest and Dividend Income (419)		3,748	19,924		
38	Allowance for Other Funds Used During Construction (419.1)		753,110	996,474		
39	Miscellaneous Nonoperating Income (421)		166	436		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		87,776,720	79,422,585		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		410,260	696,843		
46	Life Insurance (426.2)		-558,357	597,099		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		177,535	192,631		
49	Other Deductions (426.5)		5,507,598	3,170,365		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,537,036	4,656,938		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	29,935	29,482		
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)		29,935	29,482		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		82,209,749	74,736,165		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		36,788,995	36,647,506		
63	Amort. of Debt Disc. and Expense (428)		544,912	547,051		
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)		3,258,880	2,780,535		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		424,314	567,074		
70	Net Interest Charges (Total of lines 62 thru 69)		40,168,473	39,408,018		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		77,759,836	80,454,031		
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)		77,759,836	80,454,031		

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		103,905,407	76,139,939
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)		77,759,836	80,454,031
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			-45,028,875	(41,604,125)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-45,028,875	(41,604,125)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-18,077,403	(11,084,438)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		118,558,965	103,905,407
	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	12/31/2019	End of 2019/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)		119,346,383	104,692,825
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		152,240,873	141,156,435
50	Equity in Earnings for Year (Credit) (Account 418.1)		86,284,106	77,237,061
51	(Less) Dividends Received (Debit)		68,206,704	66,152,623
52				
53	Balance-End of Year (Total lines 49 thru 52)		170,318,275	152,240,873

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	12/31/2019	End of 2019/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)	77,759,836	80,454,031
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	56,047,191	54,413,842
5	Amortization of Other	-8,302,554	5,080,841
6	Other Non Cash Items	-110,418	1,212,424
7			
8	Deferred Income Taxes (Net)	2,893,027	16,868,987
9	Investment Tax Credit Adjustment (Net)	-137,321	-139,414
10	Net (Increase) Decrease in Receivables	-2,517,585	-2,194,779
11	Net (Increase) Decrease in Inventory	-1,026,392	-1,318,857
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-10,485,986	8,889,719
14	Net (Increase) Decrease in Other Regulatory Assets	6,128,647	-20,700,333
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	753,110	996,474
17	(Less) Undistributed Earnings from Subsidiary Companies	17,810,890	4,120,572
18	Other (provide details in footnote):		
19	Other Assets	-1,516,920	-2,935,156
20	Other Liabilities	4,409,781	2,507,185
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	104,577,306	137,021,444
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-121,670,656	-83,106,159
27	Gross Additions to Nuclear Fuel	-483,129	-667,022
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-753,110	-996,474
31	Other (provide details in footnote):		
32			
33	All Other	-6,082,537	-1,678,084
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-127,483,212	-84,454,791
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		42,763
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-28,704,366	-17,923,920
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies	295,914	1,812,075
43			
44	Purchase of Investment Securities (a)	-2,789,187	-2,101,475
45	Proceeds from Sales of Investment Securities (a)	2,417,714	1,899,035

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	12/31/2019	End of 2019/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			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-156,263,137	-100,726,313
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	130,000,000	45,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):	42,500	
65	Capital from Parent	10,000,000	
66	Net Increase in Short-Term Debt (c)		-25,000,000
67	Other (provide details in footnote):		
68	Borrowings on Revolving Line of Credit	502,327,194	582,328,451
69	Repayments on Revolving Line of Credit	-474,324,239	-581,028,527
70	Cash Provided by Outside Sources (Total 61 thru 69)	168,045,455	21,299,924
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-71,300,000	-16,280,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		-405,283
77	Debt Issuance Costs	-810,867	-476,039
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-45,527,542	-41,604,125
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	50,407,046	-37,465,523
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-1,278,785	-1,170,392
87			
88	Cash and Cash Equivalents at Beginning of Period	4,335,503	5,505,895
89			
90	Cash and Cash Equivalents at End of period	3,056,718	4,335,503

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

Cash Balance Calculation:

	2019	2018
Account 131	$3,018,972	$4,325,957
Account 135	$ 37,746	$ 9,546
Account 135	-	-
Less resticted cash recorded on CF line 33	-	-
Total cash and cash equivalents	$3,056,718	$4,335,503

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.

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	12/31/2019	End of 2019/Q4

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				

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	12/31/2019	End of 2019/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to 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				[redacted]	[redacted]
2				[redacted]	[redacted]
3				[redacted]	[redacted]
4				80,454,031	80,454,031
5				[redacted]	[redacted]
6				[redacted]	[redacted]
7				[redacted]	[redacted]
8				[redacted]	[redacted]
9				77,759,836	77,759,836
10				[redacted]	[redacted]

The notes below are excerpts from the Company's GAAP basis consolidated financial statements as of and for the years ended September 30, 2019 and 2018. 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 (GMP or the Company), 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 265,600 customer accounts. On June 27, 2012, NNEEC acquired Central Vermont Public Service Corporation (CVPS). CVPS was then merged with and into GMP effective October 1, 2012. GMP is regulated by the Vermont Public Utility Commission (VPUC) and utilizes the Uniform System of Accounts established by the Federal Energy Regulatory Commission (FERC).

GMP'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. The Sponsors, a group of seven New England utilities, are severally obligated to pay VYNPC their entitlement percentage of amounts equal to VYNPC's cost of service including total operating expenses and an allowed return on equity (ROE) (7.5% since July 31, 2002). GMP's entitlement share is 55%. See note 16(h). VYNPC is subject to regulation by the FERC and the VPUC with respect to rates, accounting and other matters.

(2) Summary of Significant Accounting Policies

(a) Principles of Consolidation and Presentation

The accompanying consolidated financial statements of GMP include the accounts of wholly owned subsidiaries as well as those of variable interest entities (VIEs) for which GMP is the primary beneficiary. Noncontrolling interests represent the proportionate equity interest of owners in GMP's consolidated entities that are not wholly owned. See note 22. All significant intercompany transactions with consolidated affiliates have been eliminated upon consolidation.

GMP 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, 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. GMP'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.

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

GMP uses the hypothetical liquidation at book value (HLBV) method to account for its interests in the subsidiaries GMP VT Solar LLC (GMP Solar) and GMP VT Microgrid (GMP Microgrid) which are held in partnership with tax equity investors. This method is being used because GMP Solar and GMP Microgrid are limited liability companies and the agreements between GMP and its tax equity partners state that liquidation rights and distribution priorities do not correspond to the percentage ownership interests. For interests accounted for under the HLBV method, using ownership percentage to allocate the investee's net income to the partners fails to reflect the economic benefits that each partner will receive outside the structure. The HLBV method is a balance sheet method that considers the amount that each partner would receive or pay if the partnership liquidated all its assets and settled all its liabilities at book value and distributed the liquidation proceeds to the partners based on the priorities set out in the agreements. This method also takes into account the tax considerations created for each partner.

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. Significant items subject to such estimates and assumptions include unbilled revenue, pension and postretirement plan obligations, contingency reserves, environmental reserves, asset retirement obligations, regulatory assets and liabilities, the allowance for uncollectible accounts receivable, the valuation of utility plant, deferred tax assets and liabilities and derivative financial instruments. Actual results could differ from those estimates.

(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 VPUC.

The Company accounts for certain transactions in accordance with permitted regulatory accounting principles. 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 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 the fair value adjustments related to derivative financial instruments that cannot be considered as income or expense for rate-making purposes until the derivative financial instrument is settled.

(c) Cash and Cash Equivalents

GMP considers all highly liquid investments purchased with original maturities of three months or less to be cash equivalents.

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

Revenues from rate-regulated activities come mainly from electricity distribution activities. Most of the Company's contracts have only one performance obligation, namely the delivery of energy. More specifically, energy distribution revenues are recorded as the energy is delivered and according to the amount that the Company is permitted to bill customers in accordance with the underlying price agreements approved by the VPUC. The unbilled revenues, which totaled \$24,130 and \$22,083 at September 30, 2019 and 2018, 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 GMP'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.

GMP 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

GMP'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. GMP's inventories consist of the following:

	September 30	
	2019	**2018**
Fuel	$ 4,461	4,709
Materials and supplies	19,343	19,796
RECs	10,385	6,980
Total inventory	$ 34,189	31,485

GMP 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 and retires RECs to meet regulatory mandates (see note 16i). REC revenue and costs are reflected in retail rates. GMP accounts for purchased RECs using the inventory method. RECs are recorded to inventory at their acquisition cost. When RECs are sold or retired the RECs are removed from inventory at cost. GMP's self-generated RECs have an inventory carrying cost of zero.

During the years ended September 30, 2019 and 2018, net REC revenue was $18,506 and $21,735, respectively.

(f) Utility Plant in Service and Long-Lived Assets

Utility plant in service 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 replacements 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 VPUC. The Company amortizes its intangible and regulatory assets using the straight-line method based on the cost and amortization period approved by the VPUC.

(g) Long-Term Investments

At September 30, 2019 and 2018, investment securities included in the VYNPC Spent Fuel Disposal Trust, the VYNPC Rabbi Trust, and the Millstone Decommissioning Trust consist primarily of debt and equity securities and are reflected on the consolidated balance sheets at their aggregate fair values.

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, GMP 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.

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, 2019 and 2018, there were no permanent impairments or credit losses associated with investment securities.

Millstone Decommissioning Trust Fund: All dividend and interest income and 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.

VYNPC Spent Fuel Disposal and Rabbi Trust Funds: Realized gains and losses on the sale of securities are recognized at the time of sale and dividend and interest income are recognized when earned. For the VYNPC Spent Fuel Disposal Trust whose investments are primarily debt securities, unrealized gains (losses) on investments, generally recorded in accumulated other comprehensive income in stockholder's equity under GAAP, are recorded as regulatory assets or liabilities in GMP's balance sheets because GMP is a cost-of-service rate regulated entity and such amounts have been and continue to be recoverable or creditable in rates when realized, through its contracts with Sponsors. For the VYNPC Rabbi Trust whose investments are primarily equity securities, unrealized gains and losses are recorded to the income statement. These unrealized gains and losses are returned to/collected from Sponsors through VYNPC FERC tariff.

(h) Impairment of Long-Lived Assets

GMP performs an evaluation of long-lived assets, including utility plant, regulatory assets subject to amortization, 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. Fair value is determined based on discounted cash flow models.

Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. Based upon management's analysis of the regulatory environment within which the Company operates, the Company does not believe that an impairment loss for long-lived assets should be recorded.

(i) Environmental Liabilities

GMP 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 can be considered "probable and reasonably estimable." As costs become probable and reasonably estimable, environmental liability reserves are adjusted as appropriate. As reserves are recorded, regulatory assets are recorded to the extent environmental expenditures will be recovered in 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 values of those derivatives are accounted for pursuant to a regulatory accounting orders issued by the VPUC 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 anticipates that the counterparties will be able to fully satisfy their obligations under the hedge agreements. The Company monitors the credit standing of the counterparties.

On April 11, 2001, the VPUC issued an accounting order that requires GMP 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, GMP records as power supply costs or wholesale revenues, as appropriate. There is no realized gain and loss impact to earnings since all power supply costs and wholesale revenues are included in the PSA.

(k) 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.

(l) 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 for regulated business is recorded in a regulatory liability and recognized in income in periods when the regulatory liability is amortized or otherwise reversed. The effect on deferred tax assets and liabilities of a change in tax rates for non-regulated business 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 (ITCs) 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 to be sustained. Recognized income tax positions are measured 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 income, net in the consolidated statements of income.

GMP files a consolidated tax return with its parent company, NNEEC. NNEEC pays all federal and most state income taxes on behalf of GMP. GMP has a tax-sharing agreement with NNEEC to pay an amount equal to the tax that would be paid if GMP filed tax returns on a separate return basis. There was $220 and $197 in income taxes payable to NNEEC under the tax-sharing agreement at September 30, 2019 and 2018, respectively.

(m) Pension and Other Postretirement Benefit Plans

GMP 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 employees and April 1, 2010 for former CVPS employees, newly hired employees are not eligible to participate in GMP'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 based on current rates and trends annually. The effect of modifications to those assumptions is recorded in regulatory assets and amortized to net periodic cost over future periods using the corridor method. 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. The Company's methodology for estimating the service cost and interest cost components of their pension and postretirement plans applies specific spot rates along the yield curve to the projected cash flows in order to estimate the service cost and interest cost for each plan. 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.

(n) Contingencies

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

(o) Fair Value Measurements

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 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 the 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, which 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 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. All investments for which NAV is used to measure fair value are not required to be categorized within the fair value hierarchy.

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 spent fuel disposal fee and accrued interest obligation, the Millstone and Spent Fuel Decommissioning and Rabbi Trust Funds, and pension assets.

(p) Recently Adopted Standards

Revenues

On October 1, 2018, the Company adopted Accounting Standard Update ("ASU") 2014-09, *Revenue From Contracts With Customers (Topic 606)*. This standard aims to improve comparability among revenue recognition practices. It requires that a new five-step model based on certain core principles be applied across all revenue types. It also sets out additional disclosure requirements, in particular the nature, amount and uncertainty of revenue recognition as well as the related cash flows and the moment at which they will be collected by the entity.

The Company's revenue recognition accounting policy was amended as follows:

Revenues from rate-regulated activities come mainly from electricity distribution activities. Most of the Company's contracts have only one performance obligation, namely the delivery of energy. More specifically, energy distribution revenues are recorded as the energy is delivered and according to the amount that the Company is permitted to bill customers in accordance with the underlying price agreements approved by the VPUC.

Financial instruments

On October 1, 2018, the Company adopted, on a prospective basis, *ASU 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. This standard amends certain presentation, measurement and disclosure requirements applicable to financial instruments. More specifically, investments in equity securities, other than equity-accounted interests and consolidated interests, must be presented at fair value, and any change in fair value must be accounted for in the consolidated statement of income. Adoption of this new guidance did not have a significant impact on the Company's consolidated financial statements.

Cash flows

On October 1, 2018, the Company adopted, on a retrospective basis, *ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*. The purpose of this standard is to reduce the diversity in the consolidated statement of cash flows presentation of eight specific kinds of transactions. Adoption of this new guidance did not have an impact on the Company's consolidated financial statements.

On October 1, 2018, the Company adopted, on a retrospective basis, *ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash*. According to this standard, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling beginning-of-period and end-of-period total amounts. Following the adoption of ASU 2016-18, changes in restricted cash and cash equivalents presented in the consolidated statement of cash flows are reported in changes in cash and cash equivalents rather than in operating or investing activities. This change led to a consolidated statement of cash flow reclassification of $379 from operating activities, $109 from investing activities, and $488 to the change in cash and cash equivalents for the year ended September 30, 2018.

Employee future benefits

On October 1, 2018, the Company adopted *ASU 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The new guidance requires the "service cost" component of the net projected benefit cost to be included in compensation-related operating expenses, whereas other components of net cost will be presented in non-operating expenses. Under this new guidance, the only component eligible for capitalization is the "service cost." The Company adopted this new guidance on a prospective basis for the capitalization component and on a retrospective basis for the consolidated income statement presentation component. Following the adoption of this new guidance, the Company retrospectively restated the consolidated statement of income for the comparative year ended September 30, 2018. An amount of $377 net benefit, previously reported in the Selling, administrative and marketing item of the consolidated statements of income was reclassified to the Other income, net item for the year ended September 30, 2018.

(q) Accounting Pronouncements Issued, But Not Yet Adopted

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)". ASU 2016-02 requires the recognition of operating lease obligations and right of use assets by lessees for those leases currently classified as operating leases and makes certain changes to the accounting for lease expenses. The Company adopted the new leases guidance effective October 1, 2019 and has elected the optional transition method under which the Company will initially apply the standard on that date without adjusting amounts presented for prior periods and record the cumulative effect of applying the new guidance as an adjustment to beginning retained earnings. The Company expects the adjustment to retained earnings will be immaterial.

Concerning certain transition and other practical expedients, the Company:

- elected the package of three practical expedients available under the transition provisions, including (i) not reassessing whether expired or existing contracts contain leases, (ii) lease classification, and (iii) not revaluing initial direct costs for existing leases;
- elected the land easement practical expedient and did not reassess land easements and did not account for as leases prior to our adoption of the new leases guidance;
- will not recognize lease assets and liabilities for short-term leases (less than one year), for all classes of underlying assets; and
- did not separate lease and associated nonlease components for transitioned leases, but will instead account for them together as a single lease component.

The adoption of the new standard is not expected to have a material impact on GMP.

(3) Rate Regulation and Regulatory Assets and Liabilities

(a) Rate Regulation

As a condition of the VPUC'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 years 2016 through 2020, customers and the Company share synergy savings on a 50/50 basis.
- In years 2021 through 2022, all synergy savings will be credited to customers.
- If total measured savings to customers are less than $144,000 at the end of the 10 year period, the Company shall provide the difference to retail customers by means of a Savings Guarantee Plan approved by the VPUC.

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.

On November 29, 2017, the VPUC approved the continuation of the PSA and Exogenous Change Adjustments of the Successor Alternative Regulation Plan for the Company (Successor Plan) through December 31, 2018. On May 24, 2018, the VPUC approved their continuation through the approval of a successor regulation plan or until December 31, 2019, whichever occurs first. The PSA and Exogenous Change Adjustments were in effect throughout 2019.

In December 2017, the VPUC approved a 5.37% increase in base rates effective January 3, 2018. The allowed ROE was 9.1%.

On September 11, 2018, the Company announced a multi-year term contract was reached with its only Transmission Class customer to provide the customer with stable and predictable energy costs through a fixed rate. In exchange, the customer agrees to maintain its power use on site, and forgo credits or rate cuts flowing to other Company customers during the term of the agreement, including the significant tax reform credits. The term contract is effective from January 1, 2019 through September 30, 2022 and has been approved by the VPUC.

In December 2018, for customers other than in the Rate 70 Transmission Class, the VPUC approved a 5.43% increase in base rates on or after January 3, 2019, and an allowed annualized ROE of 9.30%. In addition, the VPUC approved a return of $27.4 million related to corporate tax reform benefits as a separate bill credit during the 9 month rate period starting January 3, 2019 through September 30, 2019, more than offsetting the base rate increase occurring during that period.

On June 4, 2018, the Company filed a proposed Multi-Year Regulation Plan (MYRP) to establish the process to set the Company's rates for the three-year period starting in 2020, (October 1, 2019 through September 30, 2022), and on May 24, 2019, the VPUC approved the MYRP.

The MYRP includes the following principle elements:

- This filing provides the projected, smoothed base rate for all three years of the Plan, based on a three-year forecast of all costs. The projected, smoothed base rate is the projected average rate for each fiscal year in the Plan. This rate will be used to set the initial annual base rate for 2020 as filed for approval in June 2019 and to provide the projected rates for 2021 and 2022, which will still be subject to any annual adjustments authorized under the Plan as described below.
- Once approved, the non-power costs contained in the initial annual base rate filing for 2020, 2021 and 2022 will be fixed for the term of the Plan. The MYRP provides for annual base rate adjustments to the Company's power supply costs, revenue forecasts, return on equity and associated ancillary impacts on income tax expense and gross revenue and fuel gross receipts tax. These subsequent base rate filings will be made on June 1 of each year for 2021 and 2022.
- The allowed ROE will adjust annually, up or down based on 50% of the change in the 10-yr Treasury bond yield. For 2020, the change is measured from the last quarter of calendar year 2018. For 2021 and 2022, the bond yield will be determined by taking the daily average for the period February 16^{th} to May 15^{th} each year to determine the change in allowed ROE.
- GMP's capital expenditures closed to plant in service are limited to $256.5 million over the life of the MYRP or approximately $85 million per year, subject to limited exceptions under the MYRP.
- The MYRP includes a quarterly Power Supply Adjustor and Retail Revenue Adjustor.

  The Power Supply Adjustor trues up actual power supply costs against forecasted costs on a quarterly basis, with a cost variance calculation and power cost efficiency band of +$150 (retained by GMP) and -$307 (absorbed by GMP) applied to a portion of the power costs. The Power Supply Adjustor will compare actual costs during the quarterly measurement period against the same forecasted costs in the relevant quarterly period included in rates and then will collect or return any adjustments outside of the efficiency band.

The Retail Revenue Adjustor tracks actual retail revenue every quarter against the forecasted amount for that quarter. Any variations between the forecasted retail revenue and the actual quarterly results are reported as an over-or-under collection at the end of each quarter. The calculated collection or return resulting from both the Retail Revenue Adjustor and the Power Supply Adjustor will be netted against each other on a quarterly basis and the resulting return or collection from both Adjustors will be set out as a separate line item on customer bills in a subsequent quarter.

- The MYRP includes a three-part Exogenous Change Adjustor.

  The first component of the Exogenous Change adjustor addresses non-storm exogenous events outside of the Company's control and in excess of $1,200 in any fiscal year.

  The second component addresses Major Storm events that occur during the term of the MYRP. A Major Storm is, as defined in the GMP Service Quality and Reliability Plan, an event that exceeds $1,200 in maintenance costs. There will also be a $1,200 deductible for the aggregate of all Major Storm exogenous events each fiscal year.

  The third and final component of the Exogenous Change adjustor addresses collection of Prior Major Storm costs that have been incurred prior to the inception of the MYRP that are not being collected from customers at the inception of the MYRP. On October 1, 2019, the Company will start collecting $8,000 per year from customers as a separate line item surcharge to cover the approximately $24,000 of prior year major storm costs that have accrued to date.

- The MYRP includes an Earning Sharing Adjustment Mechanism "ESAM" under which the Company has the opportunity to earn up to 68.75 basis points above its allowed ROE, return 100% of earnings in excess of 68.75 basis points above the allowed ROE, recover 50% of any earnings shortfall between 50 basis points and 150 basis points below the allowed ROE and 100% of any earnings short fall in excess of 150 basis points below the allowed ROE. Under the MYRP, 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 as a separate line item on customer bills for a 12-month period starting April 1 of the following year, unless otherwise ordered by the VPUC.
- The MYRP establishes an Emerald Ash Borer "EAB" Adjustor which will collect $1,200 annually as a separate line item on customer bills to proactively remove ash trees in power line corridors that are confirmed to have EAB infestations or are at high risk of EAB infestation. Each year the Company will file an annual report on actual EAB expenditures under the mitigation plan and identify any returns or collections necessitated by changes in infestation spread rate which will be collected or returned through an adjustment to the EAB line item.
- The MYRP continues the Company's existing innovative pilot program and existing service quality and reliability performance monitoring and reporting requirements.
- The MYRP authorizes the Company to seek approval of a Climate Resiliency Plan to address threats to GMP's system from more frequent and intense storm events related to climate change and to accelerate the pace of GMP's current storm-hardening measures to maintain service quality.
- The MYRP requires GMP to file a traditional cost of service rate case no later than January 15, 2022, for rates for 2023.

On June 13, 2019, the Company filed its initial annual base rate filing pursuant to the MYRP.

On September 12, 2019, the Company filed updated cost of service schedules incorporating the requested adjustments by the Department and accepted by the VPUC to power supply, property taxes and return on equity. These adjustments resulted in a final base rate increase of 2.72% for 2020 with an allowed ROE of 9.06%.

On September 26, 2019, the VPUC approved the base rate increase and allowed ROE to go into effect October 1, 2019.

