ELECTRIC AND/OR GAS UTILITIES
CLASSES A AND B
ANNUAL REPORT

OF

Niagara Mohawk Power Corporation

Exact legal name of reporting electric and/or gas utility

(If name was changed during year, show also the previous name and date of change)

300 Erie Boulevard West

Syracuse, New York 13202

(Address of principal business office at end of year)

FOR THE

Year ended December 31, 2018

TO THE

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Name, title, address and telephone number (including area code), of the person to contact concerning this report:

George Carlin, VP, NY Controller

One MetroTech Center, Brooklyn New York 11201-3850 (929) 324-5249

Comment Sheet

Please use this sheet to record any changes you made to this file. If you altered this file in anyway, except by entering data, you must record those changes here. You may also use this sheet to make any comments about this file or the joint cost file.

Item Number	Description	Schedule Number	Page Number
1	Added Beginning of year balance, column (b)		232

GENERAL INSTRUCTIONS

1. The completed original of this report form, properly filled out, shall be filed with the Public Service Commission, Albany, NY, on or before the 31st of March next following the end of the year to which the report applies. At least one additional copy shall be retained in the files of the reporting utility.

2. All utility companies upon which this report form is served are required by statute to complete and to file the report. The statute further provides that when any such report is defective or believed to be erroneous, the reporting utility shall be duly notified and given a reasonable time within which to make the necessary amendments or corrections.

3. All accounting terms and phrases used in this form are to be interpreted in accordance with the Uniform Systems of Accounts prescribed by this Commission. Whenever the term respondent is used, it shall be understood to mean the reporting utility.

4. If the report is made for a period other than the calendar year, the period covered must be clearly stated on the front cover and elsewhere throughout the report where the period covered is shown. When operations cease during the year because of the disposition of property the balance sheet and supporting schedules should consist of balances and items immediately prior to transfer (for accounting purposes). If the books are not closed as of that date, the data in the report should nevertheless be complete and the amounts reported should be supported by information set forth in, or as part of the books of account.

5. Every inquiry must be definitely answered. If "none" or "not applicable" states the fact, such an answer may be used. The annual report should be complete in itself. Reference to reports of previous years or to any paper or document should not be made in lieu of required entries except as specifically outlined.

6. Upon filing, the report may, if desired, be permanently bound. If it is so bound, the requirement for page by page identification of the reporting company set forth in paragraph 9 below, may be disregarded. Extra copies of any page will be furnished upon request.

7. If the utility conducts operations both within and without the State of New York, data should be reported so that there will be shown the quantities of commodities sold within this State, and (separately by accounts) the operating revenues from sources within this State, the operating revenue deductions applicable thereto and the plant investment as of the end of the year within this State.

8. All entries shall be made in black or dark blue except those of a contrary or opposite nature, which should be made in red or enclosed in parentheses. Inserts, if any, should be appropriately identified with the schedules to which they relate.

9. Insert the initials of the reporting utility and the year which the report covers in the space provided on each page.

10. Cents are to be omitted on all schedules except where they apply to averages and figures per unit where cents are important. The amounts shown on all supporting schedules shall agree with the item in the statement they support.

Name of Respondent Niagara Mohawk Power Corporation	The report is (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

LIST OF SCHEDULES

Enter in column (d) 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".

Name of Respondent Niagara Mohawk Power Corporation	The report is (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

LIST OF SCHEDULES (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
Balance Sheet Supporting Schedules (Liabilities and Other Credits) (Continued)			
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	12-96	
Taxes Accrued, Prepaid and Charged During the Year	262-263	12-96	NYPSC Modified
Accumulated Deferred Investment Tax Credits	266-267	12-89	NYPSC Modified
Other Deferred Credits	269	12-15	
Accumulated Deferred Income Taxes - Accelerated Amortization	272-273	12-96	None
Accumulated Deferred Income Taxes - Other Property	274-275	12-96	
Accumulated Deferred Income Taxes - Other	276-277	12-96	
Other Regulatory Liabilities	278	12-15	
Income Account Supporting Schedules			
Electric Operating Revenues	300-301	12-15	NYPSC Modified
Regional Transmission Service Revenues	302	12-15	N/A
Sales of Electricity by Rate Schedules	304	12-15	
Sales for Resale	310-311	12-88	NYPSC Modified
Electric Operation and Maintenance Expenses	320-323	12-15	
Number of Electric Department Employees	323	12-93	
Purchased Power	326-327	12-15	NYPSC Modified
Transmission of Electricity for Others	328-330	12-15	NYPSC Modified
Transmission of Electricity by ISO/RTOs	331	12-15	
Transmission of Electricity by Others	332	12-15	NYPSC Modified - N/A
Miscellaneous General Expenses	335	12-94	NYPSC Modified
Depreciation and Amortization of Electric Plant	336-337	12-15	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340	12-87	NYPSC Modified
Common Section			
Regulatory Commission Expenses	350-351	12-96	NYPSC Modified
Research, Development, and Demonstration Activities	352-353	12-15	
Distribution of Salaries and Wages	354-355	12-15	
Common Utility Plant and Expenses	356	12-87	NYPSC Modified
Electric Plant Statistical Data			
Amounts included in ISO/RTO Settlement Statements	397	12-15	
Purchase and Sale of Ancillary Services	398	12-15	
Monthly Transmission System Peak Load	400	12-15	
Monthly ISO/RTO Transmission System Peak Load	400a	12-15	
Electric Energy Account	401	12-15	
Monthly Peaks and Output	401	12-90	
Steam - Electric Generating Plant Statistics (Large Plants)	402-403	12-15	N/A
Hydroelectric Generating Plant Statistics (Large Plants)	406-407	12-15	N/A
Pumped Storage Generating Plant Statistics (Large Plants)	408-409	12-15	N/A
Generating Plant Statistics (Small Plants)	410-411	12-15	N/A
Energy Storage Operations (Large Plants)	414-416	12-15	N/A
Energy Storage Operations (Small Plants)	419-420	12-15	N/A

Name of Respondent Niagara Mohawk Power Corporation	The report is (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

LIST OF SCHEDULES (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
Electric Plant Statistical Data (Continued)			
Transmission Line Statistics	422-423	12-87	
Transmission Lines Added During Year	424-425	12-15	N/A
Substations	426-427	12-96	
Electric Distribution Meters and Line Transformers	429	12-88	
Transactions with Associated (Affiliated) Companies	430	12-15	
Footnote Data	450	12-87	N/A
Stockholders' Reports Check appropriate box:			
Two copies will be submitted [ ]			
No annual report to stockholders is submitted [X]			
PSC Supplemental Filing	Jan-94	12-15	

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

GENERAL INFORMATION

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

George Carlin
VP, NY Controller
One MetroTech Center
Brooklyn, New York 11201-3850
The Official books of record are kept at: Niagara Mohawk - A National Grid Company
300 Erie Boulevard West
Syracuse, New York 13202

2. Provide 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.

New York - Certificate of Consolidation filed January 5, 1950, pursuant to sections 26-a and 86 of the Stock Corporation Law and to Subdivision 4 of Section II of the Transportation Corporation Law of the State of New York.

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

Not Applicable

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

Purchase, transmission, distribution and sale of both natural gas and electricity in the State of New York.

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.

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at the end of the year, state the name of the controlling corporation or organization, manner in which control was held and the 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 the name of the trustee(s), name of the beneficiary or beneficiaries for whom the trust was maintained, and the purpose of the trust.

On March 18, 1999, Niagara Mohawk Power Corporation ("Niagara Mohawk" or "the Company") was reorganized into a holding company structure in accordance with an Agreement and Plan of Exchange between Niagara Mohawk and Niagara Mohawk Holdings, Inc. ("Holdings"). Niagara Mohawk's outstanding common stock was exchanged on a share-for-share basis for Holdings' common stock making Niagara Mohawk a wholly-owned subsidiary of Holdings. Niagara Mohawk's preferred stock and debt were not exchanged as part of the share exchange and continue as obligations of Niagara Mohawk.

On January 30, 2002, Holdings was acquired by National Grid USA ("NGUSA") for approximately $3 billion in cash and American Depository shares in exchange for all of Holdings common outstanding shares. NGUSA is a wholly-owned subsidiary of National Grid plc.

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by the respondent at any time during the year. If control ceased prior to the end of the 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 facts 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	NM Properties, Inc.	(1)	100	
2	1) A real estate subsidiary operating			
3	exclusively in the State of New York that owns			
4	100% of Land Management and Development, Inc.;			
5	Landwest, Inc.; Upper Hudson			
6	Development, Inc.; and 65 Willis Lane, Inc.			
7	Land Management and Development, Inc. owns			
8	controlling interest in Port of the Islands			
9	North LLC.			
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OFFICERS AND DIRECTORS (Including Compensation)

1. Furnish the indicated data with respect to each executive officer and director, whether or not they received any compensation from the respondent.
2. Executive officers include a company's 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.
3. Indicate with an asterisk (*) in column (a) those directors who were members of the executive committee, if any, and by a double asterisk (**) the chairman, if any, of that committee, at the end of the year.

Line No.	Name of Person (a)	Title and Department Over Which Jurisdiction Is Exercised (b)	Term Expired or Current Term Will Expire (c)	Salary: Rate at Year End (d)	Salary: Paid During Year (e)
1	David Doxsee	Chief Finanical Officer & Director		$78,290	$70,998
2	Jeannette Mills	Senior Vice President		92,633	77,696
3	Ross Turrini	Senior Vice President		29,592	27,549
4	Ronald Macklin	Senior Vice President		87,565	72,192
5	George Carlin	Vice President, NY Controller		88,522	77,282
6					
7					
8					
9	Appointments				
10	John Bruckner - 5/31/2018	President & Director		46,382	37,376
11	Christopher Kelly - 5/31/2018	Senior Vice President		193,096	81,853
12	David Way - 6/12/2018	Senior Vice President		80,267	64,881
13	Kenneth Daly - 5/31/2018	Chief Operating Officer, Electric		159,658	141,598
14					
15	Resignations				
16	John Bruckner - 5/31/2018	Senior Vice President			
17	Kenneth Daly - 5/31/2018	President & Director			
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NOTES:

Please complete the information on this schedule for all copies (paper and electronic version) of the report.

Ln 1 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $144,354. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Ln 2 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $211,675. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Ln 3 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $248,496. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Ln 4 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $209,149. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Ln 5 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $115,657. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Ln 10 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $268,483. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

OFFICERS AND DIRECTORS (Including Compensation - Continued)

4. If any person reported in this schedule received remuneration directly or indirectly other than salary shown in column (e) list the amount in column (f) through (k) with the footnotes necessary to explain the essentials of the plan, the basis of determining the ultimate benefits receivable and the payments or provisions made during the year to each person reported herein. If the word "none" correctly states the facts in regard to the entries for column (f) through (k), so state.

5. If any person reported hereunder received compensation from more than one affiliated company or was carried on the payroll of an affiliated company, details shall be given in a note.

Foot-note Ref.	Deferred Compensation (f)	Incentive Pay (Bonuses, etc.) (g)	Savings Plans (h)	Stock Options (i)	Life Insurance Premiums (j)	Other (Explain Below) (k)	Total (e thru k) (l)	Line No.
		$31,958	$3,434		$267	$989	$107,646	1
		27,924	2,954		305	0	108,879	2
		7,711	0		362	798	36,420	3
		31,489	2,823		155	2,053	108,712	4
		36,385	3,705		100	1,202	118,674	5
								6
								7
								8
								9
		15,675	1,328		213	978	55,570	10
		45,434	3,423		1,535	2,754	134,999	11
		27,015	2,414		93	2,227	96,630	12
		77,565	4,153		457	3,046	226,819	13
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NOTES:

Ln 11 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $155,953. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Ln 12 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $168,237. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Ln 13 Salary disclosure includes amounts that have been allocated to Niagara Mohawk Power Corporation (reporting entity). The salary amount allocated to other companies was $230,246. These salary amounts exclude incentive compensation payments and reflect base salary paid by the Company from 01/01/2018 through 12/31/2018.

Other: Includes remuneration items such as imputed value of automobiles, financial planning, annual physical, health club, performance bonuses, and other miscellaneous payments

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a footnote the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors of the respondent and number of such votes cast by proxy. Total: By proxy:	3. Give the date and place of such meeting:

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	187,364,863	187,364,863		
5	TOTAL number of security holders	1	1		
6	TOTAL votes of security holders listed below	187,364,863	187,364,863		

7 Niagara Mohawk has 187,364,863 shares outstanding, which are all held by Holdings and are not traded.

8

9 In its September 12, 2007, "Order Authorizing Acquisition subject to Conditions and Making Some Revenue
10 Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island", issued in Case 06-M-0878, the NYPSC authorized the merger of KeySpan Corporation and National
11 Grid subject to the adoption of various financial and other conditions.

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14 One of the conditions was the requirement that the Company issue a class of preferred stock having one
15 share (the "Golden Share"), subordinate to any existing preferred stock, the holder of which would having
16 rights that limit the Company's right to commence any voluntary bankruptcy, liquidation, receivership
17 or similar proceeding without the consent of the holder of such share of stock. The NYPSC subsequently
18 authorized the issuance of the Golden Share to a trustee, GSS Holdings, Inc. ("GSS"), who will hold the

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SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
19	Golden Share subject to a Services and Indemnity				
20	in the best interests of New York State. The Golden Share was issued by the Company on July 8, 2011.				
21					
22					
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28	Niagara Mohawk Holdings, Inc.	187,364,863	187,364,863		
29	300 Erie Boulevard West				
30	Syracuse, New York 13202				
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IMPORTANT CHANGES DURING THE 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 conditions. State name of Commission authorizing lease and give reference to such

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 any materially important transactions of the respondent, not disclosed elsewhere in this report, in which an officer, director, security holder reported on page 6, voting trustee, associated company or known associate of such persons was a party or in which 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 (Paper Copy Only).

IMPORTANT CHANGES DURING THE YEAR (Continued)

1. Changes in Franchise Rights:
None

2. Information on consolidations, mergers, and reorganizations:
None

3. Purchase or sale of an operating unit or system:
None

4. Important Leaseholds:
None

5. Important extension or reduction of transmission or distribution system:
None

6. Issuance of securities or assumption of liabilities or guarantees:
The settlement of the Company’s various transactions with NGUSA and certain affiliates generally occurs via the intercompany money pool. The Company is a participant in the Regulated Money Pool and can both borrow and lend funds. Borrowings from the Regulated Money Pool bear interest in accordance with the terms of the intercompany money pool agreement. As the Company fully participates in the Regulated Money Pool rather than settling intercompany charges with cash, all changes in the intercompany money pool balance and accounts receivable and payable from affiliate balances, are reflected as investing or financing activities in the accompanying statements of cash flows. In addition, for the purpose of presentation in the statement of cash flows, it is assumed all amounts settled through intercompany money pool are constructive cash receipts and payments, and therefore are presented as such.

7. Changes in Articles of Incorporation:
None

8. Wage Scale Increase:
Local 97 received a 2.5% increase and Local 97C received a 2.0% increase effective 04/01/2018

9. Status of Legal Proceedings:
Refer to Page 123 - Notes to Financial Statements - Note 13. Commitments and Contingencies

10. Additional Material Transactions Not Reported Elsewhere in this Report:
None

11. Reserved:
None

12. N/A

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Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beg. of Year (c)	Balance at End of Year (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	$ 11,943,910,117	$ 12,568,021,609
3	Construction Work in Progress (107)	200-201	370,698,538	438,319,836
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		12,314,608,655	13,006,341,445
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	200-201	3,771,246,116	3,964,093,617
6	Net Utility Plant (Enter Total of line 4 less 5)	-	8,543,362,539	9,042,247,828
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203		
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203		
9	Net Nuclear Fuel (Enter Total of line 7 less 8)	-		
10	Net Utility Plant (Enter Total of lines 6 and 9)	-	8,543,362,539	9,042,247,828
11	Utility Plant Adjustments (116)	-		
12	Gas Stored Underground - Noncurrent (117)	-		
13	**OTHER PROPERTY AND INVESTMENTS**			
14	Nonutility Property (121)	221	11,562,002	11,562,002
15	(Less) Accum. Prov. for Depr. and Amort. (122)	-	53,623	27,785
16	Investments in Associated Companies (123)	-		
17	Investment in Subsidiary Companies (123.1)	224-225	778,606	733,807
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)	-		
19	Noncurrent Portion of Allowances	-		
20	Other Investments (124)		5,882,286	6,472,690
21	Special Funds (125-128)	-	34,447,353	33,923,410
22	Long-Term, Portion of Derivative Assets (175)		855,619	16,332,122
23	Long-Term, Portion of Derivative Assets - Hedges (176)			
24	TOTAL Other Property and Investments (Total of lines 14-17, 19-23)		53,472,243	68,996,246
25	**CURRENT AND ACCRUED ASSETS**			
26	Cash (131)	-	1,081,689	7,367,468
27	Special Deposits (132-134)	-	20,515,417	2,733,610
28	Working Fund (135)	-		
29	Temporary Cash Investments (136)	-		
30	Notes Receivable (141)			
31	Customer Accounts Receivable (142)	-	462,947,677	479,302,227
32	Other Accounts Receivable (143)	-	65,398,251	55,756,400
33	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	148,613,954	148,775,435
34	Notes Receivable from Associated Companies (145)	-	182,917,175	600,501,047
35	Accounts Receivable from Assoc. Companies (146)	-	72,469,078	11,643,673
36	Fuel Stock (151)	227		
37	Fuel Stock Expenses Undistributed (152)	227		
38	Residuals (Elec) and Extracted Products (153)	227		
39	Plant Materials and Operating Supplies (154)	227	47,053,177	45,016,786
40	Merchandise (155)	227		
41	Other Materials and Supplies (156)	227		
42	Nuclear Materials Held for Sale (157)	202-203/227		
43	Allowances (158.1 and 158.2)	228-229		51,506
44	(Less) Noncurrent Portion of Allowances	228-229		
45	Stores Expense Undistributed (163)	-		
46	Gas Stored Underground - Current (164.1)	-	26,965,736	35,365,060
47	Liquefied Natural Gas Stored and Held for Processing(164.2-164.3)	-		
48	Prepayments (165)	-	45,836,349	36,953,969
49	Advances for Gas (166-167)	-		
50	Interest and Dividends Receivable (171)	-		
51	Rents Receivable (172)	-	7,033,617	12,782,749
52	Accrued Utility Revenues (173)	-	144,367,294	131,832,567
53	Miscellaneous Current and Accrued Assets (174)		6,767,364	29,411,231
54	Derivative Instrument Assets (175)			
55	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
56	Derivative Instrument Assets - Hedges (176)		7,118,732	14,522,018
57	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
58	TOTAL Current and Accrued Assets (Enter Total of lines 26 thru 57)		$ 941,857,602	$ 1,314,464,876

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beg. of Year (c)	Balance at End of Year (d)
59	**DEFERRED DEBITS**			
60	Unamortized Debt Expense (181)	-	17,453,503	19,547,486
61	Extraordinary Property Losses (182.1)	230		
62	Unrecovered Plant and Regulatory Study Costs (182.2)	230		3,461,250
63	Other Regulatory Assets (182.3)	232	1,150,654,773	554,749,053
64	Prelim. Survey and Investigation Charges (Electric) (183)	-	24,659,470	25,589,460
65	Prelim. Survey and Investigation Charges (Gas) (183.1, 183.2)	-		
66	Clearing Accounts (184)	-	(104,919)	(124,558)
67	Temporary Facilities (185)	-		
68	Miscellaneous Deferred Debits (186)	233	339,690,537	373,261,283
69	Def. Losses from Disposition of Utility Plt. (187)	-		
70	Research, Devel. and Demonstration Expend. (188)	352-353		
71	Unamortized Loss on Reacquired Debt (189)	-	9,653,989	8,128,349
72	Accumulated Deferred Income Taxes (190)	234	741,319,453	736,311,601
73	Unrecovered Purchased Gas Costs (191)	-		
74	TOTAL Deferred Debits (Enter Total of lines 60 thru 74)		2,283,326,806	1,720,923,924
75	TOTAL Assets and Other Debits (Enter Total of lines 10, 11, 12, 24, 58, and 74)		$ 11,822,019,190	$ 12,146,632,874

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beg. of Year (c)	Balance at End of Year (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	187,364,863	187,364,863
3	Preferred Stock Issued (204)	250-251	28,984,701	28,984,701
4	Capital Stock Subscribed (202, 205)	-		
5	Stock Liability for Conversion (203, 206)	-		
6	Premium on Capital Stock (207)	-		
7	Other Paid-in Capital (208-211)	253	1,773,485,310	1,810,363,763
8	Installments Received on Capital Stock (212)	-		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	1,188,971,762	1,386,230,139
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	(2,736,209)	(2,746,968)
13	(Less) Reacquired Capital Stock (217)	250-251		
14	Accumulated Other Comprehensive Income (219)	122(a)(b)	2,441,133	34,293
15	TOTAL Proprietary Capital (Enter Total of lines 2 thru 14)	-	3,178,511,560	3,410,230,791
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	2,465,705,000	3,274,165,000
18	(Less) Reacquired Bonds (222)	256-257		
19	Advances from Associated Companies (223)	256-257		
20	Other Long-Term Debt (224)	256-257	313,760,000	-
21	Unamortized Premium on Long-Term Debt (225)	-		
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-	6,716	10,982
23	TOTAL Long-Term Debt (Enter Total of Lines 17 thru 22)	-	2,779,458,284	3,274,154,018
24	**OTHER NONCURRENT LIABILITIES**			
25	Obligations Under Capital Leases - Noncurrent (227)	-		
26	Accumulated Provision for Property Insurance (228.1)	-		
27	Accumulated Provision for Injuries and Damages (228.2)	-	25,554,080	25,178,765
28	Accumulated Provision for Pensions and Benefits (228.3)	-	359,077,929	272,246,591
29	Accumulated Miscellaneous Operating Provisions (228.4)	-	359,631,704	339,789,898
30	Accumulated Provision for Rate Refunds (229)	-		
31	Long-Term Portion of Derivative Instrument Liabilities		11,913,778	1,131,038
32	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
33	Asset Retirement Obligations (230)		15,437,087	14,533,068
34	TOTAL Other Noncurrent Liabilities (Enter Total of lines 25 thru 33)		771,614,578	652,879,360
35	**CURRENT AND ACCRUED LIABILITIES**			
36	Notes Payable (231)	-		
37	Accounts Payable (232)	-	175,251,699	227,168,684
38	Notes Payable to Associated Companies (233)	-		
39	Accounts Payable to Associated Companies (234)	-	168,963,574	124,590,032
40	Customer Deposits (235)	-	32,184,023	30,695,721
41	Taxes Accrued (236)	262-263	121,385,382	71,122,143
42	Interest Accrued (237)	-	26,708,077	30,833,981
43	Dividends Declared (238)	-		
44	Matured Long-Term Debt (239)	-		
45	Matured Interest (240)	-		
46	Tax Collections Payable (241)	-	-	(1,273,992)
47	Miscellaneous Current and Accrued Liabilities (242)	-	184,163,770	241,861,035
48	Obligations Under Capital Leases - Current (243)	-		
49	Derivative Instrument Liabilities (244)		14,526,710	5,552,387
50	(Less) Long-Term Portion of Derivative Instrument Liabilities			
51	Derivative Instrument Liabilities - Hedges (245)		1,954,832	2,026,656
52	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges			
53	TOTAL Current and Accrued Liabilities (Enter Total of lines 36 - 52)		$ 725,138,067	$ 732,576,647

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beg. of Year (c)	Balance at End of Year (d)
54	**DEFERRED CREDITS**			
55	Customer Advances for Construction (252)		4,961,398	3,839,233
56	Accumulated Deferred Investment Tax Credits (255)	266-267	14,346,995	13,518,460
57	Deferred Gains from Disposition of Utility Plant (256)			
58	Other Deferred Credits (253)	269	224,733,072	244,992,205
59	Other Regulatory Liabilities (254)	278	2,299,569,151	1,972,760,825
60	Unamortized Gain on Reacquired Debt (257)	269		
61	Accumulated Deferred Income Taxes (281 - 283)	272-277	1,823,686,085	1,841,681,335
62	TOTAL Deferred Credits (Enter Total of lines 55 thru 61)		4,367,296,701	4,076,792,058
63				
64				
65				
66				
67				
68				
69				
70				
71				
72				
73				
74				
75				
76	TOTAL Liabilities and Other Credits (Enter Total of lines 15, 23, 34, 53 and 62)		$ 11,822,019,190	$ 12,146,632,874

Note:
Please use the appropriate accounts under the heading "Other Noncurrent Liabilities" for accounts that the PSC classifies as "Operating Reserves".

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over lines 02 through 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use page 122-123 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected 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 and gas purchases.
6. Give concise explanations concerning significant amount of any refunds made or received during the year resulting

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	**UTILITY OPERATING INCOME**			
2	Operating Revenues (400)	300-301	$3,227,348,951	$3,004,236,020
3	Operating Expenses			
4	Operation Expenses (401)	320-323	1,917,531,633	1,709,742,231
5	Maintenance Expenses (402)	320-323	302,266,487	246,921,687
6	Depreciation Expense (403)	336-337	281,723,486	259,698,083
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	0	0
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,366,556	1,177,786
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	0	0
10	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		0	0
11	Amort. of Conversion Expenses (407)		1,153,750	0
12	Regulatory Debits (407.3)		30,919,339	2,255,806
13	(Less) Regulatory Credits (407.4)		4,650,000	11,465,839
14	Taxes Other Than Income Taxes (408.1)	262-263	286,281,176	270,877,270
15	Income Taxes -- Federal (409.1)	262-263	42,480,745	114,486,458
16	-- Other (409.1)	262-263	12,105,885	24,534,453
17	Provision for Deferred Income Taxes (410.1)	234,272-277	11,865,151	(11,602,931)
18	(Less) Provision for Deferred Income Taxes -Cr. (411.1)	234,272-277	0	0
19	Investment Tax Credit Adj. -- Net (411.4)	266	0	0
20	(Less) Gains from Disp. of Utility Plant (411.6)		0	290,785
21	Losses from Disp. of Utility Plant (411.7)		(305)	39,277
22	(Less) Gain from Disposition of Allowances (411.8)		0	0
23	Losses from Disposition of Allowances (411.9)		0	0
24	Accretion Expense (411.10)		0	0
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		2,883,043,903	2,606,373,496
26	*Net Utility Operating Income (Enter Total of line 2 less 25) (Carry forward to page 117, line 27)*		$344,305,048	$397,862,524

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF INCOME FOR THE YEAR (Continued)

from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on page 122-123.
8. Enter on page 122-123 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 approximate dollar effect of such changes.
9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.
10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on page 122-123 or in a footnote.

Electric Utility		Gas Utility		Other Utility		
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	Line No.
						1
$2,601,981,039	$2,446,693,772	$623,143,301	$557,449,458	$2,224,611	$92,790	2
						3
1,514,398,831	1,370,294,748	403,132,802	339,447,483	0	0	4
272,687,524	220,190,899	29,578,963	26,730,788	0	0	5
229,639,100	209,689,197	52,084,386	50,008,886	0	0	6
0	0	0	0	0	0	7
1,304,094	1,130,866	62,462	46,920	0	0	8
0	0	0	0	0	0	9
0	0	0	0	0	0	10
1,153,750	0	0	0	0	0	11
32,863,449	35,887	(1,944,110)	2,219,919	0	0	12
4,650,000	11,362,606	0	103,233	0	0	13
228,499,659	218,049,708	57,781,517	52,827,562	0	0	14
28,851,151	99,829,773	13,629,594	14,656,685	0	0	15
8,595,750	21,416,476	3,510,135	3,117,977	0	0	16
14,999,272	(14,981,325)	(3,134,121)	3,378,394	0	0	17
0	0	0	0	0	0	18
0	0	0	0	0	0	19
0	290,785	0	0	0	0	20
(305)	0	0	39,277	0	0	21
0	0	0	0	0	0	22
0	0	0	0	0	0	23
0	0	0	0	0	0	24
2,328,342,275	2,114,002,838	554,701,628	492,370,658	0	0	25
$273,638,764	$332,690,934	$68,441,673	$65,078,800	$2,224,611	$92,790	26

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF INCOME FOR THE YEAR (Continued)

	Other Utility		Other Utility		Other Utility	
Line No.	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1						
2						
3						
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15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	0	0	0	0	0	0
26	$0	$0	$0	$0	$0	$0

	Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref). Page No. (b)	TOTAL Current Year (c)	 Previous Year (d)
27	Net Utility Operating Income (Carried forward from page 114)	- -	$344,305,048	$397,862,524
28	**OTHER INCOME AND DEDUCTIONS**			
29	Other Income			
30	Nonutility Operating Income			
31	Revenues From Merchandising, Jobbing and Contract Work (415)		0	0
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		0	0
33	Revenues From Nonutility Operations (417)		0	0
34	(Less) Expenses of Nonutility Operations (417.1)		5,920,012	7,711,592
35	Nonoperating Rental Income (418)		23,187	43,437
36	Equity in Earnings of Subsidiary Companies (418.1)	119	(10,759)	(89,247)
37	Interest and Dividend Income (419)		8,007,020	22,165,637
38	Allowance for Other Funds Used During Construction (419.1)		13,602,040	11,831,665
39	Miscellaneous Nonoperating Income (421)		1,332,383	2,093,486
40	Gain in Disposition of Property (421.1)		0	0
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		17,033,859	28,333,386
42	Other Income Deductions			
43	Loss on Disposition of Property (421.2)		0	3,501
44	Miscellaneous Amortization (425)	340	0	0
45	Miscellaneous Income Deductions (426.1 - 426.5)	340	11,119,189	2,032,730
46	TOTAL Other Income Deductions (Total of lines 43 thru 45)		11,119,189	2,036,231
47	Taxes Applic. to Other Income and Deductions			
48	Taxes Other Than Income Taxes (408.2)	262-263	558,425	556,312
49	Income Taxes -- Federal (409.2)	262-263	(2,072,570)	3,794,185
50	Income Taxes -- Other (409.2)	262-263	(515,799)	874,970
51	Provision for Deferred Inc. Taxes (410.2)	234,272-277	(1,169,520)	0
52	(Less) Provision for Deferred Income Taxes -- Cr. (411.2)	234,272-277	0	0
53	Investment Tax Credit Adj. -- Net (411.5)		0	0
54	(Less) Investment Tax Credits (420)		828,536	1,788,219
55	TOTAL Taxes on Other Income and Deduct. (Total of 48 thru 54)		(4,028,000)	3,437,248
56	Net Other Income and Deductions (Enter Total of lines 41, 46, 55)		9,942,670	22,859,907
57	**INTEREST CHARGES**			
58	Interest on Long-Term Debt (427)		115,084,668	107,692,297
59	Amort. of Debt Disc. and Expense (428)		2,766,118	3,021,923
60	Amortization of Loss on Reacquired Debt (428.1)		1,422,427	1,422,427
61	(Less) Amort. of Premium on Debt-Credit (429)		0	0
62	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		0	0
63	Interest on Debt to Assoc. Companies (430)	340	0	0
64	Other Interest Expense (431)	340	41,821,891	56,478,867
65	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,155,501	3,866,455
66	Net Interest Charges (Enter Total of lines 58 thru 65)		155,939,603	164,749,059
67	Income Before Extraordinary Items (Total of lines 27, 56 and 66)		198,308,115	255,973,372
68	**EXTRAORDINARY ITEMS**			
69	Extraordinary Income (434)			
70	(Less) Extraordinary Deductions (435)			
71	Net Extraordinary Items (Enter Total of line 69 less line 70)		0	0
72	Income Taxes -- Federal and Other (409.3)	262-263		
73	Extraordinary Items After Taxes (Enter Total of line 71 less line 72)		0	0
74	Net Income (Enter Total of lines 67 and 73)		$198,308,115	$255,973,372

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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).
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. 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.
8. 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)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance -- Beginning of Year		$1,188,971,762
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Acct. 439) (Total of lines 4 thru 8)		0
10	Debit:		
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Acct. 439) (Total of lines 10 thru 14)		0
16	Balance Transferred from Income (Account 433 less Account 418.1)		198,318,874
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations to Retained Earnings (Acct. 436) (Total of lines 18 thru 21)		0
23	Dividends Declared -- Preferred Stock (Account 437)		
24	Dividends Declared-Preferred Stock		(1,060,497)
25			
26			
27			
28			
29	TOTAL Dividends Declared -- Preferred Stock (Acct. 437) (Total of lines 24 thru 28)		(1,060,497)
30	Dividends Declared -- Common Stock (Account 438)		
31	Dividends Declared-Common Stock		0
32			
33			
34			
35			
36	TOTAL Dividends Declared -- Common Stock (Acct. 438) (Total of lines 31 thru 35)		0
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		
38	Balance -- End of year (Total of lines 01, 09, 15, 16, 22, 29, 36 and 37)		1,386,230,139

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	0
	APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings -- Amortization Reserve, Federal(Account 215.1)	
47	TOTAL Appropriated Retained Earnings (Account 215, 215.1) (Enter Total of lines 45 and 46)	0
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Enter Total of lines 38 and 47)	1,386,230,139
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)	
49	Balance -- Beginning of Year (Debit or Credit)	(2,736,209)
50	Equity in Earnings for Year (Credit) (Account 418.1)	(10,759)
51	(Less) Dividends Received (Debit)	
52	Other Changes (Explain)	
53	Balance -- End of Year (Total of Lines 49 thru 52)	(2,746,968)

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included on pages 122-123. Information about noncash investing and financing activities should be provided on pages 122-123. Provide also on page 122 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.

2. Under "Other" specify significant amounts and group others.

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 on page 122-123 the amounts of interest paid (net of amounts capitalized) and

Line No.	Description (See Instructions for Explanations of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income (Line 74(c) on page 117)	$198,308,115
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	283,090,042
5	Amortization of Debt Discount and Expense	2,766,118
6	Amortization of Loss on Reacquired Debt	1,422,427
7	Amortization of Regulatory Debits and Credits, Net	26,269,339
8	Deferred Income Taxes (Net)	10,695,631
9	Investment Tax Credit Adjustment (Net)	(828,535)
10	Net (Increase) Decrease in Receivables	234,377
11	Net (Increase) Decrease in Inventory	(6,362,933)
12	Net (Increase) Decrease in Allowances Inventory	(51,506)
13	Net Increase (Decrease) in Payables and Accrued Expenses	95,885,669
14	Net (Increase) Decrease in Other Regulatory Assets	242,331,199
15	Net Increase (Decrease) in Other Regulatory Liabilities	(160,467,477)
16	(Less) Allowance for Other Funds Used During Construction	13,602,040
17	(Less) Undistributed Earnings from Subsidiary Companies	(10,759)
18	Other:	(30,734,623)
19	Net Increase (Decrease) in Deferred Credits	0
20	Net Decrease (Increase) in Prepaid and Other Current Assets	0
21		
22	Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 21)	648,966,562
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including Land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(709,369,498)
27	Gross Additions to Nuclear Fuel	0
28	Gross Additions to Common Utility Plant	(8,083,200)
29	Gross Additions to Nonutility Plant	0
30	(Less) Allowance for Other Funds Used During Construction	(13,602,040)
31	Other:	(1,796,127)
32	Cost of Removal	(44,025,032)
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(749,671,817)
35		
36	Acquisition of Other Noncurrent Assets (d)	0
37	Proceeds from Disposal of Noncurrent Assets (d)	0
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	0
40	Contributions and Advances from Assoc. and Subsidiary Companies	0
41	Disposition and Investments in (and Advances to)	
42	Associated and Subsidiary Companies	0
43		
44	Purchase of Investment Securities (a)	0
45	Proceeds from Sales of Investment Securities (a)	$0

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

STATEMENT OF CASH FLOWS (Continued)

4. Investing Activities
Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123.
Do not include on this statement the dollar amount of leases capitalized per USOA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost on pages 122-123.

5. Codes used:
(a) Net proceeds or payments.
(b) Bonds, debentures and other long-term debt.
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanations of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	$0
47	Collections on Loans	0
48		
49	Net (Increase) Decrease in Receivables	0
50	Net (Increase) Decrease in Inventory	0
51	Net (Increase) Decrease in Allowances Held for Speculation	0
52	Net Increase (Decrease) in Payables and Accrued Expenses	0
53	Other (provide details in footnote):	(3,298,267)
54	Affiliate Moneypool Lending and Receivables/Payables, Net	(401,132,009)
55	Net Increase (Decrease) in Special Deposits	0
56	Net Cash Provided by (Used in) Investing Activities	
57	(Total of lines 34 thru 55)	(1,154,102,093)
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	500,000,000
62	Preferred Stock	0
63	Common Stock	0
64	Other (provide details in footnote):	0
65		
66	Net Increase in Short-Term Debt (c)	
67	Other (provide details in footnote):	0
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	500,000,000
71		
72	Payments for Retirement of:	
73	Long-term Debt (b)	(5,300,000)
74	Preferred Stock	0
75	Common Stock	0
76	Other (provide details in footnote):	0
77		
78	Net Decrease in Short-Term Debt (c)	0
79		
80	Dividends on Preferred Stock	(1,060,497)
81	Dividends on Common Stock	0
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	493,639,503
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57 and 83)	(11,496,028)
87		
88	Cash and Cash Equivalents at Beginning of Year	21,597,106
89		
90	Cash and Cash Equivalents at End of Year	$10,101,078

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

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, 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 reference to Commission 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
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.

Note 1 - Notes to Financial Statements for the Statement of Cash Flows Schedule of Noncash and Other Charges (Credits) to Income:

Change in Derivative Instrument Assets	(22,879,789)
Change in Prepayments	8,882,380
Change in Miscellaneous Current and Accrued Assets	(22,643,867)
Change in Unamortized Debt Expense	(4,860,101)
Change in Unrecovered Plant and Regulatory Study Costs	(3,461,250)
Change in Preliminary Survey and Investigation Charges	(929,990)
Change in Clearing Accounts	19,639
Change in Miscellaneous Deferred Debits	(33,570,746)
Change in Unamortized Loss on Reacquired Debt	103,213
Change in Share Based Compensation	(243,135)
Change in (Less) Unamortized Discount on Long-Term Debt	(4,266)
Change in Accumulated Provision for Injuries and Damages	(375,315)
Change in Accumulated Provision for Pensions and Benefits	59,313,731
Change in Miscellaneous Operating Provisions	(8,632,837)
Change in Asset Retirement Obligations	(904,019)
Change in Derivative Instrument Liabilities	(19,685,239)
Change in Customer Advances for Construction	(1,122,165)
Change in Other Deferred Credits	20,259,133
Total Other Page 120 Line 18	(30,734,623)
Change in Utility Plant - Other	(1,796,127)
Total Other Page 120 Line 31	(1,796,127)
Change in Other Investments	(590,404)
Change in Special Funds	523,943
Property Tax Reimbursement	34,040
Change in Accumulated Other Comprehensive Income	(3,265,846)
Total Other Page 121 Line 53	(3,298,267)
Parent Tax Loss Allocation	-
Total Other Page 121 Line 76	-

Note 2 - Goodwill

The Company's balance sheets as of December 31, 2018 and 2017 included in this annual report reflect the removal of $1.3 billion of goodwill along with an offsetting reduction to Other Paid-In Capital. This is different from the treatment of goodwill for FERC reporting under which goodwill is included in Utility Plant and is different from the treatment of goodwill for U.S. GAAP reporting under which goodwill is reported as a separate long-term asset.

NIAGARA MOHAWK POWER CORPORATION
NOTES TO THE FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Niagara Mohawk Power Corporation ("the Company"), a New York Corporation, is engaged principally in the regulated energy delivery business in New York State ("NYS"). The Company provides electric service to approximately 1.7 million customers in the areas of eastern, central, northern, and western New York and sells, distributes, and transports natural gas to approximately 0.6 million customers in the areas of central, northern, and eastern New York.

The Company is a wholly-owned subsidiary of Niagara Mohawk Holdings, Inc. ("NMHI"), which is a wholly-owned subsidiary of National Grid USA ("NGUSA" or the "Parent"), a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution, and sale of both natural gas and electricity. NGUSA is a direct wholly-owned subsidiary of National Grid North America Inc. ("NGNA") and an indirect wholly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

The accompanying financial statements are unaudited and prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") and the New York State Public Service Commission ("NYPSC") as set forth in their applicable Uniform System of Accounts. This is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("U.S. GAAP"). The primary differences consist of the following:

- For FERC and NYPSC reporting, regulatory assets and liabilities are classified as non-current. For U.S. GAAP reporting, regulatory assets and liabilities are classified as current or long-term as applicable.

- The accumulated amounts collected in rates for cost of removal over spending are included within accumulated depreciation for FERC and NYPSC reporting, but are presented as a regulatory liability for U.S. GAAP reporting.

- All debt is classified as long-term in the balance sheet for FERC and NYPSC reporting. Under U.S. GAAP, the presentation reflects current and long-term debt separately.

- For FERC and NYPSC reporting, the debt issuance costs related to term loans are presented in the balance sheet within deferred charges and other assets. Under U.S. GAAP, this is presented in the balance sheet as a direct deduction from the carrying value of debt.

- For FERC and NYPSC reporting, the liability for uncertain tax positions related to temporary differences is not recognized pursuant to regulatory guidance and deferred taxes are recognized based on the difference between positions taken in filed tax returns and amounts reported in the financial statements. For U.S. GAAP reporting, the liability for uncertain tax positions related to temporary differences is recognized and deferred taxes are recognized based on the difference between the positions taken in filed tax returns adjusted for uncertain tax positions related to temporary differences and amounts reported in the financial statements.

- For FERC and NYPSC reporting, deferred tax assets and liabilities are presented on a gross basis. For U.S. GAAP reporting, deferred tax assets and liabilities are presented on a net basis.

- For FERC and NYPSC reporting, certain revenues or expenses are classified as either utility or non-utility in nature. For GAAP reporting, no distinction between utility and non-utility is made.

In addition, for NYPSC reporting in accordance with Docket 01-M-0075, the Company has excluded goodwill in the amount of $1.3 billion from the financial statements, as a reduction of equity, consistent with its annual report presentation. This presentation is different from the required presentation under U.S. GAAP.

Supplemental Cash Flow Information

	Years Ended December 31,			
	2018		2017	
	(in thousands of dollars)			
Supplemental disclosures:				
Interest paid	**$**	**(111,017)**	$	(107,705)
Income taxes paid		**(60,639)**		(28,346)
Supplemental disclosure of non-cash financing and investing activities:				
Capital-related accruals	**$**	**21,647**	$	21,152
Parent tax loss allocation		**37,122**		-

The Company has evaluated subsequent events and transactions through April 17, 2019, the date of issuance of these financial statements, and concluded that there were no events or transactions that require adjustment to, or disclosure in, the financial statements as of and for the year ended December 31, 2018.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

In preparing financial statements that conform to FERC and NYPSC requirements, the Company must make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses, and the disclosure of contingent assets and liabilities included in the financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The FERC and the NYPSC regulate the rates the Company charges its customers. In certain cases, the rate actions of the FERC and NYPSC can result in accounting that differs from non-regulated companies. In these cases, the Company defers costs (as regulatory assets) or recognizes obligations (as regulatory liabilities) if it is probable that such amounts will be recovered from, or refunded to, customers through future rates. Regulatory assets and liabilities are reflected on the balance sheet consistent with the treatment of the related costs in the ratemaking process.

Revenue Recognition

Revenues are recognized for energy service provided on a monthly billing cycle basis. The Company records unbilled revenues for the estimated amount of services rendered from the time meters were last read to the end of the accounting period.

As approved by the NYPSC, the Company is allowed to pass through commodity-related costs to customers and also bills for approved rate adjustment mechanisms. In addition, the Company has separate revenue decoupling mechanisms for gas and electric which allow for annual adjustments to the Company’s delivery rates as a result of the reconciliation between allowed revenue and billed revenue. Any difference between the allowed revenue and the billed revenue is recorded as a regulatory asset or regulatory liability.

Transmission Formula Rate

The Company's wholesale transmission service charge ("TSC") rates are established based on a FERC-approved formula. The Company is required to make an informational filing annually to update certain components of the TSC formula rate. The revenue requirement component of the annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect in the prior year and the actual revenue requirement for that year.

Other Taxes

The Company collects taxes and fees from customers such as sales taxes, other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. The Company accounts for taxes that are imposed on customers (such as sales taxes) on a net basis (excluded from revenues), while taxes imposed on the Company, such as excise taxes, are recognized on a gross basis. Excise taxes collected and paid for the years ended December 31, 2018 and 2017 were $39.7 million and $35.5 million, respectively.

The state of New York imposes on corporations a franchise tax that is computed as the higher of a tax based on income or a tax based on capital. To the extent the Company's state tax based on capital is in excess of the state tax based on income, the Company reports such excess in other taxes and taxes accrued in the accompanying financial statements.

The Company's policy is to accrue for property taxes on a calendar year basis, taking into account the assessment period. The Company had prepaid property taxes of $0.3 million and zero at December 31, 2018 and 2017, respectively.

Income Taxes

Federal and state income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred income taxes also reflect the tax effect of net operating losses, capital losses, and general business credit carryforwards. The Company assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that the Company will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount.

The effects of tax positions are recognized in the financial statements when it is more likely than not that the position taken, or expected to be taken, in a tax return will be sustained upon examination by taxing authorities based on the technical merits of the position. The financial effect of changes in tax laws or rates is accounted for in the period of enactment. Deferred investment tax credits are amortized over the useful life of the underlying property.

NGNA files consolidated federal tax returns including all of the activities of its subsidiaries. Each subsidiary determines its tax provision based on the separate return method, modified by a benefits-for-loss allocation pursuant to a tax sharing agreement between NGNA and its subsidiaries. The benefit of consolidated tax losses and credits are allocated to the NGNA subsidiaries giving rise to such benefits in determining each subsidiary's tax expense in the year that the loss or credit arises. In a year that a consolidated loss or credit carryforward is utilized, the tax benefit utilized in consolidation is paid proportionately to the subsidiaries that gave rise to the benefit regardless of whether that subsidiary would have utilized the benefit. The tax sharing agreement also requires NGNA to allocate its parent tax losses, excluding deductions from acquisition indebtedness, to each subsidiary in the consolidated federal tax return with taxable income. The allocation of NGNA's parent tax losses to its subsidiaries is accounted for as a capital contribution and is performed in conjunction with the annual intercompany cash settlement process following the filing of the federal tax return.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Cash and cash equivalents are carried at cost which approximates fair value.

Special Deposits

Special deposits primarily consist of collateral paid to the Company's counterparties for outstanding derivative instruments, a release of property account for mortgaged property under a mortgage trust indenture, and a reserve for potential environmental violations.

Accounts Receivable and Accumulated Provision for Uncollectible Accounts

The Company recognizes an accumulated provision for uncollectible accounts to record accounts receivable at estimated net realizable value. The provision is determined based on a variety of factors including, for each type of receivable, applying an estimated reserve percentage to each aging category, taking into account historical collection and write-off experience, and management's assessment of collectability from individual customers, as appropriate. The collectability of receivables is continuously assessed and, if circumstances change, the provision is adjusted accordingly. Receivable balances are written off against the provision for uncollectible accounts when the accounts are disconnected and/or terminated and the balances are deemed to be uncollectible.

Plant Materials and Operating Supplies and Gas Stored Underground

Plant materials and operating supplies are stated at weighted average cost, which represents net realizable value, and are expensed or capitalized as used. The Company's policy is to write-off obsolete plant materials and operating supplies; there were no material write-offs of obsolete plant materials and operating supplies for the years ended December 31, 2018 or 2017.

Gas stored underground is stated at weighted average cost and the related cost is recognized when delivered to customers. Existing rate orders allow the Company to pass directly through to customers the cost of gas purchased, along with any applicable authorized delivery surcharge adjustments. Gas costs passed through to customers are subject to regulatory approvals and are audited annually by the NYPSC.

Derivative Instruments

The Company uses various derivative instruments to manage commodity price risk. All derivative instruments, except those that qualify for the normal purchase normal sale exception, are recorded on the balance sheet at their fair value. All commodity costs, including the impact of derivative instruments, are passed on to customers through the Company's commodity rate adjustment mechanisms. Therefore, gains or losses on the settlement of these contracts are initially deferred and then refunded to, or collected from, customers consistent with regulatory requirements.

The Company has certain non-trading instruments for the physical purchase of electricity that qualify for the normal purchase normal sale exception and are accounted for upon settlement. If the Company were to determine that a contract no longer qualifies for the normal purchase normal sale exception, then the Company would recognize the fair value of the contract in accordance with the regulatory accounting described above.

The Company's accounting policy is to not offset fair value amounts recognized for derivative instruments and related cash collateral receivable or payable with the same counterparty under a master netting agreement, but rather to record and present the fair value of the derivative instrument on a gross basis, with related cash collateral recorded within special deposits on the balance sheet.

Power Purchase Agreements

The Company enters into power purchase agreements to procure commodity to serve its electric service customers. The Company evaluates whether such agreements are leases, derivative instruments, or executory contracts. Power purchase agreements that do not qualify as leases or derivative instruments are accounted for as executory contracts and are, therefore, recognized as the electricity is purchased. In making its determination of the accounting for power purchase agreements, the Company considers many factors, including: the source of the electricity; the level of output from any specified facility that the Company is taking under the contract; the involvement, if any, that the Company has in operating the specified facility; and the pricing mechanisms in the contract.

Natural Gas Long-Term Arrangements

The Company enters into long-term gas contracts to procure commodity to serve its gas customers. Those contracts include Asset Management Agreements, Baseload, and Peaking gas contracts. Similar to the power purchase agreements noted above, the Company evaluates whether such agreements are derivative instruments or executory contracts and applies the appropriate accounting treatment.