(b) Regulatory Assets and Liabilities

Regulatory assets and liabilities at September 30, 2019 and 2018 consist of the following:

			Amortizable 2019 balances in rates	Original amortization period
Regulatory assets:				
Unfunded pension and postretirement benefits	$	91,321	—	
Deferred storm costs		23,901	23,901	2-3 years
CEED fund		12,711	12,711	10 years
Pine Street Barge Canal costs		8,842	5,975	20 years
PSA costs-under collection		3,698	2,438	2-3 years
Deferred efficiency fund		1,337	615	10 years
Income taxes		3,026	—	
Digester development costs		1,805	1,805	3 years
Derivative financial instrument		22,419	—	
Asset retirement obligations (ARO)		217	217	18 years
Microgrid day one gain		3,086	3,086	1 year
Excess tax reform refunded to customers		4,043	—	
Tax reform		238	—	
Other regulatory assets		18	67	Various
Total regulatory assets		176,662	50,815	
Regulatory liabilities:				
Accumulated nonlegal costs of removal		33,486	—	
Derivative financial instrument		3,226	—	
Millstone Unit #3 ARO		10,284	—	
Microgrid development fee		1,760	1,760	3 years
Overfunded postretirement benefits		1,934	—	
VYNPC net unrealized gains on long-term investments		1,073	—	
Transco investment gain		241	241	3 years

Tax reform	148,179	84,000	33 years
Other regulatory liabilities	522	—	
Total regulatory liabilities	200,705	86,001	
Net regulatory liabilities	$ (24,043)	(35,186)	
Regulatory assets classified as current	$ 28,275		
Regulatory liabilities classified as current	3,463		

	2018	Amortizable 2018 balances in rates	Original amortization period
Regulatory assets:			
Unfunded pension and postretirement benefits	$ 59,166	—	
Deferred storm costs	13,664	1,755	2 years
CEED fund	14,767	14,767	10 years
Pine Street Barge Canal costs	9,059	6,507	20 years
PSA costs-under collection	14,118	6,912	2 years
Meter retirements	392	392	5 years
Deferred efficiency fund	2,425	1,702	10 years
Income taxes	2,807	—	
Renewable energy due diligence costs	52	52	3 years
Derivative financial instrument	22,831	—	
Asset retirement obligations (ARO)	248	248	18 years
Synergy savings	400	400	
No rate change	1,280	—	
Tax reform	10,229	—	
Other regulatory assets	1,262	125	Various
Total regulatory assets	152,700	32,860	
Regulatory liabilities:			
Accumulated nonlegal costs of removal	32,546	612	2 years
Derivative financial instrument	11,101	—	
Electricity assistance program	340	—	1-2 years
Millstone Unit #3 ARO	9,942	—	
Solar development fee	399	399	2 years
Overfunded postretirement benefits	6,424	—	
VYNPC net unrealized gains on long-term investments	667	—	
Deferred PSA revenues-over collection	5	5	1 year
Transco Utopus gain	6,972	—	
Tax reform	187,429	—	
Other regulatory liabilities	862	—	

Total regulatory liabilities		256,687	1,016
Net regulatory (liabilities) assets	$	(103,987)	31,844
Regulatory assets classified as current	$	23,023	
Regulatory liabilities classified as current		38,400	

The preceding table indicates the amount of net regulatory assets (liabilities) currently recorded. These amounts do not include the recognition of tax effects, which generally would be approximately 27.7%. 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.

i. Unfunded and Overfunded Pension Benefits and Postretirement Benefits

The pension and other postretirement benefit regulatory assets and liabilities 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. Any overfunded benefit plans will be returned to customers in future rates so they are recorded as regulatory liabilities. See note 13.

ii. Deferred Storm Costs

Under Company's Regulation Plan, exogenous storm costs in excess of $1,200 allowed for exogenous factors may be recorded as a regulatory assets and recovered in future periods.

On November 15, 2017, GMP filed its request to recover $2,331 of deferred exogenous storm cost incurred during the April 1, 2016 to March 2017 Exogenous storm measurement period. The VPUC has approved recovery of these costs over 24 months beginning April 1, 2018. The amount remaining to be recovered as of September 30, 2019 is $560.

GMP has deferred exogenous storm costs of $7,249 incurred during the April 1, 2017 to December 31, 2017 and $16,092 incurred during the January 1, 2018 to December 31, 2018 exogenous storm measurement periods. Per the MYRP, these deferred storm costs will be recovered over 3 years beginning October 1, 2019.

iii. Community Energy and Efficiency Fund (CEED Fund)

One of the conditions associated with the VPUC approval of the acquisition of the former CVPS was that GMP 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 VPUC 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 must be made by June 2019. The Required Investment must 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 plus accrued interest on unprovided benefits (Required Benefit). As of September 30, 2018, the Required Investment including accrued interest was $21,697 and the Required Benefit was $28,965. As of September 30, 2018, GMP has made the required investment which has produced a benefit of $35,557.

On August 29, 2019, the VPUC issued an order to close the CEED fund.

iv. Pine Street Barge Canal Costs

The Company has recorded a regulatory asset to reflect unrecovered past and future Pine Street Barge Canal costs. After expenses are incurred, the Company will reflect the expenditures in subsequent base rate filings and amortize the full amount of incurred costs over 20 years without a return. The amortization of the past unrecovered costs regulatory asset of $5,975 is included in rates. The estimated future unrecovered cost regulatory asset of $2,867 has a matching liability. The amortization of this regulatory asset is expected to be recovered in future rates. See note 17(b).

v. *PSA Over/Under-Collection*

Under the PSA, the Company records regulatory assets or liabilities for the future recovery from customers of 90% of energy costs that are $307 (per quarter) higher or lower than energy costs included in rates for 2019 and 2018, and the full amount of transmission and capacity higher or lower than included in rates.

As of September 30, 2019 and 2018, GMP recorded net deferred costs of $3,698 and $14,113, respectively. Deferred amounts are recovered from or credited to customers on an annual basis under the Alternative Regulation Plan.

vi. *Meter Retirements*

GMP has recorded a regulatory asset for old meters being replaced as a result of new technology related to the SmartPower implementation. The amount was amortized over a 5-year period and ended December 31, 2018.

vii. *Deferred Efficiency Fund*

One of the conditions associated with VPUC approval of the 2007 acquisition of GMP by NNEEC (2007 acquisition) was that GMP 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.

viii. *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 ITCs. These income tax regulatory assets and liabilities are combined into a net income tax regulatory asset.

ix. *Renewable Energy Due Diligence Costs*

GMP has recorded a regulatory asset for costs related to renewable energy projects which GMP has decided not to move forward with. The amount was amortized over a 3-year period that commenced October 1, 2015.

x. *Digester Development Costs*

GMP has recorded a regulatory assets for costs related to the preliminary study for the St. Albans digester project. Per the MYRP, these costs will be amortized over the 3 year period beginning October 1, 2019.

xi. *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 GMP charges and are discussed in detail in note 14.

xii. *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. GMP amortizes amounts over periods similar to associated long lived assets included in utility plant.

xiii. *Microgrid Day One Gain*

GMP has recorded a regulatory asset for GMP Microgrid day one gains returned to customers in 2019. GMP Microgrid 2020 gains will be offset against this regulatory asset.

xiv. *Excess Tax Reform Refunded to Customers*

During the period from October 1, 2018 to September 30, 2019 a refund was given to customers due to the tax reform. Over that period, more was refunded than actual tax reform benefits received so this excess will be collected as part of a future rate case.

xv. *Synergy Savings*

GMP has recorded a net regulatory asset for synergies that will be collected from customers. GMP had a regulatory asset of $400 at September 30, 2018. As of September 30, 2019 GMP had synergies that will be collected from customers of $1,750. This is included in other deferred charges and will be collected in rates in a future rate filing.

xvi. *No Rate Change*

Due to no change in base rates for the period October 1, 2017 and December 31, 2017, GMP continued the level of regulatory assets and liabilities amortization included in base rates resulting in a net excess credit amortization being returned to customers. This excess amortization resulted in a net regulatory asset which the Company recovered during the year ended September 30, 2019.

xvii. *Tax Reform*

Represents the regulatory asset created by the deferral of the utility costs resulting from federal tax reform. This regulatory asset will be netted against the related regulatory liability and the net regulatory liability will be returned to customers through future rates.

xviii. *Other Regulatory Assets*

Consists of various other projects and deferrals that the Company expects to be recovered in future rates.

xix. *Accumulated Non-Legal 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 under- or over-collected net costs of removal. The Company had a regulatory liability of $612 at September 30, 2018 for nonlegal cost of removal that was returned to customers from October 1, 2018 to December 31, 2018.

xx. *Electricity Assistance Program*

The Vermont Legislature passed a law in 2009 authorizing the VPUC 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. The balance will be used either to continue to fund the program or returned to customers in future rates.

xxi. Millstone Unit #3 ARO

The Company has legal asset retirement obligations for decommissioning related to its jointly owned nuclear plant, Millstone 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. Millstone is currently operating and the ultimate decommissioning cost is an estimate at this time. The liability balance will decrease when the forecasted decommissioning obligation exceeds the trust fund asset, resulting in a regulatory asset or returned to customers when Millstone is fully decommissioned.

xxii. Solar Development Fee

GMP has recorded a regulatory liability for fees received related to the development of certain solar projects and the deferred day one gain received from its investment in GMP VT Solar. These fees and the gain were returned to customers from October 1, 2016 to December 31, 2018 in accordance with the 2017 and 2018 base rate filings.

xxiii. Microgrid Development Fee

GMP has recorded a regulatory liability for fees received from GMP VT Microgrid related to the development of certain microgrid projects. A portion of these fees were returned to customers from October 1, 2018 to September 30, 2019 in accordance with the 2019 base rate filing. The remaining balance is being returned over 3 years beginning October 1, 2019.

xxiv. VYNPC Net Unrealized Gains on Long Term Investments

Net realized gains (losses) on investments in debt securities in the VYNPC Spent Fuel Disposal Trust have the effect of reducing (increasing) billings to VYNPC customers. Accordingly, the Company includes any net unrealized gain or loss (i.e., the difference between their cost and fair values) as an increase to regulatory assets or regulatory liabilities.

xxv. Transco Investment Gain

Pursuant to an Accounting Order issued by the VPUC, GMP has deferred its share of an investment gain recognized by Transco in 2018 and 2019. GMP deferred \$8,549 and has returned \$8,308 to customers through September 30, 2019. The remaining balance is being returned to customers over 3 years beginning October 1, 2019.

xxvi. Tax Reform

Represents the regulatory liability created by the deferral of the utility benefits resulting from federal tax reform. The regulatory liability of \$148,179 at September 30, 2019, consists of \$84,000 of protected plant which is being returned to customers over 33 years and \$64,179 associated with GMP's investment in Transco. Return of the Transco tax reform regulatory liability is dependent on Transco receiving FERC approval which has not yet been received.

(4) Investments in Associated Companies and Joint Owned Facilities

Investments in associated companies at September 30, 2019 and 2018 include the following:

	Ownership interest	
	2019	**2018**

VELCO - common stock	38.8%$	9,651	38.8%$	9,690
VELCO - preferred stock	80.1	170	80.1	174
Total VELCO		9,821		9,864
Transco LLC	74.2	613,535	72.1	585,242
Green Lantern Capital Solar Fund II, LP	99.9	561	99.9	905
New England Hydro Transmission - Common	3.2	258	3.2	237
New England Hydro Transmission Electric - Common	3.2	1,578	3.2	1,498
Connecticut Yankee	2.0	44	2.0	39
Maine Yankee	2.0	52	2.0	48
Yankee Atomic	3.5	57	3.5	57
Investments in associated companies		$ 625,906		$ 597,890

(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, GMP 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 GMP, VELCO and Transco, and VELCO remains subject to an Amended Four-Party Agreement among GMP and VELCO. VELCO currently has a 4.0% ownership interest in Transco. The remaining ownership interest in Transco is held by other Vermont-based utilities.

Pursuant to the merger agreement and VPUC 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 GMP's ability to exercise control over VELCO.

GMP has performed an evaluation to determine whether Transco LLC should be consolidated in its financial statements. GMP determined that the variable interest entity model is appropriate model for this evaluation. VELCO, as the managing member of Transco, has complete and exclusive discretion to manage and control Transco's business. The nonmanaging members, such as GMP, are not allowed to participate in the management or control of Transco. Based on this, the evaluation determined that GMP does not have a controlling financial interest in Transco, and therefore, it is not Transco's primary beneficiary and is not required to consolidate Transco in its financial statements.

Transco provides transmission services to GMP 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, GMP and all other Vermont electric utilities pay their pro rata share of Transco's total costs, including interest on debt and a fixed ROE, less revenues collected by Transco under the ISO-New England Open Access Transmission Tariff and other agreements. Under these agreements, Transco provided transmission services to GMP (reflected as transmission expenses in the consolidated statements of income) amounting to $35,709 and $19,515 for the years ended September 30, 2019 and 2018, respectively.

Transco is exposed to operating cost risk, regulatory risk associated with decisions which allow recovery of its expenses and shareholder return through tariff rates and how its customers (retail electric utilities in the State) are allowed to recover their costs in their own tariffs, and credit risk associated with a possible default by a counterparty (also retail electric utilities in the State) to the FERC tariffs under which Transco LLC operates. These risks potentially affect the amount of costs allocated to GMP as well as the carrying value of its investment in Transco LLC. The maximum exposure to loss is the carrying value of GMP's investment.

GMP made capital investments of $17,924 and $38,953 in Transco in 2019 and 2018, respectively, to support various transmission projects. GMP received a return of capital from Transco of $1,484 in 2019 and there was no return of capital in 2018. GMP 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. GMP 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:

	2019	2018
Net income	$ 93,188	101,379
GMP's equity in net income	72,485	77,521
Total assets	$ 1,334,827	1,298,797
Liabilities and long-term debt	540,858	520,314
Net assets	$ 793,969	778,483
GMP's equity in net assets	$ 613,535	585,242
Amounts due (to) from Transco, net	(96)	784

GMP's share of Transco's 2019 and 2018 net income included $1,577 and $6,972, respectively, related to the gain on the sale of an investment. Pursuant to an Accounting Order issued by the Commission, GMP has deferred this gain to a regulatory liability. The income statement deferral is included in equity in earnings of associated companies on the consolidated statements of income.

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

As of September 30, 2019, VELCO has a 4% ownership interest in Transco, bringing GMP's direct and indirect ownership interest in Transco to 75.7%.

Included in the Company's financial statements are construction service receipts of $349 and $1,154, billed to VELCO for the years ended September 30, 2019 and 2018, respectively.

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

	2019	2018
Net income	$ 2,225	2,885

GMP's equity in net income		1,039	1,026
Total assets	$	68,080	69,015
Liabilities and long-term debt		43,074	43,462
Net assets	$	25,006	25,553
GMP's equity in net assets	$	9,821	9,864

(b) Other Investments in Associated Companies

Green Lantern Capital Solar Fund II, LP: GMP 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. GMP 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 $162 and $166 during the years ended September 30, 2019 and 2018, respectively.

(c) Joint Owned Facilities

GMP's joint-ownership interests in electric generating and transmission facilities as of September 30, 2019 and 2018 are as follows:

	2019				
	Ownership interest	Share of capacity (in MW)		Share utility plant	Share of accumulated depreciation
Joseph C. McNeil	31.0%	16.7	$	30,701	28,250
Wyman #4	2.9	17.6		6,328	6,328
Stony Brook #1	8.8	31.0		12,314	11,580
Metallic Neutral Return	59.4	—		1,563	1,563
Millstone Unit #3	1.7	21.4		84,295	50,690

	2018				
	Ownership interest	Share of capacity (in MW)		Share of utility plant	Share of accumulated depreciation
Joseph C. McNeil	31.0%	16.7	$	30,211	27,238
Wyman #4	2.9	17.6		6,328	6,268
Stony Brook #1	8.8	31.0		12,264	11,434
Metallic Neutral Return	59.4	—		1,563	1,563
Millstone Unit #3	1.7	21.4		83,670	49,677

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 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. 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, 2019 and 2018, there were minimal realized gains and no realized losses. There were also no loss impairments of debt securities in 2019.

The fair values of these investments as of September 30, 2019 and 2018 are summarized below:

	2019		2018	
	Cost	**Fair value**	**Cost**	**Fair value**
Marketable equity securities	$ 4,080	11,470	$ 3,919	11,103
Marketable debt securities:				
Corporate bonds	578	638	544	550
U.S. government issued debt securities (agency and treasury)	1,114	1,180	1,167	1,160
State and municipal	67	76	48	51
Total marketable debt securities	1,759	1,894	1,759	1,761
Cash equivalents and other	96	96	76	76
Total	$ 5,935	13,460	$ 5,754	12,940

The reported trust balances include net unrealized gains of $7,525 and $7,186 as of September 30, 2019 and 2018, respectively. GMP has recorded the corresponding adjustment as a regulatory liability.

Information related to the fair value and maturities of debt securities at September 30, 2019:

Within one year	$ 145
One to five years	555
Five to ten years	420
Over ten years	774
	$ 1,894

(6) Utility Plant in Service

The major classes of utility plant are as follows:

	Depreciable life in years	September 30 2019	2018
Property, plant and equipment:			
Distribution	10-60	$ 927,738	864,933
Generation	35-110	672,535	609,703
Transmission	50-60	197,907	185,602
Intangible, FERC licenses and software	5-40	59,072	67,248
Buildings	50	48,031	47,963
General	10-30	28,005	26,207
Electric plant acquisition adjustments	11-35	33,350	22,951
Transportation	14	38,981	33,532
Office equipment	5-15	24,868	25,242
Nuclear fuel, net	1-6	1,786	1,979
Total plant in service		2,032,273	1,885,360
Accumulated depreciation and amortization		675,322	632,482
Net plant in service		1,356,951	1,252,878
Construction work in progress		39,598	51,248
Total utility plant, net		$ 1,396,549	1,304,126

In June 2019, the Company acquired certain utility poles, anchors and associated hardware located in Vermont for a total purchase price of $13,440. The Company assessed this asset acquisition in accordance with ASC 805 - *Business Combinations* as amended by ASU No. 2017-01 - *Clarifying the Definition of a Business* and meets the similar asset threshold and was accounted for as an asset acquisition. The purchase price of the poles, anchors and associated hardware is reported in the above Distribution utility plant major class.

Depreciation and amortization expense amounted to $58,265 and $56,614 in 2019 and 2018, respectively. During the years ended September 30, 2019 and 2018, administrative and general costs of $7,471 and $6,079, respectively, were capitalized, and there were no significant retirements. The composite depreciation rate for plant in service was 2.87% and 3.00%, respectively, in 2019 and 2018. The amount of construction work in progress (CWIP) included in rate base was $6,128 and $6,614 in 2019 and 2018, respectively.

(7) Credit Facilities

Effective September 14, 2018, GMP entered into a $140,000 revolving credit facility, with a $10,000 accordion feature, with KeyBank N.A. as the lead bank. This facility replaced a $110,000 revolving credit facility with a $15,000 accordion feature 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 GMP 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-. GMP has chosen to borrow using an Overnight LIBOR rate in 2019 and 2018. At September 30, 2019 and 2018, the Overnight LIBOR rate was 2.75% and 2.92%, respectively. GMP had $125,989 and $73,511 in cash borrowings, and $6,569 and $11,322 in letters of credit outstanding under its credit facility at September 30, 2019 and 2018, respectively. The Revolver balance has been classified as long-term debt at September 30, 2019 and 2018, as the current facility has a maturity date of September 13, 2022, and the previous facility had a maturity date of December 14, 2019, and no annual requirement to pay off the outstanding balance on the credit facility. GMP was in compliance with all restrictive covenants and limitations as of September 30, 2019 and 2018.

In addition, GMP has a Reimbursement Agreement with KeyBank N.A. as the lead bank under which the Company can issue up to $5,000 in letters of credit. At September 30, 2019 GMP has issued $5,000 in letters of credit under this Agreement.

(8) Long-Term Debt

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

	September 30	
	2019	**2018**
Total first mortgage bonds outstanding	$ 749,830	726,131
Revolving line of credit	125,989	73,511
Total long-term debt outstanding	875,819	799,642
Less current maturities (due within one year)	10,330	86,300
Total long-term debt outstanding, less current maturities	$ 865,489	713,342
Weighted average interest rate on first mortgage bonds	4.85%	5.14
Interest rate on revolving line of credit	2.75	2.92

The current corporate unsecured credit rating by S&P is A-; and the current senior secured debt credit ratings for GMP's first mortgage bonds by S&P is A. Amortization of capitalized bond issue expenses totaled $549 and $554 for the years ended September 30, 2019 and 2018, respectively.

On October 17, 2019, GMP agreed to issue $40,000 in First Mortgage Bonds under the 30th Supplemental Indenture in two series. The terms related to each series of bonds are anticipated to be customary and in line with past bond issuances. As in past bond issuances, the bonds will include a provision for a "make-whole premium" which would apply if GMP called the bonds prior to maturity. Since there is a make-whole premium, there would be no detriment to investors if the bonds were redeemed prior to maturity. Each series of bonds will have a fixed rate, the bonds to be issued in December 2019, consist of a $25,000 series with an interest rate of 3.53% which mature in 2049, and a $15,000 series with an interest rate of 3.01% which mature in 2034.

On June 13, 2019, GMP issued a total of $90,000 in First Mortgage Bonds under the 29th Supplemental Indenture in two series. The terms related to each series of bonds are customary and in line with the terms found within GMP's previous bond issuances. As in past bond issuances, the bonds include a provision for a "make-whole premium" which would apply if GMP 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 a $50,000 series with an interest rate of 3.79% which mature in June 2034 and a $40,000 series with an interest rate of 3.95% which mature in June 2039.

On September 19, 2018, GMP closed on a $25,000 First Mortgage Bond issuance and on December 3, 2018 GMP issued an additional $20,000, each under the 28th Supplemental Indenture. The terms related to each series of bonds are customary and in line with the terms found within GMP's previous bond issuances. As in past bond issuances, the bonds include a provision for a "make-whole premium" which would apply if GMP 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 $25,000 series with an interest rate of 3.84% which mature in September 2030 and the $20,000 series with an interest rate of 4.20% which mature in December 2048.

GMP'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, 2019 and 2018.

The table below includes the maturity of long-term debt in the five years subsequent to September 30, 2019:

2020	$ 10,330
2021	31,355
2022	134,874
2023	915
2024	17,500
Thereafter	680,845
Total	$ 875,819

The First Mortgage bonds that mature beyond 2024 have maturity dates that range between 2025 and 2049.

(9) Asset Retirement Obligations

(a) General

The Company continually reviews the regulations, laws, and contractual obligations to which it is a party to identify situations where there are legal obligations to perform asset retirement activities. Through these reviews, the Company has identified certain easements that may obligate the Company to perform asset retirement activities. There was an additional ARO identified in 2019 for GMP VT Microgrid totaling $918. There were no new obligations identified in 2018. The present value of such obligations identified and recorded as of September 30, 2019 and 2018 was $11,193 and $9,798, respectively. The increase in the asset retirement obligations is a result of the GMP VT Microgrid addition and the 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 $4,569 and $4,344 at September 30, 2019 and 2018, respectively, for the decommissioning of GMP's wind facilities located on leased property. Related to this obligation, GMP has a letter of credit against its credit facility for $6,322. See note16g.

(c) Millstone Unit #3

The asset retirement obligations include $3,176 and $2,998 at September 30, 2019 and 2018, respectively, for decommissioning related to GMP's joint-owned nuclear plant, Millstone Unit #3. See notes 3, 5b, and 15a for further information.

Changes in the total carrying value of the asset retirement obligations for the years ended September 30, 2019 and 2018 are as follows:

	2019	2018
Balance at beginning of period	$ 9,798	9,343
Additions	918	—
Accretion expense	477	455
Balance at end of period	$ 11,193	9,798

(10) Other Liabilities

Other current and noncurrent liabilities at September 30, 2019 and 2018 are as follows:

	2019	2018
Other current liabilities:		
Health, insurance and damage reserves	$ 5,573	5,207
Accrued taxes other than income	3,661	3,702
Cash concentration account - outstanding checks	4,710	3,348
Other	463	639
Accrued capital and O&M costs	4,349	3,410
SERP retirement benefits	1,965	381
Customer credit balances	8,356	6,158
Deferred compensation	542	306
Total other current liabilities	$ 29,619	23,151
Other noncurrent liabilities:		
Accrued employee-related costs	$ 731	793
Nuclear decommissioning	16	26
Other liabilities	367	81
Total other noncurrent liabilities	$ 1,114	900

(11) Stockholder's Equity

(a) Appropriated Retained Earnings

GMP had appropriated retained earnings of $787 at September 30, 2019 and 2018 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 GMP's indentures relating to long-term debt and in the Amended and Restated Articles of Incorporation. Under the most restrictive of such provisions, $233,154 and $195,972 of retained earnings were free of restrictions at September 30, 2019 and 2018, respectively.