Fair Value Measurements

The Company measures derivative instruments and available-for-sale securities at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The following is the fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access as of the reporting date;
- Level 2: inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data;
- Level 3: unobservable inputs, such as internally-developed forward curves and pricing models for the asset or liability due to little or no market activity for the asset or liability with low correlation to observable market inputs; and
- Not categorized: certain investments are not categorized within the fair value hierarchy. These investments are measured based on the fair value of the underlying investments but may not be readily redeemable at that fair value.

The asset or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. The Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

Utility Plant

Utility plant is stated at original cost. The cost of repairs and maintenance is charged to expense and the cost of renewals and betterments that extend the useful life of utility plant is capitalized. The capitalized cost of additions to utility plant includes costs such as direct material, labor and benefits, and an allowance for funds used during construction ("AFUDC").

Depreciation is computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update the composite rates and are approved by the NYPSC. The average composite rates for the years ended December 31, 2018 and 2017 are as follows:

	Composite Rates	
	Years Ended December 31,	
	2018	2017
Electric	**2.6%**	2.3%
Gas	**2.3%**	2.1%
Common	**3.3%**	3.3%

Depreciation expense includes a component for estimated future cost of removal, which is recovered through rates charged to customers.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the debt and equity costs of financing the construction of new utility plant. AFUDC equity is reported in the statements of income as non-cash income and AFUDC debt is reported as a non-cash offset to interest expense. After construction is completed, the Company is permitted to recover these costs through their inclusion in rate base and corresponding depreciation expense. The Company recorded AFUDC related to equity of $13.6 million and $11.8 million and AFUDC related to debt of $5.2 million and $3.9 million for the years ended December 31, 2018 and 2017, respectively. The average AFUDC rates for the years ended December 31, 2018 and 2017 were 6.8%.

Impairment of Long-Lived Assets

The Company tests the impairment of long-lived assets annually or when events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. The recoverability of an asset is determined by comparing its carrying value to the future undiscounted cash flows that the asset is expected to generate. If the comparison indicates that the carrying value is not recoverable, an impairment loss is recognized for the excess of the carrying value over the estimated fair value. For the years ended December 31, 2018 and 2017, there were no impairment losses recognized for long-lived assets.

Goodwill

The Company tests goodwill for impairment annually on January 1, and when events occur or circumstances change that would more likely than not reduce the fair value of each of the Company's respective reporting units below its carrying amount. The Company has early adopted Accounting Standards Update ("ASU") 2017-04, "Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment," which eliminates step two from the two-step goodwill impairment test. The one-step approach requires a recoverability test performed based on the comparison of the Company's estimated fair value with its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, then goodwill is considered not impaired. If the carrying value exceeds the estimated fair value, the Company is required to recognize an impairment charge for such excess, limited to the allocated amount of goodwill.

The fair value of the Company was calculated in the annual goodwill impairment test for the year ended December 31, 2018 utilizing both income and market approaches. The Company uses a 50% weighting for each valuation methodology, as it believes that each methodology provides equally valuable information. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment of the goodwill carrying value was required at December 31, 2018 or 2017.

Available-For-Sale Securities

The Company provides certain executives with nonqualified retirement and deferred compensation benefits which have been partially secured through separate fund arrangements. As a result, the Company holds available-for-sale securities that include equities, municipal bonds, and corporate bonds. These investments are recorded at fair value and are included in other special funds on the balance sheet. Changes in the fair value of these assets are recorded within other comprehensive income.

Asset Retirement Obligations

Asset retirement obligations are recognized for legal obligations associated with the retirement of utility plant, primarily associated with the Company's distribution facilities. Asset retirement obligations are recorded at fair value in the period in which the obligation is incurred, if the fair value can be reasonably estimated. In the period in which new asset retirement obligations, or changes to the timing or amount of existing retirement obligations are recorded, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period the asset retirement obligation is accreted to its present value. The Company applies regulatory accounting guidance and both the depreciation and accretion costs associated with asset retirement obligation are recorded as increases to regulatory assets on the balance sheet. These regulatory assets represent timing differences between the recognition of costs in accordance with FERC and NYPSC reporting and costs recovered through the ratemaking process.

The following table represents the changes in the Company's asset retirement obligations:

	Years Ended December 31,	
	2018	2017
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ 15,437**	$ 15,662
Accretion expense	**612**	622
Liabilities settled	**(1,072)**	(847)
Balance as of the end of the year	**$ 14,977**	$ 15,437

The Company had a current portion of asset retirement obligations of $0.4 million included in miscellaneous current and accrued liabilities on the balance sheet at December 31, 2018.

Employee Benefits

The Company has defined benefit pension plans and postretirement benefit other than pension ("PBOP") plans for its employees. The Company recognizes all pension and PBOP plans' funded status on the balance sheet as a net liability or asset with an offsetting adjustment to accumulated other comprehensive income ("AOCI") in shareholders' equity. The cost of providing these plans is recovered through rates; therefore, the net funded status is offset by a regulatory asset or liability. The Company measures and records its pension and PBOP funded status at the year-end date. Pension and PBOP plan assets are measured at fair value, using the year-end market value of those assets.

Supplemental Executive Retirement Plans

The Company has corporate assets included in other non-current assets on the balance sheet representing funds designated for Supplemental Executive Retirement Plans. These funds are invested in corporate owned life insurance policies and available-for-sale securities primarily consisting of equity investments and investments in municipal and corporate bonds. The corporate owned life insurance investments are measured at cash surrender value with increases and decreases in the value of these assets recorded in the accompanying statements of income.

New and Recent Accounting Guidance

Accounting Guidance Recently Adopted

Pension and Postretirement Benefits

In March 2017, the Financial Accounting Standards Board ("FASB") issued ASU No. 2017-07, "Compensation Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost," which changes certain presentation and disclosure requirements for employers that sponsor defined benefit pension and other postretirement benefit plans. For U.S. GAAP reporting, the ASU requires the service cost component of the net benefit cost to be in the same line item as other compensation in operating income and the other components of net benefit cost to be presented outside of operating income on a retrospective basis. For FERC and NYPSC reporting purposes, all costs will continue to be reported in operating expenses. In addition, only the service cost component will be eligible for capitalization when applicable, on a prospective basis. For the Company, the requirements of the new standard are effective for the current fiscal year ending March 31, 2019 and interim periods therein. The application of the new guidance did not have a material impact on the results of the Company's operations, cash flows, and financial position since the Company defers the difference between actual pension costs and the amounts used to establish rates (See Note 7 "Employee Benefits" for additional details).

Statement of Cash Flows

In November 2016, the FASB issued ASU No. 2016-18, "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)," which requires entities to show the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents in the statement of cash flows.

In August 2016, the FASB issued ASU No. 2016-15, "Classification of Certain Cash Receipts and Cash Payments (Topic 230)," which provides guidance about the classification of certain cash receipts and payments within the statement of cash flows, including debt prepayment or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and policies, and distributions received from equity method investments.

Both accounting updates are effective for the current fiscal year ending March 31, 2019 and interim periods therein. The application of ASU No. 2016-18 resulted only in a change in presentation on the Company's statement of cash flows. Movements in restricted cash were previously included as investing activities. The application of ASU No. 2016-15 did not have a material impact on the Company's cash flows.

Income Taxes

In October 2016, the FASB issued ASU No. 2016-16, "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory," which eliminates the exception for all intra-entity sales of assets other than inventory. As a result, a reporting entity would recognize the tax expense from the sale of the asset in the seller's tax jurisdiction when the transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. For the Company, the requirements of the new standard are effective for the current fiscal year ending March 31, 2019 and interim periods therein. The application of this guidance did not have a material impact on the results of operations, cash flows, or financial position of the Company.

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09: "Revenue from Contracts with Customers (Topic 606)." The underlying principle of this ASU is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to, in exchange for those goods or services. For the Company, the new guidance is effective for the fiscal year ending March 31, 2019 and interim periods therein, and was adopted using a modified retrospective approach.

The FASB has issued a number of additional recent ASUs related to revenue recognition, whose effective date and transition requirements are the same as those for ASU No. 2014-09. In March 2016, the FASB issued ASU No. 2016-08, “Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net),” which clarifies the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU No. 2016-10, "Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing," which provides guidance in the new revenue standard on identifying performance obligations and accounting for licenses of intellectual property. In May 2016, the FASB issued ASU No. 2016-12, “Revenue from Contracts with Customers (ASC 606) Narrow-Scope Improvements and Practical Expedients,” providing additional clarity on various aspects of Topic 606, including a) Assessing the Collectability Criterion and Accounting for Contracts That Do Not Meet the Criteria for Step 1, b) Presentation of Sales Taxes and Other Similar Taxes Collected from Customers, c) Noncash Consideration, d) Contract Modifications at Transition, e) Completed Contracts at Transition, and f) Technical Correction. Lastly, in December 2016, the FASB issued ASU No. 2016-20, "Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers." The amendments in this update cover a variety of corrections and improvements to the Codification related to the new revenue recognition standard (ASU No. 2014-09).

The Company performed detailed reviews of its revenue arrangements to ensure compliance with the new standard effective for the current fiscal year ending March 31, 2019 and interim periods therein. The adoption of ASC 606 did not have a material impact on the presentation of the Company’s results of operations, cash flows, or financial position. However, the Company has added additional qualitative and quantitative financial statement disclosures per requirements under ASC 606 pertaining to its revenue earning mechanisms (See Note 3, “Revenue” for additional details).

Financial Instruments – Classification and Measurement

In January 2016, the FASB issued ASU No. 2016-01, “Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities.” The new guidance principally affects the accounting for equity investments and financial liabilities where the fair value option has been elected, as well as the disclosure requirements for financial instruments. For the Company, the new guidance is effective for the fiscal year ending March 31, 2019 and interim periods therein. The adoption of this ASU did not have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Goodwill

In January 2017, the FASB issued ASU No. 2017-04, which eliminates Step 2 from the goodwill impairment test. For the Company, the requirements of the new standard will be effective for the fiscal year ending March 31, 2022, with early adoption permitted. The Company early adopted the ASU in the year ended March 31, 2018 for its annual goodwill impairment testing. Based on the resulting fair value from the annual analyses, the Company determined that no adjustment to the goodwill carrying value was required at March 31, 2018 or 2017.

Stock Compensation

In May 2017, the FASB issued ASU No. 2017-09, “Stock Compensation (Topic 718): Scope of Modification Accounting,” which provides clarity on the application of modification accounting upon a change to the terms or conditions of a share-based payment award. For the Company, the new guidance is effective for the fiscal year ending March 31, 2019 and interim periods therein. The adoption of this ASU did not have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Accounting Guidance Not Yet Adopted

Derivatives and Hedging

In August 2017, the FASB issued ASU No. 2017-12, "Targeted Improvements to Accounting for Hedging Activities," which will be effective for the fiscal year ending March 31, 2020, with early adoption permitted. The amendments in this update expand and refine hedge accounting for both financial and nonfinancial risk components and align the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. This update also includes changes to certain targeted improvements to ease the application of current guidance related to the assessment of hedge effectiveness. The Company is currently evaluating the impact of the new guidance on the results of its operations, cash flows, and financial position.

Leases

In February 2016, the FASB issued ASU 2016-02 "Leases" (codified as Topic 842) related to lease accounting, effective January 1, 2019 for public entities. For the Company, the new standard is effective for the fiscal year ending March 31, 2020, and interim periods within, with early adoption permitted. Under the new standard, a lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified assets for a period of time in exchange for consideration. Lessees will need to recognize leases on the balance sheet as a right-of-use asset and a related lease liability and classify the leases as either operating or finance. The liability will be equal to the present value of lease payments. The asset will be based on the liability, subject to adjustments, such as initial direct costs. The standard will also require lessors to allocate (rather than recognize as currently required) certain variable payments to the lease and non-lease components when the changes in facts and circumstances on which the variable payment is based occur.

The standard will require the Company to recognize and measure the cumulative effect of the new standard at the beginning of the earliest period presented using a modified retrospective approach.

The Company's operating leases portfolio includes mainly real estate, fleet vehicles and telecommunication towers. These operating leases will result in straight-line expense while finance leases will result in a higher initial expense pattern due to the interest component. The Company, as a regulated entity, is permitted to continue to recognize expense using the timing that conforms to the regulatory rate treatment. Additionally, lessees can elect to exclude from the balance sheet short-term contracts of one year or less. The Company is currently assessing its alternatives for electing the options allowed for lessees by the standard setters including the impact of short-term lease considerations.

The new standard provides the Company with transition practical expedients including a package of three expedients that must be taken together and allows the Company to: not reassess whether existing contracts contain leases, carryforward the existing classification of any leases, and not reassess initial direct costs associated with existing leases. The Company is still evaluating its options related to the package of practical expedients.

The standard permits an entity to elect an optional transition practical expedient to not evaluate under Topic 842 land easements that exist or expire before the Company's adoption of Topic 842, that were not previously accounted for as leases under Topic 840. The Company will exercise its option to elect this expedient.

The standard permits lessors, as an accounting policy election, to not evaluate whether certain sales taxes and other similar taxes are lessor costs or lessee costs. Instead, those lessors will account for those costs as if they are lessee costs. The company is assessing its alternatives for electing this option. The standard also allows lessors to exclude certain costs from variable payments, and therefore revenue, for lessor costs paid by lessees directly to third parties. The Company is assessing its alternatives for electing this option.

We have established a cross-functional team to assess and implement the new standard. Our assessment is substantially complete, and the Company is currently finalizing its adoption options allowed for lessees and lessors by the new standard.

The adoption of this standard will increase right-of-use assets and lease liabilities on the Company's consolidated balance sheet and require more robust disclosures related to leases. The Company is currently implementing a new lease accounting system and is evaluating the impact this standard will have on the results of operations, financial position, and lease disclosures of the Company.

Related Party

In October 2018, the FASB issued ASU No. 2018-17 "Consolidation (Topic 810), Targeted Improvements to Related Party Guidance for Variable Interest Entities ("VIE")" which allows a private company (reporting entity) not to apply VIE guidance to legal entities under common control (including common control leasing arrangements) if both the parent and the legal entity being evaluated for consolidation are not public business entities. Also, indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. For the Company, the requirements in this update are effective for the fiscal year ending March 31, 2021 and interim periods within. The Company is currently assessing the application of the standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Intangibles - Goodwill and Other

In August 2018, the FASB issued ASU No. 2018-15 "Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40), Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" to help entities evaluate the accounting for fees paid by a customer. The amendment will align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. For the Company, the requirements in this update are effective for the fiscal year ending March 31, 2021 and interim periods within. The Company is currently assessing the application of the standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Compensation

In August 2018, the FASB issued ASU No. 2018-14 "Compensation – Retirement Benefits – Defined Benefit Plans – General (Subtopic 715-20), Disclosure Framework – Changes to the Disclosure Requirements for Defined Benefit Plans" which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. For the Company, the requirements in this update are effective for the fiscal year ending March 31, 2022 and interim periods within. The Company is currently assessing the application of the standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

In June 2018, the FASB issued ASU No. 2018-07 "Compensation – Stock Compensation (Topic 718), Improvements to Nonemployee Share-Based Payment Accounting" which expands the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees. For the Company, the requirements in this update are effective for the fiscal year ending March 31, 2020 and interim periods within. The Company is currently assessing the application of the standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Fair Value

In August 2018, the FASB issued ASU No. 2018-13 "Fair Value Measurement (Topic 820), Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement" which modifies the disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement, based on the concepts in the Concepts Statement, including the consideration of costs and benefits. For the Company, the requirements in this update are effective for the fiscal year ending March 31, 2021 and interim periods within. The Company is currently assessing the application of the standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

Financial Instruments

In November 2018, the FASB issued ASU No. 2018-19 "Codification Improvements to Topic 326, Financial Instruments – Credit Losses" which mitigates the transition complexity by requiring that for nonpublic business entities the amendments in update 2016-13 are effective for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. The amendment clarifies that receivables arising from operating leases are not within the scope of Subtopic 326-20. Instead, impairment of receivables arising from operating leases should be accounted for in accordance with Topic 842. For the Company, the requirements in this update are effective for the fiscal year ending March 31, 2021 and interim periods within. The Company is currently assessing the application of the standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

In June 2016, the FASB issued ASU No. 2016-13 "Financial Instruments – Credit Losses (Topic 326), Measurement of Credit Losses on Financial Statements" requires a financial asset (or a group of financial assets) measured at amortized cost basis to be presented at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset. Credit losses relating to available-for-sale debt securities should be recorded through an allowance for credit losses. For the Company, the requirements of the new standard will be effective for the fiscal year ending March 31, 2022 and interim periods therein, with early adoption permitted from the fiscal year ending March 31, 2020 and interim periods within. The Company is currently assessing the application of the standard to determine if it will have a material impact on the presentation, results of operations, cash flows, and financial position of the Company.

3. REVENUE

Upon the adoption of ASC Topic 606, revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Company recognizes revenue when it transfers control over a product or service to a customer.

Nature of Goods and Services

The following is a description of principal activities – separated by reportable segments – from which the Company generates its revenue.

Transmission

The Transmission segment of the Company principally generates revenue from providing the services/products shown in further detail below. Transmission systems generally include overhead lines, underground cables and substations, connecting generation and interconnectors to the distribution system. The Company owns, maintains, and operates an electricity transmission system spanning upstate New York. The Company's transmission services are regulated by both the New York Independent System Operator and by the FERC in respect of interstate transmission.

Products and services	Nature, timing of satisfaction of performance obligations, and significant payment terms
Electric Transmission	Electric transmission revenues arise under Transmission Congestion Contract auctions, Transmission Service Agreements and Local / Regional Network Services under tariff/rate agreements. The Company bills its transmission services typically on a monthly basis, in the month after service has been provided. The Company recognizes the revenue as the amounts are billed, as these amounts represent the actual consideration for the services provided to customers.

Distribution

The Distribution segment of the Company principally generates revenue from providing the services/products shown in further detail below. The distribution revenues are primarily associated with cancellable contracts with the exception of certain long-term contracts with commercial and industrial customers. The Company's distribution services are regulated by the NYPSC.

Products and services	Nature, timing of satisfaction of performance obligations, and significant payment terms
Electric Distribution	The Company owns, maintains, and operates an electricity distribution network in upstate New York. The Company bills its distribution services typically on a monthly basis, in the month after service has been provided. The Company recognizes revenue based on its right to invoice its customers. This corresponds directly with the value to the customer of performance to date. The distribution revenue also includes estimated unbilled amounts, which are recognized over time and determined utilizing approved tariff rates and estimated meter volumes.
Gas Distribution	The Company owns, maintains, and operates a gas distribution network serving areas in New York, primarily consisting of domestic and commercial consumers. The Company bills its distribution services typically on a monthly basis, in the month after service has been provided. The Company recognizes revenue based on its right to invoice its customers. This corresponds directly with the value to the customer of performance to date. The amount of revenue also includes estimated unbilled amounts, which are recognized over time and determined utilizing estimated usage.

Other Activities

The Other Activities segment of the Company and the revenues generated from it are shown in further detail below.

Products and services	**Nature, timing of satisfaction of performance obligations, and significant payment terms**
Alternative Revenue Programs	The Company's distribution tariffs authorize it to increase or decrease its bills to customers for certain items other than direct compensation for the current provision of utility service. These tariff provisions constitute alternative revenue programs. Specifically, the Company has separate revenue decoupling mechanisms for gas and electric which allow for annual adjustments to the Company's delivery rates as a result of the reconciliation between allowed revenue and billed revenue.
Other	Other revenues include off-system sales, lease revenue, and various deferral mechanisms (including capital tracker and storm deferral) that are not considered revenue from contracts with customers.

Disaggregation of Revenue

In the following table, revenue is disaggregated by major products and services.

	Years Ended December 31,	
	2018	2017
	(in thousands of dollars)	
Major products and services:		
Electric Transmission	**$ 386,496**	$ 404,996
Electric Distribution	**1,882,887**	1,850,660
Gas Distribution	**604,051**	523,851
Alternative Revenue Programs	**46,957**	(26,500)
Other	**306,958**	251,229
Total	**$ 3,227,349**	$ 3,004,236

4. REGULATORY ASSETS AND LIABILITIES

The Company records regulatory assets and liabilities that result from the ratemaking process. The following table presents the regulatory assets and regulatory liabilities recorded on the balance sheet:

	December 31, 2018	December 31, 2017
	(in thousands of dollars)	
Other regulatory assets:		
Carrying charges	**$ -**	$ 49,258
Derivative instruments	**1,116**	28,395
Dunkirk settlement deferral	**16,366**	57,000
Energy efficiency	**16,606**	28,769
Environmental response costs	**369,845**	359,632
Gas costs adjustment	**28,379**	35,841
Postretirement benefits	**68,205**	185,387
Regulatory tax asset	**-**	195,900
Storm costs	**6,221**	114,402
Other	**48,011**	96,071
Total	**554,749**	1,150,655
Other regulatory liabilities:		
Carrying charges	**65,281**	157,653
Economic development fund	**38,412**	105,964
Energy efficiency	**422,324**	405,980
Environmental response costs	**54,341**	82,344
Long-term debt true-up	**14,987**	75,976
Postretirement benefits	**99,352**	38,454
Rate adjustment mechanisms	**23,930**	114,176
Regulatory tax liability, net	**820,515**	1,040,954
Storm costs	**-**	170,139
Other	**433,619**	107,929
Total	**1,972,761**	2,299,569
Net regulatory liabilities	**$ (1,418,012)**	$ (1,148,914)

Carrying charges: The Company records carrying charges on regulatory balances for which cash expenditures have been made and are subject to recovery, or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made.

Derivative instruments: The Company evaluates open derivative instruments for regulatory deferral by determining if they are probable of recovery from, or refund to, customers through future rates. Derivative instruments that qualify for recovery are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs.

Dunkirk settlement deferral: The Company is allowed to defer up to $57 million to offset the Reliability Support Services ("RSS") associated with the Dunkirk generating plant and RSS agreements with other generators. This is an on-going deferral mechanism. The timing for disposition of any associated deferred balances will be determined by future NYPSC rulings.

Economic development fund: Represents a deferral mechanism for economic development discounts. Under this mechanism, the Company reconciles the economic discounts provided to customers to the amount reflected in rates for future refund to, or recovery from, customers. This is an on-going deferral mechanism. The timing for disposition of any associated deferred balances will be determined by future NYPSC rulings.

Energy efficiency: An asset or liability is recognized resulting from the difference between revenue billed to customers through the Company's energy efficiency charge and the costs of the Company's energy efficiency programs as approved by the NYPSC.

Environmental response costs: The regulatory asset represents deferred costs associated with the Company's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated. The Company's rate plans provide for specific rate allowances for these costs at a level of $32.1 million per year, with variances deferred for future recovery from, or return to, customers. The Company believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates. The regulatory liability represents the excess of amounts received in rates over the Company's actual site investigation and remediation costs.

Gas costs adjustment: The Company is subject to rate adjustment mechanisms for commodity costs, whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the NYPSC. These amounts will be refunded to, or recovered from, customers over the next year.

Long-term debt true-up: The Company has a mechanism whereby it reconciles the actual interest expense and other debt costs related to its variable rate debt with the amount reflected in rates ($22 million for electric and $5.5 million for gas). The Company defers any over or under recoveries for future refund to, or recovery from, customers. This is an on-going deferral mechanism. The timing for disposition of any associated deferred balances will be determined by future NYPSC rulings.

Postretirement benefits: The regulatory asset represents the Company's deferral related to the underfunded status of its pension and PBOP plans. The regulatory liability primarily represents the excess of amounts received in rates over actual costs of the Company's pension and PBOP plans to be refunded in future periods.

Rate adjustment mechanisms: In addition to commodity costs, the Company is subject to a number of additional rate adjustment mechanisms whereby an asset or liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the NYPSC.

Regulatory tax asset/liability, net: Represents over-recovered federal and state deferred taxes of the Company primarily as a result of regulatory flow through accounting treatment and state income tax rate changes and excess federal deferred taxes as a result of the recently enacted Tax Cuts and Jobs Act ("Tax Act").

Storm costs: The Joint Proposal (NMPC rate proceeding Case 12-E-0201) established an annual allowance for major storm recovery of $29 million in each of the three fiscal years ended March 31, 2016. The NYPSC allowed for the continuation of this allowance in Case 15-M-0744 for the two fiscal years ended March 31, 2018. The Company deferred the difference between the base rate allowance and actual major storm incremental costs for future refund to, or recovery from, customers. Under the new NMPC rate case (Case 17-E-0238), the annual allowance for major storm recovery will be $23 million for the three fiscal years ending March 31, 2021 and a per storm deferral threshold of $0.4 million was established. At December 31, 2017, the regulatory liability represents the cumulative storm reserve allowance/funding for major storm incremental costs and the regulatory asset represents the cumulative incremental costs incurred for qualified storm events. At December 31, 2018, these amounts have been reported net.