Certain restrictions on the payment of cash dividends on common stock exist as a result of conditions of the VPUC's approval of the 2007 acquisition of GMP by NNEEC and the approval of the merger between GMP and the former CVPS. GMP is required to notify the VPUC of any changes that result in a 3% or greater change in capital structure from the structure approved in GMP's last rate proceeding. GMP 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, 2019 and 2018, GMP provided notices related to regular common stock cash dividends.

(c) Capital Contributions

In the years ended September 30, 2019 and 2018, GMP received capital contributions of $10,000 and $0, respectively, from its parent, NNEEC. The primary purpose of the investment was to fund investments in utility plant and affiliates.

(12) Income Taxes

The provision for income taxes for the years ended September 30, 2019 and 2018 is summarized as follows:

	2019	2018
Current federal income taxes	$ —	—
Current state income taxes	24	24
Total current income taxes	24	24
Deferred federal income taxes	(4,434)	16,892
Deferred state income taxes	(269)	8,190
Total deferred income taxes	(4,703)	25,082
Investment tax credits-net	(139)	(139)
Income tax (benefit) expense	$ (4,818)	24,967
Effective combined federal and state income tax rate	(6.35)%	25.14%

The significant items that reconcile between income taxes computed by applying the U.S. federal statutory rate of

21% for 2019 and 24.53% for 2018 and the reported income tax expense (benefit), for the reporting period, include the dividends received deduction, amortization of ITCs, energy credits, corporate owned life insurance, AFUDC equity, and state income tax. In 2019, GMP returned "non-protected" and "protected" accumulated deferred income taxes to customers and 2018 reflected the impact of the Tax Cuts and Jobs Act on nonregulated business deferred taxes.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at September 30, 2019 and 2018 are presented below:

	2019	2018
Deferred tax assets:		
Regulatory liability - Tax reform	$ 41,068	49,206
Net operating losses and tax credits	66,541	61,202
Asset retirement and cost of removal obligations	12,199	11,981
Deferred compensation and other benefit plans	26,234	18,451
Other liabilities and deferred credits	5,255	11,251
Derivative financial instruments	7,107	9,404
Total deferred tax assets	158,404	161,495
Deferred tax liabilities:		
Accelerated tax depreciation on property	211,703	206,307
Regulatory assets - Pension and other postretirement benefits	26,119	18,215
Pine Street Barge Canal	2,450	2,511
Investment in associated companies	125,546	111,573
Other deferred charges and other assets	19,738	22,882
Derivative financial instrument regulatory assets	7,107	9,404
Total deferred tax liabilities	392,663	370,892
Net deferred income tax liability	$ 234,259	209,397

The change in the net deferred income 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, changes in regulatory assets and liabilities and net operating losses.

As of September 30, 2019, GMP has recorded $66,541 of deferred tax assets related to net operating loss (NOL) carryforwards and tax credit carryforwards. Federal NOLs generated prior to tax reform will expire if unused starting in fiscal year 2033. State NOLs will expire if unused starting in fiscal year 2023. Management believes it is more likely than not that GMP 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 GMP has not recorded any valuation allowances as of September 30, 2019 and 2018.

GMP records the benefits of ITCs through the amortization, as approved by the VPUC, of the unamortized ITCs, which are initially recorded as a liability. The remaining balance of unamortized ITCs shown separately on the consolidated balance sheets at September 30, 2019 and 2018 was $7,306 and $7,377, respectively.

While GMP believes it has adequately provided for all tax positions, amounts asserted by taxing authorities could be greater than GMP'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.

There were no unrecognized tax benefits for the years ended September 30, 2019 and 2018.

GMP recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in nonoperating expenses. During the years ended September 30, 2019 and 2018, GMP recognized no interest or penalties. GMP is subject to income taxes in the United States, but no foreign jurisdictions.

At September 30, 2019, open tax years for federal and state tax returns are 2016 and forward. There were no federal or state income tax audits during the years ended September 30, 2019 and 2018.

On December 22, 2017 the President signed into law the "Tax Cuts and Jobs Act" (TCJA), a comprehensive tax reform law that provides significant changes that are applicable to GMP. The most significant TCJA tax law change impacting fiscal 2018 was the reduction in the federal corporate tax rate from 35% to 21%. Since GMP is a fiscal year taxpayer, it utilized a 24.53% blended federal rate for fiscal 2018 transactions, in accordance with the Internal Revenue Code, as well as a 21% federal tax rate for valuing accumulated deferred income taxes, as these will reverse in future years when the federal tax rate is expected to be 21%.

The impacts of the tax rate change on GMP's 2018 consolidated balance sheets was a $178,006 decrease in accumulated deferred income taxes and recognition of a regulatory liability of $177,544. The regulatory liabilities represent the excess taxes that have been collected from customers that will not be used to pay future income tax liabilities due to the federal corporate tax rate decrease. As agreed in the regulatory rate setting process, these will be amortized and returned to customers during future periods and in accordance with Internal Revenue Service normalization requirements.

The impact of tax reform on 2018 net income was a $1,362 decrease in tax expense, attributable to a $462 decrease in accumulated deferred income taxes related to the nonregulated business which is not subject to regulatory liability treatment and a $900 decrease due to synergy savings and nonregulatory operations.

Finally, since customers' 2018 rates were set using the 35% federal tax rate applicable at the time of rate setting, GMP elected to return excess taxes collected of $6,000 to customers in the form of bill credits from March 2018 to December 2018. Additionally, from January 2019 to September 2019. GMP returned $19,763 of "non-protected" accumulated deferred income taxes to customers in the form of bill credits and returned $1,428 of "protected" accumulated deferred income taxes to customers through rates in accordance with Internal Revenue Service normalization requirements.

(13) Employee Benefit Plans

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

GMP 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 plan. 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. GMP makes annual contributions to the plans up to the maximum amount that can be deducted for income tax purposes.

GMP 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 GMP. 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. GMP 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, 2019 and 2018, the unfunded pension obligations totaled $79,063 and $46,095, respectively. GMP recorded a regulatory asset for the net actuarial loss in the pension plan. At September 30, 2019 and 2018, the other postretirement benefit assets totaled $3,676 and $7,071, respectively, and are included in other assets on the consolidated balance sheets. The Company recorded a regulatory liability for the net actuarial gain in the postretirement benefit plan.

The following tables set forth the plans' benefit obligations, fair value of plan assets, and funded status at September 30, 2019 and 2018:

	2019		2018	
	Pension plan benefits	**Other postretirement benefits**	**Pension plan benefits**	**Other postretirement benefits**
Fair value of plan assets	$ 180,736	46,245	178,102	44,931
Projected benefit obligation	259,799	42,569	224,197	37,860
Funded status	$ (79,063)	3,676	(46,095)	7,071
Accumulated benefit obligation	$ 238,254	42,569	206,355	37,860
Net actuarial loss recognized in regulatory assets (liabilities)	89,710	(1,934)	58,152	(6,424)

GMP 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:

	2019		2018	
	Pension plan benefits	**Other postretirement benefits**	**Pension plan benefits**	**Other postretirement benefits**
Employer service cost	$ 4,935	533	5,456	651
Interest cost	8,896	1,443	8,151	1,349
Expected return on plan assets	(11,954)	(2,915)	(12,269)	(2,913)
Net amortizations	3,891	(172)	5,229	—
Net periodic benefit cost	$ 5,768	(1,111)	6,567	(913)
Employer contributions	$ 4,357	158	5,439	73
Participant contributions	—	1,010	—	1,166
Benefits paid	14,636	3,112	13,831	3,659

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

	Year ended September 30			
	2019		2018	
	Pension plan benefits	**Other postretirement benefits**	**Pension plan benefits**	**Other postretirement benefits**
Weighted average assumptions:				
Discount rate for projected benefit obligation	3.30%	3.22%	4.29%	4.24%
Discount rate for service cost	4.33	4.32	3.97	3.95
Discount rate for interest cost	4.07	3.94	3.44	3.20
Expected return on assets	6.85	6.65	6.85	6.65
Rate of compensation increase	3.25	—	3.25	—
Current year health care cost trend	—	7.00	—	7.00
Ultimate year health care cost trend	—	5.00	—	5.00
Year of ultimate trend rate	—	2023	—	2023

The mortality assumption utilized an RP-2018 mortality table with Scale MP-2018 for the year ended

September 30, 2019. The mortality assumption utilized an RP-2017 mortality table with Scale MP-2017 for the year ended September 30, 2018.

For measurement purposes, a 6.5% and 7% annual rate of increase in the per capita cost of covered medical benefits were assumed for 2019 and 2018, respectively. This rate of increase was assumed to gradually decline to 5% in 2025. The medical trend rate assumption has an 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, 2019 and 2018 by $107 or 5.4% and $124 or 6.2%, 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, 2019 and 2018 by $87 or 4.4% and $100 or 5.0%, 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, 2019 and 2018 by $2,534 or 6.0% and $2,169 or 5.7%, 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, 2019 and 2018 by $2,103 or 4.9% and $1,788 or 4.7%, respectively.

GMP'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. Investment guidelines for the other postretirement benefit plan combined assets specify that 8% be invested in equity securities, 86% be invested in debt securities and the remainder be invested in alternative and other investments. GMP's plan is to gradually de-risk the portfolio of other postretirement benefit securities , therefore the investment guidelines are more conservative than the actual allocations at September 30, 2019.

For September 30, 2019 and 2018, GMP 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. In formulating this assumed rate of return, GMP 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 20 years.

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

	2019		**2018**	
	Pension plan benefits	**Other postretirement benefits**	**Pension plan benefits**	**Other postretirement benefits**
Weighted average asset allocation asset category:				
Equity securities	43%	47%	45%	51%
Debt securities	41	47	38	42
Other	16	6	17	7
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 - September 30, 2019				
	Total	**Quoted prices in active markets for identical assets (Level1)**	**Significant observable inputs (Level2)**	**Significant unobservable inputs (Level3)**	**Measured at NAV (1)**
Asset category:					
Cash equivalents	$ 5,338	5,338	—	—	—
Limited partnerships	28,593	—	—	—	28,593
Exchange traded funds	144	144	—	—	—
Equity securities:					
U.S. companies	35,703	35,701	2	—	—
International companies	22,700	9,752	12,948	—	—
Fixed income securities:					
U.S.Treasury securities	37,416	—	37,416	—	—
Mortgage-backed securities	1,702	—	1,702	—	—
Corporate bonds – U.S. companies	30,967	—	30,967	—	—
Corporate bonds – Foreign	2,967	—	2,967	—	—
Municipal bonds	496	—	496	—	—
Mutual funds:					
Equity funds	14,710	14,710	—	—	—
Total	$ 180,736	65,645	86,498	—	28,593

(1) Investments measured at NAV amounts are comprised of certain investments measured at fair value using NAV (or its equivalent) as a practical expedient. These investments are not classified in the fair value hierarchy.

	Pension plan assets - September 30, 2018				
	Total	**Quoted prices in active markets for identical assets (Level 1)**	**Significant observable inputs (Level2)**	**Significant unobservable inputs (Level3)**	**Measured at NAV (1)**
Asset category:					
Cash equivalents	$ 4,351	4,351	—	—	—
Limited partnerships	30,821	—	—	—	30,821
Exchange traded funds	34,179	34,179	—	—	—

Equity securities:					
U.S. companies	19,574	19,572	2	—	—
International companies	4,408	2,939	1,469	—	—
Fixed income securities:					
U.S. Treasury securities	20,140	—	20,140	—	—
Mortgage-backed securities	1,851	—	1,851	—	—
Corporate bonds – U.S. companies	37,369	—	37,369	—	—
Corporate bonds – Foreign	5,215	—	5,215	—	—
Mutual funds:					
Equity funds	20,194	20,194	—	—	—
Total	$ 178,102	81,235	66,046	—	30,821

(1) Investments measured at NAV amounts are comprised of certain investments measured at fair value using NAV (or its equivalent) as a practical expedient. These investments are not classified in the fair value hierarchy.

	Other postretirement benefit plan assets - September 30, 2019			
	Total	Quoted prices in active markets for identical assets (Level1)	Significant observable inputs (Level2)	Significant unobservable inputs (Level3)
Asset category:				
Cash equivalents	$ 1,049	1,049	—	—
Exchange traded funds	11,272	11,272	—	—
Fixed income securities:				
U.S. Treasury securities	5,504	5,504	—	—
Mortgage-backed securities	237	237	—	—
Corporate bonds – U.S. companies	9,335	9,335	—	—
Corporate bonds – Foreign	371	371	—	—
Municipal bonds	62	62	—	—
Mutual funds:				
Equity funds	14,088	14,088	—	—
Fixed-income funds	3,938	3,938	—	—
Real estate funds	389	389	—	—
Total	$ 46,245	46,245	—	—

Other postretirement benefit plan assets - September 30, 2018

Quoted prices

		Total	in active markets for identical assets (Level1)	Significant observable inputs (Level2)	Significant unobservable inputs (Level3)
Asset category:					
Cash equivalents	$	1,227	1,227	—	—
Exchange traded funds		12,382	12,382	—	—
Equity securities:					
U.S. companies		348	348	—	—
International companies		13	13	—	—
Fixed income securities:					
U.S. Treasury securities		4,220	4,220	—	—
Mortgage-backed securities		152	152	—	—
Corporate bonds – U.S. companies		8,305	8,305	—	—
Corporate bonds – Foreign		671	671	—	—
Mutual funds:					
Equity funds		14,323	14,323	—	—
Fixed-income funds		3,279	3,279	—	—
Real estate funds		11	11	—	—
Total	$	44,931	44,931	—	—

(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:					
2020	$	7,700	13,910	200	2,289
2021		—	14,041	—	2,345
2022		—	14,386	—	2,365
2023		—	14,285	—	2,348
2024		—	14,749	—	2,368
2025 through 2029		—	76,498	—	11,778

The expected benefits in the table above are based on the same assumptions used to measure the Company's benefit obligations at September 30, 2019 and include estimated future employee service. Pension and postretirement contributions beyond 2020 have yet to be determined.

(d) Defined Contribution Plan

GMP maintains a 401(k) Savings Plan for substantially all employees. This plan provides for employee contributions up to specified limits. GMP matches employee pretax contributions up to 4%. GMP contributes each year an additional 0.75% 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, GMP contributes each year an additional 3.25% of eligible compensation, made on a nonmatching basis. GMP's matching contribution is immediately vested. GMP's matching and nonmatching contributions for the years ended September 30, 2019 and 2018 totaled $2,481 and $2,391, respectively.

(e) Supplemental Executive Retirement Plan

GMP 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, 2019 and 2018 was $223 and $284, respectively. As of September 30, 2019 and 2018, the SERP benefit obligation, based on a discount rate of 2.53% and 3.74%, was $4,918 and $4,518, respectively. As of September 30, 2019, the current and long-term portions were $1,852 and $3,066, respectively. As of September 30, 2018, the current and long-term portions were $268 and $4,250, respectively. As of September 30, 2019 and 2018, regulatory assets were recorded for the unrecognized benefit costs associated with actuarial losses in the amount of $842 and $482, 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, 2019 and 2018, the total cash surrender value was $22,069 and $17,020, of which $11,803 and $7,036, respectively, is included in a Rabbi Trust.

(f) Deferred Compensation

GMP 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, 2019 and 2018, the obligations were $3,847 and $3,981, respectively.

(14) Derivative Financial Instruments

GMP purchases the majority of its power supply, and uses long-term power supply contracts to mitigate rate volatility to customers. GMP may also sell power when an excess supply is forecasted. GMP enters into physical power purchase and sale agreements with various counterparties to hedge against fossil fuel price changes. Some of the purchase contracts are derivatives that meet the exception for a normal purchase and sale contract. For these contracts, GMP records contract-specified prices for electricity as an expense in the period used, as opposed to the changes occurring in fair market values. Other derivative contracts do not meet the exception for a normal purchase and sale contract, and they are carried at fair value. See note 16.

GMP previously entered into two capacity rate swap contracts to hedge a portion of its forward capacity costs. Since these contracts 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. In 2018, GMP reclassified capacity rate swap contracts from Level 3 to Level 2 fair value measures, because we were able to include observable pricing information in the valuation technique. Previously, these rate swap contracts were considered Level 3 fair value measures that relied on the use of unobservable pricing information. Only one capacity rate swap contract remains open at September 30, 2019.

No new derivative contracts were entered into during 2019, except for one short-term sale contract that expired April 30, 2019 and no new derivative contracts were entered into during 2018, except for one short-term sale contract that expired March 31, 2018.

Due to a regulatory order from the VPUC that requires GMP to defer recognition of any earnings or other comprehensive income effects relating to future periods from power supply arrangements that qualify as derivatives, GMP records an offsetting regulatory asset or liability for the fair value and any subsequent unrealized gains or losses, of their derivative instruments. There are no realized gains or losses in the consolidated statements of income because all gains and losses on power contracts are included in the PSA as the contracts settle. 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 GMP or the counterparty will not execute upon the arrangement. Actual value upon settlement may differ materially from the fair values shown below:

	Fair value as of September 30				
	2019			2018	
		Assets	Liabilities	Assets	Liabilities
Forward energy purchases	$	—	19,642	4,296	18,903
Forward energy sales		3,226	—	1,672	1,268
Capacity rate swaps		—	2,777	5,133	2,660
Total power supply derivative	$	3,226	22,419	11,101	22,831
Current portion	$	2,607	8,839	9,191	8,433

The tables below present assumptions used to estimate the fair value of the derivative contracts at September 30, 2019 and 2018. The forward energy purchase and sale prices are based on energy market quotations, and the forward capacity prices are based on forward capacity auction prices determined by ISO New England.

	September 30, 2019						
	Valuation model	Risk free interest rate	e volatilit y		Average forward price/MWh price/kW-M	(1)(2)	Contract s expire
Forward energy purchases	Net present value	1.36-1.97%	n/a	$	39.35	(1)	2019-2025
Forward energy sales	Net present value	1.78-1.97%	n/a		37.55	(1)	2019-2020
Capacity rate swaps	Net present value	1.76-1.97%	n/a		5.99	(2)	2019-2021

	September 30, 2018						
	Valuation model	Risk free interest rate	Price volatility		Average forward price/MWh price/kW-M o	(2) .	Contracts expire
Forward energy purchases	Net present value	2.07-3.00%	n/a	$	42.16	(1)	2018-2025
Forward energy sales	Net present value	2.07-2.75%	n/a		42.86	(1)	2018-2020
Capacity rate swaps	Net present value	2.07-2.75%	n/a		7.29	(2)	2019-2021

Certain of GMP's derivative instruments contain reciprocal provisions that require the counter-parties' and GMP'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 the 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, as shown in the tables below.

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, 2019 and 2018:

	2019			
	Market value			**Collateral required if below investment grade**
	Risk free	**With credit risk**	**Assets/ (liabilities)**	
Next Era	$ 3,231	3,226	3,226	—
Shell	(478)	(474)	(474)	(474)
Citigroup	(1,910)	(1,899)	(1,899)	(1,899)
BP Energy	(2,454)	(2,452)	(2,452)	(2,452)
Next Era	(18,080)	(17,594)	(17,594)	(14,818)
Net total	$ (19,691)	(19,193)	(19,193)	(19,643)

	2018			
	Market value			**Collateral required if below investment grade**
	Risk free	**With credit risk**	**Assets/ (liabilities)**	
Next Era	$ 10,084	10,071	10,071	—
Shell	1,028	1,030	1,030	—
Cargill	(163)	(164)	(164)	(164)
Citigroup	(1,282)	(1,264)	(1,264)	(1,264)
BP Energy	(9,239)	(9,204)	(9,204)	(9,204)
Next Era	(12,563)	(12,199)	(12,199)	(4,602)
Net total	$ (12,135)	(11,730)	(11,730)	(15,234)

GMP recorded corresponding regulatory liabilities and assets related to these derivative balances. Amounts due during the next fiscal year, if any, are classified in current assets and current liabilities.

(15) Fair Value of Financial Instruments

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, 2019 and 2018, the fair value of GMP's first mortgage bonds included in long-term debt was $898,007 and $780,477 (carrying amount of $749,830 and $726,131), respectively. The fair value of GMP'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:

	September 30, 2019			
	Level 1	**Level 2**	**Level 3**	**Total**
Spent Fuel Disposal and Decommissioning Trusts:				
Marketable equity securities	$ 4,356	7,114	—	11,470
U.S. government issued debt securities (agency and treasury)	88,799	7,333	—	96,132
Municipal obligations	—	22,695	—	22,695
Corporate and other bonds	3 0 , 1 0 —3	30,103	—	30,103
Money market funds	4,136	92	—	4,228
Total Spent Fuel Disposal and Decommissioning Trusts	97,291	67,337	—	164,628
VYNPC Rabbi Trust:				
Fixed Income mutual funds	429	—	—	429
Equity mutual funds	2,312	—	—	2,312
Money market funds	79	—	—	79
Total Rabbi Trust	2,820	—	—	2,820
Derivatives:				
Forward energy purchases	—	(9,286)	(10,356)	(19,642)
Forward energy sales	—	3,226	—	3,226
Capacity rate swaps	—	(2,777)	—	(2,777)

Total derivatives	—	(8,837)	(10,356)	(19,193)
Total	$ 100,111	58,500	(10,356)	148,255

	September 30, 2018			
	Level 1	Level 2	Level 3	Total
Spent Fuel Disposal and Decommissioning Trusts:				
Marketable equity securities	$ 4,198	6,905	—	11,103
U.S. government issued debt securities (agency and treasury)	73,530	8,315	—	81,845
Municipal obligations	—	26,478	—	26,478
Corporate and other bonds	—	36,291	—	36,291
Money market funds	3,193	72	—	3,265
Total Spent Fuel Disposal and Decommissioning Trusts	80,921	78,061	—	158,982
VYNPC Rabbi Trust:				
Fixed Income mutual funds	432	—	—	432
Equity mutual funds	2,442	—	—	2,442
Money market funds	4	—	—	4
Total Rabbi Trust	2,878	—	—	2,878
Derivatives:				
Forward energy purchases	—	(8,480)	(6,128)	(14,608)
Forward energy sales	—	404	—	404
Capacity rate swaps	—	2,474	—	2,474
Total derivatives	—	(5,602)	(6,128)	(11,730)
Total	$ 83,799	72,459	(6,128)	150,130

(a) Millstone Decommissioning Trust

GMP'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 – Forward Energy Contracts and Capacity Rate Swaps

At September 30, 2019, 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 derivative contracts that are classified as Level 3 in the fair value hierarchy:

Balance at beginning of period	$	(6,128)
Change in fair value relating to unrealized losses		(4,228)
Balance at September 30, 2019	$	(10,356)

See note 14 for additional fair value information related to derivative financial instruments.

(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		
		2019	2018
Hydro-Québec	$	57,579	53,540
Independent Power Producers		33,750	38,720
Next Era		53,520	48,677
Macquarie (formerly Cargill)		4,612	15,777
Granite Reliable		14,543	13,974
Citigroup		4,757	2,464
Deerfield		6,099	4,006
Shell		9,424	4,797
BP Energy		30,299	25,798

Certain 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 GMP'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 GMP takes delivery of the electricity. See note 14 for contracts that are accounted for as derivatives.

Significant purchased power contracts in effect as of September 30, 2019, including estimates for GMP's portion of certain minimum costs, are as follows:

		Estimated payments contractually due
Years ending September 30:		
2020	$	210,993
2021		200,647

2022	195,236
2023	192,256
Thereafter	2,244,839
Total	$ 3,043,971

(b) Hydro-Québec Contracts

On April 15, 2011, the VPUC 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. GMP 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 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 and end in 2038. In 2019, the energy volumes under the contract represent an estimated 24% of GMP's projected annual energy requirement, which is similar to 2018. The new HQUS contract does not include capacity, which must be purchased from other parties or left open to market prices.

GMP'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

GMP 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 counterparties are responsible for acquiring and taking title to the power that is purchased by GMP. GMP presently has in place several system energy purchases for deliveries through 2025, for terms from several months to 5 years.

(d) Other Renewable Power Contracts

GMP has committed to several contracts to purchase output from new renewable power plants, some for periods of up to 35 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, hydroelectric 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. GMP has also entered into three renewable power contracts that include battery storage systems. These contracts have a twenty-five year term.

(e) Next Era Seabrook Purchase

GMP 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. All purchases are unit contingent from the Seabrook Nuclear Power Plant beginning at 60 MW, which will decrease to 50 MW over the life of the contract that ends in 2034.

(f) Unit Purchases (Nonrenewable)

Under a long-term contract with Massachusetts Municipal Wholesale Electric Company (MMWEC), GMP is purchasing a percentage of the electrical output of the Stony Brook production plant constructed by MMWEC. The contract obligates GMP to pay certain minimum annual amounts representing GMP'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, GMP completed construction and began daily commercial operation of the Kingdom Community Wind project (KCW) a 63-MW wind facility in Lowell. 8 MW of the project's output is being sold to Vermont Electric Cooperative, Inc. under a long-term contract. The remainder is incorporated into GMP'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. GMP's obligations related to these plants are described in note 4. The balance of GMP's net nuclear decommissioning cost liability was $26 at September 30, 2019. The current and long-term portions of $11 and $15 are included in accounts payable, trade and accrued liabilities and other liabilities. The balance of GMP's net nuclear decommissioning cost liability was $36 at September 30, 2018. The current and long-term portions of $11 and $25 are included in accounts payable, trade and accrued liabilities and other liabilities.

(i) Renewable Energy Credits

During the years ended September 30, 2019 and 2018, GMP received $18,506 and $21,735, respectively, of net revenue from RECs. GMP's RECs for the year ended September 30, 2019 were approximately 18% from Granite Reliable, 5% from McNeil, 1% from Moretown, 17% from KCW, 16% from owned hydro, 8% from Rygate, 11% from Deerfield and 24% 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

(1) Kingdom Community Wind Land Leases

In 2009, GMP entered into four 48 year land leases associated with the property upon which Kingdom Community Wind Farm was constructed in Lowell, VT. As of September 30, 2019, future minimum rental payments required under the KCW land leases are expected to total $4,809 consisting of $127 per year in 2020 through 2024 and $4,174 for years thereafter.

(2) *Solar and Substation Land Leases*

In March 2018, GMP entered into a long term land lease to accommodate a future substation. GMP also has operating leases which are for leased land to host GMP's solar-related utility plant for solar power production and related activities.

The total minimum payments under the Substation land lease are $1,087. The most significant solar lease is for land at a landfill site used to host a solar farm. The total minimum lease payments under this agreement are $660. As of September 30, 2019, future minimum rental payments required under non-cancelable solar and sub-station land operating leases are expected to total $1,841 consisting of $53 per year in 2020 through 2024 and $1,576 for years thereafter.

(3) *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 $2,011 and $2,776 for the years ended September 30, 2019 and 2018, respectively. These rental expenses are included in maintenance and other operating expenses on the consolidated statements of income.

(k) Avangrid Renewables Agreement

In October 2015, GMP signed a twenty-five year purchase power agreement with Avangrid 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 GMP 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 began producing electricity in December 2017. GMP has an option to buy Deerfield at the end of 10 years at a predetermined purchase price of $50,000.

(l) 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 Department 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 began in 2017 based on the calendar year 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 calendar year 2019 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 program.

(m) Hydro Dam Power Contracts

GMP has executed 25 year purchased power agreements to purchase 100% of the output of 2 hydroelectric power plants. The plants are located in Sheldon Springs, Vermont and LaChute, New York. The Sheldon Springs plant has a nameplate capacity rating of 27MW and the LaChute plant has a nameplate capacity of 9 MW. The agreements require GMP to pay a fixed price per MWh generated plus a fixed monthly capacity payment. The energy and capacity prices escalate by 2% each year. Deliveries under the Sheldon Springs contract began in April 2018. Deliveries under the LaChute contract are pending acceptance of the generation facility to be a wholesale generator by the New York Independent System Operator.

GMP has concluded the purchased power agreements meet the requirements of an operating lease as contained in ASC 840 – *Leases.*

(17) Environmental Matters

(a) General

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

(b) Pine Street Barge Canal Superfund Site

In 1999, GMP 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, 2019, GMP has estimated total costs of GMP's future obligations under the consent decree to be approximately $2,867, net of recoveries. The estimated liability is not discounted, and it is possible that GMP's estimate of future costs could change by a material amount. As of September 30, 2019 and 2018, GMP has recorded a regulatory asset of $8,842 and $9,059, respectively, to reflect unrecovered past and future Pine Street Barge Canal costs. Pursuant to GMP's 2003 Rate Plan, as approved by the VPUC, GMP began to amortize and recover these costs in 2005. GMP 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 the regulatory asset is fully amortized.

(c) Air Quality Rules and Laws

The United States Environmental Protection Agency and various states have enacted air quality rules and laws which do not result in material direct costs to GMP because of GMP's limited involvement in power plants impacted by these laws and regulations. Future regional or national emission regulations (or tightening of existing regulations like the Regional Greenhouse Gas Initiative) could indirectly affect GMP by increasing wholesale power market prices; GMP's exposure to such increases is limited because a large fraction of its long-term energy needs will be met with long-term, stable-priced sources.

(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. GMP 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 federal courts issued a series of decisions regarding Phase I damages, and in December 2012, the DOE's right to further appeals expired. Accordingly, the judgment awarding Phase I damages to Maine Yankee, Connecticut Yankee and Yankee Atomic became final. In January 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 and the Government has not appealed the decision. GMP received $1,568 in 2017 which was returned to customers through the PSA.

A complaint for Phase IV damages was filed in May 2017 for damages through 2016. In April 2019, an order awarding partial summary judgment and a substantial portion of the Phase IV damages became final and no longer subject to appeal. On June 11, 2019, the federal government reimbursed Maine Yankee, Connecticut Yankee and Yankee Atomic per that order. On June 12, 2019, the remaining disputed amount was resolved by the court's acceptance of an Offer of Judgment, and the federal government reimbursed the three companies pursuant to the Offer of Judgment on July 17, 2019. On September 23, 2019, per the process established by the FERC in 2013, the three companies made a filing with the FERC which is required prior to disbursing the funds to wholesale customers like GMP.

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. GMP 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 $450,000, 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 $13.935 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 $138,000 per reactor per incident, limited to a maximum annual payout of $20,500 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, GMP could become liable for expenses of approximately $354,712 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

GMP does not expect any litigation to result in a significant adverse effect on its operating results or financial condition.

(19) Related-Party and Associated Company Transactions

Effective April 12, 2007, GMP became related to Vermont Gas Systems (VGS) when GMP was acquired by NNEEC. The rates at which GMP buys gas for facility heating from VGS and the rates at which VGS buys electricity from GMP are regulated and required to be transacted at rates approved by the VPUC, 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 GMP. Payments totaling $26 and $50 were received for the Pine Street Barge Canal Superfund Site during the years ended September 30, 2019 and 2018, respectively, and there were no other transactions between VGS and GMP during the years ended September 30, 2019 and 2018.

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

	September 30, 2019		
	Accounts receivable	**Accounts payable**	**Net receivable (payable)**
NNEEC	$ 24	—	24
Energir	66	—	66
Firstar	7,678	—	7,678
Connecticut Yankee Atomic Power Company	1	—	1
Transco	298	394	(96)
Total	$ 8,067	394	7,673

	September 30, 2018		
	Accounts receivable	**Accounts payable**	**Net receivable (payable)**
NNEEC	$ 27	—	27
Connecticut Yankee Atomic Power Company	5	—	5
Transco	784	—	784
Total	$ 816	—	816

(20) Concentration Risks

(a) HQ and NextEra Power Supply Contracts

GMP's material power supply contracts are principally with HQ and NextEra. HQ contracts are expected to meet from 23% to 25% of GMP'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 11% of GMP's annual demand requirements over the life of the contract that ends in 2034. Under GMP'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, 2019 and 2018, GMP had 517 and 519 employees, respectively. Of these employees, 286 were represented at September 30, 2019 and 2018 by Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers. On January 14, 2013, GMP agreed to a new five-year contract with its employees represented by the union, which was effective on January 1, 2013 and expired on December 31, 2017. On August 8, 2017, GMP agreed to a new five-year contract with its employees represented by the union, which was effective on January 1, 2018 and expires on December 31, 2022.

(21) Supplemental Cash Flow Information

Supplemental cash flow information for the years ended September 30, 2019 and 2018 are as follows:

	2019	2018
Cash paid for:		
Interest	$ 43,543	41,519
Income taxes paid, net	2	2
Supplemental disclosures of noncash information:		
Increase (decrease) in unfunded pension and other postretirement benefit obligations	41,287	(14,795)
Plant addition for allowance for equity funds used during construction	677	1,143
Noncash utility plant in accounts payable	12,061	5,121
Partner investment in GMP Vt Microgrid included in due from associated companies and related parties	7,678	—

Cash, cash equivalents and restricted cash included in:			
Cash and cash equivalents	$	10,977	8,762
Restricted cash included in other assets		979	488
Cash, cash equivalents and restricted cash at end of year	$	11,956	9,250

Restricted cash consists of cash reserves that GMP VT Solar and GMP VT Microgrid are contractually required to maintain to fund decommissioning and inverter replacements.

(22) Noncontrolling Interests

The Company follows FASB 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.

GMP VT Solar:

GMP 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. On May 4, 2016, GMP executed an Equity Capital Contribution Agreement with a tax equity partner (the Tax Equity Partner) to fund the cost to construct the 5 facilities. All 5 projects were placed in service by December 31, 2016. GMP has invested $41,990 and the Tax Equity Partner has invested $20,264 into GMP Solar.

The terms and conditions of the various agreements executed in connection with this investment are customary terms and conditions for a tax equity investment. GMP is 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 is entitled to 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%).

GMP 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.

GMP 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 GMP to GMP Solar and the Project Companies in connection with the development, construction and installation of the solar energy facilities, the Project Companies paid GMP a $5,619 development fee.

Certain Project Companies have executed leases with various third 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 GMP, as the owner of the land.

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

Certain risks exist with respect to GMP'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.

GMP determined GMP Solar to be a VIE under ASC 810. GMP concluded it is the primary beneficiary of GMP Solar, therefore, GMP consolidates GMP Solar.

Summarized GMP Solar financial information follows:

	Years ended September 30	
	2019	**2018**
Net income	$ 490	721
Allocation of net income (loss) to partners:		
GMP	664	(507)
Tax equity partner	(174)	1,227
Total assets	57,528	59,532
Total liabilities	2,328	2,178

GMP VT Microgrid LLC (GMP Microgrid):

GMP formed GMP Microgrid on June 13, 2017 to construct, operate and maintain, through wholly-owned limited liability companies (each, a "Project Company," together, the "Project Companies"), 3 solar generating facilities each paired with battery storage systems located throughout Vermont. On July 25, 2019, GMP executed an Equity Capital Contribution Agreement with a tax equity partner (the "Tax Equity Partner") to invest up to $45,900 in GMP Microgrid to fund the total cost to construct the 3 facilities. GMP will invest approximately $31,400 and the Tax Equity Partner will invest approximately $14,500. The Tax Equity Partner will make its investment in installments as certain construction milestones are met. GMP will be required to fund construction costs in excess of $45,900.

All 3 projects were in service by September 30, 2019.

The terms and conditions of the various agreements executed in connection with this investment are customary for a tax equity investment. Although GMP contributes 68% of the combined capital in exchange for its share of GMP Microgrid, GMP will be entitled to 1% of GMP Microgrid's profits, losses, deductions, and credits for the first six years, and 95% of each such item for the remaining term of GMP Microgrid. The Tax Equity Partner will contribute the remaining 32% of required capital in exchange for its interest in 99% of GMP Microgrid'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%).

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

As of September 30, 2019, GMP and the Tax Equity Partner are obligated to invest $31,400 and $14,500, respectively, in GMP Microgrid. GMP Microgrid has recorded receivables of $4,500 and $7,678 from GMP and Tax Equity Partner, respectively.

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

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

In consideration for the services provided by GMP to GMP Microgrid and the Project Companies in connection with the development, construction and installation of the solar energy facilities, the Project Companies will pay GMP a $5,056 development fee. The development fee will be paid as certain construction milestones are achieved. As of September 30, 2019, development fees of $1,568 were paid to GMP.

The Project Companies have executed leases with various 3rd parties to lease the land upon which three solar generation facilities will be built.

GMP has executed purchase power agreements with the Project Companies. The term of each of the agreements is 25 years, and GMP will pay a fixed price per kWh and receive all power output produced by the facilities and a fixed price per year for all services performed by the battery energy storage systems payable in equal monthly installments.

Certain risks exist with respect to GMP's investment in and management of GMP Microgrid, 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.

During the VIE assessment process, it was concluded that GMP is the primary beneficiary of GMP Microgrid and therefore the GMP will consolidate GMP Microgrid. GMP was deemed to be the primary beneficiary.

The carrying amounts and classification of GMP Microgrid's assets and liabilities included in the consolidated balance sheets as of September 30, 2019 are as follows:

	2019
Net loss	$ (424)
Allocation of net income (loss) to partners:	
GMP	6,290
Tax equity partner	(6,714)
Total assets	59,128
Total liabilities	13,772

(23) Subsequent Events

GMP considers events or transactions that occur after the balance sheet date, but before the financial statements are issued, to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure. These financial statements were available to be issued on November 22, 2019 and subsequent events have been evaluated through that date.

On November 21, 2019, GMP amended their $140,000 revolving credit facility with a $10,000 accordion with Keybank, N.A. as the lead bank to increase the facility to a $150,000 facility with a $10,000 accordion feature. The maturity date and other terms and conditions within the facility were unchanged.

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	12/31/2019	End of 2019/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)	1,898,778,151	1,898,778,151
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	-17,655	-17,655
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,898,760,496	1,898,760,496
9	Leased to Others		
10	Held for Future Use	42,820	42,820
11	Construction Work in Progress	47,627,950	47,627,950
12	Acquisition Adjustments	33,350,004	33,350,004
13	Total Utility Plant (8 thru 12)	1,979,781,270	1,979,781,270
14	Accum Prov for Depr, Amort, & Depl	712,088,919	712,088,919
15	Net Utility Plant (13 less 14)	1,267,692,351	1,267,692,351
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	663,734,545	663,734,545
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	30,166,842	30,166,842
22	Total In Service (18 thru 21)	693,901,387	693,901,387
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	18,187,532	18,187,532
33	Total Accum Prov (equals 14) (22,26,30,31,32)	712,088,919	712,088,919

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
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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	12/31/2019	End of 2019/Q4

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)	714,346	552,618
9	In Reactor (120.3)	3,747,596	
10	SUBTOTAL (Total 8 & 9)	4,461,942	
11	Spent Nuclear Fuel (120.4)	18,550,611	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	20,999,072	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	2,013,481	
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)		

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
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			6
			7
69,489		1,197,475	8
		3,747,596	9
		4,945,071	10
		18,550,611	11
			12
-1,050,133		22,049,205	13
		1,446,477	14
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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	12/31/2019	End of 2019/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	13,789,102	1,254,286
4	(303) Miscellaneous Intangible Plant	55,819,176	3,888,528
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	69,620,424	5,142,814
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	101,483	
9	(311) Structures and Improvements	7,282,646	20,746
10	(312) Boiler Plant Equipment	21,128,629	158,010
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	5,443,936	109,874
13	(315) Accessory Electric Equipment	1,512,611	52,470
14	(316) Misc. Power Plant Equipment	656,781	483
15	(317) Asset Retirement Costs for Steam Production	6,624	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	36,132,710	341,583
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	11,720	
19	(321) Structures and Improvements	22,670,770	31,154
20	(322) Reactor Plant Equipment	36,657,355	168,153
21	(323) Turbogenerator Units	11,046,946	119,202
22	(324) Accessory Electric Equipment	9,533,441	15,096
23	(325) Misc. Power Plant Equipment	3,780,084	5,012
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	83,700,316	338,617
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	3,952,075	83,506
28	(331) Structures and Improvements	19,638,037	325,291
29	(332) Reservoirs, Dams, and Waterways	94,948,612	3,454,843
30	(333) Water Wheels, Turbines, and Generators	64,349,616	641,251
31	(334) Accessory Electric Equipment	35,500,656	708,161
32	(335) Misc. Power PLant Equipment	1,985,211	26,600
33	(336) Roads, Railroads, and Bridges	2,883,249	4,311
34	(337) Asset Retirement Costs for Hydraulic Production	34,327	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	223,291,783	5,243,963
36	D. Other Production Plant		
37	(340) Land and Land Rights	698,805	
38	(341) Structures and Improvements	5,186,810	8,208
39	(342) Fuel Holders, Products, and Accessories	4,227,579	74,509
40	(343) Prime Movers	15,804,894	12,826
41	(344) Generators	130,551,920	235,665
42	(345) Accessory Electric Equipment	8,285,368	622,502
43	(346) Misc. Power Plant Equipment	33,610,816	28,497
44	(347) Asset Retirement Costs for Other Production	3,415,752	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	201,781,944	982,207
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	544,906,753	6,906,370

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	12/31/2019	End of 2019/Q4

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	4,694,510	
49	(352) Structures and Improvements	7,005,139	169,544
50	(353) Station Equipment	87,188,272	5,142,058
51	(354) Towers and Fixtures	351,058	
52	(355) Poles and Fixtures	45,775,893	1,408,478
53	(356) Overhead Conductors and Devices	45,180,147	2,284,444
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	1,010	7,687
57	(359.1) Asset Retirement Costs for Transmission Plant	38,091	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	190,234,120	9,012,211
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	17,127,585	
61	(361) Structures and Improvements	27,994,375	260,175
62	(362) Station Equipment	107,388,457	6,509,523
63	(363) Storage Battery Equipment		11,200,115
64	(364) Poles, Towers, and Fixtures	194,987,340	22,533,166
65	(365) Overhead Conductors and Devices	219,442,887	10,794,131
66	(366) Underground Conduit	19,371,483	366,033
67	(367) Underground Conductors and Devices	40,593,270	2,535,833
68	(368) Line Transformers	138,150,360	6,573,930
69	(369) Services	48,020,354	1,509,497
70	(370) Meters	40,661,322	1,535,646
71	(371) Installations on Customer Premises	1,209,371	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	18,430,740	1,136,587
74	(374) Asset Retirement Costs for Distribution Plant	340,709	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	873,718,253	64,954,636
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	3,368,715	
87	(390) Structures and Improvements	44,632,390	78,860
88	(391) Office Furniture and Equipment	25,728,801	921,404
89	(392) Transportation Equipment	37,123,951	2,106,431
90	(393) Stores Equipment	622,650	6,944
91	(394) Tools, Shop and Garage Equipment	6,214,248	693,137
92	(395) Laboratory Equipment	3,743,981	24,577
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	13,605,215	1,331,565
95	(398) Miscellaneous Equipment	2,647,118	158,519
96	SUBTOTAL (Enter Total of lines 86 thru 95)	137,687,069	5,321,437
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	72,634	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	137,759,703	5,321,437
100	TOTAL (Accounts 101 and 106)	1,816,239,253	91,337,468
101	(102) Electric Plant Purchased (See Instr. 8)	16,374,450	
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)	1,832,613,703	91,337,468

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	12/31/2019	End of 2019/Q4

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
		425,420	15,468,808		3
15,824,662			43,883,042		4
15,824,662		425,420	59,363,996		5
					6
					7
			101,483		8
			7,303,392		9
			21,286,639		10
					11
			5,553,810		12
			1,565,081		13
			657,264		14
			6,624		15
			36,474,293		16
					17
			11,720		18
			22,701,924		19
			36,825,508		20
			11,166,148		21
			9,548,537		22
			3,785,096		23
					24
			84,038,933		25
					26
		232,225	4,267,806		27
14,383		2,534,839	22,483,784		28
130,354		9,163,946	107,437,047		29
22,111		8,440,979	73,409,735		30
17,706		2,988,637	39,179,748		31
		56,000	2,067,811		32
			2,887,560		33
			34,327		34
184,554		23,416,626	251,767,818		35
					36
			698,805		37
186			5,194,832		38
24,651			4,277,437		39
239,521			15,578,199		40
714,072			130,073,513		41
29,257			8,878,613		42
10			33,639,303		43
			3,415,752		44
1,007,697			201,756,454		45
1,192,251		23,416,626	574,037,498		46

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	12/31/2019	End of 2019/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
			4,694,510		48
3,264			7,171,419		49
461,589			91,868,741		50
			351,058		51
136,597			47,047,774		52
33,712			47,430,879		53
					54
					55
			8,697		56
			38,091		57
635,162			198,611,169		58
					59
			17,127,585		60
71,125			28,183,425		61
964,297		303,748	113,237,431		62
114,286		7,417,217	18,503,046		63
2,308,046		-7,417,217	207,795,243		64
1,778,115			228,458,903		65
25,767			19,711,749		66
434,740			42,694,363		67
6,138,335			138,585,955		68
168,475			49,361,376		69
			42,196,968		70
46,193			1,163,178		71
					72
347,192			19,220,135		73
			340,709		74
12,396,571		303,748	926,580,066		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			3,368,715		86
			44,711,250		87
1,667,942		648	24,982,911		88
214,625			39,015,757		89
88,805			540,789		90
4,696		8,088	6,910,777		91
74,766			3,693,792		92
					93
821,237			14,115,543		94
12,239		5,021	2,798,419		95
2,884,310		13,757	140,137,953		96
					97
			72,634		98
2,884,310		13,757	140,210,587		99
32,932,956		24,159,551	1,898,803,316		100
	7,785,101	-24,159,551			101
					102
					103
32,932,956	7,785,101		1,898,803,316		104

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

Amounts for Electric Plant in Service include the following:

Transmission

December 2018	190,234,120
January 2019	190,569,428
February	191,080,258
March	191,329,726
April	191,773,053
May	191,766,254
June	192,452,941
July	194,046,525
August	194,854,645
September	197,907,354
October	198,319,356
November	198,438,701
December	198,611,169

Amount for Total Transmission Plant includes Y-25 $1,751,722 and the Woodsville Tap $102,984, 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 2018	873,718,253
January 2019	875,378,184
February	877,274,405
March	879,475,766
April	883,166,923
May	885,422,278
June	904,194,943
July	905,443,828
August	910,997,913
September	920,308,183
October	921,670,860
November	922,508,152
December	926,580,066

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

Amounts for Electric Plant in Service include the following:

General

December 2018	137,759,703
January 2019	137,906,299
February	137,957,364
March	138,464,486
April	138,538,026
May	139,149,015
June	139,371,400
July	139,227,410
August	139,342,964
September	139,884,991
October	139,866,028
November	139,997,637
December	140,210,587

Schedule Page: 204 Line No.: 101 Column: e

Accumulated provision for depreciation - Hydro	17,723,584
Accumulated provision for depreciation - General	13,889
Accumulated provision for depreciation - Hydro	417,240
Prepayments	29,165
Electric plant acquisition adjustment	(10,398,777)

	7,785,101
	============

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

Amounts for Electric Plant in Service include the following:

Total Plant in Service

December 2018	1,832,613,703
January 2019	1,835,211,725
February	1,837,950,141
March	1,836,295,183
April	1,840,686,103
May	1,844,005,625
June	1,863,117,426
July	1,873,285,100
August	1,881,208,170
September	1,890,744,362
October	1,892,549,853
November	1,893,696,983
December	1,898,803,316

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	12/31/2019	End of 2019/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					
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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	12/31/2019	End of 2019/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	Minor Items			42,820
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16				
17				
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21	Other Property:			
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47	Total			42,820