5. RATE MATTERS

Electric and Gas Filing

On April 28, 2017, the Company filed a proposal to reset electric and natural gas delivery prices beginning in April 2018. On January 19, 2018, the Company reached a settlement agreement with the NYPSC Staff and other parties to the case and filed a Joint Proposal for a three-year rate plan. The proposal reflects the new federal tax law changes and provides a cumulative revenue requirement increase of $240.8 million and $60.8 million for the electric and gas business, respectively, based on a 9.0% return on equity and 48% common equity ratio. On March 15, 2018, the NYPSC issued a final order approving the Joint Proposal and the new rates took effect on April 1, 2018.

As of March 31, 2018, resulting from the Joint Proposal, a new electric rate plan settlement credit of $44.9 million and a new gas rate plan settlement credit of $28.4 million were established. These credits are included in other regulatory liabilities in the preceding table within Note 4, "Regulatory Assets and Liabilities." The Company applied $38.4 million of existing regulatory liabilities towards the creation of these credits.

Tax Act

On March 15, 2018, the FERC initiated multiple proceedings intended to adjust FERC-jurisdictional rates to reflect the corporate tax changes as a result of the passage of the Tax Act signed into law on December 22, 2017. Proceedings initiated relevant to the Company are the Notice of Inquiry ("NOI") seeking comments on the effects of the Tax Act on all FERC-jurisdiction rates and a Notice of Proposed Rulemaking ("NOPR") issued as a result of the NOI. In response to the FERC NOI, the Company had made recommendations designed to mitigate the cash flow impacts of the expected refunds including providing flexibility regarding the methods used to refund accumulated deferred income tax ("ADIT") to customers and providing flexibility regarding the time period of the flow back. In the NOPR, the FERC proposes to give flexibility we proposed. Comments on the NOPR were due on January 22, 2019, and the FERC will issue a final rule sometime thereafter, hopefully in the first half of fiscal year 2020. The amortization of the excess deferred taxes is expected to result in a net margin reduction of $12 million per year.

In response to the Tax Act signed into law on December 22, 2017, the NYPSC issued an Order Instituting Proceeding under Case 17-M-0815 - Proceeding on Motion of the Commission on Changes in Law that May Affect Rates. This proceeding was instituted to solicit comments on the Tax Act's implications and places the utilities on notice of the NYPSC's intent to protect ratepayers' interest and to ensure that any cost reductions from the changes in federal income taxes are deferred for future ratepayer benefit. On March 29, 2018, the NYPSC Staff released its proposal to address accounting and ratemaking related to the Tax Act. Comments on NYPSC Staff's proposal were filed June 27, 2018.

On August 9, 2018, the NYPSC issued an order in its generic proceeding considering the impacts of federal tax reform. NYPSC Staff had advocated that all New York utilities implement a sur-credit by October 1st that would reflect the immediate effects of the Tax Act and also return any deferred benefits to customers. In response, the Company filed a proposal to (i) delay any sur-credit to January 1st to offset scheduled rate increases and (ii) retain any deferred benefits, including accumulated deferred federal income taxes ("ADFIT"), for future rate moderation.

The NYPSC's order effectively approved all aspects of the Company's proposal. The NYPSC agreed that the Company should be allowed to defer both the pass back of calendar year 2018 tax savings (to the extent not already returned in the new rate plan) and the amortization of excess ADFIT balances and use the benefits as a rate moderator when base rates are next revised in 2020/2021. Specifically, the NYPSC directed that no sur-credit is required as the current rate plan already reflects the reduction of the tax rate to 21% and the termination of bonus depreciation. The NYPSC approved the Company's proposal to defer the tax benefit realized for the three-month period (January-March) prior to new rates, of $18.0 million for electric and $4.6 million for gas, to offset future rate increases or investments. Protected balances of $620 million of electric excess ADFIT and $129 million of gas excess ADIT and unprotected electric excess ADFIT of $76 million and unprotected gas excess ADFIT of $14 million will be deferred for future disposition in rate proceedings.

Operations Staffing Audit

In January 2014, the NYPSC initiated an operational audit to review internal staffing levels and use of contractors for the core utility functions of the investor owned utilities operating in New York, including the Company. On June 26, 2014, the NYPSC selected a third party to conduct the audit. On February 21, 2017, the third party submitted its final report, which contained recommendations for all of National Grid's New York utilities designed to improve the staffing and workforce management processes. The report contained 27 recommendations for National Grid. The Company filed its implementation plan on March 23, 2017. On December 15, 2017, the NYPSC issued an Order approving the Company's implementation plan without modification, with updates to be made every four months to the NYPSC on the status of implementation. The Company submitted its most recent update on December 17, 2018.

New York Management Audit

In 2018, the NYPSC initiated a comprehensive management and operations audit of National Grid's three New York electric and gas utilities. New York law requires periodic management audits of all utilities at least once every five years. National Grid last underwent a New York management audit in 2014/2015, when the NYPSC audited our New York gas business. The audit will be process oriented and forward looking and presents opportunities to obtain feedback on how to improve service to customers and meet regulatory expectations. Areas of focus will include the traditional audit areas of corporate governance, budgeting and finance, customer, work management, and long-term planning, as well as organization design, information systems, gas safety, and grid modernization.

6. UTILITY PLANT AND NONUTILITY PROPERTY

The following table summarizes utility plant and nonutility property at cost along with accumulated depreciation and amortization:

	December 31,	
	2018	2017
	(in thousands of dollars)	
Plant and machinery	**$ 11,895,450**	$ 11,307,604
Land and buildings	**628,939**	593,845
Assets in construction	**438,320**	370,699
Motor vehicles and equipment	**35,015**	34,543
Software and other intangibles	**8,618**	7,918
Non-utility property	**11,562**	11,562
Total utility plant and nonutility property	**13,017,904**	12,326,171
Accumulated depreciation and amortization	**(3,964,121)**	(3,771,300)
Utility plant and nonutility property, net	**$ 9,053,783**	$ 8,554,871

7. DERIVATIVE INSTRUMENTS

The Company utilizes derivative instruments to manage commodity price risk associated with its natural gas and electricity purchases. The Company's commodity risk management strategy is to reduce fluctuations in firm gas and electricity sales prices to its customers.

The Company's financial exposures are monitored and managed as an integral part of the Company's overall financial risk management policy. The Company engages in risk management activities only in commodities and financial markets where it has an exposure, and only in terms and volumes consistent with its core business.

Volumes

Volumes of outstanding commodity derivative instruments measured in dekatherms ("dths") and megawatt hours ("mwhs") are as follows:

	Electric		Gas	
	December 31,		December 31,	
	2018	2017	**2018**	2017
	(in thousands)		*(in thousands)*	
Gas option contracts (dths)	**-**	-	**8,105**	1,940
Gas purchase contracts (dths)	**-**	-	**7,282**	10,808
Gas swap contracts (dths)	**-**	-	**2,740**	7,580
Electric capacity (mwhs)	**475**	576	**-**	-
Electric option contracts (mwhs)	**101**	-	**-**	-
Electric swap contracts (mwhs)	**12,648**	12,253	**-**	-
Electric swaption contracts (mwhs)	**-**	218	**-**	-
Total	**13,224**	13,047	**18,127**	20,328

Amounts Recognized on the Balance Sheet

	Asset Derivatives			Liability Derivatives	
	December 31,			December 31,	
	2018	2017		**2018**	2017
	(in thousands of dollars)			*(in thousands of dollars)*	
Current and accrued assets:			Current and accrued liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas option contracts	**$ 30**	$ -	Gas option contracts	**$ 207**	$ 349
Gas purchase contracts	**72**	365	Gas purchase contracts	**1,596**	630
Gas swap contracts	**161**	124	Gas swap contracts	**224**	975
Electric capacity contracts	**49**	49	Electric capacity contracts	**-**	-
Electric option contracts	**126**	164	Electric option contracts	**-**	250
Electric swap contracts	**14,084**	6,417	Electric swap contracts	**5,552**	14,278
	14,522	7,119		**7,579**	16,482
Other property and investments:			Other noncurrent liabilities:		
Rate recoverable contracts:			Rate recoverable contracts:		
Gas options contracts	**188**	-	Gas options contracts	**47**	19
Gas purchase contracts	**60**	17	Gas purchase contracts	**-**	-
Gas swap contracts	**-**	21	Gas swap contracts	**-**	62
Electric capacity contracts	**443**	742	Electric capacity contracts	**-**	-
Electric swap contracts	**15,641**	76	Electric swap contracts	**1,084**	11,833
	16,332	856	Total	**1,131**	11,914
Total	**$ 30,854**	$ 7,975		**$ 8,710**	$ 28,396

The changes in fair value of the Company's rate recoverable contracts are offset by changes in regulatory assets and liabilities. As a result, the changes in fair value of those contracts had no impact in the accompanying statements of income. All of the Company's derivative instruments are subject to rate recovery as of December 31, 2018 and 2017.

Credit and Collateral

The Company is exposed to credit risk related to transactions entered into for commodity price risk management. Credit risk represents the risk of loss due to counterparty non-performance. Credit risk is managed by assessing each counterparty's credit profile and negotiating appropriate levels of collateral and credit support.

The credit policy for commodity transactions is managed and monitored by the Finance Committee to National Grid plc's Board of Directors ("Finance Committee"), which is responsible for approving risk management policies and objectives for risk assessment, control and valuation, and the monitoring and reporting of risk exposures. NGUSA's Energy Procurement Risk Management Committee ("EPRMC") is responsible for approving transaction strategies, annual supply plans, and counterparty credit approval, as well as all valuation and control procedures. The EPRMC is chaired by the Vice President of U.S. Treasury and reports to both the NGUSA Board of Directors and the Finance Committee.

The EPRMC monitors counterparty credit exposure and appropriate measures are taken to bring such exposures below the limits, including, without limitation, netting agreements, and limitations on the type and tenor of trades. The Company enters into enabling agreements that allow for payment netting with its counterparties, which reduce its exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. In instances where a counterparty's credit quality has declined, or credit exposure exceeds certain levels, the Company may limit its credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support, and negotiating the early termination of certain agreements. Similarly, the Company may be required to post collateral to its counterparties.

The Company's credit exposure for all commodity derivative instruments, normal purchase normal sale contracts, and applicable payables and receivables, net of collateral, and instruments that are subject to master netting agreements, was an asset of $20.9 million and a liability of $12.5 million as of December 31, 2018 and 2017, respectively.

The aggregate fair value of the Company's commodity derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2018 and 2017 was $1.7 million and $24.7 million, respectively. The Company had zero and $8.8 million collateral posted for these instruments at December 31, 2018 and 2017, respectively. At December 31, 2018, if the Company's credit rating were to be downgraded by one or two levels, it would not be required to post any additional collateral to its counterparties and if the Company's credit rating were to be downgraded by three levels, it would be required to post additional collateral to its counterparties of $2.0 million. At December 31, 2017, if the Company's credit rating had been downgraded by one, two, or three levels, it would have been required to post additional collateral to its counterparties of zero, $1.3 million, or $20.2 million, respectively.

Offsetting Information for Derivative Instruments Subject to Master Netting Arrangements

December 31, 2018
Gross Amounts Not Offset in the Balance Sheets
(in thousands of dollars)

ASSETS:	Gross amounts of recognized assets *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of assets presented in the Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral received *Db*	Net amount *E=C-D*
Derivative instruments						
Gas option contracts	$ 218	$ -	$ 218	$ -	$ -	$ 218
Gas purchase contracts	132	-	132	-	-	132
Gas swap contracts	161	-	161	-	-	161
Electric capacity contracts	492	-	492	-	-	492
Electric option contracts	126	-	126	-	-	126
Electric swap contracts	29,725	-	29,725	-	1,700	28,025
Total	$ 30,854	$ -	$ 30,854	$ -	$ 1,700	$ 29,154

LIABILITIES:	Gross amounts of recognized liabilities *A*	Gross amounts offset in the Balance Sheets *B*	Net amounts of liabilities presented in the Balance Sheets *C=A+B*	Financial instruments *Da*	Cash collateral paid *Db*	Net amount *E=C-D*
Derivative instruments						
Gas option contracts	$ 254	$ -	$ 254	$ -	$ -	$ 254
Gas purchase contracts	1,596	-	1,596	-	-	1,596
Gas swap contracts	224	-	224	-	-	224
Electric option contracts	-	-	-	-	-	-
Electric swap contracts	6,636	-	6,636	-	-	6,636
Total	$ 8,710	$ -	$ 8,710	$ -	$ -	$ 8,710

December 31, 2017

Gross Amounts Not Offset in the Balance Sheets

(in thousands of dollars)

ASSETS:	Gross amounts of recognized assets A	Gross amounts offset in the Balance Sheets B	Net amounts of assets presented in the Balance Sheets C=A+B	Financial instruments Da	Cash collateral received Db	Net amount E=C-D
Derivative instruments						
Gas purchase contracts	$ 382	$ -	$ 382	$ -	$ -	$ 382
Gas swap contracts	145	-	145	-	-	145
Electric capacity contracts	791	-	791	-	-	791
Electric option contracts	164	-	164	-	-	164
Electric swap contracts	6,493	-	6,493	-	-	6,493
Total	$ 7,975	$ -	$ 7,975	$ -	$ -	$ 7,975

LIABILITIES:	Gross amounts of recognized liabilities A	Gross amounts offset in the Balance Sheets B	Net amounts of liabilities presented in the Balance Sheets C=A+B	Financial instruments Da	Cash collateral paid Db	Net amount E=C-D
Derivative instruments						
Gas option contracts	$ 368	$ -	$ 368	$ -	$ -	$ 368
Gas purchase contracts	630	-	630	-	-	630
Gas swap contracts	1,037	-	1,037	-	-	1,037
Electric option contracts	250	-	250	-	-	250
Electric swap contracts	26,111	-	26,111	-	8,800	17,311
Total	$ 28,396	$ -	$ 28,396	$ -	$ 8,800	$ 19,596

8. FAIR VALUE MEASUREMENTS

The following tables present assets and liabilities measured and recorded at fair value on the balance sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2018 and 2017:

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(in thousands of dollars)			
Assets:				
Derivative instruments				
Gas option contracts	$ -	$ -	$ 218	$ 218
Gas purchase contracts	-	-	132	132
Gas swap contracts	-	161	-	161
Electric capacity contracts	-	-	492	492
Electric option contracts	-	-	126	126
Electric swap contracts	-	29,725	-	29,725
Total	-	29,886	968	30,854
Liabilities:				
Derivative instruments				
Gas option contracts	-	-	254	254
Gas purchase contracts	-	1,596	-	1,596
Gas swap contracts	-	224	-	224
Electric swap contracts	-	6,636	-	6,636
Total	-	8,456	254	8,710
Net assets	$ -	$ 21,430	$ 714	$ 22,144

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(in thousands of dollars)			
Assets:				
Derivative instruments				
Gas purchase contracts	$ -	$ -	$ 382	$ 382
Gas swap contracts	-	145	-	145
Electric capacity contracts	-	-	791	791
Electric option contracts	-	-	164	164
Electric swap contracts	-	6,493	-	6,493
Available-for-sale securities	22,782	11,665	-	34,447
Total	22,782	18,303	1,337	42,422
Liabilities:				
Derivative instruments				
Gas option contracts	-	-	368	368
Gas purchase contracts	-	391	239	630
Gas swap contracts	-	1,037	-	1,037
Electric option contracts	-	-	250	250
Electric swap contracts	-	26,111	-	26,111
Total	-	27,539	857	28,396
Net assets (liabilities)	$ 22,782	$ (9,236)	$ 480	$ 14,026

Derivative instruments: The Company's Level 2 fair value derivative instruments primarily consist of over-the-counter ("OTC") electric and gas swap contracts with pricing inputs obtained from the New York Mercantile Exchange and the Intercontinental Exchange ("ICE"), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. The Company may utilize discounting based on quoted interest rate curves, including consideration of non-performance risk, and may include a liquidity reserve calculated based on bid/ask spread for the Company's Level 2 derivative instruments. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 95% or higher.

The Company's Level 3 fair value derivative instruments consist of gas option and purchase, and electric option and capacity transactions, which are valued based on internally-developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, Monte Carlo simulation, and Financial Engineering Associates libraries are used for valuing such instruments. A derivative is designated Level 3 when it is valued based on a forward curve that is internally developed, extrapolated, or derived from market observable curves with correlation coefficients less than 95%, where optionality is present, or if non-economic assumptions are made.

Available-for-sale securities: Available-for-sale securities are included in other special funds on the balance sheet and primarily include equity and debt investments based on quoted market prices (Level 1) and municipal and corporate bonds based on quoted prices of similar traded assets in open markets (Level 2).

Changes in Level 3 Derivative Instruments

	Years Ended December 31,	
	2018	2017
	(in thousands of dollars)	
Balance as of the beginning of the year	**$ 480**	$ 3,737
Net gains (losses) included in regulatory assets and liabilities	**4,444**	(2,070)
Settlements	**(4,210)**	(1,187)
Balance as of the end of the year	**$ 714**	$ 480

A transfer into Level 3 represents existing assets or liabilities that were previously categorized at a higher level for which the inputs became unobservable during the year. A transfer out of Level 3 represents assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed previously for classification in Level 2. These transfers, which are recognized at the end of each period, result from changes in the observability of forward curves from the beginning to the end of each reporting period. There were no transfers between Level 1 and Level 2, and no transfers into or out of Level 3, during the years ended December 31, 2018 or 2017.

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Company considers non-performance risk and liquidity risk in the valuation of derivative instruments categorized in Level 2 and Level 3.

Quantitative Information About Level 3 Fair Value Measurements

The following tables provide information about the Company's Level 3 valuations:

Commodity	Level 3 Position	Fair Value as of December 31, 2018 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in thousands of dollars)					
Gas	Cross Commodity contracts	$ 34	$ -	$ 34	Discounted Cash Flow	Forward Curve	$28.22 - $332.47/dth
Gas	Option contracts	218	(254)	(36)	Discounted Cash Flow	Forward Curve Implied Volatility	$0.11 - $0.35/dth 26% - 55%
Gas	Purchase contracts	98	-	98	Discounted Cash Flow	Forward Curve	$5.86 - $10.67/dth
Electric	Capacity contracts	492	-	492	Discounted Cash Flow	Forward Curve	$0.10 - $2.36/MW
Electric	Option contracts	126	-	126	Discounted Cash Flow	Implied Volatility	20% - 321%
	Total	$ 968	$ (254)	$ 714			

Commodity	Level 3 Position	Fair Value as of December 31, 2017 Assets	(Liabilities)	Total	Valuation Technique(s)	Significant Unobservable Input	Range
		(in thousands of dollars)					
Gas	Option contracts	$ -	$ (368)	$ (368)	Discounted Cash Flow	Forward Curve Implied Volatility	$0.30 - $0.42/dth 26% - 54%
Gas	Purchase contracts	382	(239)	143	Discounted Cash Flow	Forward Curve	$3.39 - $5.59/dth $31.41 - $206.02/dth
Electric	Capacity contracts	791	-	791	Discounted Cash Flow	Forward Curve	$0.20 - $2.88/MW
Electric	Option contracts	164	(250)	(86)	Discounted Cash Flow	Implied Volatility	21% - 138%
	Total	$ 1,337	$ (857)	$ 480			

The significant unobservable inputs listed above would have a direct impact on the fair values of the Level 3 instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of the Company's gas option derivative instruments and electric option and swap derivative instruments are implied volatility and gas forward curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Other Fair Value Measurements

The Company's balance sheet reflects long-term debt at amortized cost. The fair value of the Company's long-term debt was based on quoted market prices when available or estimated using quoted market prices for similar debt. The fair value of this debt at December 31, 2018 and 2017 were $3.3 billion and $2.9 billion, respectively.

All other financial instruments on the balance sheet such as accounts receivable, accounts payable, and notes receivable from and payable to associated companies are stated at cost, which approximates fair value.

9. EMPLOYEE BENEFITS

The Company participates in two non-contributory defined benefit pension plans (the “Pension Plans”) and two PBOP plans (the “PBOP Plans,” together with the Pension Plans, the “Plans”). The Company calculates benefits under these plans based on age, years of service and pay using March 31 as a measurement date. In addition, the Company also participates in defined contribution plans for eligible employees. The plans are sponsored by National Grid USA Service Company.

Plan assets are maintained in commingled trusts. In respect of cost determination, plan assets are allocated to the Company based on the Company’s proportionate share of the Plan’s projected benefit obligation. The Plan’s costs are first directly charged to the Company based on the Company’s employees that participate in the Plan. Costs associated with affiliated service companies’ employees are then allocated as part of the labor burden for work performed on the Company’s behalf. The Company applies deferral accounting for pension and PBOP expenses associated with its regulated gas and electric operations. Any differences between actual pension costs and amounts used to establish rates are deferred and collected from, or refunded to, customers in subsequent periods. Pension and PBOP expense are included within operation expenses in the accompanying statements of income. Portions of the net periodic benefit costs disclosed below have been capitalized as a component of property, plant and equipment.

Pension Plans

The Pension Plans are composed of both a qualified and a non-qualified plan. The qualified pension plan provides substantially all union employees, as well as all non-union employees hired before January 1, 2011, with a retirement benefit. The qualified pension plan is a cash balance pension plan design in which pay-based credits are applied based on service time and interest credits are applied at rates set forth in the plan. For non-union employees, effective January 1, 2011, pay-based credits are based on a combination of service time and age. The non-qualified pension plans provide additional defined pension benefits to certain eligible executives. The funding policy is determined largely by the Company’s rate agreements with the NYPSC. However, the contribution to the qualified pension plan for any year will not be less than the minimum amount required under Internal Revenue Service (“IRS”) regulations. During the years ended December 31, 2018 and 2017, the Company made contributions of approximately $10.3 million and $28.3 million, respectively, to the qualified pension plans. The Company expects to contribute approximately $4.5 million to the Pension Plans during the year ending December 31, 2019.

PBOP Plans

The Company’s PBOP Plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage. The PBOP Plans are funded based on rate agreements with the NYPSC. During the years ended December 31, 2018 and 2017, the Company made contributions of approximately $16.1 million and $44.5 million, respectively, to the PBOP Plans. The Company does not expect to contribute to the PBOP Plans during the year ending December 31, 2019.

Defined Contribution Plan

NGUSA has a defined contribution pension plan that covers substantially all employees. For the years ended December 31, 2018 and 2017, the Company recognized an expense in the accompanying statements of income of $10.3 million and $9.0 million, respectively, for matching contributions.

Net Periodic Benefit Costs

The Company’s total pension cost for the years ended December 31, 2018 and 2017 are $46.9 million and $34.4 million, respectively. The Company recognized an estimated settlement loss of $8.0 million as part of total pension costs during the current fiscal year due to plan payouts that exceeded the threshold as prescribed in ASC 715.

The Company's total PBOP cost for the years ended December 31, 2018 and 2017 are $15.5 million and $39.2 million, respectively.

Amounts Recognized in AOCI and Regulatory Assets

The following tables summarize other pre-tax changes in plan assets and benefit obligations recognized primarily in regulatory assets and accumulated other comprehensive income for the years ended December 31, 2018 and 2017:

	Pension Plans		PBOP Plans	
	Years Ended December 31,		Years Ended December 31,	
	2018	2017	**2018**	2017
	(in thousands of dollars)			
Net actuarial gain	**$ (7,178)**	$ (42,368)	**$ (66,620)**	$ (258,040)
Amortization of net actuarial loss	**(61,127)**	(48,438)	**(17,764)**	(29,346)
Amortization of prior service cost, net	**(2,905)**	(3,123)	**203**	539
Total	**$ (71,210)**	$ (93,929)	**$ (84,181)**	$ (286,847)
Included in regulatory assets	**$ (71,203)**	$ (93,689)	**$ (84,181)**	$ (286,847)
Included in AOCI	**(7)**	(240)	**-**	-
Total	**$ (71,210)**	$ (93,929)	**$ (84,181)**	$ (286,847)

Amounts Recognized in AOCI and Regulatory Assets – not yet recognized as components of net actuarial loss

The following tables summarize the Company's amounts in regulatory assets and other comprehensive income on the accompanying balance sheet that have not been recognized as components of net actuarial loss at December 31, 2018 and 2017:

	Pension Plans		PBOP Plans	
	Years Ended December 31,		Years Ended December 31,	
	2018	2017	**2018**	2017
	(in thousands of dollars)			
Net actuarial loss (gain)	**$ 55,026**	$ 123,331	**$ (36,791)**	$ 47,594
Prior service cost	**7,929**	10,834	**(8,537)**	(8,740)
Total	**$ 62,955**	$ 134,165	**$ (45,328)**	$ 38,854
Included in regulatory assets	**$ 61,800**	$ 133,003	**$ (45,328)**	$ 38,854
Included in AOCI	**1,155**	1,162	**-**	-
Total	**$ 62,955**	$ 134,165	**$ (45,328)**	$ 38,854

The NYPSC's statement of policy requires that prior service costs and gains and losses be amortized over a ten-year period calculated on a vintage year basis. The amount of net actuarial loss and prior service cost to be amortized from regulatory assets during the year ending December 31, 2019 for the Pension Plans is $42.5 million and $2 million, respectively, and net actuarial loss and prior service benefit to be amortized from regulatory assets during the year ending December 31, 2019 for the PBOP Plans is $7.1 million and $0.04 million, respectively.