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	12/31/2019	End of 2019/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	Airport substation rebuild	2,760,637
2	Websterville substation rebuild	2,531,377
3	Goshen hydro spillway	1,053,173
4	Vergennes hydro electrical controls	4,164,985
5	Marshfield hydro spillway water control gate	1,604,964
6	Peterson hydro runner and electrical modernization	2,966,095
7	Work management system	1,882,049
8	Maple Avenue substation breakers and capacitors	1,106,329
9		
10	Miscellaneous minor projects (under $1,000,000)	29,558,341
11		
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43	TOTAL	47,627,950

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	12/31/2019	End of 2019/Q4

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	617,992,226	617,992,226		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	45,656,758	45,656,758		
4	(403.1) Depreciation Expense for Asset Retirement Costs	135,060	135,060		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,146,447	2,146,447		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Non-utility depn adj offset account 12	-7,412	-7,412		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	47,930,853	47,930,853		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	17,108,294	17,108,294		
13	Cost of Removal	2,859,974	2,859,974		
14	Salvage (Credit)	55,896	55,896		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	19,912,372	19,912,372		
16	Other Debit or Cr. Items (Describe, details in footnote):	17,723,838	17,723,838		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	663,734,545	663,734,545		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	34,459,352	34,459,352		
21	Nuclear Production	50,765,946	50,765,946		
22	Hydraulic Production-Conventional	90,008,069	90,008,069		
23	Hydraulic Production-Pumped Storage				
24	Other Production	76,092,677	76,092,677		
25	Transmission	57,693,945	57,693,945		
26	Distribution	312,603,507	312,603,507		
27	Regional Transmission and Market Operation				
28	General	42,111,049	42,111,049		
29	TOTAL (Enter Total of lines 20 thru 28)	663,734,545	663,734,545		

Schedule Page: 219 Line No.: 16 Column: c

Electric plant purchased accumulated depreciation - offset FERC account 10230	17,737,473
Accumulated depreciation adjustment - offset FERC account 10700	(13,635)

	17,723,838
	==========

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

Amounts for Accoumulated Depreciation include the following:

Transmission

December 2018	55,259,426
January 2019	55,519,204
February	55,777,968
March	56,039,030
April	56,290,641
May	56,450,817
June	56,674,396
July	56,691,490
August	56,942,567
September	56,871,568
October	57,138,672
November	57,419,170
December	57,693,945

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

Amounts for Accoumulated Depreciation include the following:

Distribution

December 2018	306,940,976
January 2019	308,192,303
February	309,643,860
March	306,331,531
April	307,715,245
May	307,960,744
June	308,855,435
July	310,001,262
August	310,001,262
September	311,564,120
October	312,979,695
November	312,468,797
December	312,603,507

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

Amounts for Accoumulated Depreciation include the following:

General

December 2018	37,350,891
January 2019	37,983,262
February	38,616,585

March	39,248,833
April	39,884,904
May	40,521,250
June	41,159,987
July	41,598,502
August	42,236,966
September	40,206,147
October	40,841,012
November	41,475,854
December	42,111,049

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	12/31/2019	End of 2019/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			1,068,951
8	SUBTOTAL			9,843,234
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			-11,013,659
14	Return of Capital			-16,666,243
15	SUBTOTAL			382,595
16				
17	C. NEW ENGLAND HYDRO ELECTRIC TRANSMISSION CO.			
18	Common stock			985,874
19	Undistributed Equity in Earnings			532,279
20	SUBTOTAL			1,518,153
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			96,415
26	SUBTOTAL			242,187
27				
28	E. VERMONT TRANSCO LLC	6-30-06		
29	Membership units purchased			451,758,030
30	Undistributed Earnings			153,928,884
31				
32	SUBTOTAL			605,686,914
33				
34	F. MAINE YANKEE ATOMIC POWER CORP			
35	Common Stock			14,899
36	Equity in undistributed earnings			33,566
37	SUBTOTAL			48,465
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	674,497,138

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	12/31/2019	End of 2019/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			25,312
10	SUBTOTAL			52,111
11				
12	I. CONNECTICUT YANKEE ATOMIC POWER CO.			
13	Common Stock and Paid in Capital			40,694
14	Equity in undistributed Earnings			-1,804
15	SUBTOTAL			38,890
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			-619,321
25	SUBTOTAL			576,802
26				
27	M. GMP VT SOLAR LLC			
28	Common Stock			41,990,305
29	Equity in undistributed earnings			12,939,074
30	SUBTOTAL			54,929,379
31				
32	N. GMP Microgrid LLC			
33	Common Stock			
34	Equity in undistributed earnings			
35	SUBTOTAL			
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	674,497,138

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
991,270	-1,082,817	977,404		7
991,270	-1,082,817	9,751,687		8
				9
				10
				11
		28,062,497		12
-252		-11,013,911		13
		-16,666,243		14
-252		382,343		15
				16
				17
		985,874		18
80,232		612,511		19
80,232		1,598,385		20
				21
				22
		1,333,978		23
		-1,188,206		24
20,592		117,007		25
20,592		262,779		26
				27
				28
7,994,090		459,752,120		29
73,372,766	-62,971,092	164,330,558		30
				31
81,366,856	-62,971,092	624,082,678		32
				33
				34
		14,899		35
3,565		37,131		36
3,565		52,030		37
				38
				39
				40
				41
129,310,275	-68,154,472	735,645,499		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	12/31/2019	End of 2019/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
4,845		30,157		9
4,845		56,956		10
				11
				12
		40,694		13
5,433		3,629		14
5,433		44,323		15
				16
				17
		-144,670		18
		389,044		19
		244,374		20
				21
				22
		1,196,123		23
50,004	-66,218	-642,977		24
50,004	-66,218	553,146		25
				26
				27
		41,990,305		28
901,801	-2,503,282	11,337,593		29
901,801	-2,503,282	53,327,898		30
				31
				32
35,024,636		35,024,636		33
10,791,240	-1,461,010	9,330,230		34
45,815,876	-1,461,010	44,354,866		35
				36
				37
				38
				39
				40
				41
129,310,275	-68,154,472	735,645,499		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	12/31/2019	End of 2019/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)	4,382,119	4,294,199	
2	Fuel Stock Expenses Undistributed (Account 152)	60,385	38,920	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	13,045,018	13,003,304	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,440,094	3,271,467	
8	Transmission Plant (Estimated)	19,467	31,823	
9	Distribution Plant (Estimated)	354,005	777,811	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,430,262	801,184	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	18,288,846	17,885,589	
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)	1,508,153	550,660	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	24,239,503	22,769,368	

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 No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 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				

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	12/31/2019	End of 2019/Q4

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.

2021 No. (f)	2021 Amt. (g)	2022 No. (h)	2022 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
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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	12/31/2019	End of 2019/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		2020	
		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				

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	12/31/2019	End of 2019/Q4

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.

2021		2022		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
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								43
								44
								45
								46

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	12/31/2019	End of 2019/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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	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	12/31/2019	End of 2019/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)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
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	12/31/2019	End of 2019/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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	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	12/31/2019	End of 2019/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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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	12/31/2019	End of 2019/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**				
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21	**Generation Studies**				
22	SolarSense VT XV LLC (Brandon)	1,145	235	1,145	235
23	Middlebury Resource Recovery Cen	1,709	235	1,709	235
24	Otter Creek Solar (OC3)	6,369	235	6,369	235
25	BP Ascutney 2 LLCTriland Partners	1,408	235	1,403	235
26	Triland Partners (Clarendon Middl)	2,517	235	2,517	235
27	Shelburne Museum 500 kW	4,112	235	4,112	235
28	Apple Hill/Chelsea MS-G50 SIS			3,073	235
29	Apple Hill/Chelsea MS-G50 FAC	987	235		
30	Barnard Project I SIS EB-Y38	18,559	235		
31	Bennington Chapel RD LS-G61	14	235		
32	CID 36238 MHG Upper QSI FACS	1,972	235	1,972	235
33	CID 41738 ER Walker FACS	402	235	402	235
34	CID 42085 FACS BP Ascutney 2	3,918	235	3,918	235
35	CID 42217 Triland Mid 2 FACS	1,434	235	1,434	235
36	CID 42516 FEAS SSVT XXII	2,226	235	2,226	235
37	CID 42647 FEAS Morrison's	1,276	235	1,276	235
38	CID 42855 T&T Solar FEAS	842	235	842	235
39	CID 44249 Josh Kahan FEAS	1,808	235	1,808	235
40	CID 44258 TES - Bromley FEAS	843	235	843	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	12/31/2019	End of 2019/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	CID 44408 Sunny Raymond FEAS	9,040	235	904	235
23	CID 44444 PLH Can Green FACS			10,000	235
24	CID 44446 PLH (Willard) SIS			14,000	235
25	CID 44483 Velco Solar FEAS	1,054	235	1,054	235
26	CID 44491 Aegis Rsvlt Hwy FEAS				
27	CID 44720 Wthrsfield (TS) FEAS	1,263	235	1,263	235
28	CID 44729 Wthrsfield (TG) FEAS	1,271	235	1,271	235
29	CID 44732 Sun A (Portlnd) FEAS	1,050	235	1,050	235
30	CID 44735 ER Sandhill FEAS	2,811	235	2,811	235
31	CID 44735 Sandhill Solar FACS	4,412	235	4,412	235
32	CID 44856 Malthouse Solar FEAS	3,141	235	3,313	235
33	CID 45043 Velco 250 BESSS	859	235	859	235
34	CID 45151 PLH SAFFORD FEAS	1,699	235	1,758	235
35	CID 45861 Wakefield Mdw FEAS	2,979	235	2,979	235
36	CID 46071 ER Midd Col Sol SIS	18,766	235	25,000	235
37	CID 46071 ER South Street FACS			5,000	235
38	CID 47391 DG NE St Albans FEAS			4,500	235
39	CID 47393 DG NE Charlotte FEAS	1,373	235	3,500	235
40	CID 47395 DG NE Frrsburgh FEAS	1,640	235	4,500	235

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	CID 47672 MHG Mill Street FEAS	1,647	235	1,000	235
23	CID 47758 MHG Richville FEAS	1,398	235	1,000	235
24	CID 47797 MHG (MAHAR RD) FEAS	1,050	235	1,000	235
25	CID 47981 MHG (RMG STONE) FEAS	1,321	235	1,000	235
26	CID 48281 M Rothblatt FEAS			1,000	235
27	CID 48284 Ralph Shepard FEAS			1,000	235
28	CID 48371 PURPOSE SAINT SIS	3,246	235	25,000	235
29	CID 48674 Castleton Hgts FEAS			1,000	235
30	Comtu Falls Hydro SS-G36 FEAS	483	235	1,060	235
31	E.Barre Co. Batt 61G2 SIS			7,073	235
32	E.Barre Co. Batt 61G2 FAC	7,362	235		
33	East New Haven GLC FAC WY-G80	4,801	235		
34	East New Haven GLC FEAS WY-G80			380	235
35	ER Lemon Fair LJ-G13 FEAS	(1,452)	235		
36	ER Verulamium FEAS NE-G16	(3,898)	235		
37	Fair Haven GLC FH-J28 FEAS	4,674	235	4,674	236
38	French Meadow NS-G63 FEAS	1,173	235	1,173	235
39	Georgia Solar I GI-G71 FEAS	2,740	235	1,000	235
40	GMP Champlain Biogas	(19,365)	235		

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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	GMP MicroGrid Essex 33Y4 SIS				
23	GMP MicroGrid-Milton	(5,529)	235		
24	Granger Enterprses GT-G47 FEAS	126	235		
25	groSolar (Greenbush) 45G1 FAC			791	235
26	groSolar (Greenbush) 45G1 SIS			25,564	235
27	GroSolar (Halladay) EM-G75 FAC	2,634	235		
28	GroSolar (Halladay) EM-G75 SIS	353	235		
29	Hoosic Hydro, LLC FAC	(772)	235		
30	IMPEY BAY-G5 FEAS	25,680	235		
31	Machia Farm Bio SD-G10 FEAS			3,086	235
32	Malone Hull Prop FEAS PS-G42	(1,025)	235		
33	Malone Hull Prop FACPS-G42	(1,469)	235		
34	Malone Hull Prop PS-G42 FACS	46,340	235		
35	MHG (Blissville) HY-G24 FEAS	904			
36	MHG (Button Falls) PA-G21 FEAS			1,922	235
37	MHG (Warren Swtch) PA-G21 FEAS	1,988	235	1,988	235
38	MHG Furnace Brook MS-G50 FEAS	1,556	235	1,556	235
39	MHG Sol (Upper Rd) SP-J1 FEAS	118	235	570	235
40	MHG Solar (Benn) LS-G61 FEAS	203	235		

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	MHG Solar (High Rd) SP-J1 FEAS	1,767	235	1,767	
23	MRRC BIO M-G26 SIS	21,979	235		
24	MRRC BIO M-G26 FAC	847	235		
25	Newbury GLC 83G2 FAC	9,515	235		
26	Northfield Elec - Nantana Mill	2,618	235		
27	Northfield Elec Aegis 350 kW	1,351	235		
28	Northfield Elec ER Bone Hill	5,664	235		
29	Norwich Tech TA-G12 FEAS	(43)	235		
30	Norwich Tech TA-G12 FAC	(9,200)	235		
31	Novus Wash Landfill 61G3 FEAS	943	235	943	235
32	OC Solar (Stark) SK-G59 FAC	(4,621)	235		
33	OC Solar (Stark) SK-G59 SIS	(15,361)	235		
34	OC Solar (Warner) SK-G59 FAC	(4,621)	235		
35	OC Solar (Warner) SK-G59 SIS	(15,474)	235		
36	Panton Battery Verg 9-G2 SIS	(20,244)	235		
37	Park Road Solar WI-G31 FEAS			400	235
38	PigPenMCG14	2,220	235	2,220	235
39	QP660 Vernon Solar FEAS	151	235		
40	QP660 Vernon Solar SIS	151	235		

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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	QP673 Davenport Solar FEAS	388	235		
23	QP673 Davenport Solar SIS	1,361	235		
24	QP674 Shaftsbury SIS	606	235		
25	QP674 Shaftsbury Solar FEAS	158	235		
26	QP676 Claremont Solar FEAS	2,194	235		
27	QP676 Claremont Solar SIS	151	235		
28	QP680 Fair Haven Solar SIS	2,176	235		
29	QP727 Chariot Solar ISO FEAS	(1,406)	235		
30	QP727 Chariot Solar ISO SIS	2,990	235	2,990	235
31	QP751 Randolph Ctr Solar SIS	2,389	235	1,834	235
32	QP751 Randolph Ctr Solar FEAS	(297)	235		
33	QP753 Sheldon Solar	(297)	235		
34	QP799 Steel Mill FEAS	2,095	235	2,095	235
35	QP807 Panton Solar ISO SIS	156	235		
36	River Bend Solar NGRID	151	235	151	235
37	Royalton Town GLC BE-G28 FEAS	161	235		
38	Ryegate Solar PV/BESS 34.5 SIS	38,258	235		
39	Sandlot Solar HY-G24 FEAS	10,366	235		
40	South Ridge Solar M-G27 FEAS	4,355	235	643	235

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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	SSVT XXVII BAY-G4 FEAS	4,966	235	3,966	235
23	Stratified Stone FH-J28 FEAS	1,455	235		
24	Sunny Acres Edgewd RI-G66 FEAS			720	235
25	Tri Thomas Dairy I NR-G33 FEAS			455	235
26	Trout Brook SIS WM-G91 FAC			2,274	235
27	Trout Brook SIS WM-G91 SIS			27,915	235
28	Troy Minerals WF-G23 FEAS	2,811	235	1,909	235
29	VEC JERICHO ER PV & BESS	5,886	235	4,000	235
30	VEC JERICHO ER PV & BESS FACS	612		5,000	235
31	W&C Kendall 40G5 FEAS	1,000	235		
32	W&C Kendall 40G5 FAC	4,888	235		
33	Wallingford Solar WF-G23 FEAS	14	235		
34	Wallingford Solar WF-G23 FAC	9,493	235		
35	Weathersfield Sol WI-G11 FEAS			91	235
36	WEC MORETOWN 3310 DTT	5,670	235	5,670	235
37	Winham White RD LO-G26	1,984	235	1,984	235
38	WMG FEAS BF-G63	(443)	235		
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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.
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5. In column (c) report the account charged with the cost of the study.
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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	SolarSense VT XV LLC (Brandon)	1,145	235	1,145	235
23	Middlebury Resource Recovery Cen	1,709	235	1,709	235
24	Otter Creek Solar (OC3)	6,369	235	6,369	235
25	BP Ascutney 2 LLCTriland Partners	1,408	235	1,403	235
26	Triland Partners (Clarendon Middl)	2,517	235	2,517	235
27	Shelburne Museum 500 kW	4,112	235	4,112	235
28	Apple Hill/Chelsea MS-G50 SIS			3,073	235
29	Apple Hill/Chelsea MS-G50 FAC	987	235		
30	Barnard Project I SIS EB-Y38	18,559	235		
31	Bennington Chapel RD LS-G61	14	235		
32	CID 36238 MHG Upper QSI FACS	1,972	235	1,972	235
33	CID 41738 ER Walker FACS	402	235	402	235
34	CID 42085 FACS BP Ascutney 2	3,918	235	3,918	235
35	CID 42217 Triland Mid 2 FACS	1,434	235	1,434	235
36	CID 42516 FEAS SSVT XXII	2,226	235	2,226	235
37	CID 42647 FEAS Morrison's	1,276	235	1,276	235
38	CID 42855 T&T Solar FEAS	842	235	842	235
39	CID 44249 Josh Kahan FEAS	1,808	235	1,808	235
40	CID 44258 TES - Bromley FEAS	843	235	843	235

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	CID 44408 Sunny Raymond FEAS	9,040	235	904	235
23	CID 44444 PLH Can Green FACS			10,000	235
24	CID 44446 PLH (Willard) SIS			14,000	235
25	CID 44483 Velco Solar FEAS	1,054	235	1,054	235
26	CID 44491 Aegis Rsvlt Hwy FEAS				
27	CID 44720 Wthrsfield (TS) FEAS	1,263	235	1,263	235
28	CID 44729 Wthrsfield (TG) FEAS	1,271	235	1,271	235
29	CID 44732 Sun A (Portlnd) FEAS	1,050	235	1,050	235
30	CID 44735 ER Sandhill FEAS	2,811	235	2,811	235
31	CID 44735 Sandhill Solar FACS	4,412	235	4,412	235
32	CID 44856 Malthouse Solar FEAS	3,141	235	3,313	235
33	CID 45043 Velco 250 BESSS	859	235	859	235
34	CID 45151 PLH SAFFORD FEAS	1,699	235	1,758	235
35	CID 45861 Wakefield Mdw FEAS	2,979	235	2,979	235
36	CID 46071 ER Midd Col Sol SIS	18,766	235	25,000	235
37	CID 46071 ER South Street FACS			5,000	235
38	CID 47391 DG NE St Albans FEAS			4,500	235
39	CID 47393 DG NE Charlotte FEAS	1,373	235	3,500	235
40	CID 47395 DG NE Frrsburgh FEAS	1,640	235	4,500	235

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	CID 47672 MHG Mill Street FEAS	1,647	235	1,000	235
23	CID 47758 MHG Richville FEAS	1,398	235	1,000	235
24	CID 47797 MHG (MAHAR RD) FEAS	1,050	235	1,000	235
25	CID 47981 MHG (RMG STONE) FEAS	1,321	235	1,000	235
26	CID 48281 M Rothblatt FEAS			1,000	235
27	CID 48284 Ralph Shepard FEAS			1,000	235
28	CID 48371 PURPOSE SAINT SIS	3,246	235	25,000	235
29	CID 48674 Castleton Hgts FEAS			1,000	235
30	Comtu Falls Hydro SS-G36 FEAS	483	235	1,060	235
31	E.Barre Co. Batt 61G2 SIS			7,073	235
32	E.Barre Co. Batt 61G2 FAC	7,362	235		
33	East New Haven GLC FAC WY-G80	4,801	235		
34	East New Haven GLC FEAS WY-G80			380	235
35	ER Lemon Fair LJ-G13 FEAS	(1,452)	235		
36	ER Verulamium FEAS NE-G16	(3,898)	235		
37	Fair Haven GLC FH-J28 FEAS	4,674	235	4,674	236
38	French Meadow NS-G63 FEAS	1,173	235	1,173	235
39	Georgia Solar I GI-G71 FEAS	2,740	235	1,000	235
40	GMP Champlain Biogas	(19,365)	235		

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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	GMP MicroGrid Essex 33Y4 SIS				
23	GMP MicroGrid-Milton	(5,529)	235		
24	Granger Enterprses GT-G47 FEAS	126	235		
25	groSolar (Greenbush) 45G1 FAC			791	235
26	groSolar (Greenbush) 45G1 SIS			25,564	235
27	GroSolar (Halladay) EM-G75 FAC	2,634	235		
28	GroSolar (Halladay) EM-G75 SIS	353	235		
29	Hoosic Hydro, LLC FAC	(772)	235		
30	IMPEY BAY-G5 FEAS	25,680	235		
31	Machia Farm Bio SD-G10 FEAS			3,086	235
32	Malone Hull Prop FEAS PS-G42	(1,025)	235		
33	Malone Hull Prop FACPS-G42	(1,469)	235		
34	Malone Hull Prop PS-G42 FACS	46,340	235		
35	MHG (Blissville) HY-G24 FEAS	904			
36	MHG (Button Falls) PA-G21 FEAS			1,922	235
37	MHG (Warren Swtch) PA-G21 FEAS	1,988	235	1,988	235
38	MHG Furnace Brook MS-G50 FEAS	1,556	235	1,556	235
39	MHG Sol (Upper Rd) SP-J1 FEAS	118	235	570	235
40	MHG Solar (Benn) LS-G61 FEAS	203	235		

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	MHG Solar (High Rd) SP-J1 FEAS	1,767	235	1,767	
23	MRRC BIO M-G26 SIS	21,979	235		
24	MRRC BIO M-G26 FAC	847	235		
25	Newbury GLC 83G2 FAC	9,515	235		
26	Northfield Elec - Nantana Mill	2,618	235		
27	Northfield Elec Aegis 350 kW	1,351	235		
28	Northfield Elec ER Bone Hill	5,664	235		
29	Norwich Tech TA-G12 FEAS	(43)	235		
30	Norwich Tech TA-G12 FAC	(9,200)	235		
31	Novus Wash Landfill 61G3 FEAS	943	235	943	235
32	OC Solar (Stark) SK-G59 FAC	(4,621)	235		
33	OC Solar (Stark) SK-G59 SIS	(15,361)	235		
34	OC Solar (Warner) SK-G59 FAC	(4,621)	235		
35	OC Solar (Warner) SK-G59 SIS	(15,474)	235		
36	Panton Battery Verg 9-G2 SIS	(20,244)	235		
37	Park Road Solar WI-G31 FEAS			400	235
38	PigPenMCG14	2,220	235	2,220	235
39	QP660 Vernon Solar FEAS	151	235		
40	QP660 Vernon Solar SIS	151	235		

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**				
2					
3					
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21	**Generation Studies**				
22	QP673 Davenport Solar FEAS	388	235		
23	QP673 Davenport Solar SIS	1,361	235		
24	QP674 Shaftsbury SIS	606	235		
25	QP674 Shaftsbury Solar FEAS	158	235		
26	QP676 Claremont Solar FEAS	2,194	235		
27	QP676 Claremont Solar SIS	151	235		
28	QP680 Fair Haven Solar SIS	2,176	235		
29	QP727 Chariot Solar ISO FEAS	(1,406)	235		
30	QP727 Chariot Solar ISO SIS	2,990	235	2,990	235
31	QP751 Randolph Ctr Solar SIS	2,389	235	1,834	235
32	QP751 Randolph Ctr Solar FEAS	(297)	235		
33	QP753 Sheldon Solar	(297)	235		
34	QP799 Steel Mill FEAS	2,095	235	2,095	235
35	QP807 Panton Solar ISO SIS	156	235		
36	River Bend Solar NGRID	151	235	151	235
37	Royalton Town GLC BE-G28 FEAS	161	235		
38	Ryegate Solar PV/BESS 34.5 SIS	38,258	235		
39	Sandlot Solar HY-G24 FEAS	10,366	235		
40	South Ridge Solar M-G27 FEAS	4,355	235	643	235

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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**				
2					
3					
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20					
21	**Generation Studies**				
22	SSVT XXVII BAY-G4 FEAS	4,966	235	3,966	235
23	Stratified Stone FH-J28 FEAS	1,455	235		
24	Sunny Acres Edgewd RI-G66 FEAS			720	235
25	Tri Thomas Dairy I NR-G33 FEAS			455	235
26	Trout Brook SIS WM-G91 FAC			2,274	235
27	Trout Brook SIS WM-G91 SIS			27,915	235
28	Troy Minerals WF-G23 FEAS	2,811	235	1,909	235
29	VEC JERICHO ER PV & BESS	5,886	235	4,000	235
30	VEC JERICHO ER PV & BESS FACS	612		5,000	235
31	W&C Kendall 40G5 FEAS	1,000	235		
32	W&C Kendall 40G5 FAC	4,888	235		
33	Wallingford Solar WF-G23 FEAS	14	235		
34	Wallingford Solar WF-G23 FAC	9,493	235		
35	Weathersfield Sol WI-G11 FEAS			91	235
36	WEC MORETOWN 3310 DTT	5,670	235	5,670	235
37	Winham White RD LO-G26	1,984	235	1,984	235
38	WMG FEAS BF-G63	(443)	235		
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	12/31/2019	End of 2019/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	41,764		282	9,773	31,991
2	Current revenue due to income taxes					
3	Asset Retirement	239,879		108/407	30,952	208,927
4	St Albans Digester		1,805,499	183/407	150,458	1,655,041
5	PSA Under-Collected		357,027	186/407	29,752	327,275
6	Depreciation Study - 4 yrs	70,475	6,989	407	17,470	59,994
7	Deerfield Wind					
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43						
44	**TOTAL :**	352,118	2,169,515		238,405	2,283,228

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	12/31/2019	End of 2019/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	Deferred ESAM/Storm	1,470,822		407	1,210,948	259,874
2	Synergy regulatory asset	1,060,300	2,339,483			3,399,783
3	Reduced Transco Earnings					
4	SFAS109 regulatory assets-amort	3,160,665	185,698			3,346,363
5	Pine Street - 20 years	6,321,141	215,523	404	769,812	5,766,852
6	Power Suppy Adjustor	8,254,604		186/449	5,174,070	3,080,534
7	Storm Deferral - 1 year	23,644,021	-302,634	407	1,956,572	21,384,815
8	Tax Reform Unprotected Balance	172,222	75,772			247,994
9	Efficiency fund payments - 10 y	1,334,264	-322,684	404	604,240	407,340
10	Pine St. Future	2,551,538	315,684			2,867,222
11	Evergreen	722,312				722,312
12	CEED Fund - 10 yr	14,285,721		404	2,107,362	12,178,359
13	Derivative Regulatory Asset	21,229,677		245	2,952,898	18,276,779
14	JT Owned Def.	167,022	86,311			253,333
15	VTEL Prepayment - 10 yr	1,928,067		921	265,940	1,662,127
16	Goodwill - Not in Rate Base	1,250,000				1,250,000
17	Pension Funding Offset	64,785,171	27,624,443			92,409,614
18	Rate Smoothing		1,662,261			1,662,261
19	Dam Expenses - 3 yrs	343,618		407	28,635	314,983
20	Dam Depreciation - 3 yrs	403,898		403/404	33,658	370,240
21	Microgrid Day 1 Gain		3,085,767			3,085,767
22	Excess Tax Reform Refund		4,042,543			4,042,543
23	Storm Adjustor		4,625,527			4,625,527
24	Deferred Tree Trimming - 3 yrs		1,200,000	407	100,000	1,100,000
25	MYRP Legal Costs		577,857	923	48,153	529,704
26	Op Lease Right of Use Asset		3,554,856	931	17,545	3,537,311
27						
28	Other Minor Items	14,997,198		Various	14,996,616	582
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44						
45						
46						
47	Misc. Work in Progress	829,853				720,703
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	168,912,114				187,502,922

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	12/31/2019	End of 2019/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	Tax Reform Reg Liability	49,100,670	40,779,844
3	Power Supply Derivative ASC815	7,414,223	6,396,316
4	Reg Liability - Cost of Removal	6,719,355	6,719,335
5	Deferred Comp./Post Ret Health ASC 715	17,500,185	25,046,798
6	Unfunded Def Income Taxes	62,830,537	66,614,157
7	Other	21,455,463	11,928,770
8	TOTAL Electric (Enter Total of lines 2 thru 7)	165,020,433	157,485,220
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)	165,020,433	157,485,220

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	12/31/2019	End of 2019/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	Tax Reform Reg Liability	49,100,670	40,779,844
3	Power Supply Derivative ASC815	7,414,223	6,396,316
4	Reg Liability - Cost of Removal	6,719,355	6,719,335
5	Deferred Comp./Post Ret Health ASC 715	17,500,185	25,046,798
6	Unfunded Def Income Taxes	62,830,537	66,614,157
7	Other	21,455,463	11,928,770
8	TOTAL Electric (Enter Total of lines 2 thru 7)	165,020,433	157,485,220
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)	165,020,433	157,485,220

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	12/31/2019	End of 2019/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			
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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 AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
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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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	12/31/2019	End of 2019/Q4

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	Additional investment by Parent in 2019	10,000,000
15		
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40	TOTAL	569,393,341

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	12/31/2019	End of 2019/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		
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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	12/31/2019	End of 2019/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 - First Mortgage		
2	9.64% Bonds	9,000,000	186,729
3	8.65% Bonds	9,000,000	214,354
4	6.53% Bonds (8/06)	30,000,000	242,645
5	6.17% Bonds	16,000,000	226,933
6	5.98% Bonds	15,000,000	191,432
7	3.00% - 5.00% & 6% Bonds	29,765,000	989,241
8	4.56% Bonds	50,000,000	445,942
9	4.61%Bonds	25,000,000	210,295
10	3.99% Bonds	85,000,000	487,569
11	8.91% Bonds,Series JJ	15,000,000	178,357
12	6.90% Bonds, Series OO	17,500,000	188,420
13	5.72% Bonds, Series TT-PSB Docket No. 6943 Dated May 7, 2004	55,000,000	728,848
14	6.83% Bonds, Series UU - PSB Docket No. 7421 dated April 23, 2008	60,000,000	955,339
15	5% Vermont Economic Development Authority Bonds PSB Dkt No.7620 dtd July 14 2010	30,000,000	796,059
16	5.89% Bonds Series WW - PSB Docket No. 7682 dated Jun 15, 2011	40,000,000	389,116
17	Consolidationi of bonds - merger		630,084
18	4.39% Bonds	20,000,000	209,617
19	4.89% Bonds	43,000,000	209,617
20	4.07% Bonds	12,000,000	209,617
21	3.31% Bonds	18,000,000	211,987
22	4.26% Bonds	32,000,000	211,987
23	4.17% Bonds	15,000,000	197,560
24	3.45% Bonds	65,000,000	197,560
25	3.84% Bonds	25,000,000	174,391
26	4.20% Bonds	20,000,000	174,391
27	3.79% Bonds	50,000,000	232,359
28	3.95% Bonds	40,000,000	232,359
29	3.01% Bonds	15,000,000	153,468
30	3.53% Bonds	25,000,000	153,468
31			
32			
33	TOTAL	866,265,000	9,629,744

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	12/31/2019	End of 2019/Q4

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
09/01/1990	09/01/2020	09/01/1990	09/01/2020	9,000,000	867,600	2
03/11/1992	03/11/2022	03/11/1992	03/11/2022	9,000,000	796,521	3
08/01/2006	08/01/2036	08/01/2006	08/01/2036	30,000,000	1,959,000	4
12/15/2007	12/01/2037	12/15/2007	12/01/2037	16,000,000	987,200	5
04/16/2009	04/16/2019	04/16/2009	04/16/2019		264,117	6
04/01/2010	04/01/2035	04/01/2010	04/01/2035	23,330,046	1,166,408	7
11/18/2011	11/18/2041	11/18/2011	11/18/2041	50,000,000	2,280,000	8
11/18/2011	11/18/2041	11/18/2011	11/18/2041	25,000,000	1,152,500	9
12/05/2012	12/05/2042	12/01/2012	12/01/2042	85,000,000	3,391,500	10
12/15/1991	12/15/2031	01/01/1992	12/15/2031	15,000,000	1,336,500	11
12/15/1993	12/15/2023	02/01/1994	12/15/2023	17,500,000	1,207,500	12
07/15/2004	06/15/2019	08/01/2004	06/01/2019		1,328,311	13
05/15/2008	05/15/2028	06/01/2008	05/01/2028	60,000,000	4,098,000	14
12/02/2010	12/15/2020	12/02/2010	12/15/2020	30,000,000	1,500,000	15
06/15/2011	06/15/2041	06/15/2011	06/15/2041	40,000,000	2,356,000	16
10/01/2012	Various	10/01/2012	10/01/2029			17
12/16/2013	12/16/2033	01/01/2014	01/01/2033	20,000,000	878,000	18
12/16/2013	12/16/2043	01/01/2014	01/01/2043	43,000,000	2,102,700	19
01/09/2014	01/09/2029	01/01/2014	01/01/2029	12,000,000	488,400	20
12/16/2015	12/15/2027	01/01/2016	01/01/2028	18,000,000	595,800	21
12/16/2015	12/15/2045	01/01/2016	01/01/2046	32,000,000	1,363,200	22
04/26/2017	04/26/2047	05/01/2017	05/01/2032	15,000,000	625,500	23
06/27/2017	06/27/2029	07/01/2017	07/01/2047	65,000,000	2,242,500	24
09/19/2018	09/19/2030	02/01/2019	02/01/2031	25,000,000	960,000	25
12/03/2018	12/03/2048	02/01/2019	02/01/2049	20,000,000	840,000	26
06/13/2019	06/13/2034	09/01/2019	09/01/2034	50,000,000	1,063,306	27
06/13/2019	06/13/2039	09/01/2019	09/01/2039	40,000,000	886,555	28
12/18/2019	12/18/2034	04/01/2020	04/01/2035	15,000,000	17,558	29
12/18/2019	12/18/2049	04/01/2020	04/01/2050	25,000,000	34,319	30
						31
						32
				789,830,046	36,788,995	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	12/31/2019	End of 2019/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)	77,759,836
2		
3		
4	Taxable Income Not Reported on Books	
5	CAFC	5,084,700
6	Power supply adjustor	4,007,352
7		
8	Gain/loss on disposals	-7,331,451
9	Deductions Recorded on Books Not Deducted for Return	
10	Income tax accruals	2,755,704
11	Perm differences - off life, meals, lobbying etc	-540,351
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Undistributed earnings in affiliates	-53,127,164
16	CEED fund	2,107,362
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation and other fixed asset differences	2,806,612
21	Retirement benefits	-8,032,045
22	Dividend received deduction	-671,201
23	Deferred charges	-165,127
24		
25		
26		
27	Federal Tax Net Income	24,654,226
28	Show Computation of Tax:	
29		
30	Taxable incpme $24,654,226 x 21%	5,177,387
31		
32	Recalss to net operating loss deferred tax asset	-5,063,832
33	Return accrual adjustment etc	-113,557
34		
35	Total current federal taxes	-3
36		
37		
38		
39		
40		
41		
42		
43		
44		

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	-647,835		-3		
4	Unemployment	-6,488		23,818	22,226	
5	Fica	99,449		4,312,739	4,115,459	
6						
7	State of VT					
8	Income	583,089		23,267		
9	Unemployment	-19,301		116,862	116,202	
10	Gross Revenue	3,573,890		6,529,597	6,407,517	
11	Hazardous Waste			3,762	3,762	
12						
13	State of MA					
14	Income					
15	State of CT					
16	State of ME					
17	State of NY					
18						
19						
20						
21						
22	Property Taxes					
23	Vermont		2,884,376	27,745,109	27,843,372	
24	Massachusetts		-13,688	92,064	90,292	
25	Maine		-16,871	45,162	46,629	
26	Connecticut		119,805	248,265	247,192	
27	New Hampshire		519,773	480,317	381,688	
28	New York		166,118	57,669	58,028	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	3,582,804	3,659,513	39,678,628	39,332,367	

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	12/31/2019	End of 2019/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
-647,838		-3				3
-4,896						4
296,728		2,736,384				5
						6
						7
606,356		23,267				8
-18,641						9
3,695,970		6,529,597				10
		9,492				11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
	2,982,439	27,715,174			29,935	23
	-15,460	92,064				24
	-15,404	45,162				25
	118,732	248,265				26
	421,144	480,317				27
	166,477	57,669				28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
3,927,679	3,657,928	37,937,388			29,935	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	12/31/2019	End of 2019/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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	1,231,341				105,701	
6		5,606,688		67,823			
7		504,505				31,620	
8	TOTAL	7,342,534		67,823		137,321	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
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48							

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
1,125,640			5
5,674,511			6
472,885			7
7,273,036			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
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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	12/31/2019	End of 2019/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	46,563,915	186	9,216,358	42,048,955	79,396,512
3	Evergreen	722,312				722,312
4	Derivative Reg Liability	5,521,985	176/253	23,141,533	22,421,662	4,802,114
5	Customer Synergies					
6	Millstone ARO	9,413,421	128/230	187,039	1,857,687	11,084,069
7	Environmental reserve	2,551,538	186		315,684	2,867,222
8	Electricity Assistance Program	161,088	131/142	4,379,781	3,805,041	-413,652
9	OPEB - AOCI	6,380,776	186	4,446,755		1,934,021
10	TCAJA Tax Rate Change					
11	Customer Refund - Tax Reform					
12	Accrued EIC revenue	153,062	454/456	73,334	322,949	402,677
13	Transco Utopus Gain	6,971,882	407	8,327,654	1,577,000	221,228
14	Microgrid Developer Fee		407/131	3,459,950	5,055,761	1,595,811
15	Microgrid Day 1 Gain		407	9,375,390	11,287,781	1,912,391
16						
17	Other Minor Items	9,970,025	Various	9,628,003		342,022
18						
19						
20						
21						
22						
23						
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46						
47	TOTAL	88,410,004		72,235,797	88,692,520	104,866,727

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	12/31/2019	End of 2019/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

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
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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	12/31/2019	End of 2019/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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	205,561,922	5,682,868	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	205,561,922	5,682,868	
6				
7	Non-Utility	1,243,502		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	206,805,424	5,682,868	
10	Classification of TOTAL			
11	Federal Income Tax	157,083,949	2,683,231	
12	State Income Tax	49,721,475	2,999,637	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
			152,131			211,092,659	2
							3
							4
			152,131			211,092,659	5
							6
			-192,055			1,435,557	7
							8
			-39,924			212,528,216	9
							10
			-24,454			159,791,634	11
			-15,470			52,736,582	12
							13

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	12/31/2019	End of 2019/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	Investment in Affiliates Book	115,297,380	14,438,635	
4	CEED Fund	3,959,287	-584,055	
5	Other Deferred Charges			
6	Other	46,401,163	6,223,157	
7	Efficiency fund Reg Asset	369,792	-256,897	
8				
9	TOTAL Electric (Total of lines 3 thru 8)	166,027,622	19,820,840	
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)	166,014,922	19,820,840	
20	Classification of TOTAL			
21	Federal Income Tax	115,801,773	13,634,413	
22	State Income Tax	50,213,149	6,186,427	
23	Local Income Tax			

NOTES

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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						129,736,015	3
						3,375,232	4
							5
			-570			52,624,890	6
						112,895	7
							8
			-570			185,849,032	9
							10
							11
							12
							13
							14
							15
							16
							17
						-12,700	18
			-570			185,836,332	19
							20
			-395			129,436,581	21
			-175			56,399,751	22
							23

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) 12/31/2019	Year/Period of Report End of 2019/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	322,041			998	323,039
2	Current Revenue Due to Income Taxes					
3	SFAS109 Reg Liab TCAJA Protected	87,772,083	190/282/283	4,439,447		83,332,636
4	SFAS109 Reg Liab TCAJA Transco	64,175,981			3,618	64,179,599
5	SFAS109 Reg Liab TCAJA Excess Tax	25,595,655			1,745,302	27,340,957
6	SFAS109 Reg Liab Not Protected Amort		190/410	27,340,956		-27,340,956
7						
8						
9						
10						
11						
12						
13						
14						
15						
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40						
41	TOTAL	177,865,760		31,780,403	****************	147,835,275

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	12/31/2019	End of 2019/Q4

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	286,919,159	278,235,082
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	239,701,000	232,239,766
5	Large (or Ind.) (See Instr. 4)	123,839,046	121,712,849
6	(444) Public Street and Highway Lighting	2,558,298	2,481,960
7	(445) Other Sales to Public Authorities		499
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	653,017,503	634,670,156
11	(447) Sales for Resale	38,151,750	52,924,137
12	TOTAL Sales of Electricity	691,169,253	687,594,293
13	(Less) (449.1) Provision for Rate Refunds	29,861,943	16,556,233
14	TOTAL Revenues Net of Prov. for Refunds	661,307,310	671,038,060
15	Other Operating Revenues		
16	(450) Forfeited Discounts	876,664	949,474
17	(451) Miscellaneous Service Revenues	2,019,537	2,326,301
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	6,976,879	6,163,086
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	18,149,593	23,293,426
22	(456.1) Revenues from Transmission of Electricity of Others	8,751,534	9,428,430
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(415) Business Development Revenues (Contract Work		
26	TOTAL Other Operating Revenues	36,774,207	42,160,717
27	TOTAL Electric Operating Revenues	698,081,517	713,198,777

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	12/31/2019	End of 2019/Q4

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
1,501,957	1,531,307	222,748	221,981	2
				3
1,474,557	1,522,180	43,221	42,599	4
1,148,103	1,164,785	72	67	5
3,809	3,959	158	159	6
	35		1	7
				8
				9
4,128,426	4,222,266	266,199	264,807	10
1,090,344	1,374,862	4	4	11
5,218,770	5,597,128	266,203	264,811	12
				13
5,218,770	5,597,128	266,203	264,811	14

Line 12, column (b) includes $ 2,611,000 of unbilled revenues.

Line 12, column (d) includes 13,643 MWH relating to unbilled revenues

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	12/31/2019	End of 2019/Q4

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	286,919,159	278,235,082
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	239,701,000	232,239,766
5	Large (or Ind.) (See Instr. 4)	123,839,046	121,712,849
6	(444) Public Street and Highway Lighting	2,558,298	2,481,960
7	(445) Other Sales to Public Authorities		499
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	653,017,503	634,670,156
11	(447) Sales for Resale	38,151,750	52,924,137
12	TOTAL Sales of Electricity	691,169,253	687,594,293
13	(Less) (449.1) Provision for Rate Refunds	29,861,943	16,556,233
14	TOTAL Revenues Net of Prov. for Refunds	661,307,310	671,038,060
15	Other Operating Revenues		
16	(450) Forfeited Discounts	876,664	949,474
17	(451) Miscellaneous Service Revenues	2,019,537	2,326,301
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	6,976,879	6,163,086
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	18,149,593	23,293,426
22	(456.1) Revenues from Transmission of Electricity of Others	8,751,534	9,428,430
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(415) Business Development Revenues (Contract Work		
26	TOTAL Other Operating Revenues	36,774,207	42,160,717
27	TOTAL Electric Operating Revenues	698,081,517	713,198,777

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
1,501,957	1,531,307	222,748	221,981	2
				3
1,474,557	1,522,180	43,221	42,599	4
1,148,103	1,164,785	72	67	5
3,809	3,959	158	159	6
	35		1	7
				8
				9
4,128,426	4,222,266	266,199	264,807	10
1,090,344	1,374,862	4	4	11
5,218,770	5,597,128	266,203	264,811	12
				13
5,218,770	5,597,128	266,203	264,811	14

Line 12, column (b) includes $ 2,611,000 of unbilled revenues.

Line 12, column (d) includes 13,643 MWH relating to unbilled revenues

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	12/31/2019	End of 2019/Q4

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					
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13					
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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	12/31/2019	End of 2019/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	1,304,945	252,223,427	207,578	6,287	0.1933
3	EAP 01 low income non-TOU	74,239	14,068,756	10,135	7,325	0.1895
4	Rate 03 off peak water heating	33,745	4,912,886	14,107	2,392	0.1456
5	Rate 9 critical peak non-TOU	73	13,470	10	7,300	0.1845
6	Rate 11/22 optional TOU	74,609	12,069,357	4,885	15,273	0.1618
7	EAP 11/22 low income TOU	2,155	353,554	135	15,963	0.1641
8	Rate 13 space heatin/elec load mg	1,698	235,270	185	9,178	0.1386
9	Rate 14 critical peak TOU	49	8,213	5	9,800	0.1676
10	Rate 19 area lighting	630	262,875	1,259	500	0.4173
11	Green power		50,387			
12	Unbilled revenue	9,814	1,676,394			0.1708
13	Earnings sharing adj		-566,637			
14	Power adjustor		1,611,207			
15	Total	1,501,957	286,919,159	238,299	6,303	0.1910
16	Account 442 Comm & Ind					
17	Rate 3 off peak water heating	1,130	155,504	397	2,846	0.1376
18	Rate 06 general service - no dema	278,162	54,130,540	32,231	8,630	0.1946
19	Rate 08 general service - w/deman	105,016	17,701,878	5,298	19,822	0.1686
20	Rate 12 optional general service	9,989	1,501,530	21	475,667	0.1503
21	Rate 13 space htg elec load mgmt	1,895	313,256	47	40,319	0.1653
22	Rate 15 cable TV	7,994	1,371,694	1,990	4,017	0.1716
23	Rate 19 area lighting	5,138	1,680,368	2,430	2,114	0.3270
24	Rate 65 time of use	1,063,562	160,743,052	3,680	289,011	0.1511
25	Special contracts		1,314	1		
26	Green power		76,947			
27	Unbilled revenue	1,671	908,306			0.5436
28	Earnings sharing adj		-470,896			
29	Power adjustor		1,587,507			
30	Total	1,474,557	239,701,000	46,095	31,990	0.1626
31	Account 443 Ind					
32	Rate 63 time of use	748,427	86,881,245	71	10,541,225	0.1161
33	Rate 19 area lighting	15	5,409	4	3,750	0.3606
34	Rate 70 transmission service	397,499	36,298,406	1	397,499,000	0.0913
35	Unbilled revenue	2,162	18,763			0.0087
36	Earnings sharing adj		-173,416			
37	Power adjustor		808,639			
38	Total	1,148,103	123,839,046	76	15,106,618	0.1079
39	Account 444 Public St & Highway					
40	Rate 19 area lighting	3,813	2,550,761	158	24,133	0.6690
41	TOTAL Billed	4,114,783	650,406,503	266,199	15,458	0.1581
42	Total Unbilled Rev.(See Instr. 6)	13,643	2,611,000	0	0	0.1914
43	TOTAL	4,128,426	653,017,503	266,199	15,509	0.1582

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	12/31/2019	End of 2019/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	Unbilled revenue	-4	7,537			-1.8843
2	Earnings sharing adj					
3	Total	3,809	2,558,298	158	24,108	0.6716
4	Account 445 Other Sales to Public					
5	Contract 19					
6	Total					
7						
8						
9						
10	Duplicate Customers					
11	- Residential					
12	- Commercial					
13	- Industrial					
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41	TOTAL Billed	4,114,783	650,406,503	266,199	15,458	0.1581
42	Total Unbilled Rev.(See Instr. 6)	13,643	2,611,000	0	0	0.1914
43	TOTAL	4,128,426	653,017,503	266,199	15,509	0.1582