Reconciliation of Funded Status to Amount Recognized

	Pension Plans		PBOP Plans	
	Years Ended December 31,		Years Ended December 31,	
	2018	2017	**2018**	2017
	(in thousands of dollars)			
Deferred debits	**$ 368,590**	$ 333,783	**$ -**	$ -
Current and accrued liabilities	**(332)**	(340)	**(3,700)**	(5,200)
Other noncurrent liabilities	**(1,233)**	(1,434)	**(271,014)**	(357,644)
Total	**$ 367,025**	$ 332,009	**$ (274,714)**	$ (362,844)

Expected Benefit Payments

Based on current assumptions, the Company expects to make the following benefit payments subsequent to December 31, 2018:

(in thousands of dollars) Years Ending December 31,	Pension Plans	PBOP Plans
2019	$ 180,270	$ 73,143
2020	166,261	75,906
2021	152,247	78,872
2022	142,233	81,885
2023	124,218	84,243
2024 - 2028	443,874	441,676
Total	$ 1,209,103	$ 835,725

Assumptions Used for Employee Benefits Accounting

	Pension Plans		PBOP Plans	
	Years Ended December 31,		Years Ended December 31,	
	2018	2017	**2018**	2017
Benefit Obligations:				
Discount rate	**4.10%-4.50%**	4.30%	**4.10%**	4.30%
Rate of compensation increase	**3.50%**	3.50%	**n/a**	n/a
Expected return on plan assets	**6.00%**	6.25%	**6.25%-6.75%**	6.50% - 6.75%
Net Periodic Benefit Costs:				
Discount rate	**4.30%**	4.25%	**4.30%**	4.25%
Rate of compensation increase	**3.50%**	3.50%	**n/a**	n/a
Expected return on plan assets	**6.25%**	6.25%	**6.50%-6.75%**	6.25% - 6.75%

The Company selects its discount rate assumption based upon rates of return on highly rated corporate bond yields in the marketplace as of each measurement date. Specifically, the Company uses the Hewitt AA Above Median Curve along with the expected future cash flows from the Company retirement plans to determine the weighted average discount rate assumption.

The expected rate of return for various passive asset classes is based both on analysis of historical rates of return and forward-looking analysis of risk premiums and yields. Current market conditions, such as inflation and interest rates, are evaluated in connection with the setting of the long-term assumptions. A small premium is added for active management of both equity and fixed income securities. The rates of return for each asset class are then weighted in accordance with the actual asset allocation, resulting in a long-term return on asset rate for each plan.

Assumed Health Cost Trend Rate

	December 31,	
	2018	2017
Health care cost trend rate assumed for next year		
Pre 65	**7.25%**	6.50%
Post 65	**5.75%**	5.75%
Prescription	**9.75%**	9.50%
Rate to which the cost trend is assumed to decline (ultimate)	**4.50%**	4.50%
Year that rate reaches ultimate trend		
Pre 65	**2028**	2025
Post 65	**2026**	2024
Prescription	**2027**	2025

Plan Assets

The National Grid Retirement Plans Committee is the fiduciary who manages the benefit plan investments to minimize the long-term cost of operating the Plans, with a reasonable level of risk. Risk tolerance is determined as a result of a periodic asset/liability study which analyzes the Plans' liabilities and funded status and results in the determination of the allocation of assets across equity fixed income securities and other investments. Equity investments are broadly diversified across U.S. and non-U.S. stocks, as well as across growth, value, and small and large capitalization stocks. Likewise, the fixed income portfolio is broadly diversified across market segments. Approximately ten percent of the total investment portfolio is approved for investments in private equity, real estate, and infrastructure with the objective of enhancing long-term returns while improving portfolio diversification. For the PBOP Plans, since the earnings on a portion of the assets are taxable, those investments are managed to maximize after tax returns consistent with the broad asset class parameters established by the asset allocation study. Investment performance is reviewed by the National Grid Retirement Plans Committee on a quarterly basis.

The Pension Plan is a trusted non-contributory defined benefit plan covering all eligible represented employees of the Company and eligible non-represented employees of the participating National Grid companies. The PBOP Plans are both a contributory and non-contributory, trusteed, employee life insurance and medical benefit plan sponsored by the Service Company. Life insurance and medical benefits are provided for eligible retirees, dependents, and surviving spouses of the Company.

The target asset allocations for the benefit plans as of December 31, 2018 and 2017 are as follows:

	Pension Plans		Union PBOP Plans		Non-Union PBOP Plans	
	December 31,		December 31,		December 31,	
	2018	2017	**2018**	2017	**2018**	2017
U.S. equities	**17%**	17%	**34%**	34%	**45%**	45%
Global equities (including U.S.)	**7%**	7%	**12%**	12%	**0%**	0%
Global tactical asset allocation	**10%**	10%	**17%**	17%	**0%**	0%
Non-U.S. equities	**6%**	6%	**17%**	17%	**25%**	25%
Fixed income securities	**50%**	50%	**20%**	20%	**30%**	30%
Private equity	**4%**	4%	**0%**	0%	**0%**	0%
Real estate	**4%**	4%	**0%**	0%	**0%**	0%
Infrastructure	**2%**	2%	**0%**	0%	**0%**	0%
	100%	100%	**100%**	100%	**100%**	100%

Fair Value Measurements

The following tables provide the fair value measurements amounts for the pension and PBOP assets:

	December 31, 2018				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in thousands of dollars)		
Pension Assets:					
Cash and cash equivalents	$ -	$ 44,946	$ -	$ 1,273	$ 46,219
Accounts receivable	36,546	-	-	-	36,546
Accounts payable	(87,323)	-	-	-	(87,323)
Convertible securities	-	146	-	-	146
Equity	94,235	-	-	365,661	459,896
Global tactical asset allocation	44,742	-	-	87,647	132,389
Fixed income securities	-	594,280	-	239,539	833,819
Preferred securities	-	5,584	-	-	5,584
Private equity	-	-	-	175,473	175,473
Real estate	-	-	-	76,987	76,987
Other	3,001	-	-	-	3,001
Total	$ 91,201	$ 644,956	$ -	$ 946,580	$ 1,682,737
PBOP Assets:					
Cash and cash equivalents	$ 39,099	$ -	$ -	$ 857	$ 39,956
Accounts receivable	3,014	-	-	-	3,014
Accounts payable	(1,179)	-	-	-	(1,179)
Equity	174,532	-	-	649,540	824,072
Global tactical asset allocation	94,583	-	-	86,054	180,637
Fixed income securities	-	273,292	-	-	273,292
Other	(227)	-	-	-	(227)
Total	$ 309,822	$ 273,292	$ -	$ 736,451	$ 1,319,565

	December 31, 2017				
	Level 1	Level 2	Level 3	Not categorized	Total
			(in thousands of dollars)		
Pension Assets:					
Cash and cash equivalents	$ (488)	$ 41,647	$ -	$ 1,238	$ 42,397
Accounts receivable	40,004	-	-	-	40,004
Accounts payable	(83,920)	(24,917)	-	-	(108,837)
Equity	218,770	(76)	-	416,827	635,521
Global tactical asset allocation	-	-	-	165,989	165,989
Fixed income securities	-	662,715	-	288,717	951,432
Preferred securities	-	7,463	-	-	7,463
Futures contracts	486	-	-	-	486
Private equity	-	-	-	106,422	106,422
Real estate	-	-	-	72,396	72,396
Total	$ 174,852	$ 686,832	$ -	$ 1,051,589	$ 1,913,273
PBOP Assets:					
Cash and cash equivalents	$ 22,278	$ -	$ -	$ 565	$ 22,843
Accounts receivable	2,198	-	-	-	2,198
Accounts payable	(25)	-	-	-	(25)
Equity	278,566	-	-	747,257	1,025,823
Global tactical asset allocation	38,777	-	-	87,186	125,963
Fixed income securities	-	288,258	-	-	288,258
Futures contracts	86	-	-	-	86
Total	$ 341,880	$ 288,258	$ -	$ 835,008	$ 1,465,146

The methods used to fair value pension and PBOP assets are described below:

Cash and cash equivalents: Cash and cash equivalents that can be priced daily are classified as Level 1. Active reserve funds, reserve deposits, commercial paper, repurchase agreements, and commingled cash equivalents are classified as Level 2. Cash and cash equivalents invested in commingled money market investment funds which have net asset value ("NAV") pricing per fund share are excluded from the fair value hierarchy.

Accounts receivable and accounts payable: Accounts receivable and accounts payable are classified as Level 1. Such amounts are short-term and settle within a few days of the measurement date.

Equity and preferred securities: Common stocks, preferred stocks, and real estate investment trusts are valued using the official close of the primary market on which the individual securities are traded. Equity securities are primarily comprised of securities issued by public companies in domestic and foreign markets plus investments in commingled funds, which are valued on a daily basis. The Company can exchange shares of the publicly traded securities and the fair values are primarily sourced from the closing prices on stock exchanges where there is active trading, in which case they are classified as Level 1 investments. If there is less active trading, then the publicly traded securities would typically be priced using observable data, such as bid and ask prices, and these measurements are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For investments in commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, derived from the underlying securities' quoted prices in active markets, and they are excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Global tactical asset allocation: Assets held in global tactical asset allocation funds are managed by investment managers who use both top-down and bottom-up valuation methodologies to value asset classes, countries, industrial sectors, and individual securities in order to allocate and invest assets opportunistically. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, and is excluded from the fair value hierarchy. Investments with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Fixed income securities: Fixed income securities (which include corporate debt securities, municipal fixed income securities, U.S. Government and Government agency securities including government mortgage backed securities, index linked government bonds, and state and local bonds) convertible securities, and investments in securities lending collateral (which include repurchase agreements, asset backed securities, floating rate notes and time deposits) are valued with an institutional bid valuation. A bid valuation is an estimated price at which a dealer would pay for a security (typically in an institutional round lot). Oftentimes, these evaluations are based on proprietary models which pricing vendors establish for these purposes. In some cases there may be manual sources when primary vendors do not supply prices. Fixed income investments are primarily comprised of fixed income securities and fixed income commingled funds. The prices for direct investments in fixed income securities are generated on a daily basis. Prices generated from less active trading with wider bid ask prices are classified as Level 2 investments. Mutual funds with publicly quoted prices and active trading are classified as Level 1 investments. For commingled funds that are not publicly traded and have ongoing subscription and redemption activity, the fair value of the investment is the NAV per fund share, and is excluded from the fair value hierarchy. Investments in commingled funds with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

Private equity and real estate: Commingled equity funds, commingled special equity funds, limited partnerships, real estate, venture capital, and other investments are valued using evaluations (NAV per fund share) based on proprietary models, or based on the NAV. Investments in private equity and real estate funds are primarily invested in privately held real estate investment properties, trusts, and partnerships as well as equity and debt issued by public or private companies. The Company's interest in the fund or partnership is estimated based on the NAV. The Company's interest in these funds cannot be readily redeemed due to the inherent lack of liquidity and the primarily long-term nature of the underlying assets. Distribution is made through the liquidation of the underlying assets. The Company views these investments as part of a long-term investment strategy. These investments are valued by each investment manager based on the underlying assets. The funds utilize valuation techniques consistent with the market, income, and cost approaches to measure the fair value of certain real estate investments. The majority of the underlying assets are valued using significant unobservable inputs and often require significant management judgment or estimation based on the best available information. Market data includes observations of the trading multiples of public companies considered comparable to the private companies being valued. Investments in limited partnerships with redemption restrictions and that use NAV are excluded from the fair value hierarchy.

While management believes its valuation methodologies are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the NAV as a practical expedient could result in a different fair value measurement at the reporting date.

Other Benefits

At December 31, 2018 and 2017, the Company had accrued workers compensation, auto, and general insurance claims which have been incurred but not yet reported ("IBNR") of $12.5 million and $13.2 million, respectively. IBNR reserves have been established for claims and/or events that have transpired, but have not yet been reported to the Company for payment.

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

The following table represents the changes in the Company's AOCI for the years ended December 31, 2018 and 2017:

	Unrealized Gain (Loss) on Available-For-Sale Securities	Pension and Other Postretirement Benefits	Total
	(in thousands of dollars)		
Balance as of December 31, 2016	$ 2,018	$ (692)	$ 1,326
Other comprehensive income before reclassifications:			
Unrecognized net actuarial gain (net of $53 tax expense)	-	85	85
Gain on investment (net of $940 tax expense)	1,621	-	1,621
Amounts reclassified from other comprehensive income (loss):			
Amortization of net actuarial loss (net of $39 tax expense) [1]	-	63	63
Gain on investment (net of $379 tax benefit) [1]	(654)	-	(654)
Net current period other comprehensive income	967	148	1,115
Balance as of December 31, 2017	**$ 2,985**	**$ (544)**	**$ 2,441**
Other comprehensive loss before reclassifications:			
Unrecognized net actuarial loss (net of $25 tax benefit)	-	(69)	(69)
Loss on investment (net of $580 tax benefit)	(1,640)	-	(1,640)
Amounts reclassified from other comprehensive income (loss):			
Amortization of net actuarial loss (net of $27 tax expense) [1]	-	75	75
Gain on investment (net of $273 tax benefit) [1]	(773)	-	(773)
Net current period other comprehensive (loss) income	(2,413)	6	(2,407)
Balance as of December 31, 2018	**$ 572**	**$ (538)**	**$ 34**

[1] Amounts are reported as net other income and deductions in the accompanying statements of income.

11. CAPITALIZATION

Long-term Debt

Long-term debt at December 31, 2018 and 2017 is as follows:

	Interest Rate	Maturity Date	December 31, 2018	December 31, 2017
			(in thousands of dollars)	
Unsecured notes:				
Senior Note	4.88%	August 15, 2019	**$ 750,000**	$ 750,000
Senior Note	2.72%	November 28, 2022	**300,000**	300,000
Senior Note	3.51%	October 1, 2024	**500,000**	500,000
Senior Note	4.28%	October 1, 2034	**400,000**	400,000
Senior Note	4.28%	December 15, 2028	**500,000**	-
Senior Note	4.12%	November 28, 2042	**400,000**	400,000
State Authority Financing - tax-exempt:				
2023	3.23%	December 1, 2023	**69,800**	69,800
2025	3.29%	December 1, 2025	**75,000**	75,000
2026	3.42%	December 1, 2026	**44,700**	50,000
2027	3.45%	March 1, 2027	**25,760**	25,760
2027	3.43%	July 1, 2027	**68,200**	68,200
2027	3.48%	July 1, 2027	**25,000**	25,000
2029	3.43%	July 1, 2029	**115,705**	115,705
Bonds			**3,274,165**	**2,779,465**
Unamortized debt discount			**(11)**	(7)
Total long-term debt			**$ 3,274,154**	$ 2,779,458

The aggregate maturities of long-term debt for the years subsequent to December 31, 2018 are as follows:

(in thousands of dollars) Years Ending December 31,	
2019	$ 750,000
2020	-
2021	-
2022	300,000
2023	69,800
Thereafter	2,154,365
Total	$ 3,274,165

The Company's debt agreements and banking facilities contain covenants, including those relating to the periodic and timely provision of financial information by the issuing entity and financial covenants such as restrictions on the level of indebtedness. Failure to comply with these covenants, or to obtain waivers of those requirements, could in some cases trigger a right, at the lender's discretion, to require repayment of some of the Company's debt and may restrict the Company's ability to draw upon its facilities or access the capital markets. During the years ended December 31, 2018 and 2017, the Company was in compliance with all such covenants.

Debt Authorizations

Since January 12, 2015, the Company had regulatory approval from the FERC to issue up to $1 billion of short-term debt, internally or externally. The authorization was renewed with an effective date of January 11, 2019 for a period of two years that expires on January 10, 2021. The Company had no external short-term debt as of December 31, 2018 and 2017. Refer to Note 15, "Related Party Transactions" under "Notes Receivable from and Notes Payable to Associated Companies ("Intercompany Money Pool")" for short-term debt outstanding to associated companies.

Since May 19, 2016, the NYPSC authorized the Company to issue up to $2.1 billion of incremental long-term debt in one or more transactions through March 31, 2020. The Company can issue up to $429.5 million of the total authorization for optional refunding of existing debt. On November 29, 2018, the Company issued $500 million of unsecured senior long-term debt at 4.28% with a maturity date of December 15, 2028.

State Authority Financing Bonds

The assets of the Company were subject to liens and other charges and were provided as collateral over borrowings of $429.5 million of State Authority Financing Bonds at December 31, 2017. These bonds were issued to secure a like amount of tax-exempt revenue bonds issued by the New York State Energy Research and Development Authority ("NYSERDA"). In September 2018, the Company converted six of the eight series of the State Authority Financing Bonds from a variable rate into a fixed rate. In October 2018, the remaining two series were converted from a variable rate into a fixed rate as well. The fixed rates on the bonds range from 3.23% to 3.48%. During the conversions, the Company was discharged of liens and charges associated with these bonds, and $5.3 million of the $50 million 1986 Series A bond with the maturity date of December 1, 2026 was redeemed. These conversions were accounted for as extinguishments in accordance with ASC 470, "Debt." Prior to conversion, the bonds bore interest at short-term adjustable interest rates (with an option to convert to other rates, including a fixed interest rate) ranging from 0.69% to 5.53% and 0.66% to 4.13% for the years ended December 31, 2018 and 2017, respectively.

Advances from Associated Companies

Since January 2015, the Company had FERC and board authorization to borrow up to $500 million from NGUSA from time to time for working capital needs. The advance is non-interest bearing. At December 31, 2018 and 2017, the Company had no outstanding advance from associated companies.

In June 2009, the Company received board authorization to borrow up to $450 million from NMHI from time to time for working capital needs. At December 31, 2018 and 2017, the Company had no outstanding advance from associated companies.

Dividend Restrictions

The Company's debt and credit arrangements contain various financial and other covenants as described below. The Company was in compliance with all such covenants during the years ended December 31, 2018 and 2017.

The Company is limited by the various rate plans, NYPSC orders, and FERC orders with respect to the amount of dividends the Company can pay. If the Company's total debt exceeds 55% of its total capital excluding goodwill but does not exceed 57%, then the Company will be permitted to pay dividends up to an amount equal to but no greater than 50% of its net income for the previous twelve months until its average total debt for the most recent six month period is less than or equal to 55%. If the Company's total capital exceeds 57% then the Company may not pay dividends until the average total debt for the most recent six months ending is less than or equal to 55%. As long as the bond ratings on the least secure forms of debt issued by the Company and National Grid plc remain investment grade and do not fall to the lowest investment grade rating (with one or more negative watch downgrade notices issued with respect to such debt), the Company is allowed to pay dividends.

The Company's filed rate plan includes a ratemaking capital structure of approximately 52% debt and 48% equity through the combination of long-term debt issuance and dividend payments. In September 2017, the Company paid dividends on common stock of $550 million to NMHI to align the capital structure more closely to its filed rate plan.

Cumulative Preferred Stock

The Company has certain issues of non-participating cumulative preferred stock outstanding which can be redeemed at the option of the Company. There are no mandatory redemption provisions on the Company's cumulative preferred stock. A summary of cumulative preferred stock is as follows:

	Shares Outstanding		Amount		
	December 31,		December 31,		Call
Series	2018	2017	2018	2017	Price
	(in thousands of dollars, except per share and number of shares data)				
$100 par value -					
3.40% Series	**57,524**	57,524	**$ 5,753**	$ 5,753	$ 103.50
3.60% Series	**137,152**	137,152	**13,715**	13,715	104.85
3.90% Series	**95,171**	95,171	**9,517**	9,517	106.00
Golden Share	**1**	1	**-**	-	Non-callable
Total	**289,848**	289,848	**$ 28,985**	$ 28,985	

In connection with the acquisition of KeySpan by NGUSA, the Company became subject to a requirement to issue a class of preferred stock, having one share (the "Golden Share"), subordinate to any existing preferred stock. The holder of the Golden Share would have voting rights that limit the Company's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceeding without the consent of the holder of the Golden Share. The NYPSC subsequently authorized the issuance of the Golden Share to a trustee, GSS Holdings, Inc. ("GSS"), who will hold the Golden Share subject to a Services and Indemnity Agreement requiring GSS to vote the Golden Share in the best interests of NYS. On July 8, 2011, the Company issued the Golden Share with a par value of $1.

The Company did not redeem any preferred stock during the years ended December 31, 2018 or 2017. The annual dividend requirement for cumulative preferred stock was $1.1 million for each of the years ended December 31, 2018 and 2017.

12. INCOME TAXES

Components of Income Tax Expense (Benefit)

	Years Ended December 31,	
	2018	2017
	(in thousands of dollars)	
Current tax expense:		
Federal	**$ 40,408**	$ 118,281
State	**11,590**	25,409
Total current tax expense	**51,998**	143,690
Deferred tax expense (benefit):		
Federal	**8,270**	(10,190)
State	**2,426**	(1,413)
Total deferred tax expense (benefit)	**10,696**	(11,603)
Amortized investment tax credits (1)	**(829)**	(1,788)
Total deferred tax expense (benefit)	**9,867**	(13,391)
Total income tax expense	**$ 61,865**	$ 130,299

(1) Investment tax credits ("ITC") are being deferred and amortized over the depreciable life of the property giving rise to the credits.

	Years Ended December 31,	
	2018	2017
	(in thousands of dollars)	
Total income taxes in the statements of income:		
Income taxes charged to operations	**$ 66,451**	$ 127,418
Income taxes credited to other income (deductions)	**(4,586)**	2,881
Total	**$ 61,865**	$ 130,299

Statutory Rate Reconciliation

The Company's effective tax rates for the years ended December 31, 2018 and 2017 are 23.8% and 33.7%, respectively. The following table presents a reconciliation of income tax expense at the federal statutory tax rate of 21% and 31.6%, respectively, to the actual tax expense:

	Years Ended December 31,	
	2018	2017
	(in thousands of dollars)	
Computed tax	**$ 55,906**	$ 123,875
Change in computed taxes resulting from:		
Equity-based compensation and dividends	**(2,857)**	(3,830)
Investment tax credits	**(1,335)**	(1,788)
State income tax, net of federal benefit	**11,048**	16,292
Temporary differences flowed through	**355**	(291)
Other items, net	**(1,252)**	(3,959)
Total changes	**5,959**	6,424
Total income tax expense	**$ 61,865**	$ 130,299

The Company is included in the NGNA and subsidiaries consolidated federal income tax return and New York unitary state income tax return. The Company has joint and several liability for any potential assessments against the consolidated group.

Tax Reform

On December 22, 2017, the Tax Act was signed into law. The Tax Act includes significant changes to various federal tax provisions applicable to the Company, including provisions specific to regulated public utilities. The most significant changes include the reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018 and the limitation of the net operating loss deduction for net operating losses generated in tax years starting after December 31, 2017 to 80% of taxable income with an indefinite carryforward period. The Tax Act provisions related to regulated public utilities eliminate bonus depreciation for certain property acquired or placed in service after September 27, 2017 and extend the normalization requirements for ratemaking treatment of excess deferred taxes.

On August 3, 2018, the IRS released proposed regulations associated with the expanded depreciation rules enacted as part of the Tax Act. The proposed regulations would enable utilities to claim additional bonus depreciation on property acquired and placed in service between September 28, 2017 and March 31, 2018. The company adopted the guidance in the proposed regulations and revised the impact of the income tax effect of the Tax Act to reflect the additional six months of bonus depreciation.

On December 22, 2017, the Securities Exchange Commission issued Staff Accounting Bulletin ("SAB") 118, which provides guidance on accounting for the effects of the Tax Act. The FASB staff subsequently issued guidance stating that private companies may apply SAB 118 to the financial statements. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements. If a company cannot determine a provisional amount, the company should continue to apply existing accounting guidance for income taxes based on provisions of the tax laws that were in effect immediately prior to the enactment of the Tax Act.

On November 15, 2018, FERC issued a Notice of Proposed Rulemaking (“NOPR”) in which it is proposing to require all public utility transmission providers with transmission rates under an Open Access Transmission Tariff (“OATT”), a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the Tax Act. Specifically, for transmission formula rates, the Commission is proposing to require that public utilities deduct excess Accumulated Deferred Income Taxes (ADIT) from their rate bases and adjust their income tax allowances by amortized excess ADIT. The Commission is also proposing to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information. Additionally, the Commission is proposing to require all public utilities with transmission stated rates to determine the amount of excess and deferred income tax caused by the Tax Act’s reduction to the federal corporate income tax rate and return or recover this amount to or from customers. The company plans to implement the NOPR requirements once it is finalized.

During the period ending December 31,2018, the Company adjusted its remeasurement of federal deferred tax assets and liabilities to the enacted tax rate of 21% and recognized the impact of the Tax Act. The Company recognized a net decrease in its deferred tax liability in the amount of $700 million with $2 million recorded to deferred income tax expense and $702 million recorded as a regulatory deferred tax liability for the refund of excess deferred income taxes to the ratepayers. The resulting measurement of the impact of the Tax Act was a decrease in the deferred tax assets and liabilities in accounts 190, 282, and 283 of $700 million and a tax regulatory liability in account 254 of $950 million. The protected excess ADIT is $607.2 million and unprotected excess ADIT is $92.8 million. The company is not currently amortizing the amounts into rates and an amortization period has not been agreed between the company and the regulator. Once agreed, the excess ADIT will be amortized to account 411 and the unfunded ADIT will be amortized to account 410.

Deferred Tax Components

	Years Ended December 31,	
	2018	2017
	(in thousands of dollars)	
Deferred tax assets:		
Allowance for doubtful accounts	**$ 40,913**	$ 40,869
Environmental remediation costs	**101,708**	98,899
Future federal benefit on state taxes	**24,000**	21,009
Regulatory liabilities - other	**270,022**	261,005
Regulatory tax asset	**226,377**	232,400
Other items	**73,292**	87,137
Total deferred tax assets [(1)]	**736,312**	741,319
Deferred tax liabilities:		
Postretirement benefits and other employee benefits	**51,286**	16,002
Property related differences	**1,684,099**	1,629,931
Regulatory assets - environmental response costs	**86,764**	76,254
Regulatory assets - postretirement benefits	**-**	36,773
Regulatory assets - other	**16,256**	60,551
Other items	**3,276**	4,175
Total deferred tax liabilities	**1,841,681**	1,823,686
Net deferred income tax liabilities	**1,105,369**	1,082,367
Deferred investment tax credits	**13,518**	14,347
Net deferred income tax liabilities and investment tax credits	**$ 1,118,887**	$ 1,096,714

(1) The Company established a valuation allowance for deferred tax assets related to expiring charitable contribution carryforwards in the amounts of $1.3 million and $1.2 million as of December 31, 2018 and December 31, 2017, respectively.

Unrecognized Tax Benefits

The Company adopted the provisions of FASB guidance which clarifies the accounting for uncertain tax positions as modified by FERC Docket AI07-2-000. FASB guidance provides that the financial effects of a tax position shall initially be recognized when it is more likely than not, based on the technical merits, that the position will be sustained upon examination, assuming the position will be audited, and the taxing authority has full knowledge of all relevant information. FERC docket AI07-2-000 issues supplementary guidance requiring entities to continue to recognize deferred income taxes for Commission accounting and reporting purposes based on the difference between positions taken in tax returns filed or expected to be filed and amounts reported in the financial statements. As of December 31, 2018 and December 31, 2017, the Company did not have any unrecognized tax benefits on a FERC basis.

As of December 31, 2018, and 2017, the Company has accrued for interest related to unrecognized tax benefits of $36.0 million and $ 25.7 million, respectively. During years ended December 31, 2018 and 2017 the Company recorded interest expense of $10.3 million and $8.0 million, respectively. The Company recognizes interest related to unrecognized tax benefits in other interest, including affiliate interest and related penalties, if applicable, in other deductions, net, in the accompanying statements of income. No tax penalties were recognized during the years ended December 31, 2018 and 2017.

It is reasonably possible that other events will occur during the next twelve months that would cause the total amount of unrecognized tax benefits to increase or decrease. However, the Company does not believe any such increases or decreases would be material to its results of operations, financial position, or cash flows.

During the period, the Company reached a settlement with the IRS for the tax years ended March 31, 2008 and March 31, 2009. The outcome of the settlement did not have a material impact to its results of operations, financial position, or cash flows. The IRS continues its examination of the next cycle which includes income tax returns for the years ended March 31, 2010 through March 31, 2012. The examination is not expected to conclude in the next fiscal year. The income tax returns for the years ended March 31, 2013 through March 31, 2018 remain subject to examination by the IRS.

During the period, the state of New York concluded its examination of Niagara Mohawk Holdings, Inc. & Combined Affiliates' income tax returns for the years ended March 31, 2009 through March 31, 2012. The examination resulted in a capital tax refund of $3.3 million. The income tax returns for the years ended March 31, 2014 through March 31, 2018 remain subject to examination by the state of New York.

The following table indicates the earliest tax year subject to examination:

Jurisdiction	**Tax Year**
Federal	March 31, 2010
New York	March 31, 2013

13. ENVIRONMENTAL MATTERS

The normal ongoing operations and historic activities of the Company are subject to various federal, state, and local environmental laws and regulations. Under federal and state Superfund laws, potential liability for the historic contamination of property may be imposed on responsible parties jointly and severally, without regard to fault, even if the activities were lawful when they occurred.

The United States Environmental Protection Agency ("EPA"), and the New York State Department of Environmental Conservation ("DEC"), as well as private entities, have alleged that the Company is a potentially responsible party under state or federal law for the remediation of numerous sites. The Company's most significant liabilities relate to former Manufactured Gas Plant ("MGP") facilities formerly owned or operated by the Company. The Company is currently investigating and remediating, as necessary, those MGP sites and certain other properties under agreements with the EPA and the DEC. Expenditures incurred for the years ended December 31, 2018 and 2017 were $8.6 million and $11.8 million, respectively.

The Company estimated the remaining costs of environmental remediation activities were $369.8 million and $359.6 million at December 31, 2018 and 2017, respectively. The Company had a current portion of environmental remediation costs of $30.1 million included in other miscellaneous current and accrued liabilities on the balance sheet at December 31, 2018. These costs are expected to be incurred over approximately 41 years. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered. The Company has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, the Company may seek additional recovery from other insurers and from other potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

By rate orders issued and effective April 1, 2018, the NYPSC has provided an annual rate allowance of $32.1 million ($27.3 million in electric base rates and $4.8 million in gas base rates). Any annual spend above the $32.1 million rate allowance is deferred for future recovery. Previous rate orders have provided for similar recovery mechanisms (with different rate allowances and thresholds). Accordingly, as of December 31, 2018 and 2017, the Company has recorded environmental regulatory assets of $369.8 million and $359.6 million, respectively, and environmental regulatory liabilities of $54.3 million and $82.3 million, respectively.

The Company believes that its ongoing operations, and its approach to addressing conditions at historic sites, are in substantial compliance with all applicable environmental laws. Where the Company has regulatory recovery, it believes that the obligations imposed on it because of the environmental laws will not have a material impact on its results of operations or financial position.

14. COMMITMENTS AND CONTINGENCIES

Operating Lease Obligations

The Company has various operating leases relating to office space. Total rental expense for operating leases included in operation expenses in the accompanying statements of income was $4.4 million and $4.3 million for the years ended December 31, 2018 and 2017, respectively.

The future minimum lease payments for the years subsequent to December 31, 2018 are as follows:

(in thousands of dollars)		
Years Ending December 31,		
2019	$	4,419
2020		4,433
2021		3,116
2022		2,777
2023		2,386
Thereafter		11,363
Total	$	28,494

Purchase Commitments

The Company has several long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment. Additionally, the Company has entered into various contracts for gas delivery, storage, and supply services. Certain of these contracts require payment of annual demand charges, which are recoverable from customers. The Company is liable for these payments regardless of the level of service required from third-parties.

The Company's commitments under these long-term contracts for the years subsequent to December 31, 2018 are summarized in the table below:

(in thousands of dollars) Years Ending December 31,	Energy Purchases	Capital Expenditures
2019	$ 190,070	$ 28,417
2020	165,591	-
2021	131,519	-
2022	116,865	-
2023	116,146	-
Thereafter	466,356	-
Total	$ 1,186,547	$ 28,417

The Company purchases additional energy to meet load requirements from independent power producers, other utilities, energy merchants or the New York Independent System Operator at market prices.

Legal Matters

The Company is subject to various legal proceedings arising out of the ordinary course of its business. The Company does not consider any of such proceedings to be material, individually or in the aggregate, to its business or likely to result in a material adverse effect on its results of operations, financial position, or cash flows.

Nuclear Contingencies

As of December 31, 2018 and 2017, the Company had a liability of $173.0 million and $169.8 million, respectively, recorded in other deferred credits on the balance sheet, for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Policy Act of 1982 provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until the year in which Constellation Energy Group Inc., which purchased the Company's nuclear assets, initially plans to ship irradiated fuel to an approved Department of Energy ("DOE") disposal facility.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository. A Blue Ribbon Commission ("BRC") on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that was planned to be operational in 2025. However, due to continued delays on the part of the DOE, and the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term spent nuclear fuel storage, the Company cannot predict the date at which the DOE will begin accepting spent nuclear fuel.

15. RELATED PARTY TRANSACTIONS

Accounts Receivable from and Accounts Payable to Associated Companies

NGUSA and its affiliates provide various services to the Company, including executive and administrative, customer services, financial (including accounting, auditing, risk management, tax, and treasury/finance), human resources, information technology, legal, and strategic planning, that are charged between the companies and charged to each company.

The Company records short-term receivables from, and payables to, certain of its associated companies in the ordinary course of business. The amounts receivable from, and payable to, its associated companies do not bear interest and are settled through the intercompany money pool. A summary of outstanding accounts receivable from associated companies and accounts payable to associated companies is as follows:

	Accounts Receivable from Associated Companies				Accounts Payable to Associated Companies			
	December 31,				December 31,			
	2018		2017		**2018**		2017	
	(in thousands of dollars)							
Massachusetts Electric Company	**$**	**119**	$	8,365	**$**	**124**	$	-
National Grid Engineering Services, LLC		**6,589**		6,550		**448**		466
NGUSA		**185**		18,851		**4,235**		50,657
NGUSA Service Company		**4,492**		38,142		**117,103**		117,066
Other		**259**		561		**2,680**		775
Total	**$**	**11,644**	$	72,469	**$**	**124,590**	$	168,964

Notes Receivable from and Notes Payable to Associated Companies ("Intercompany Money Pool")

The settlement of the Company's various transactions with NGUSA and certain associated companies generally occurs via the intercompany money pool in which it participates. The Company is a participant in the Regulated Money Pool and can both borrow and invest funds. Borrowings from the Regulated Money Pool bear interest in accordance with the terms of the Regulated Money Pool Agreement. As the Company fully participates in the Regulated Money Pool rather than settling intercompany charges with cash, all changes in the intercompany money pool balance and accounts receivable from associated companies and accounts payable to associated companies balances are reflected as investing or financing activities in the accompanying statements of cash flows. In addition, for the purpose of presentation in the statements of cash flows, it is assumed all amounts settled through the intercompany money pool are constructive cash receipts and payments, and therefore are presented as such.

The Regulated Money Pool is funded by operating funds from participants. NGUSA has the ability to borrow up to $3 billion from National Grid plc for working capital needs including funding of the Regulated Money Pool, if necessary. The Company had short-term intercompany money pool investments of $600.5 million and $182.9 million at December 31, 2018 and 2017, respectively. The average interest rates for the intercompany money pool were 2.2% and 1.4% for the years ended December 31, 2018 and 2017, respectively.

Service Company Charges

The affiliated service companies of NGUSA provide certain services to the Company at their cost. The service company costs are generally allocated to associated companies through a tiered approach. First and foremost, costs are directly charged to the benefited company whenever practicable. Secondly, in cases where direct charging cannot be readily determined, costs are allocated using cost/causation principles linked to the relationship of that type of service, such as number of employees, number of customers/meters, capital expenditures, value of property owned, and total transmission and distribution expenditures. Lastly, all other costs are allocated based on a general allocator determined using a 3-point formula based on net margin, net utility plant, and operations and maintenance expense.

Charges from the service companies of NGUSA, including but not limited to non-power goods and services, to the Company for the years ended December 31, 2018 and 2017 were $390.2 million and $384.6 million, respectively.

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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 Loses 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	2,018,403	(691,699)		
2	Preceding Year Reclassification from Account 219 Net Income	(654,357)	62,708		
3	Preceding Year Changes in Fair Value	1,620,547	85,531		
4	Total (lines 2 and 3)	966,190	148,239		
5	Balance of Account 219 at End of Preceding Quarter/Year	2,984,593	(543,460)		
6	Balance of Account 219 at Beginning of Preceding Quarter/Year	2,984,593	(543,460)		
7	Current Year Reclassifications From Account 219 to Net Income	(772,796)	75,104		
8	Current Year Changes In Fair Value	(1,639,521)	(69,627)		
9	Total (lines 7 and 8)	(2,412,317)	5,477		
10	Balance of Account 219 at End of Current Year	572,276	(537,983)		
11					
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Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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.

Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 74) (i)	Total Comprehensive Income (j)	Line No.
		1,326,704			1
		(591,649)			2
		1,706,078			3
		1,114,429	255,973,372	257,087,801	4
		2,441,133			5
		2,441,133			6
		(697,692)			7
		(1,709,148)			8
		(2,406,840)	198,308,115	195,901,275	9
		34,293			10
				0	11
				0	12
				0	13
				0	14
				0	15
				0	16
				0	17
				0	18
				0	19
				0	20
				0	21
				0	22
				0	23
				0	24
				0	25
				0	26
				0	27
				0	28
				0	29
				0	30
				0	31
				0	32
				0	33
				0	34
				0	35
				0	36
				0	37
				0	38
				0	39

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original	(Mo., Day, Yr.)	
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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)	$12,010,474,229	$9,319,338,435
4	Property Under Capital Leases	0	
5	Plant Purchased or Sold	0	
6	Completed Construction not Classified	554,122,253	487,271,941
7	Experimental Plant Unclassified	0	
8	TOTAL (Enter Total of lines 3 thru 7)	12,564,596,482	9,806,610,376
9	Leased to Others	3,425,127	3,425,127
10	Held for Future Use	0	
11	Construction Work in Progress	438,319,836	375,115,349
12	Acquisition Adjustments	0	
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	13,006,341,445	10,185,150,852
14	Accum. Prov. for Depr., Amort., & Depl.	3,964,093,617	2,980,582,307
15	Net Utility Plant (Enter Total of line 13 less 14)	$9,042,247,828	$7,204,568,545
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service		
18	Depreciation	$3,958,516,026	$2,975,387,283
19	Amort. and Dep. of Producing Natural Gas Land and Land Rights		
20	Amort. of Underground Storage Land and Land Rights		
21	Amort. of Other Utility Plant	4,462,069	4,079,502
22	TOTAL In Service (Enter Total of lines 18 thru 21)	3,962,978,095	2,979,466,785
23	Leased to Others		
24	Depreciation	0	
25	Amortization and Depletion	0	
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)	0	0
27	Held for Future Use		
28	Depreciation	1,115,522	1,115,522
29	Amortization	0	
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)	1,115,522	1,115,522
31	Abandonment of Leases (Natural Gas)		
32	Amort. of Plant Acquisition Adj.	0	
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22, 26, 30, 31 and 32)	$3,964,093,617	$2,980,582,307

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo., Day, Yr.) April 17, 2019	Year of Report December 31, 2018

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
$2,428,883,314				$262,252,480	3
					4
					5
53,655,392				13,194,920	6
					7
2,482,538,706	0	0	0	275,447,400	8
					9
					10
56,908,567				6,295,920	11
					12
2,539,447,273	0	0	0	281,743,320	13
889,411,623	0	0	0	94,099,687	14
$1,650,035,650	$0	$0	$0	$187,643,633	15
					16
					17
$889,029,056				$94,099,687	18
					19
					20
382,567					21
889,411,623	0	0	0	94,099,687	22
					23
					24
					25
0	0	0	0	0	26
					27
					28
					29
0	0	0	0	0	30
					31
					32
$889,411,623	$0	$0	$0	$94,099,687	33

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original	(Mo, Day, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

ELECTRIC PLANT IN SERVICE (Accounts 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

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$0	
3	(302) Franchises and Consents	$6,357,778	
4	(303) Miscellaneous Intangible Plant	1,029,954	239,349
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	7,387,732	239,349
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbo generator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	0	0
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbo generator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	0	0
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Day, Yr) April 17, 2019	December 31, 2018

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

account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Show in a footnote the account 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. In showing the clearance of 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 requirements 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 purchaser, 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			$0	(301)	2
			6,357,778	(302)	3
			1,269,303	(303)	4
0	0	0	7,627,081		5
					6
					7
			0	(310)	8
			0	(311)	9
			0	(312)	10
			0	(313)	11
			0	(314)	12
			0	(315)	13
			0	(316)	14
			0	(317)	15
0	0	0	0		16
					17
			0	(320)	18
			0	(321)	19
			0	(322)	20
			0	(323)	21
			0	(324)	22
			0	(325)	23
			0	(326)	24
0	0	0	0		25
					26
			0	(330)	27
			0	(331)	28
			0	(332)	29
			0	(333)	30
			0	(334)	31
			0	(335)	32
			0	(336)	33
			0	(337)	34
0	0	0	0		35
					36
			0	(340)	37
			0	(341)	38
			0	(342)	39
			0	(343)	40
			0	(344)	41
			0	(345)	42

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
43	(346) Misc. Power Plant Equipment	$1,607,861	$246,109
44	(347) Asset Retirement costs for Other Production	0	
45	(348) Energy Storage Equipment - Production	0	
46	TOTAL Other Production Plant (Enter Total of lines 37 thru 45)	1,607,861	246,109
47	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 46)	1,607,861	246,109
48	3. TRANSMISSION PLANT		
49	(350) Land and Land Rights	103,742,379	4,305,914
50	(351) Energy Storage Equipment - Transmission	0	0
51	(352) Structures and Improvements	48,619,758	248,638
52	(353) Station Equipment	1,148,682,879	128,240,740
53	(354) Towers and Fixtures	120,686,567	811,920
54	(355) Poles and Fixtures	781,652,057	55,018,177
55	(356) Overhead Conductors and Devices	550,678,689	28,470,778
56	(357) Underground Conduit	39,880,702	2,385,930
57	(358) Underground Conductors and Devices	137,248,504	11,289,705
58	(359) Roads and Trails	4,545,322	5,167,071
59	(359.1) Asset Retirement Costs for Transmission Plant	546,264	
60	TOTAL Transmission Plant (Enter Total of lines 49 thru 59)	2,936,283,121	235,938,873
61	4. DISTRIBUTION PLANT		
62	(360) Land and Land Rights	48,409,664	6,608,342
63	(361) Structures and Improvements	48,652,647	1,191,258
64	(362) Station Equipment	762,519,339	51,638,940
65	(363) Storage Battery Equipment - Distribution	0	0
66	(364) Poles, Towers, and Fixtures	1,151,114,304	45,373,473
67	(365) Overhead Conductors and Devices	1,286,817,537	42,967,224
68	(366) Underground Conduit	207,523,756	9,498,328
69	(367) Underground Conductors and Devices	662,615,586	28,369,489
70	(368) Line Transformers	965,539,780	50,989,485
71	(369) Services	499,733,944	12,544,219
72	(370) Meters	151,639,683	22,332,902
73	(371) Installations on Customer Premises	7,594,742	412,109
74	(372) Leased Property on Customer Premises	0	0
75	(373) Street Lighting and Signal Systems	273,609,318	10,896,472
76	(374) Asset Retirement Cost for Distribution Plant	1,690,172	0
77	TOTAL Distribution Plant (Enter Total of lines 62 thru 76)	6,067,460,472	282,822,241
78	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
79	(380) Land and Land Rights		
80	(381) Structures and Improvements		
81	(382) Computer Hardware		
82	(383) Computer Software		
83	(384) Communication Equipment		
84	(385) Miscellaneous Regional Transmission and Market Operation Plant		
85	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
86	TOTAL Transmission and Market Operation Plant (Total line 79 thru 86)	0	0
87	6. GENERAL PLANT		
88	(389) Land and Land Rights	2,341,028	0
89	(390) Structures and Improvements	105,238,361	4,783,795
90	(391) Office Furniture and Equipment	4,954,886	3,669,803
91	(392) Transportation Equipment	8,063,206	0
92	(393) Stores Equipment	64,869	0
93	(394) Tools, Shop and Garage Equipment	45,691,464	3,507,577
94	(395) Laboratory Equipment	12,832,440	321,886
95	(396) Power Operated Equipment	279,275	0
96	(397) Communication Equipment	65,609,663	5,005,620
97	(398) Miscellaneous Equipment	41,707,357	540,179
98	SUBTOTAL (Enter Total of lines 71 thru 80)	286,782,549	17,828,860
99	(399) Other Tangible Property	0	
100	(399.1) Asset Retirement Costs for General Plant	733,058	
101	TOTAL General Plant (Enter Total of lines 98, 99 and 100)	287,515,607	17,828,860
102	TOTAL (Accounts 101 and 106) (lines 5,47,60,77,86,101)	9,300,254,793	537,075,432
103	(102) Electric Plant Purchased (See Instr. 8)		
104	(Less) (102) Electric Plant Sold (See Instr. 8)		
105	(103) Experimental Plant Unclassified		
106	TOTAL Electric Plant in Service (Enter Total of lines 102 thru 105)	$9,300,254,793	$537,075,432

Name of Respondent	This Report Is:	Date of Report	Year of Report		
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ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
$207			1,853,763	(346)	43
			0	(347)	44
			0	(348)	45
207	0	0	1,853,763		46
207	0	0	1,853,763		47
					48
11,997	0		108,036,296	(350)	49
0	0		0	(351)	50
175,338	16,378		48,709,436	(352)	51
5,630,812	(310,183)		1,270,982,624	(353)	52
636,329	460,405		121,322,563	(354)	53
(14,380,049)	(110,141)		850,940,142	(355)	54
907,511	(65,534)		578,176,422	(356)	55
0	0		42,266,632	(357)	56
1,274,534	0		147,263,675	(358)	57
0	0		9,712,393	(359)	58
			546,264	(359.1)	59
(5,743,528)	(9,075)	0	3,177,956,447		60
					61
(1,722)	0	0	55,019,728	(360)	62
256,823	0	0	49,587,082	(361)	63
1,428,000	(54,289)	0	812,675,990	(362)	64
0	0	0	0	(363)	65
4,359,147	(305,748)	0	1,191,822,882	(364)	66
3,103,845	(38,744)	(357,105)	1,326,285,067	(365)	67
1,926,996	(8,484)	0	215,086,604	(366)	68
3,086,115	106,156	0	688,005,116	(367)	69
5,348,443	6,950	0	1,011,187,772	(368)	70
3,644,119	235,045	0	508,869,089	(369)	71
2,043,433	0	0	171,929,152	(370)	72
162,101	0	0	7,844,750	(371)	73
0	0	0	0	(372)	74
7,456,493	7,235	0	277,056,532	(373)	75
0	0	3,676	1,693,848	(374)	76
32,813,793	(51,879)	(353,429)	6,317,063,612		77
					78
				(380)	79
				(381)	80
				(382)	81
				(383)	82
				(384)	83
				(385)	84
				(386)	85
0	0	0	0		86
					87
0	0	0	2,341,028	(389)	88
398,595	(45,541)	0	109,578,020	(390)	89
626,129	45,541	0	8,044,101	(391)	90
0	0	0	8,063,206	(392)	91
4,518	0	0	60,351	(393)	92
1,302,658	0	0	47,896,383	(394)	93
521,859	0	0	12,632,467	(395)	94
0	0	0	279,275	(396)	95
383,550	48,043	0	70,279,776	(397)	96
0	0	0	42,247,536	(398)	97
3,237,309	48,043	0	301,422,143		98
			0	(399)	99
45,728			687,330	(399)	100
3,283,037	48,043	0	302,109,473		101
30,353,509	(12,911)	(353,429)	9,806,610,376		102
				(102)	103
					104
			0	(103)	105
$30,353,509	($12,911)	($353,429)	$9,806,610,376		106

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

1. Report below the information called for concerning electric plant leased to others.

2. In column (c) give the date of Commission authorization of the lease of electric plant to others.

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
1	Mill Street Hydro	Land and Water Rights	2/19/1919	12/14/2026	$104,999
2		Watertown, NY			
3		Authorized by NYS PSC			
4		Case 10150			
5					
6	Hydro Development Group, Inc	Hydroelectric Plant and Land	12/16/1993	12/31/2023	390,790
7		Rights			
8		Theresa, NY			
9		Authorized by NYS PSC			
10		Case 28629			
11					
12	Hydro Development Group, Inc	Hydroelectric Plant and Land	12/16/1993	12/31/2023	415,014
13		Rights, Watertown, NY			
14		Authorized by NYS PSC			
15		Case 28689			
16					
17	Union Falls Hydropower	Hydroelectric Plant and Land	09/15/1986	06/30/2024	410,947
18	Limited Partnership	Rights, Town of Black Brook, NY			
19		Authorized by NYS PSC			
20		Case 28689			
21					
22	Middle Falls Limited Partnership	Hydroelectric Plant and Land	08/19/1988	04/25/2029	514,603
23		Rights, Town of Easton and			
24		Greenwich			
25		Authorized by NYS PSC			
26		Case 88-E-087			
27					
28	South Glens Falls Limited	Water and Land Rights	12/17/1991	09/20/2034	710,562
29		Village of South Glens Falls			
		Case 91-E-1119			
30					
31	Northern Electric Power	Land and Water Rights, Former	12/17/1991	11/20/2035	280,334
32	Company, L.P.	Hudson Falls Hydro Station			
33		Authorized by NYS PSC			
34		Case 91-E-1119			
35					
36	Northern Electric Power	Land and Water Rights, Former	12/17/1991	11/20/2035	597,878
37	Company, L.P.	Moreau Hydro Station			
38		Town of Moreau			
39		Authorized by NYS PSC			
40		Case 91-E-1119			
41					
42					
43					
44					
45					
46					
47	TOTAL				$3,425,127