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/Q4

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	0	0	0
2	New York State Electric & Gas	RQ	29			
3	Western Massachusetts Electric	RQ	8			
4	Vermont Electric Co-Op	LU	1			
5	Vermont Electric Co-Op	OS		0	0	0
6	ISO	OS	NA	NA	NA	NA
7	Nextera	RQ	2	NA	NA	NA
8	Citigroup	RQ	2	NA	NA	NA
9	BP Energy	RQ	2	NA	NA	NA
10	ISO New England	OS	79			
11	DTE Energy Trading	SF		NA	NA	NA
12	Constellation Power Source	SF		NA	NA	NA
13	Sempra Trading Corp	SF		NA	NA	NA
14	GMP Trans Component FERC 890					
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
					1
38	662	5,924		6,586	2
53	785	8,698		9,483	3
19,690		2,882,724		2,882,724	4
					5
584,938		14,220,467		14,220,467	6
416,025		18,184,192		18,184,192	7
34,400		1,566,920		1,566,920	8
35,200		1,281,378		1,281,378	9
					10
					11
					12
					13
					14
485,716	1,447	21,047,112	0	21,048,559	
604,628	0	17,103,191	0	17,103,191	
1,090,344	**1,447**	**38,150,303**	**0**	**38,151,750**	

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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	104,603	91,852
5	(501) Fuel	4,232,867	4,951,884
6	(502) Steam Expenses	397,509	394,227
7	(503) Steam from Other Sources	284,217	400,932
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	142,691	166,983
10	(506) Miscellaneous Steam Power Expenses	755,065	772,301
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	5,916,952	6,778,179
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	21,185	23,585
16	(511) Maintenance of Structures	29,731	37,337
17	(512) Maintenance of Boiler Plant	318,660	236,553
18	(513) Maintenance of Electric Plant	963,124	137,239
19	(514) Maintenance of Miscellaneous Steam Plant	14,893	10,198
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,347,593	444,912
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	7,264,545	7,223,091
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	1,213,383	1,323,732
25	(518) Fuel	1,204,031	1,361,420
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	2,092,144	1,566,187
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	4,509,558	4,251,339
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	468,176	332,905
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	221,348	24,196
38	(531) Maintenance of Electric Plant	558,451	4,936
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	1,247,975	362,037
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	5,757,533	4,613,376
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	44,356	39,234
45	(536) Water for Power	4,348	4,902
46	(537) Hydraulic Expenses	1,975,216	1,943,530
47	(538) Electric Expenses	429,362	445,101
48	(539) Miscellaneous Hydraulic Power Generation Expenses	63,043	51,195
49	(540) Rents	64,120	36,197
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	2,580,445	2,520,159
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures	75,505	31,303
55	(543) Maintenance of Reservoirs, Dams, and Waterways	697,750	583,397
56	(544) Maintenance of Electric Plant	1,345,654	1,095,479
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,071,490	674,253
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,190,399	2,384,432
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	5,770,844	4,904,591

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	181,657	176,468
63	(547) Fuel	408,035	1,849,294
64	(548) Generation Expenses	481,351	629,815
65	(549) Miscellaneous Other Power Generation Expenses	1,216,390	1,224,869
66	(550) Rents	472,555	488,329
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,759,988	4,368,775
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	21,833	22,162
70	(552) Maintenance of Structures	61,180	63,835
71	(553) Maintenance of Generating and Electric Plant	390,252	270,272
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,926,396	2,897,915
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,399,661	3,254,184
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,159,649	7,622,959
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	338,615,996	344,644,535
77	(556) System Control and Load Dispatching	1,078,669	972,884
78	(557) Other Expenses	120,596	117,612
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	339,815,261	345,735,031
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	364,767,832	370,099,048
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	85,309	61,667
84			
85	(561.1) Load Dispatch-Reliability	154,164	147,687
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	2,734,391	2,968,039
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	562,988	602,932
93	(562) Station Expenses	589,989	589,060
94	(563) Overhead Lines Expenses	215,713	215,888
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	109,255,827	93,927,931
97	(566) Miscellaneous Transmission Expenses	254	
98	(567) Rents	416,849	390,722
99	TOTAL Operation (Enter Total of lines 83 thru 98)	114,015,484	98,903,926
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	11,133	10,720
102	(569) Maintenance of Structures	33,971	36,796
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	521,018	303,743
108	(571) Maintenance of Overhead Lines	2,993,540	3,016,648
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	9,364	1,891
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,569,026	3,369,798
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	117,584,510	102,273,724

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	2,912,386	3,118,138
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	2,912,386	3,118,138
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)	2,912,386	3,118,138
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	735,589	790,607
135	(581) Load Dispatching	122,618	121,394
136	(582) Station Expenses	164,450	179,471
137	(583) Overhead Line Expenses	430,953	675,322
138	(584) Underground Line Expenses	165,300	34,291
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	379,692	311,607
141	(587) Customer Installations Expenses	50,818	50,253
142	(588) Miscellaneous Expenses	2,327,254	1,909,002
143	(589) Rents	968,197	2,324,837
144	TOTAL Operation (Enter Total of lines 134 thru 143)	5,344,871	6,396,784
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	71,840	126,630
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	2,010,608	1,665,947
149	(593) Maintenance of Overhead Lines	29,612,236	28,643,434
150	(594) Maintenance of Underground Lines	625,399	661,832
151	(595) Maintenance of Line Transformers	-218	
152	(596) Maintenance of Street Lighting and Signal Systems	71,225	71,104
153	(597) Maintenance of Meters	342,236	275,640
154	(598) Maintenance of Miscellaneous Distribution Plant	265,363	233,917
155	TOTAL Maintenance (Total of lines 146 thru 154)	32,998,689	31,678,504
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	38,343,560	38,075,288
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	337,002	119,540
160	(902) Meter Reading Expenses	676,964	727,651
161	(903) Customer Records and Collection Expenses	4,921,157	4,658,608
162	(904) Uncollectible Accounts	1,863,580	1,570,626
163	(905) Miscellaneous Customer Accounts Expenses	3,911	28,564
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	7,802,614	7,104,989

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	12/31/2019	End of 2019/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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		386
168	(908) Customer Assistance Expenses	2,075,672	2,129,972
169	(909) Informational and Instructional Expenses	30,998	28,427
170	(910) Miscellaneous Customer Service and Informational Expenses	252,353	319,642
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	2,359,023	2,478,427
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	14,908	8,027
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	14,908	8,027
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	12,034,990	12,036,233
182	(921) Office Supplies and Expenses	3,542,964	3,901,840
183	(Less) (922) Administrative Expenses Transferred-Credit	7,565,109	6,137,075
184	(923) Outside Services Employed	3,234,365	3,952,968
185	(924) Property Insurance	1,428,331	1,664,626
186	(925) Injuries and Damages	2,447,541	2,159,187
187	(926) Employee Pensions and Benefits	13,327,249	11,973,586
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	381,180	1,304,047
190	(929) (Less) Duplicate Charges-Cr.	318,905	317,598
191	(930.1) General Advertising Expenses	76,593	110,469
192	(930.2) Miscellaneous General Expenses	1,229,809	844,503
193	(931) Rents	164,517	178,380
194	TOTAL Operation (Enter Total of lines 181 thru 193)	29,983,525	31,671,166
195	Maintenance		
196	(935) Maintenance of General Plant	9,045,194	8,110,150
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	39,028,719	39,781,316
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	572,813,552	562,938,957

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.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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)	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	National Grid	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	12/31/2019	End of 2019/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.

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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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EX - For exchanges of electricity. Use this category for 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	Vermont Electric Power Co.	OS				
2	Granite Reliable	SF				
3	Decomission Conn Maine & Yankee Atomic	LU	FPC1			
4	ENEL North America Sweetwater Hydro	LU	FPC1			
5	NorthHartland Hydro	LU	NUG			
6	Ampersand Hydro	LU	NUG			
7	Florida Power & Light Wyman	OS				
8	Fitchburg	OS				
9	Unitil	OS				
10	Vermont Electric Power Prod Ryegate	LU				
11	OATI	OS				
12	Links & Itron	OS				
13	Nextsun Energy	LU				
14	Green Maple	LU				
	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	12/31/2019	End of 2019/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.

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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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EX - For exchanges of electricity. Use this category for 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	Shell	IF				
2	Energy New England	LF				
3	Winooski 8	SF				
4	Cypress Creek Holdings, LLC	LU				
5	Bondville Solar	LU				
6	GMP VT Solar	LU				
7	TESLA Battery Control	OS				
8	Sheldon Springs Missisquoi Associates	LU				
9	AEP onsite Partners LLC	LU				
10	Burlington Electric Dept	OS				
11	RES compliance Tier I, II, III	OS				
12	Elizabeth Mine Solar	LU				
13	GSPP Gilman	LU				
14	Deerfiled Wind	LU				
	Total					

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.

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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	Sugar River Power LLC	LU				
2	Dynegy	OS				
3	Citigroup	IF				
4	GMP Micro grids	OS				
5						
6						
7						
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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,799			523,555	51,392		574,947	1
10,749			108,840	918,972		1,027,812	2
680,312				27,553,341	32,130,222	59,683,563	3
5,714			29,668	28,625		58,293	4
4,173				129,164		129,164	5
21,751				2,627,952	-26,125	2,601,827	6
					-395,557	-395,557	7
192,308				38,711,252		38,711,252	8
90,543				16,471,796	-7,489	16,464,307	9
583,825			7,435,407	26,348,194		33,783,601	10
524,912				26,605,662		26,605,662	11
1,041,727				57,766,759	18	57,766,777	12
510,600				30,299,130		30,299,130	13
					5,728	5,728	14
4,607,663			11,973,696	287,198,644	39,443,656	338,615,996	

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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					-31,989	-31,989	1
192,096			-61,073	14,615,377		14,554,304	2
					-604,276	-604,276	3
278				29,094		29,094	4
15,376				697,350	369,232	1,066,582	5
24,142				1,070,777	173,674	1,244,451	6
					-1,685,159	-1,685,159	7
					403,677	403,677	8
					689,523	689,523	9
106,733				10,844,955	28,767	10,873,722	10
					11,003	11,003	11
					29,400	29,400	12
4,870				730,373		730,373	13
2,465				362,041		362,041	14
4,607,663			11,973,696	287,198,644	39,443,656	338,615,996	

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)	
219,000				8,869,500		8,869,500	1
					-2,949	-2,949	2
34				339	76	415	3
7,480				574,815		574,815	4
2,558				257,793	1,543	259,336	5
32,357				3,046,594		3,046,594	6
					38,870	38,870	7
59,249			-67,886	2,821,547		2,753,661	8
3,417				413,456		413,456	9
					-3,353	-3,353	10
					7,456,541	7,456,541	11
6,922				834,806		834,806	12
2,989				251,791		251,791	13
103,784				6,250,972		6,250,972	14
4,607,663			11,973,696	287,198,644	39,443,656	338,615,996	

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)	
5,695				359,012	102,816	461,828	1
			4,005,185			4,005,185	2
145,825				7,655,813		7,655,813	3
3,980					759,463	759,463	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,607,663			11,973,696	287,198,644	39,443,656	338,615,996	

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	12/31/2019	End of 2019/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	EVERSOURCE	VARIOUS	EVERSOURCE	FNO
12	MAG ENERGY	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
13	MAG ENERGY	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
14	NALCOR	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
15	HYDRO QUEBEC	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
16	HYDRO QUEBEC	HYDRO QUEBEC	ISO-NEW ENGLAND	FNO
17	BROOKFIELD ENERGY	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
18	BROOKFIELD ENERGY	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
19	TRANS ALTA ENERGY	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	FNO
20	HYDRO QUEBEC MARKETING	HYDRO QUEBEC TRANSENERGIE	ISO-NEW ENGLAND	NF
21	BURLINGTON ELECTRIC	GMP	BURLINGTON ELECTRIC	LFP
22	METALIC NEUTRAL			
23	ACCRUAL ADJUSTMENT			
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	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	12/31/2019	End of 2019/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)	MegaWatt Hours Delivered (j)	Line No.
3	GMP	VARIOUS		61,207	57,369	1
3	GMP	VARIOUS		95,688	92,422	2
3	GMP	VARIOUS		33,661	30,652	3
3	GMP	VILLAGE OF NORTHFIED		29,999	29,099	4
3	GMP	VARIOUS		59,424	57,551	5
3	GMP	VILLAGE OF JACKSONVI		5,733	5,435	6
3	GMP	VARIOUS		5,175	4,903	7
3	GMP	VARIOUS		18,606	17,445	8
3	GMP	HYDE PARK		11,567	21,965	9
3	GMP	WOODSVILLE		24,199	23,473	10
3	GMP	VARIOUS		169,006	163,072	11
3	GMP	VARIOUS		26,280	26,280	12
3	NEW ENGLAND BORDER	SANDY POND, MA		184	184	13
3	NEW ENGLAND BORDER	SANDY POND, MA		26,280	26,280	14
3	NEW ENGLAND BORDER	SANDY POND, MA		26,280	26,280	15
3	NEW ENGLAND BORDER	SANDY POND, MA		395	395	16
3	NEW ENGLAND BORDER	SANDY POND, MA		26,280	26,280	17
3	NEW ENGLAND BORDER	SANDY POND, MA		1,000	1,000	18
3	NEW ENGLAND BORDER	SANDY POND, MA		26,280	26,280	19
3	NEW ENGLAND BORDER	SANDY POND, MA		2,186,445	2,186,445	20
3	GEORGIA	BURLINGTON		27,561	27,561	21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**2,861,250**	**2,850,371**	

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.
436,794		-66,878	369,916	1
633,872		2,686	636,558	2
208,546		-31,454	177,092	3
173,222		-16,218	157,004	4
315,202		9,026	324,228	5
32,659		-5,732	26,927	6
28,310		310	28,620	7
119,000		9,443	128,443	8
80,420		-315	80,105	9
128,058		6,440	134,498	10
956,589		55,317	1,011,906	11
113,557		-118,279	-4,722	12
907		-171	736	13
113,557		-115,575	-2,018	14
113,557		-99,930	13,627	15
2,714		-5,174	-2,460	16
113,557		-99,930	13,627	17
10			10	18
113,557		-93,968	19,589	19
5,374,992		-93,687	5,281,305	20
307,200			307,200	21
		44,343	44,343	22
		5,000	5,000	23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
9,366,280	**0**	**-614,746**	**8,751,534**	

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	$1,648
Delivery point charge	4,784
Load dispatch	55,528
2018 True-up	(31,110)
Phase in	(62,448)
Specific Facility Credit	(15,432)
Highgate Credit	(19,848)
TOTAL	$(66,878)

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	$30,125
Regulatory Commission expense	2,564
Delivery point charge	9,568
Load dispatch	76,738
2018 True-up	(39,473)
Specific Facility Credit	(43,596)
Highgate Credit	(33,240)
TOTAL	$2,686

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	$911
Delivery point charge	1,196
Load dispatch	26,317
2018 True-up	(16,318)
Phase in	(25,332)
Specific Facility Credit	(8,040)
Highgate Credit	(10,188)
TOTAL	$(31,454)

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	$815
Delivery point charge	598
Load dispatch	22,472
2018 True-up	(10,715)
Phase in	(21,324)
Highgate Credit	(8,064)

TOTAL	$(16,218)

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	$1,584
Delivery point charge	1,794
Load dispatch	40,084
2018 True-up	(19,892)
Highgate Credit	(14,544)
TOTAL	$9,026

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	$154
Delivery point charge	598
Load dispatch	4,159
2018 True-up	(2,147)
Phase in	(6,936)
Highgate Credit	(1,560)
TOTAL	$(5,732)

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	$139
Delivery point charge	1,196
Load dispatch	3,535
2018 True-up	(1,848)
Specific Facility Credit	(1,296)
Highgate Credit	(1,416)
TOTAL	$310

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	$499
Load dispatch	15,199
Distribution	6,401
2018 True-up	(6,848)
Highgate Credit	(5,808)
TOTAL	$9,443

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	$310
Delivery point charge	598
Load dispatch	10,305
2018 True-up	(5,000)
Phase in	(2,808)
Highgate Credit	(3,720)
TOTAL	$(315)

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	$657
Delivery point charge	598
Load dispatch	16,151
2018 True-up	(8,364)
Highgate Credit	(6,312)
Distribution	3,710
TOTAL	$6,440

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

Eversource

Regulatory Commission expense	$4,592
Delivery point charge	4,186
Load dispatch	122,058
Distribution	30,087
2018 True-up	(58,650)
Highgate Credit	(46,956)
TOTAL	$55,317

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

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	12/31/2019	End of 2019/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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	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	12/31/2019	End of 2019/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)	TRANSFER OF ENERGY: 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					4,148,437	4,148,437
3	VELCO NEPOOL OATT	FNS					-940,521	-940,521
4	VELCO VTA	FNS	2,865,056	2,847,918	32,700,948			32,700,948
5	VELCO Network	OS					214,131	214,131
6	State of Vt NYPA	OLF			122,083			122,083
7	National Grid	FNS			1,808,962			1,808,962
8	VELCO Phases I & II	LFP			3,796,242			3,796,242
9	ISO New England	FNS			66,871,307			66,871,307
10	Vermont Electric Co-op	SFP			316,383			316,383
11	Vermont Electric Pwr Pr	SFP					52,376	52,376
12	Eversource (Millstone)	OS	164,286	164,286	152,658			152,658
13	Pub Serv New Hampshire	OS					12,820	12,820
14	TOTAL		3,029,342	3,012,204	105,768,583		3,487,243	109,255,826
15								
16								
	TOTAL		3,029,342	3,012,204	105,768,583		3,487,243	109,255,826

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	12/31/2019	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	253,994
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	32,617
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	46,437
7	A&G Expense - Trustee	252,985
8	A&G Expense - Misc. Communications	15,273
9	A&G Expense - Misc. Other	187,094
10		
11		
12	Directors Fees:	
13	Bankowski, Elizabeth	43,875
14	Coates, David R	38,750
15	Tessier, Robert	38,750
16	Rathke, Frances	43,875
17	Wolk, David	38,750
18	Reilly, Lawrence	38,750
19	Brochu, Sophie	134,688
20		
21	Directors Expenses	63,971
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46	TOTAL	1,229,809

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	12/31/2019	End of 2019/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			12,967,960		12,967,960
2	Steam Production Plant	1,192,837				1,192,837
3	Nuclear Production Plant	1,029,370				1,029,370
4	Hydraulic Production Plant-Conventional	6,664,293				6,664,293
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,923,282	135,060			8,058,342
7	Transmission Plant	3,338,019				3,338,019
8	Distribution Plant	20,017,412				20,017,412
9	Regional Transmission and Market Operation					
10	General Plant	5,491,545				5,491,545
11	Common Plant-Electric					
12	TOTAL	45,656,758	135,060	12,967,960		58,759,778

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	12/31/2019	End of 2019/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	12/31/2019	End of 2019/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	12/31/2019	End of 2019/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			12,967,960		12,967,960
2	Steam Production Plant	1,192,837				1,192,837
3	Nuclear Production Plant	1,029,370				1,029,370
4	Hydraulic Production Plant-Conventional	6,664,293				6,664,293
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,923,282	135,060			8,058,342
7	Transmission Plant	3,338,019				3,338,019
8	Distribution Plant	20,017,412				20,017,412
9	Regional Transmission and Market Operation					
10	General Plant	5,491,545				5,491,545
11	Common Plant-Electric					
12	TOTAL	45,656,758	135,060	12,967,960		58,759,778

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	12/31/2019	End of 2019/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	12/31/2019	End of 2019/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
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16	395	3,252	24.69		4.05	SQ	10.30
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19	Subtotal	121,437					
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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).
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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.
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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)
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7	Transmission Plant	3,338,019				3,338,019
8	Distribution Plant	20,017,412				20,017,412
9	Regional Transmission and Market Operation					
10	General Plant	5,491,545				5,491,545
11	Common Plant-Electric					
12	TOTAL	45,656,758	135,060	12,967,960		58,759,778

B. Basis for Amortization Charges

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)
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23	336	2,705	56.18		1.78	R4	30.00
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28	344	127,121	39.67	0.13	3.22	S2.5 & R3	20.45
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43	367	35,835	55.56	0.10	1.80	R2	35.20
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45	369	45,076	50.00	0.10	2.00	R1.5	28.00
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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

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)
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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					
21							
22							
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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	12/31/2019	End of 2019/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	Alternative Regulation Base Rate Filing		317,688	317,688	
3	Rate Design				
4	FERC Proceedings		35,439	35,439	
5	Schedule 21		15,303	15,303	
6					
7	Various less than $25,000		12,750	12,750	
8					
9					
10					
11					
12					
13					
14					
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44					
45					
46	TOTAL		381,180	381,180	

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	12/31/2019	End of 2019/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
							2
							3
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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		Research America Inc
5		
6		
7		
8		
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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.
	32,617	930	32,617		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	12/31/2019	End of 2019/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	3,075,158		
4	Transmission	334,773		
5	Regional Market			
6	Distribution	3,574,706		
7	Customer Accounts	2,549,439		
8	Customer Service and Informational	2,228,142		
9	Sales	14,168		
10	Administrative and General	12,187,028		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	23,963,414		
12	Maintenance			
13	Production	1,676,659		
14	Transmission	448,469		
15	Regional Market			
16	Distribution	11,760,873		
17	Administrative and General	546,018		
18	TOTAL Maintenance (Total of lines 13 thru 17)	14,432,019		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	4,751,817		
21	Transmission (Enter Total of lines 4 and 14)	783,242		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	15,335,579		
24	Customer Accounts (Transcribe from line 7)	2,549,439		
25	Customer Service and Informational (Transcribe from line 8)	2,228,142		
26	Sales (Transcribe from line 9)	14,168		
27	Administrative and General (Enter Total of lines 10 and 17)	12,733,046		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	38,395,433	1,078,573	39,474,006
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			

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)	38,395,433	1,078,573	39,474,006
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	14,087,138	395,724	14,482,862
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	14,087,138	395,724	14,482,862
72	Plant Removal (By Utility Departments)			
73	Electric Plant	944,571	26,534	971,105
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	944,571	26,534	971,105
77	Other Accounts (Specify, provide details in footnote):			
78	Business Development	290,967	8,174	299,141
79	Other work in progress	1,186,186	33,321	1,219,507
80	Misc. Payroll	3,917,502	110,047	4,027,549
81	Lobbying	47,488	1,333	48,821
82	Other Operating Revenue	311,799	8,759	320,558
83	Rental Water Heater	90,153	2,533	92,686
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	5,844,095	164,167	6,008,262
96	TOTAL SALARIES AND WAGES	59,271,237	1,664,998	60,936,235

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	12/31/2019	End of 2019/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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)	11,240,620	16,938,695	20,953,750	26,981,765
3	Net Sales (Account 447)	(5,447,502)	(9,226,277)	(11,958,312)	(14,217,156)
4	Transmission Rights	(287,247)	(396,548)	(497,906)	(559,435)
5	Ancillary Services	297,391	296,753	376,956	558,830
6	Other Items (list separately)				
7	Real time Regulation	182,827	261,218	378,687	572,180
8	ICAP Settlement	11,242,630	20,792,554	26,968,168	32,130,222
9					
10					
11					
12					
13					
14					
15					
16					
17					
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33					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	17,228,719	28,666,395	36,221,343	45,466,406

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	12/31/2019	End of 2019/Q4

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			1,232,126			
2	Reactive Supply and Voltage			565,419			
3	Regulation and Frequency Response			572,181			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement			558,830			
7	Other			3,549,643			
8	Total (Lines 1 thru 7)			6,478,199			

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	12/31/2019	End of 2019/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	775	21	18	671	102	10			8
2	February	727	12	18	631	89	10			3
3	March	717	7	19	621	89	10			3
4	Total for Quarter 1				1,923	280	30			14
5	April	608	9	20	524	78	10			4
6	May	570	28	19	496	68	10			4
7	June	627	27	21	546	74	10			3
8	Total for Quarter 2				1,566	220	30			11
9	July	756	20	21	657	94	10			6
10	August	701	19	19	613	82	10			4
11	September	629	23	19	549	72	10			2
12	Total for Quarter 3				1,819	248	30			12
13	October	614	17	19	533	71	10			9
14	November	717	13	18	622	85	10			3
15	December	755	19	8	656	89	10			6
16	Total for Quarter 4				1,811	245	30			18
17	Total Year to Date/Year				7,119	993	120			55

Schedule Page: 400 Line No.: 1 Column: b

Monthly Transmission System Peak Loads are calculated from metering data at the kw level and rounded to the nearest MW.

Day	Hour	Kwh	Rounded to nearest MW
1/21/2019	18	774,882	775
2/12/2019	18	727,220	727
3/7/2019	19	717,101	717
4/9/2019	20	608,364	608
5/28/2019	19	570,290	570
6/27/2019	21	626,806	627
7/20/2019	21	755,561	756
8/19/2019	19	701,195	701
9/23/2019	19	629,494	629
10/17/2019	19	614,470	614
11/13/2019	18	716,889	717
12/19/2019	8	755,361	755

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	12/31/2019	End of 2019/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	12/31/2019	End of 2019/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)	4,128,426
3	Steam	70,626			
4	Nuclear	164,286	23	Requirements Sales for Resale (See instruction 4, page 311.)	485,716
5	Hydro-Conventional	408,671			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	604,628
7	Other	175,522			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	819,105	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	8,720
10	Purchases	4,607,663	27	Total Energy Losses	210,157
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,437,647
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	2,861,250			
17	Delivered	2,850,371			
18	Net Transmission for Other (Line 16 minus line 17)	10,879			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	5,437,647			

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	12/31/2019	End of 2019/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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	511,753	53,639	612	21	18
30	February	443,815	46,707	576	12	18
31	March	466,591	57,407	558	7	19
32	April	456,705	55,159	477	8	20
33	May	453,974	73,565	453	28	19
34	June	435,491	62,740	499	27	21
35	July	450,377	36,497	606	20	21
36	August	468,070	43,487	565	19	19
37	September	412,469	51,896	512	23	19
38	October	431,695	55,906	493	17	19
39	November	433,974	34,562	560	13	18
40	December	472,732	33,063	585	19	18
41	TOTAL	5,437,646	604,628			

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	12/31/2019	End of 2019/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	70,626
4	Nuclear	164,286
5	Hydro-Conventional	408,671
6	Hydro-Pumped Storage	
7	Other	175,522
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	819,105
10	Purchases	4,607,663
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	2,861,250
17	Delivered	2,850,371
18	Net Transmission for Other (Line 16 minus line 17)	10,879
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	5,437,647
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	4,128,426
23	Requirements Sales for Resale (See instruction 4, page 311.)	485,716
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	604,628
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	8,720
27	Total Energy Losses	210,157
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,437,647

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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	511,753	53,639	612	21	18
30	February	443,815	46,707	576	12	18
31	March	466,591	57,407	558	7	19
32	April	456,705	55,159	477	8	20
33	May	453,974	73,565	453	28	19
34	June	435,491	62,740	499	27	21
35	July	450,377	36,497	606	20	21
36	August	468,070	43,487	565	19	19
37	September	412,469	51,896	512	23	19
38	October	431,695	55,906	493	17	19
39	November	433,974	34,562	560	13	18
40	December	472,732	33,063	585	19	18
41	TOTAL	5,437,646	604,628			

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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	91300			464020		
13	Cost of Plant: Land and Land Rights	2439			48218		
14	Structures and Improvements	516275			897653		
15	Equipment Costs	4804980			12625389		
16	Asset Retirement Costs	0			0		
17	Total Cost	5323694			13571260		
18	Cost per KW of Installed Capacity (line 17/5) Including	295.7608			323.8964		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	54477			110037		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	22418			40346		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	49681			80585		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	4079			9531		
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	6085			10861		
33	Maintenance of Misc Steam (or Nuclear) Plant	12119			64334		
34	Total Production Expenses	148859			315694		
35	Expenses per Net KWh	1.6304			0.6803		
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

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	-7600			-9200		
13	Cost of Plant: Land and Land Rights	0			1810		
14	Structures and Improvements	1957			25765		
15	Equipment Costs	3464674			3827889		
16	Asset Retirement Costs	0			0		
17	Total Cost	3466631			3855464		
18	Cost per KW of Installed Capacity (line 17/5) Including	262.6236			289.8845		
19	Production Expenses: Oper, Supv, & Engr	1762			3378		
20	Fuel	44285			78001		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	13154			76650		
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	1573			7762		
33	Maintenance of Misc Steam (or Nuclear) Plant	12110			7715		
34	Total Production Expenses	72884			173506		
35	Expenses per Net KWh	-9.5900			-18.8593		
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

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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			31.20			16.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
53			34			40			11
179200			3939770			70446800			12
5738			738			85746			13
836247			2178470			6467144			14
5454676			10180334			23608118			15
0			0			0			16
6296661			12359542			30161008			17
349.8145			396.1392			1885.0630			18
0			0			104603			19
45685			108411			4187183			20
0			0			0			21
284217			562819			397509			22
0			0			0			23
0			0			0			24
0			168260			142691			25
0			0			755065			26
0			0			0			27
0			0			0			28
0			21833			21185			29
0			58313			29731			30
0			0			318660			31
0			342476			963124			32
0			8785			14893			33
329902			1270897			6934644			34
1.8410			0.3226			0.0984			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

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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

(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

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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
0	0	0	10
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	12/31/2019	End of 2019/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	158,772,500
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	158,772,500
12	Cost of Plant	
13	Land and Land Rights	568,330
14	Structures and Improvements	1,349,426
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	133,180,825
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	135,098,581
22	Cost per KW of installed cap (line 21 / 4)	2,144.4219
23	Production Expenses	
24	Operation Supervision and Engineering	159,090
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	556,105
28	Misc Pumped Storage Power generation Expenses	
29	Rents	469,555
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	2,499,961
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	3,684,711
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	3,684,711
38	Expenses per KWh (line 37 / 9)	0.0232

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	12/31/2019	End of 2019/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		11,664	7,512,407
3	Marshfield Station # 6	1927	5.00		11,335	17,200,667
4	Vergennes Station # 9 License# 2674	1912	2.40		5,868	12,670,421
5	W, Danville Station # 15	1917	1.00		3,652	5,991,518
6	Gorge Station # 18	1928	3.00		12,701	9,475,081
7	Essex station # 19 License# 2531	1917	7.20		43,959	16,498,467
8	Waterbury Station # 22 A License# 2090	1953	5.52		17,822	8,100,186
9	DeForge station # 1 D License# 2879	1986	7.50		28,044	16,581,137
10	Huntington Falls #203	1911	5.50		20,266	19,055,702
11	Beldens #204	1913	5.85		19,616	8,279,661
12	Proctor #205	1905	6.93		31,177	24,636,492
13	Center Rutland #206	1898	0.28		460	1,228,127
14	Pittsford #207	1941	3.60		11,389	9,348,739
15	Glen #208	1920	2.00		8,921	9,598,269
16	Patch #209	1921	0.40		437	723,091
17	Carver Falls #210	1894	2.55		7,861	4,345,842
18	Cavendish #211	1907	1.44		3,782	2,379,235
19	Salisbury #212	1917	1.30		4,676	1,901,185
20	Silver Lake #213	1917	2.20		6,963	3,662,207
21	Middlebury Lower #214	1917	2.25		-869	3,528,102
22	Weybridge #215	1951	3.00		17,048	3,859,575
23	Taftsville #216	1910	0.50		818	697,469
24	Smith #217	1982	1.50		3,413	5,142,705
25	Pierce Mills #218	1928	0.25		802	417,197
26	Arnold Falls #219	1928	0.35		1,151	2,373,748
27	Gage #220	1921	0.70		1,785	2,609,865
28	Passumpsic #221	1929	0.70		1,438	1,049,762
29	East Barnet #222	1984	2.20		7,156	6,344,399
30	Fairfax #223	1919	4.20		22,873	4,662,530
31	Clark Falls #224	1937	3.00		16,193	7,113,000
32	Milton #225	1929	7.50		43,659	5,988,005
33	Peterson #226	1948	6.35		16,483	1,930,429
34	Barnet #120	1986	0.56		6	352,816
35	Dewey Mills #121	1985	2.75		2,202	3,295,666
36	Newbury #122	2004	0.42		261	4,086,426
37	Ottauquechee #123	1924	1.69		1,376	3,117,840
38	Woodsville #124	1924	0.36			1,714,952
39	Mascoma #125	1988	2.05		3,718	2,402,739
40	Lower Village #126	1909	0.92			1,273,554
41	EHC #127	1983	1.12		3,577	4,018,095
42	Kelleys #128	1987	0.40		1,693	529,518
43	Somersworth #129	1984	1.28		3,259	1,042,852
44	Rollingsford #130	1983	1.50		6,208	1,395,789
45	Salmon Falls #131	1923	1.20		3,830	3,537,526
46						

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	12/31/2019	End of 2019/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		29	2,716,117
3	Essex Station #19B	1947	4.00		52	967,784
4						
5						
6	OTHER					
7	Millstone Nuclear #227		21.00		164,286	84,038,934
8	Searsburg Wind #92	1997	6.90		12,151	4,391,934
9	Post Road Solar #232				37	75,970
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				13,720,996
15	Milton Solar #117*	2016				73,915
16	Peterson Solar #118*	2016				66,783
17	Panton Battery #119					2,638,172
18						
19	* Generation is recorded as company use					
20						
21						
22						
23						
24						
25						
26	TOTAL		151.52		585,226	362,081,314
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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
2,347,627	78,893		111,337			2
3,440,133	94,698		98,979			3
5,279,342	40,662		120,874			4
5,991,518	47,700		36,972			5
3,158,360	55,159		77,737			6
2,291,454	91,362		250,762			7
1,467,425	27,678		163,229			8
2,210,818	31,097		132,909			9
3,464,673	56,055		151,258			10
1,415,327	74,790		251,583			11
3,555,049	84,720		131,522			12
4,386,170	22,761		20,913			13
2,596,872	60,515		86,827			14
4,799,135	46,389		38,343			15
1,807,729	27,844		17,785			16
1,704,252	48,139		63,936			17
1,652,246	89,791		34,902			18
1,462,450	39,286		39,479			19
1,664,640	41,321		177,313			20
1,568,045	42,654		57,141			21
1,286,525	45,127		100,760			22
1,394,938	53,598		4,728			23
3,428,470	44,078		54,411			24
1,668,790	32,268		31,774			25
6,782,138	30,427		30,787			26
3,728,379	46,472		49,128			27
1,499,660	36,056		40,411			28
2,883,818	45,119		58,861			29
1,110,126	63,290		64,180			30
2,371,000	55,759		75,647			31
798,401	76,062		77,821			32
304,005	54,515		75,678			33
630,029	23,016		10,711			34
1,198,424	68,305		47,215			35
9,729,586	55,487		41,215			36
1,844,876	77,163		75,458			37
4,763,755	12,117		5,989			38
1,172,068	117,971		136,680			39
1,384,297	17,421		5,490			40
3,587,585	121,332		26,455			41
1,323,794	108,733		41,410			42
814,728	122,286		12,634			43
930,526	83,570		15,877			44
2,947,938	88,759		12,659			45
						46

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
679,029	33,225	6,147	13,609	# 2 OIL		2
241,946	50,769	6,677	5,668	# 2 OIL		3
						4
						5
						6
4,001,854	1,771,834	1,204,031	2,781,667			7
636,512	105		266,109			8
						9
	58					10
	711					11
	3,373		155			12
						13
6,860,498	27,656		50,288			14
						15
						16
	1,184		5,991			17
						18
						19
						20
						21
						22
						23
						24
						25
	4,469,360	1,216,854	6,283,268			26
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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	12/31/2019	End of 2019/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	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	126.32	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	Putnam Rd	69.00	69.00	H. Frame	10.74		1
31	Putnam Rd	Searsburg	69.00	69.00	H Frame	0.42		1
32					Steel			
33	Ladder Hill	Vernon Road	115.00	115.00	Wood Pole	0.61		1
34								
35			120.00	120.00	H. Frame			
36					TOTAL	1,000.57	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	12/31/2019	End of 2019/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		Group	450.00			35.00		1
4		Group	115.00			3.19		5
5		Group	69.00			23.70		10
6		Group	34.50			386.20	1.67	60
7		Group	13.80			2.44		1
8		Group	11.00			2.75		1
9		Group	46.00			547.29	8.43	100
10								
11		Remove Sub-totals				-1,000.57	-10.10	-178
12								
13								
14								
15								
16								
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22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,000.57	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	12/31/2019	End of 2019/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)	
2839.8MCM								1
ACSR		1,563,276	1,563,276					2
								3
								4
								5
								6
								7
								8
750 MCMCU								9
								10
#2AL		44,734	44,734					11
								12
Various	1,083,991	39,493,470	40,577,461	69,303	13,932		83,235	13
								14
								15
								16
								17
								18
								19
Various	3,189,177	41,850,831	45,040,008	120,894	53,366		174,260	20
								21
								22
								23
								24
								25
								26
Various	13,430	1,834,470	1,847,900	611	238		849	27
								28
								29
								30
								31
								32
795 ACRS	19,819	66,396	86,215	1,800			1,800	33
								34
								35
	4,306,417	84,853,177	89,159,594	192,608	67,536		260,144	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	12/31/2019	End of 2019/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)	
								1
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	4,306,417	84,853,177	89,159,594	192,608	67,536		260,144	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	12/31/2019	End of 2019/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							
2							
3							
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43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
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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) 12/31/2019	Year/Period of Report End of 2019/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/Hill Top/Essex	Dist./Unatt.	34.50	12.47	
9	Mountain View #27/Montpelier	Dist./Unattended	34.50	4.16	
10	Mountain View #27/Montpelier	Dist./Unattended	34.50	12.47	
11	Queen City #32/So. Burlington	Dist./Unattended	34.50	12.47	
12	Sand Road #33/Essex	Dist/Unattended	34.50	12.47	
13	Mallets Bay #34/Colchester	Dist./Unattended	34.50	12.47	
14	So. End #37/Barre City	Dist./Unattended	34.50	12.47	
15	Madubush #38/Warren	Dist./Unattended	34.50	12.47	
16	Irasville #39/Fayston	Dist./Unattended	34.50	12.47	
17	Bolton #41/Bolton	Dist./Unattended	34.50	12.47	
18	Digital #43/So. Burlington	Dist./Unattended	34.50	12.47	
19	Shelburne #53/Shelburne	Dist./Unattended	115.00	12.47	
20	Wilmington #56/Wilmington	Dist./Unattended	67.00	12.47	
21	Websterville #61Barre Town	Dist./Unattended	34.50	12.47	
22	Sharon	Dist./Unattended	46.00	12.47	
23	Barre North End #63/Barre City	Dist./Unattended	34.50	12.47	
24	Berlin #40/Berlin	Dist./Unattended	34.50	4.16	
25	Berlin #40/Berlin	Dist./Unattended	34.50	12.47	
26	Richmond #51/Richmond (Jt Owned VEC)	Dist./Unattended	34.50	12.47	
27	Wilder #71/Hartford	Dist./Unattended	4.60	12.47	
28	Dorset St. #78/So. Burlington	Dist./Unattended	34.50	12.47	
29	Dover #90/Dover	Dist./Unattended	67.00	12.47	
30	Dover #90/Dover	Dist./Unattended	67.00	12.47	
31	Bolton Falls #1/Duxbury	Trans/Unattended	4.16	34.50	
32	Charlotte #28/Charlotte	Dist./Unattended	115.00	13.20	
33	Waterbury/Waterbury	Dist./Unattended	34.50	12.47	
34	Town Line #44/Williston	Dist./Unattended	34.40	13.20	
35	Putney #69/Putney	Dist./Unattended	67.00	8.32	
36	Sleeply Hollow #92/Searsburg	Trans/Unattended	13.20	67.00	
37	Tafts Corners #73/Williston	Dist/Unattened	115.00	13.20	
38	Barnet #14/Barnet	Dist/Unattended	34.50	13.20	
39	West Danville #15/Danville	Dist/Unattended	34.50	7.20	
40	Middlesex #2/Moretown	Dist/Unattended	34.50	2.40	

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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	Little River #22/Waterbury	Dist/Unattended	34.50	4.16	
2	Ethan Allen #36/Colchester	Dist/Unattended	34.50	12.47	
3	North Ferrisburgh #45/Ferrisburgh	Dist/Unattended	115.00	12.47	
4	Marshfield #6/Marshfield	Dist/Unattended	34.50	4.16	
5	Riverton #62/Berlin	Dist/Unattended	34.50	4.16	
6	Waterford #65/Waterford	Dist/Unattended	34.50	4.16	
7	Moretown #66/Moretown	Dist/Unattended	34.50	4.16	
8	Bridge St #67/Bellows Falls	Dist/Unattended	46.00	13.20	
9	White River #70/Hartford	Dist/Unattended	46.00	12.47	
10	Westminster #74/Westminster	Dist/Unattended	67.00	8.32	
11	Airport#79/So. Burlington	Dist/Unattended	34.50	4.16	
12	Iroquois #81/Colchester	Dist/Unattended	34.50	12.47	
13	Legare #83/Ryegate	Dist/Unattended	34.50	12.47	
14	Woodford Road -Bennington VT	Dist/Unattended	44.00	12.50	
15	No. Brattleboro-Brattleboro VT	Dist/ Unattended	67.00	44.00	
16	No. Brattleboro-Brattleboro VT	Dist/Unattended	44.00	12.50	
17	Brudies Road - Brattleboro VT	Dist/Unattended	69.00	12.50	
18	Vernon Road - Brattleboro VT	Transmission U	115.00	46.00	
19	Vernon Road - Brattleboro VT	Dist/Unattended	44.00	12.50	
20	Fair Haven Village - Fair Haven VT	Dist/Unattended	44.00	4.00	
21	Ely - Fairlee VT	Dist/Unattended	44.00	12.50	
22	Mendon - Mendon VT	Dist/Unattended	44.00	34.50	
23	Wells River - Newbury VT	Dist/Unattended	44.00	12.50	
24	Newbury - Newbury VT	Dist/Unattended	46.00	12.50	
25	Rochester - Rochester VT	Dist/Unattended	44.00	12.50	
26	East Rutland - Rutland City VT	Dist/Unattended	44.00	12.50	
27	North Rutland - Rutland Town VT	Dist/Unattended	44.00	12.50	
28	Mill Street - Bennington VT	Dist/Unattended	44.00	12.50	
29	Georgia - Georgia VT	Dist/Unattended	34.50	12.50	
30	Quechee - Hartford VT	Dist/Unattended	44.00	12.50	
31	Pleasant Street - Randolph VT	Dist/Unattended	44.00	12.50	
32	Bay Street - St. Johnsbury VT	Dist/Unattended	34.50	12.50	
33	South Street - Springfield VT	Dist/Unattended	44.00	12.50	
34	Riverside - Springfield VT	Dist/Unattended	46.00	12.50	
35	Windsor - Windsor VT	Dist/Unattended	44.00	12.50	
36	Gas Turbine - Rutland VT	Combination U	44.00	12.50	
37	Gas Turbine - Ascutney VT	Combination U	44.00	13.20	
38	South Poultney VT	Dist/Unattended	46.00	12.47	
39	Lowell - Lowell VT	Transmission U	44.00	34.50	
40	East Thetford - Thetford VT	Dist/Unattended	44.00	12.50	

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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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	South Rutland - Rutland VT	Dist/Unattended	44.00	12.50	
2	Lalor Avenue - Rutland VT	Dist/Unattended	46.00	12.50	
3	Weybridge - Weybridge VT	Combination U	44.00	12.50	
4	Milton - Milton VT	Combination U	34.50	2.30	
5	Milton - Milton VT	Dist/Unattended	34.50	12.50	
6	Nason Street - St Albans VT	Dist/Unattended	34.50	12.50	
7	Rawsonville - Jamaica VT	Dist/Unattended	44.00	12.50	
8	East Barnard - Barnard VT	Dist/Unattended	44.00	34.50	
9	Silk Road - Bennington VT	Dist/Unattended	44.00	12.50	
10	South Brattleboro - Brattleboro VT	Dist/Unattended	69.00	12.50	
11	Manchester - Manchester VT	Dist/Unattended	44.00	12.50	
12	Sheldon Springs - Sheldon VT	Dist/Unattended	34.50	12.50	
13	Underhill - Jericho VT	Dist/Unattended	34.50	12.50	
14	Ryegate - Ryegate VT	Transmission U	46.00	34.50	
15	Stratton Mountain - Winhall VT	Dist/Unattended	46.00	12.50	
16	Bromley - Winhall VT	Dist/Unattended	44.00	12.50	
17	Woodstock - Woodstock VT	Dist/Unattended	44.00	12.50	
18	Snowshed - Sherburne VT	Dist/Unattended	34.50	12.50	
19	Middlebury dist - Middlebury VT	Dist/Unattended	44.00	12.50	
20	East Middlebury - Middlebury VT	Dist/Unattended	44.00	12.50	
21	Sherburne - Sherburne VT	Dist/Unattended	44.00	12.50	
22	North Bennington - Bennington VT	Dist/Unattended	44.00	12.50	
23	Pittsford Village - Pittsford VT	Dist/Unattended	44.00	12.50	
24	East - St Albans VT	Dist/Unattended	34.50	12.50	
25	Lyons Street - Bennington VT	Dist/Unattended	44.00	12.50	
26	North Springfield - Springfield VT	Dist/Unattended	44.00	12.50	
27	Bethel - Royalton VT	Dist/Unattended	44.00	12.50	
28	Londonderry - Londonderry VT	Dist/Unattended	44.00	12.50	
29	West Milton - Milton VT	Dist/Unattended	34.50	12.50	
30	North Elm Street - St Albans VT	Dist/Unattended	34.50	12.50	
31	Kendall Farm - Winhall VT	Transmission U	46.00	13.80	
32	Proctor - Proctor VT	Dist/Unattended	46.00	4.16	
33	Ballard Road - Georgia	Transmission U			
34	Wallingford - Wallaingford VT	Dist/Unattended	46.00	12.47	
35	Putnam Rd	Transmission U			
36	Graniteville	Dist/Unattended	34.50	12.47	
37	Total		4891.56	1629.49	
38	Miscellaneous - Various (78)	Dist/Unattended			
39	Miscellaneous - Various (33)	Transmission U			
40	Miscellaneous - Various (10)	Combination U			

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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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
56	1					2
7	1					3
14	1					4
18	1					5
5	1					6
20	2					7
36	2					8
7	1					9
20	1					10
22	1					11
11	1					12
14	1					13
28	1					14
22	1					15
11	1					16
11	1					17
22	1					18
20	1					19
14	3					20
11	1					21
11	1					22
28	1					23
11	1					24
11	1					25
11	1					26
14	1					27
22	1					28
23	1					29
14	1					30
11	1					31
20	1					32
28	1					33
14	1					34
14	1					35
7	1					36
56	1					37
7	1					38
1						39
4	1					40

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.
7	1					1
14	1					2
10	1					3
6	3					4
9	3					5
1	3					6
2	1					7
14	1					8
28	1					9
14	1					10
2	1					11
11	1					12
4	1					13
13	1					14
13	1					15
13	1					16
13	1					17
72	2					18
13	1					19
6	1					20
4	1					21
31	2	1				22
4	1					23
6	1					24
4	1					25
13	1					26
11	1					27
13	1					28
13	1					29
13	1					30
13	1					31
9	1					32
13	1					33
13	1					34
13	1					35
18	3					36
11	1					37
4	1					38
20	1					39
6	1					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.
25	2					1
13	1					2
13	2					3
9	1					4
11	1					5
13	1	1				6
6	1					7
20	1					8
13	1					9
28	1					10
22	2					11
9	1					12
10	2					13
19	1					14
56	2	1				15
13	1					16
24	1					17
13	1					18
21	2					19
13	1					20
25	2					21
13	1					22
13	1					23
13	1					24
13	1					25
13	1					26
13	1					27
9	1					28
9	1					29
12	1					30
32	2		Condenser	2	32	31
7	1					32
						33
10	1					34
						35
10	1					36
1727	135	3		2	32	37
257	78					38
52	33					39
23	10					40

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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	Vermont Transco LLC	107	711,390
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	143/173	
22				280,091
23				
24				
25				
26				
27				
28				
29				
30				
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42				