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corpora	(1) [ ] An Original	(Mo, Day, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

CONSTRUCTION WORK IN PROGRESS-ELECTRIC AND GAS (Account 107)

1. Report below descriptions and balances at end of the year for each projects in process, of construction (107). for Electric, Gas and Common, respectively.
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (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 Each Project for Electric, Gas and Common, respectively (a)	Construction Work in Progress-Electric/Gas (Account 107) (b)
1	Electric	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18	From Insert Page	375,115,349
19	Subtotal	375,115,349
20		
21	Gas	
22		
23		
24		
25		
26		
27		
28		
29		
30	From Insert Page	56,908,567
31	Subtotal	56,908,567
32		
33	Common	
34		
35		
36		
37		
38		
39		
40		
41	From Insert Page	6,295,920
42	Subtotal	6,295,920
43	TOTAL	438,319,836

If applicable, see insert page below

CONSTRUCTION WORK IN PROGRESS-ELECTRIC AND GAS (Account 107)

DISTRIBUTION	
Ohio St - Buffalo River Tunnel/Bore	12,510,848
Collamer Crossing_D_Sub_Work	8,384,694
Sodeman Rd Station - new station -	7,720,118
I&M - NC D-Line OH Work From Insp.	6,923,142
I&M - NE D-Line OH Work From Insp.	6,889,626
I&M - NW D-Line OH Work From Insp.	6,000,291
Buffalo Station 59 Rebuild - Sub	5,533,800
New Two Mile Creek Dist Sub	5,371,855
Lehigh Add 2nd Transformer	4,550,597
East NY-Genl Equip Budgetary Reserv	2,914,629
Pin#2805.32 Route 5s Utica	2,859,135
NC ARP Breakers & Reclosers	2,692,151
Van Dyke Station - New 115/13.2kV s	2,516,796
Cable Replacement - Ntwk Secondary	2,262,273
MV-Poland 62258 Route 8 Reconducto	2,163,994
Buffalo Street Light Cable Replacem	2,094,966
Demand Reduction REV Demonstration	1,807,170
Spectrum Broadband Expansion	1,735,191
NYW Mobile Sub #10 115-5kV/12MVA	1,688,452
New Maple Ave Substation	1,638,250
PS&I Activity Dist Gen NY.	1,633,549
West Hamlin #82 - New TB2 - Install	1,509,624
New 115-13.2kV Mobile Sub #11W	1,508,561
Altamont TB1 Replacement	1,435,555
Kenmore Station 22 Battery Storage	1,424,953
Buffalo Station 122 Rebuild - Sub	1,319,974
Cable Replacement - Ntwk Sec NYE	1,284,171
East NY-Dist-New Bus-Resid Blanket.	1,168,543
Cent NY-Dist-New Bus-Resid Blanket	1,159,363
*Menands 10151 / 52 Relocations	1,140,833
West NY-General-Genl Equip Blanket	1,138,657
Stoner 52 - Mohawk Dr Conversion	1,132,622
West NY-Dist-New Bus-Resid Blanket.	1,117,193
Spare 115kV-13.8kV Transformer NYW	1,111,800
Cent NY-Dist-Damage/Failure Blankt	1,023,879
Two Mile Creek F101151& F68451 Tie	960,499
Recloser Communications - Central	953,154
REV - FEEDER MONITORS	942,274
Sodeman Rd - Feeder Getaways	939,883
INVP 4473-US Con-UNY Voice Upg	924,228
*NR-Higley 92451-NYS Hwy 56-FdrTie	914,651
NE ARP Breakers & Reclosers	899,539
BAT18_Roof	867,586
East NY-Dist-Reliability Blanket.	841,516
RTU M9000 Distribution	818,274
Lysander 29754_Swgr 6 to 52a	802,282
Buffalo Sta 56- upgrade 4 Xfmrs	797,650
Hopkins 253 - Replace Metalclad Gea	781,270
West NY-Dist-Asset Replace Blanket.	778,180
New Cicero Substation DSub	776,489
Cent NY-Dist-Reliability Blanket.	765,614
New Two Mile Creek D-Line	760,712

CONSTRUCTION WORK IN PROGRESS-ELECTRIC AND GAS (Account 107)

Temple Relay repl for Ash St line		745,771
West NY-Dist-New Bus-Comm Blanket.		741,298
Delameter TB1 Replacement		732,951
Cent NY-General-Genl Equip Blanket		716,291
Minor projects		49,104,257
	Subtotal	173,931,624
TRANSMISSION	TRANSMISSION	
Gardenville-Rebuild Line Relocation		13,447,371
Rebuild Huntley Station Asset Separ		13,296,534
NY Inspection Repairs - Capital		9,404,133
Schaghticoke Switching Station		8,590,228
Clay-Teall#10,Clay-Dewitt#3 Recond		7,951,811
Lasher Road Substation		7,910,263
Ohio Street new 115 - 34.5kV sub		6,849,980
Oswego - 115kV & 34.5kV - Rebuild		6,657,163
Gard-Dun 141-142 N Phase Rebuild		6,124,773
Rotterdam - Curry #11 recond		5,325,256
Purchase Spare Transformers		5,137,960
Central Breaker Upgrades - Ash		4,702,151
Albany-Greenbush 1&2 Reconductoring		3,809,749
Rotterdam-Reconfig Bus& add breaker		3,648,314
Ticonderoga- Inst Cap Bank, Rpl OCB		3,428,331
Gardenville Rebuild		3,405,237
Alabama-Telegraph 115 T1040 ACR.		3,207,150
Ballston-Mechanicville 6-34.5kv		3,119,878
W. Ashville substation TxT		2,936,802
Trans Station Failure Budget Blankt		2,516,258
Conductor Clearance - NY Program		2,286,264
I&M - NW Sub-T Line Work From Insp.		2,207,075
Battle Hill - replace 3 OCBs		2,150,817
W. Portland -Sherman 867-34.5kV		2,086,835
CAP OH 5210 NYT1000		2,031,155
Land-Clay-Teall#10,Clay-Dewitt #3		1,897,813
Packard Relays line 191 to 195		1,757,209
Scriba Relay Replacement		1,639,203
Batavia Second 115 kV Cap Bank		1,569,067
Rosa Rd add 115kV Cap Bank		1,550,019
I&M - NE Sub-T Line Work From Insp.		1,440,763
Relocate S. Dow-Poland 865-34.5kV		1,358,423
Mortimer #3 Auto TRF Replace		1,355,410
I&M - NC Sub-T Line Work From Insp.		1,299,810
Telegraph Road TRF #2 Asset Replace		1,208,279
Volney station Relay Replacement		1,160,502
Independence - Physical Security		1,148,226
Golah Cap Bank Installation		1,120,244
Huntley-Lockport 36 37 ACR		1,103,260
Frontier 181 ACR/Recond		1,071,019
Lafayette - Physical Security		1,051,891
TransLine D/F Budget Blanket		1,024,901
Ash St. 115-12kV TRF1 Asset replace		1,006,762
Seneca Reactor 71E asset replace		995,468
Machias - Replace TB#2		928,495

CONSTRUCTION WORK IN PROGRESS-ELECTRIC AND GAS (Account 107)

Ticonderoga 2-3 T5810-T5830 ACR		888,039
Schaghticoke Tap Sw St - Line taps		884,838
Edic: Protection Migration		719,819
Royal (New Harper) TxT Substation		715,772
Schuyler - replace OCBs		710,101
RTUs M9000 protocol upgrades Trans		694,182
Schaghticoke Control House		689,344
345kV Laminated Cross-arm-Program		670,513
GE-Geres Lock 8 T2240 Reconductor		645,843
Breaker T Repl Program 4-69kV NYW		640,824
Collamer Crossing_115kV_Line_TAP		635,434
Woodard - Replace three OCBs		627,498
Amsterdam-Rotterdam3/4 Relocation		627,050
Rotterdam Breaker Replacement		607,163
W. ASHVILLE SUB CONTROL HOUSE		600,315
Elm St Relief_Add 4th Xfer		598,161
NYISO Comm Protocols Support		574,794
WD - Install ScadaMates on the 301		573,478
Rotterdam - Add Reactors LN19/20		561,557
Dunkirk Rebuild		556,594
Callanan Tap - Rebuild exist 34.5ln		538,563
Feura Bush Relay Replacement		520,496
Oswego: 115kV Control House		517,213
BatteryRplStrategyCo36TxT		504,599
Lasher Rd Transmission Line		444,610
Minor Projects		27,518,673
	Subtotal	201,183,725
	Subtotal Electric	**375,115,349**
GAS		
CI Main Replace < 10"-UNY		17,703,449
Growth reinforce - Proactive-UNY		3,417,124
Alplaus Station Rebuild		3,388,673
Pres Reg Facil - proactive-UNY		2,972,315
CNG Facility - UNY		2,712,269
Rebuild GRS 824-043 Elton & Salina		2,454,665
Albany Loop 16" transmission		1,939,063
System Telemetry & Control - UNY		1,861,825
Farm Tap- UNY.		1,733,963
PL 31: Onondaga Creek HDD		1,716,320
PL34-Replace 3 miles of 8 inch st		1,323,730
Cent NY-Gas-Repl Mtr Sm-NM Blanket		1,251,961
Remote Control Valve Program UNY		1,205,262
Gas Planning - Reliability-UNY.		1,184,705
React Main & Serv Work Nonleak-UNY.		1,137,062
New Bus - Res-UNY		1,020,964
Minor Projects		9,885,217
	Subtotal	**56,908,567**

CONSTRUCTION WORK IN PROGRESS-ELECTRIC AND GAS (Account 107)

COMMON	
ROM19_Roof Replacement	1,170,989
NIMO - Fleet Tools & Equip	941,270
Airplane Avionics Upgrade	278,031
HCB18_Roof	211,801
GLV15_Master Plan for Renovations	181,275
SOC18_Cooling Tower Replacement	169,353
SOC18_Heat Pump Replacement	136,589
AIR15_Hanger Renovations	136,288
General Fleet Equip & Tools - 5210	104,370
Minor Projects	2,965,954
Subtotal	**6,295,920**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Day, Yr) April 17, 2019	December 31, 2018

CONSTRUCTION OVERHEADS ELECTRIC, GAS AND COMMON

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.

2. On page 218 furnish information concerning construction overheads, for electric, gas and common operations respectively.

3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 218, the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc., which are directly charged to construction, for electric, gas and common operations respectively.

4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs for electric, gas and common operations respectively.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Electric	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18	From Insert Pages	69,664,475
19	Subtotal	$69,664,475
20	Gas	
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31	From Insert Pages	12,695,613
32	Subtotal	$12,695,613
33	Common	
34	Pension Burden	$15,837
35	Other Post Retirement SFAS 106 OPEB	6,305
36	Other Post Employment SFAS 112 Benefits	409
37	Payroll Taxes Burden	16,447
38	Healthcare	25,905
39	Group Insurance	1,293
40	401K Match Burden Thrift	8,862
41	Variable Pay Management Incentive Comp	23,973
42	Variable pay Non Management Gainsharing	2,289
43	Time Not Worked	29,215
44	Workers' Compensation Burden	1,902
45	Subtotal	$132,437
46	TOTAL	$82,492,525

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Day, Yr) April 17, 2019	December 31, 2018

CONSTRUCTION OVERHEADS ELECTRIC, GAS AND COMMON

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.

2. On page 218 furnish information concerning construction overheads, for electric, gas and common operations respectively.

3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 218, the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc., which are directly charged to construction, for electric, gas and common operations respectively.

4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs for electric, gas and common operations respectively.

Line No.	Description of Overhead (a)		Total Amount Charged for the Year (b)
	Electric		
1	**Distribution**		
2	Pension Burden		4,807,151
3	Other Post Retirement SFAS 106 OPEB		3,625,322
4	Other Post Employment SFAS 112 Benefits		536,236
5	Payroll Taxes Burden		5,553,766
6	Healthcare		9,239,203
7	Group Insurance		375,695
8	401K Match Burden Thrift		2,278,766
9	Variable Pay Management Incentive Comp		907,937
10	Variable Pay Non Management Gainsharing		2,543,768
11	Time Not Worked		11,635,226
12	Workers' Compensation Burden		1,140,970
13	Stores Handling Burdens		6,649,812
14	Supervision & Admin		(6,541)
15		Subtotal	49,287,311
16	**Transmission**		
17	Pension Burden		2,061,375
18	Other Post Retirement FAS 106 OPEB		1,334,146
19	Other Post Employment FAS 112 Benefits		188,287
20	Payroll Taxes Burden		2,330,762
21	Healthcare		3,812,506
22	Group Insurance		161,931
23	401K Match Burden Thrift		1,019,490
24	Variable Pay Management Incentive Comp		1,211,257
25	Variable pay Non Management Gainsharing		854,332
26	Time Not Worked		4,699,001
27	Workers' Compensation Burden		431,498
28	Stores Handling Burdens		2,273,606
29	Supervision & Admin		(1,027)
30		Subtotal	20,377,164
31			
32		**Subtotal Electric**	**69,664,475**
33	**GAS**		
34	Pension Burden		1,274,957
35	Other Post Retirement SFAS 106 OPEB		990,745
36	Other Post Employment SFAS 112 Benefits		153,443
37	Payroll Taxes Burden		1,505,467
38	Healthcare		2,503,245
39	Group Insurance		104,423
40	401K Match Burden Thrift		620,028
41	Variable Pay Management Incentive Comp		162,104
42	Variable Pay Non Management Gainsharing		702,486
43	Time Not Worked		3,151,872
44	Workers' Compensation Burden		320,219
45	Stores Handling Burdens		1,206,783
46	Supervision & Admin		(159)
47		**Subtotal**	**$12,695,613**

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc. the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned (Paper Copy Only).

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant Instructions 3(17) of the U. S. of A., if applicable.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

Description of Each Construction Overhead for Electric, Gas and Common, respectively

Construction Overheads consist of Burdens and Capital Overhead charges that get allocated to projects monthly. See below for a discussion of Burdens and Construction Overheads.

Burdens:

The development of the burden rate is conducted using historical data from the SAP GL. The cost elements comprise the cost base for the allocation formula. Once established, the burden rate gets loaded into SAP for monthly allocation.

401K Match Burden Thrift:

Costs for Company 401K match are allocated to construction on the basis of direct labor charged thereto.

Other Post Retirement SFAS 106 OPEBS and Pension Burden:

Costs for Other Post Retirement benefits and Pension Costs are allocated to construction on the basis of direct labor charged thereto.

Group Insurance, Healthcare, Workers' Compensation Burden:

Costs consisting of Group Life,Workers Compensation Insurance and Hospitalization,Surgical and Medical Insurance are charged to construction on the basis of direct labor charged thereto.

Payroll Taxes Burden:

Costs for Payroll Taxes are allocated to construction on the basis of direct labor charged thereto.

Variable Pay Management Incentive Compensation Burden:

Costs for Incentive Compensation are allocated to construction on the basis of direct labor charged thereto.

Paid Time Not Worked:

Costs for paid absence time such as holidays,company sickness time,etc.,are allocated to costruction on the basis of direct labor charged thereto.

Variable Pay Non Management Gainsharing Burden:

Costs for Variable Pay Non-Mgmt Gainsharing are allocated to construction on the basis of direct labor charged thereto.

Stores Handling:

This burden represents a percentage applied to each Materials and Supplies issue withdrawn from stock and represent the costs incurred in operating various storerooms. These handling charges include purchase,storage,handling,and distribution of materials and supplies.

Supervision and Administrative Burden (S&A):

Supervision and Administrative Burden (S&A): A monthly accrual for operating company back office charges supporting employees such as Accounting, Finance, Human Resources, Information Technology, Facilities, Legal, etc. to fully load intercompany or billable charges to 3rd party orders. S&A is a labor based burden with the offset charged to revenue.

Capital Overhead Clearing:

Is a pool of costs representing functions that provide direct support of the construction program, such as Construction Supervision, Engineering and Plant Accounting. Direct charging labor and related support expenditures to each individual work order is not always practical or cost effective to do so. This is because of the tremendous volume of work orders that are supported by these functions every month. In those instances, where approval has been obtained by the Plant Accounting department, the use of the Capital Overhead Clearing account is an approved means by our Regulators of capitalizing direct support costs.

FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ratio (Percent) (c)	Cost Rate Percentage (d)
1	Average Short-Term Debt	0		
2	Short-Term Interest	0		2.21%
3	Long-Term Debt	2,779,458,284	46.67%	3.75%
4	Preferred Stock	28,984,701	0.49%	3.66%
5	Common Equity	3,147,085,726	52.84%	9.30%
6	Total Capitalization	5,955,528,711	100.00%	
7	Average Construction Work in Progress Balance	333,627,604		

2. Gross Rate for Borrowed Funds

=> s(S/W)+d(D/D+P+C)(1-S/W)= 1.86%

3. Rate for Other Funds

=> (1-SW)[p(P/D+P+C)+c(C/D+P+C)] = 4.93%

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - => 1.86%

b. Rate for Other Funds - => 4.93%

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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 (d), 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	$2,816,981,648	$2,815,898,669	$0	$1,082,979
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	222,614,321	222,614,321		
4	(403.1) Depreciation Expense for Asset Retirement Costs	0			
5	(413) Exp. of Elec. Plt. Leas. to Others	32,543			32,543
6	Transportation Expenses-Clearing	0			
7	Other Clearing Accounts	0			
8	Other Accounts (Specify):	0			
9	Common	6,992,236	6,992,236		
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	229,639,100	229,606,557	0	32,543
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	30,297,506	30,297,506		
13	Cost of Removal	55,033,936	55,033,936		
14	Salvage (Credit)	10,847,663	10,847,663		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	74,483,779	74,483,779	0	0
16	Other Dr. or Cr. Items (Describe):	9,015,480	9,015,480		
17	Transfers	(4,649,644)	(4,649,644)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Total of lines 1, 10, ~~9, 14,~~ 15, 16 and 18)	$2,976,502,805	$2,975,387,283	$0	$1,115,522
	Section B. Balances at End of Year According to Functional Classifications				
20	Steam Production	$62,411	$62,411		
21	Nuclear Production	0			
22	Hydraulic Production - Conventional	1,115,180			1,115,180
23	Hydraulic Production - Pumped Storage	342			342
24	Other Production	109,108	109,108		
25	Transmission	652,081,061	652,081,061		
26	Distribution	2,131,907,250	2,131,907,250		
27	Regional Transmission and Market Operations	0	0		
28	General	191,227,453	191,227,453		
29	TOTAL (Enter Total of lines 20 thru 28)	$2,976,502,805	$2,975,387,283	$0	$1,115,522

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NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service (line 44), or (2) other nonutility property (line 45).

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	Scandaga Reservoir Assessments - Hadley and Stillwater	$1,245,051		$1,245,051
2	Development, E-145 (Town of Hadley)			
3				
4	Former Fort Edward Hydro Plant, E-309 (Village of Fort Edward)	741,634		741,634
5	Transferred to A/C 121 in January, 1979			
6				
7	Land Future Tonawanda Steam Station Transmission Line	326,874		326,874
8	Right of Way, 1-114 (City of North Tonawanda)			
9				
10	Rome Sentinel Purchase .54 Acres of Land (City of Rome)	179,444		179,444
11				
12	Town of Bellmont	5,462,563		5,462,563
13				
14	City of Saratoga Springs	1,037,807		1,037,807
15				
16	Town of Hadley	225,616		225,616
17				
18	Town of Amherst	308,650		308,650
19				
20	City of Fulton	126,673		126,673
21				
22	Town of Watertown	401,659		401,659
23				
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39				
40				
41	Minor Item Previously Devoted to Public Service	1,644,394		1,644,394
42	Minor Items-Other Nonutility Property	(138,363)		(138,363)
43	TOTAL	$11,562,002	$0	$11,562,002

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INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investment in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Subtotal 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 is 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				
2				
3				
4	NM Properties, Inc.	1993-1997		
5	Common Stock, 3075 shares, $1 par value			3,075
6	Paid-in Capital			3,308,818
7	Unappropriated Undistributed Subsidiary			(2,533,287)
8				
9				
10				
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42	TOTAL Cost of Account 123.1		TOTAL	$778,606

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INVESTMENT 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 from investments, including such revenues from 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 for 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
				3
				4
		3,075		5
		3,308,818		6
(10,759)	(34,040)	(2,578,086)		7
				8
				9
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				41
($10,759)	($34,040)	$733,807	$0	42

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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 debits 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)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	34,132,374	32,655,176	Electric/Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	4,705,318	4,501,679	Electric
9	Distribution Plant (Estimated)	8,215,485	7,859,931	Electric/Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other			
12	TOTAL Account 154 (Total of lines 5 thru 11)	$47,053,177	$45,016,786	
13	Merchandise (Account 155)			
14	Other Material and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20				
21	TOTAL Materials and Supplies (per Balance Sheet)	$47,053,177	$45,016,786	

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING THE YEAR Account Charged (d)	WRITTEN OFF DURING THE YEAR Amount (e)	Balance at End of Year (f)
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20	TOTAL	$0	$0		$0	$0

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (Account 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 Account 182.2, and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING THE YEAR Account Charged (d)	WRITTEN OFF DURING THE YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24	Electric Transmission Development Costs (Authorized in case 17-E-0238 effective April 2018);					
25	Amortization: April, 2018 to March, 2021	4,615,000	-	407	1,153,750	3,461,250
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48						
49	TOTAL	$4,615,000	$0		$1,153,750	$3,461,250

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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.
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.
8. Report Data on a year-to-date basis.

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	ALPS HVDC SRISA Q448	1,240	174	(19,851)	174
3	NA Trans Q550 SRIS Dysinger II		174	(3,134)	174
4	NA Trans Q549 SRIS Nia-Dissin		174	(2,099)	174
5	NA Q548 SRISA Dysinger-Stolle		174	(7,238)	174
6	NextEra Energy NY Q537 SWA	5,128	174		174
7	NextEra Energy NY Q538 SRIS	5,788	174		174
8	NextEra Energy NY Q539 SRIS	5,932	174		174
9	NextEra Energy NY Q539 SWA	214	174		174
10	NA Trans Q556 SIS & SWA	12,884	174	(12,884)	174
11	NA Trans Segment B Q559 SIS & SWA	338	174	(338)	174
12	NA Trans Segment B Q559 SIS & SWA	8,397	174	(12,677)	174
13	NA Trans Segment A Q558 SIS & SWA	73	174		174
14	NA Trans Segment A Q558 SIS & SWA	3,802	174		174
15	NA Trans Segment A Q557 SIS & SWA	2,409	174		174
16	NA Trans Segment A Q555 SIS & SWA	2,375	174		174
17	HP Hood LLC Q601 FESA & SWA	5,365	174	(13,215)	174
18	NA Trans Q414 Segment B SWA	5,608	174		174
19	Q543- National Grid- Segment B - SISA	601	174		174
20	Q543- National Grid- Segment B - SWA	9,984	174		174
21	**Generation Studies**				
22	Arkwright Q421---SWA	9,454	174		174
23	Erie Power Facilitiy Study SWA Q440	16	174	(176,757)	174
24	Dunkirk Unit 2 Q523 SRISA	1,127	174	(992)	174
25	Dunkirk Unit 3 & Unit 4 SRISA	255	174	(992)	174
26	Roaring Brook Q546 FESA	1,007	174	(2,608)	174
27	Great Valley Solar Q534 FESA	4	174		174
28	Galloo Island Wind Farm Q468 SRISA	259	174	(1,008)	174
29	Double Lock Solar Q563 FESA	726	174	(6,335)	174
30	Atlantic Wind, LLC Q560 FESA	39,098	174		174
31	Tayandenega Solar, Q565 FESA	776	174	(7,888)	174
32	Casadaga Wind Q387 FSA-SWA	131,711	174	(149,120)	174
33	Hidden Meadow Q562 FESA		174	(339)	174
34	Caledonia I Q585 FESA (AVON)	14,017	174	(23,403)	174
35	Q514 Empire Wind SRIS & SWA		174	(8,252)	174
36	North Ridge Wind Q526 SIS		174	(9,665)	174
37	North Ridge Wind Q526 SWA		174	(623)	174
38	Q574 - Mad River Wind - FESA	298	174	(9,574)	174
39	Q523 Dunkirk Unit 2 FSA	14,534	174	(35,570)	174
40	Q524 Dunkirk Unit 3-4 FSA	11,717	174	(24,057)	174

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Transmission Service and Generation Interconnection Study Costs

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	Q542-National Grid Seg A Edic SWA	6,985	174		174
3	Cedar Rapids Transmission Upgrade Q430	27,910	174	(75,426)	174
4	New Scotland Power Express Q631 SRIS	5,325	174		174
5	Q540-Edic PV SWA/SRIS Study Agmt	729	174	(3,987)	174
6	EDIC Rampo Q541 SWA/SRIS	657	174	(3,652)	174
7	Q595 North Park Energy FESA & SWA- SW Energy Storage	9,876	174	(14,709)	174
8	Q638 FESA & SWA Empire State Holdings	14,210	174	(9,646)	174
9	Q613 Sugar Maple FESA/SWA OneEnergy	11,305	174	(12,160)	174
10	Q632_Alps-Berkshire SISA & SWA	2,008	174	(1,083)	174
11	Q595 North Park Energy SRIS	2,836	174		174
12	ITC Q684 FSA-SWA	41,484	174	(33,029)	174
13	BEC Energy Storage Project FES Q707	1,123	174		174
14	BEC Energy Storage Project FES Q708	2,021	174	(2,021)	174
15	KCE NY6 Project Q759 FESA	725	174		174
16	HP Hood LLC Q601 FSA	285	174		174
17					
18					
19					
20					
21	**Generation Studies**				
22	Q511 Ogdensburg Generation SWA for FSA	9,914	174	(51,172)	174
23	Q571 Heritage Wind FESA Study	895	174	(15,562)	174
24	Q596 Alle Catt II Wind - SRIS	6,695	174	(13,179)	174
25	Q494 Alabama Wind SWA for FSA	59,062	174	(83,413)	174
26	Q468 Galloo Wind SWA for FSA	48,839	174	(72,242)	174
27	Q512 Northbrook Lyons SWA for FSA	23,016	174	(21,974)	174
28	Franklin Solar FESA Agreement Q624	1,217	174	(1,217)	174
29	Ball Hill Wind SWA for FSA Q505	80,274	174	(99,604)	174
30	Sun East -Hills Solar FESA Q581	8,834	174	(12,202)	174
31	Watkins Rd Solar Q568 SWA	2,928	174		174
32	Q534 Great Valley Solar SRISA		174	(7,222)	174
33	Allegany Wind SRIS SWA	23,442	174		174
34	Flint Mine Solar Q637 FESA & SWA	22,200	174	(22,806)	174
35	Johnson Solar FESA Eng. Study Q600	3,328	174	(7,971)	174
36	Albany County Solar Q598 - SRIS	4,792	174	(8,252)	174
37	Albany County Solar-Hecate Q570 - SRIS	4,043	174	(7,772)	174
38	High River Solar Q618 SRIS	14,479	174		174
39	East Point Solar Q619 SRIS	1,764	174	(2,185)	174
40	Sunny Knoll Solar Q582 SRIS	6,065	174		174

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Transmission Service and Generation Interconnection Study Costs

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	Woodruff Solar SRIS Q#610	3,146	174		174
23	Tayandenega Solar - SRIS Q#565	10,298	174		174
24	Double Lock Solar - SRIS Q#563	10,061	174		174
25	Rock District Solar - SRIS Q#564	6,285	174		174
26	Tribes Hill Solar - SRIS Q#567	5,575	174	(7,298)	174
27	North Country (Boonville) Solar Q589 FSA	6,350	174	(13,780)	174
28	Sky High Solar Project Q545 SRIS	1,837	174	(3,543)	174
29	Mohawk Solar Project Q616 SRIS	6,834	174		174
30	Franklin Solar FESA Agreement Q624	1,217	174	(1,217)	174
31	Johnson Solar FESA Eng. Study Q600	3,328	174	(7,971)	174
32	Franklin Solar SRIS Q624	5,007	174		174
33	Heritage Wind SRIS Q571	8,504	174	(8,504)	174
34	Roaring Brook Wind Q546 SISA/SWA	9,542	174	(9,542)	174
35	Admiral Wind FESA/SWA Q655	16,310	174	(15,545)	174
36	Mistral Wind FESA/SWA Q657	12,607	174	(11,863)	174
37	Liberty Dr. Solar Project Q660	4,487	174		174
38	Arkwright Wind Farm FSA Q421	25,131	174		174
39	Grissom Solar SWA-FES Q682	8,928	174	(8,230)	174
40	West Point LLC HVDC FES Q615	7,512	174		174

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Transmission Service and Generation Interconnection Study Costs

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	Atlantic Wind Q560 Deer River SRIS	3,233	174		174
23	Q574 Mad River Wind SRIS/SWA	556	174		174
24	Alder Creek Sola Q709 FESA	5,366	174		174
25	Johnson Solar Q600 SIS	2,440	174		174
26	York Solar Q725 FES	7,092	174		174
27	Niagara Falls Solar Q726 FES	1,087	174	(1,087)	174
28	Chaumont Solar Project LFIP Q705	1,104	174	(1,104)	174
29	Horseshoe Solar FESA Q710	13,221	174		174
30	North Country (Boonville) Solar Q589 SIS	4,648	174		174
31	Lyonsdale Solar Q723 FES	3,872	174		174
32	Machias Solar LLC Q732 FES	1,690	174		174
33	Arcade Solar LLC Q733 FES	412	174		174
34	Sun East -Hills Solar SRIS Q581	2,943	174		174
35	Cortland Energy Center Q718 FESA	3,263	174		174
36	East Light Energy Center Q719 FESA	6,294	174		174
37	Excelsior Energy Center Q721 FESA	167	174		174
38	Hecate Cody Road Wind Q739 SRIS	2,194	174		174
39	ELP Ticonderoga Solar Q734 FESA	4,651	174		174
40	ELP Stillwater Solar Q735 FESA	5,314	174		174

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Transmission Service and Generation Interconnection Study Costs

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	Q638 Empire State SRIS/SWA	2,717	174		174
23	Coldwater Solar Project Q662 FESA	8,414	174		174
24	Skyline Solar Q670 FES	3,158	174	(3,158)	174
25	Clay Solar Q669 FES	3,760	174	(3,172)	174
26	Martin Solar Q666 FES	4,726	174		174
27	Bakerstand Solar Q667 SIS	4,420	174		174
28	Bear Ridge Solar Q704 SRIS/SWA	10,312	174		174
29	Quiet Meadows Solar Q729 FESA	2,298	174	(1,578)	174
30	Invenergy #3 Wind Q531 FSA	69,487	174	(55,666)	174
31	Q596 Alle Catt II Wind - FSA	39,215	174	(22,456)	174
32	Easton Solar 1 Project Q730 FES	3,898	174		174
33	Easton Solar II Project Q731 FES	3,897	174		174
34	Grissom Solar II Q748 FESA	1,263	174		174
35	Goldenrod Solar Q752 FES	1,021	174		174
36	Blue Star Solar Q753 FES	695	174	(694)	174
37	Granada Solar Q757 Monarda FES	1,089	174		174
38	Sky High Solar FSA Q545	15,722	174	(21,646)	174
39	Nextera Empire State Q545A FSA	19,591	174	(10,042)	174
40	Admiral Wind SRIS Q655	162	174		174

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Transmission Service and Generation Interconnection Study Costs

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	Mistral Wind SRIS Q657	364	174		174
23	Q534 Great Valley Solar FSA	994	174		174
24	Tracy Energy Solar Q774 FES	360	174		174
25	Skyline Solar Q670 SRIS	48	174		174
26	Martin Solar Q666 SRIS	7,093	174		174
27	Clay Solar Q669 SIS	1,039	174		174
28	Q772 Hollyhock Solar Proj. FES	19,878	174		174
29	Q773 Charboneau Solar Proj. SIS	1,353	174		174
30	Cicero Solar Project Q763 FESA	1,976	174		174
31	Mistral Wind 2 Project Q771 FES	286	174		174
32	Q613 Sugar Maple SRIS/SWA OneEnergy	4,102	174		174
33	Q722 Gardner Capital FESA/SWA	256	174		174
34	East Point Solar Q619 FSA	447	174		174
35	Q570 Albany County Solar FSA	1,044	174		174
36	Q598 Albany County Solar FSA	1,044	174		174
37	Grissom Solar Q682 SIS	72	174		174
38					
39					
40					

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original	(Mo, Day, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for account 182.3 or amounts less than $100,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in a footnote, for each line item, the regulatory citation where authorization for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	Credits: Account Charged (d)	Credits: Amount (e)	Balance at End of Year (f)
1	Regulatory Tax Asset (FAS 109)	194,316,993	23,935,237	190/282/283	218,252,230	-
2	NY Energy Highway Transmission Dev. Costs					-
3	Deferred Environmental Restoration Costs	359,631,707	18,850,657	253	8,636,881	369,845,483
4	Storm Fund - Deficit	114,401,845	56,159,416	254/456	164,340,818	6,220,443
5	Revenue Decoupling - Electric	15,949,710	11,574,445	419/456	27,524,155	-
6	Asset Retirement Obligation Regulatory Asset	13,952,984	804,827	108/403/411	1,085,024	13,672,787
7	Gas Adjustement Clause	34,851,812	222,391,245	804	230,955,459	26,287,598
8	Gas Futures - Gas Supply	2,952,652	3,858,290	245/253	5,695,391	1,115,551
9	Electric Swaps - Electric Supply	26,359,388	114,889,725	244	141,249,113	-
10	Transportation Adjustment Clause Imbalance Surcharge		94,209			94,209
11	Medicare Act tax benefit deferral	3,230,756		254	2,430,579	800,177
12	Commodity Timing Impact	18,300,067	38,219,194	254/456	55,482,509	1,036,752
13	Clean Energy Standard - RECs, ZECs, ACP	1,709,582	42,354,565	555	42,455,762	1,608,385
14	Interim Gas EE Def		3,994,862	254/431	121,370	3,873,492
15	FAS158-Pension	133,002,964	23,769,015	184/253/926	94,972,196	61,799,783
16	FAS158-OPEB	38,854,338	51,807,646	184/253/926	90,661,984	-
17	Deferral Summary Case 10-E-0050	3,149,393		254	2,244,877	904,516
18	Merchant Function Charge - Electric	214,805	10,820	254/456	225,625	-
19	RDM Revenue Decoupling - Gas	2,467,511	75,547	254/419/495	2,543,058	-
20	Excess AFUDC - Electric Plant in Service	92,806	1,438	407	18,679	75,565
21	Electric Plant in Service Excess AFUDC	399,976	1,639	407	21,310	380,305
22	State Regulatory Asset (FAS 109)	1,583,353		254	1,583,353	-
23	80/20 Revenue Sharing Mechanism		1,258,194	495	397,956	860,238
24	NIMO-Merchant Function Charge - Gas	308,818	200,498	495	509,316	-
25	Pension Exp Deferred	11,326,665	4,808,603	254/926	9,729,776	6,405,492
26	OPEB Expense Deferred	2,202,859	3,754,431	254/926	5,957,290	-
27	Incentive Return on Retirement Funding	34,491		254	25,577	8,914
28	Gas Millenium Fund Deferral	132,957		254	132,957	-
29	NYPA Residential Hydropower Benefit Reconciliation		1,626,236	456	1,626,236	-
30	Legacy Transition Charge	1,992,909	7,458,161	456	8,940,448	510,622
31	Electric Supply Reconciliation Mechanism	3,788,073	83,401,630	456	78,444,222	8,745,481
32	REV Demonstration Projects - Incremental Cap	64,531	215,249	254/456	83,844	195,936
33	REV Demonstration Projects - Incremental O&M	4,880,044	2,428,327	254/456	2,347,900	4,960,471
34	Deferred Community Carring Charges Elec	48,097,948	38,327,948	254/419/431	86,425,896	-
35	Deferred Community Carring Charges Gas	1,160,078	143,229	182/419	1,303,307	-
36	Enhanced SBC Program Deferral - Elec		12,755,322	456	22,602	12,732,720
37	Vegetation Management Deferral	16,159,190		254	11,519,519	4,639,671
38	Dunkirk Settlement Deferral	57,000,000		254	40,634,482	16,365,518
39	Demand Response Programs Deferral		1,658,957	254	10,927	1,648,030
40	LED Facility Revenue/Charge Deferral	68,109	39,747	456	78	107,778
41	LED Dist Lost Devivery Revenue Deferral	47,520	30,299	456	54	77,765
42	LED Cost of Removal (COR) Deferral	3,264	176,168	456	3,264	176,168
43	Rate Case Expens - Electric	744,516	114,058	928	395,233	463,341
44	Rate Case Expense - Gas	609,149	93,320	928	317,850	384,619
45	From Insert Page A	36,611,010	13,339,131		41,198,898	8,751,243
46	From Insert Page B					
47	TOTAL	1,150,654,773	784,622,285		1,380,528,005	554,749,053

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Day, Yr) April 17, 2019	December 31, 2018

MISCELLANEOUS DEFERRED 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 items (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)	Bal. Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Oswego	5,802,754	362,545	555	1,542,407	4,622,892
2						
3	Cash Over and Short	402,306	14,449,448	Various	15,700,165	(848,411)
4						
5	Suspense Consolidations	62,458	69,402,527,938	Various	69,401,368,533	1,221,863
6						
7	HSBC-Vcard	(359,902)	20,484,681	232	20,451,474	(326,695)
8						
9	WNS-Bank Fees	0	1,168	234/690	0	1,168
10						
11	Pension Costs	333,782,921	512,622,019	Various	477,814,474	368,590,466
12						
13						
14						
15						
16						
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46						
47	Misc. Work in Progress	339,690,537				373,261,283
48	DEFERRED REGULATORY COMM. EXPENSES (See pages 350-351)					
49	TOTAL	$339,690,537	$0		$0	$373,261,283

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Balance End of Year (c)
1	Electric		
2	Reserve - Environmental	$84,063,911	$86,451,381
3	Regulatory Liabilities - Other	217,147,426	182,657,550
4	Regulatory Tax Liabilities	187,816,226	224,383,909
5	Allowance for uncolletible accounts	28,608,186	28,639,271
6	Future Federal Benefit of State Taxes	16,183,550	18,876,150
7			
8	Other	69,752,013	59,607,741
9	TOTAL Electric (Enter Total of lines 2 thru 7)	$603,571,312	$600,616,002
10	Gas		
11	Reserve - Environmental	$14,834,808	$15,256,126
12	Regulatory Liabilities - Other	43,857,899	45,638,195
13	Regulatory Tax Liabilities	44,583,655	43,719,949
14	Allowance for uncolletible accounts	12,260,651	12,273,973
15	Future Federal Benefit of State Taxes	4,825,530	5,123,780
16			
17	Other	17,385,598	13,683,576
18	TOTAL Gas (Enter Total of lines 10 thru 15)	$137,748,141	$135,695,599
19	Other (Specify)		
20	TOTAL (Acct 190)(Total of lines 8,16 and 17)	$741,319,453	$736,311,601

NOTES

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

CAPITAL STOCK (Accounts 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.
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.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)
1	Common - Account 201			
2	Common	250,000,000	$1.00	
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Total	250,000,000		
21				
22	Preferred - Account 204			
23	Cummulative Preferred	31,000,000		
24	3.40% Series		100.00	103.50
25	3.60% Series		100.00	104.85
26	3.90% Series		100.00	106.00
27	Preferred Stock - Golden Share	1	1.00	1.00
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41	Total	31,000,001		
42				

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

CAPITAL STOCK (Accounts 201 and 204) (Continued)

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
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)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	Line No.
						1
187,364,863	187,364,863					2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
187,364,863	$187,364,863	0	$0	0	$0	20
						21
						22
						23
57,524	5,752,400					24
137,152	13,715,200					25
95,171	9,517,100					26
1	1					27
						28
						29
						30
						31
						32
						33
						34
						35
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						39
						40
289,848	28,984,701	0	$0	0	$0	41
						42

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Day, Yr) April 17, 2019	December 31, 2018

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	Donations Received from Stockholders (Account 208)	
2		
3	Subtotal	$0
4		
5	Reduction in Par or Stated Value of Common Stock (Account 209)	
6		
7	Subtotal	$0
8		
9	Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Balance @ 12/31/2007.	$10,865,988
11		
12	Subtotal	$10,865,988
13		
14	Miscellaneous Paid-In Capital (Account 211)	
15	Amount set up on 1/5/50, as adjusted 12/58, regarding certain	
16	investments contributed by Niagara Hudson Power Corporation, former	
17	parent holding company in accordance with its "Dissolution Plan" which	
18	was approved by the Securities and Exchange Commission under date	
19	of 8/25/49 and by the District Court of the United States for the	
20	Northern District of New York State under date of 11/4/49.	2,137,110
21		
22	Amount of cash received upon liquidation of Niagara Hudson	
23	Power Corporation in excess of estimated liabilities.	500,000
24		
25	Contributions in aid of construction transferred from Account 217, per	28,773
26	order of the Public Service Commission of the State of New York,	
27	dated 3/8/52 in case 13343.	
28		
29	Capital surplus of the Oswego Canal Company, merged as of 3/31/52,	209,084
30	$276,296 less write down of electric plant of $67,212.	
31		
32	Excess of book value over the purchase price of the capital stock of	5,164
33	the Woodville Electric Light and Power Company, Inc.	
34		
35	Refund of deposits for script certificates of Niagara Hudson Power	124,121
36	Corporation which expired on 1/5/58.	
37		
38		
39		
40	TOTAL	$3,099,495,838

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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	Proceeds from the sale of 5,173 shares of common stock held for	
2	distribution to holders of unexchanged certificates of Niagara	
3	Hudson Power Corporation common stock. Sold pursuant to order of	
4	the United States District Court for the Northern District of New	204,267
5	York, dated 1/23/61.	
6		
7	To record subsidiaries on the "Equity" basis:	
8	Excess book value over the cost of investments at the date of	
9	acquisition of Canadian Niagara Power Co., Ltd. ($3,457,284) and	
10	St. Lawrence Power Co. ($903,145) as previously recorded on the	
11	Company's books. Ownership of these companies was transferred to	
12	Opinac Energy Corporation (formerly Opinac Investments Limited)	4,360,429
13	during 1982.	
14		
15	Excess of the cost of investment carried on the Company's books over	
16	the book value at date of acquisition of Beebee Island Corporation.	(62,872)
17		
18	Excess of the book value at the date of acquisition over the cost of	
19	investments carried on the Company's books of Moreau Manufacturing	
20	Corp.	477,984
21		
22	Merger Purchase Accounting Adjustments	2,671,376,392
23		
24	Return of Capital Dividend on common stock (7/02)	(86,086,034)
25		
26	Equity Contribution made by parent company (Niagara Mohawk Holdings)	404,127,268
27		
28	Share award adjustment & compensation	3,751,505
29		
30	Tax Provision (Parent Tax Allocation)	87,476,659
31		
32	Subtotal	$3,088,629,850
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	$3,099,495,838

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

LONG-TERM DEBT (Accounts 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	Bonds (Account 221)		
2	Unsecured notes:		
3	Senior Note @ 4.88%	750,000,000	3,805,177
4	Senior Note @ 2.72%	300,000,000	1,338,576
5	Senior Notes @ 3.51%	500,000,000	3,060,582
6	Senior Notes @ 4.28%	500,000,000	2,755,598
7	Senior Notes @ 4.28%	400,000,000	2,060,582
8	Senior Notes @ 4.12%	400,000,000	3,642,569
9			
10			
11	State Authority Financing - tax exempt:		
12	Due 12/01/23 @ 3.23%	69,800,000	934,300
13	Due 12/01/25 @ 3.29%	75,000,000	12,440,897
14	Due 12/01/26 @ 3.42%	50,000,000	787,811
15	Due 03/01/27 @ 3.45%	25,760,000	2,463,371
16	Due 07/01/27 ($68.2M @ 3.43% & $25M @ 3.48%)	93,200,000	1,609,373
17	Due 07/01/29 @ 3.43%	115,705,000	4,981,759
18			
19			
20	Subtotal	$3,279,465,000	$39,880,595
21			
22	Reacquired Bonds (Account 222)		
23			
24			
25			
26			
27			
28	Subtotal	$0	$0
29			
30	From Insert Page		
31	Advances from Associated Companies (Account 223)	0	0
32	Other Long Term Debt (Account 224)	0	0
33	TOTAL	$3,279,465,000	$39,880,595

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
08/10/2009	08/01/2019	08/10/2009	08/15/2019	750,000,000	36,607,500	3
11/28/2012	11/28/2022	11/28/2012	11/28/2022	300,000,000	8,163,000	4
09/25/2014	10/01/2024	09/25/2014	10/01/2024	500,000,000	17,540,000	5
12/04/2018	12/15/2028	12/04/2018	12/15/2028	500,000,000	1,604,250	6
09/25/2014	10/01/2034	09/25/2014	10/01/2034	400,000,000	17,112,000	7
11/28/2012	11/28/2042	11/28/2012	11/28/2042	400,000,000	16,476,000	8
						9
						10
						11
12/01/1988	12/01/2023	12/01/1988	12/01/2023	69,800,000	2,854,528	12
12/01/1985	12/01/2025	12/01/1985	12/01/2025	75,000,000	3,220,668	13
12/01/1986	12/01/2026	12/01/1986	12/01/2026	44,700,000	1,829,318	14
03/01/1987	03/01/2027	03/01/1987	03/01/2027	25,760,000	1,134,944	15
07/01/1987	07/01/2027	07/01/1987	07/01/2027	93,200,000	3,475,683	16
07/01/1994	07/01/2029	07/01/1994	07/01/2029	115,705,000	5,066,777	17
						18
						19
				$3,274,165,000	$115,084,668	20
						21
						22
						23
						24
						25
						26
						27
				$0	$0	28
						29
						30
				0	0	31
				$0	$0	32
				$3,274,165,000	$115,084,668	33

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

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	Advances from Associated Companies (Account 223)		
2			
3			
4			
5			
6			
7			
8	Subtotal	$0	$0
9			
10	Other Long-Term Debt (Account 224)		
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			
41			
42			
43			
44			
45	Subtotal	$0	$0
46			
47			
48			

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
				$0	$0	8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
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						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
				$0	$0	45
						46
						47
						48

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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 filed, indicating, however, intercompany amounts to be eliminated in such consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among 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)	$198,308,115
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Federal Income Taxes	47,849,964
6	See Details in Footnote	115,721,652
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Details in Footnote	701,272,542
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Details in Footnote	(71,390,283)
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Details in Footnote	(649,849,603)
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	$341,912,387
28	Show Computation of Tax:	
29	Federal Taxable Income, Page 261	341,912,387
30	Total Tax @ 35%/31.55% (Blended) Before Credits	88,423,424
31	Credits	(77,148)
32	Prior Year Adjustment	(47,938,101)
33		
34	Net Allocated Tax	40,408,175
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

If applicable, see insert pages below:

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

Particulars (Details) (a)	Amount (b)
RECONCILIATION OF REPORTED NET INCOME WITH FEDERAL TAXABLE INCOME	
1. Net Income per Statement of Income (Page 117)	198,308,115
2. Federal Income Taxes	47,849,964
4. Taxable Income Not Reported on Books	
Employee Stock Purchase Plan Discount	477,780
Construction - Aid of Construction	59,833,569
Add-back of Income Tax Credits	161,148
Share Based Comp_Windfall/Shortfal	18,955
Lobbying Expenses & Political Contributions	672,725
Meals and Entertainment	625,419
Flow-through Depreciation	53,932,056
Total Line 6	$115,721,652
5. Deductions Recorded on Books Not Deducted for Return	
ACCRUED INTEREST - TAX RESERVE	10,372,052
ACCRUED OTHER - TCC AUCTION REVENUE	9,745,248
ADIT - STATE	2,425,308
AFUDC DEBT	8,955,272
AMORTIZATION EXPENSE	1,537,666
BAD DEBTS	161,480
COST OF REMOVAL	6,922,839
DEFERRED GAS COST	8,564,214
DEPRECIATION EXPENSE - BOOK	228,774,069
INCENTIVE PLAN	1,607,764
INJURIES AND DAMAGES	1,212,590
INVESTMENTS - PARTNERSHIPS	10,758
POLE ATTACHMENT RENTALS	15,348
REG ASSET - CARRYING CHARGES	49,245,102
REG ASSET - HEDGING	43,929,133
REG ASSET - OPEB	64,702,569
REG ASSET - PENSION	100,073,721
REG ASSET - OTHER	94,963,061
REG ASSET - ARO	280,198
REG LIABILITY - OTHER	44,434,572
RESERVE - ENVIRONMENTAL	10,213,777
RESERVE - FIN 48 STATE	5,373,420
RESERVE - GENERAL	1,306,846
RESERVE - HEALTHCARE COSTS	2,371,000
RESERVE - SALES TAX	871,747
UNAMORTIZED DEBT DISCOUNT OR PREMIUM	158,578
UNICAP - INVENTORY	2,724,956
WORKERS' COMPENSATION	319,254
Total Line 10	$701,272,542

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

Particulars (Details) (a)	Amount (b)
7. Income Recorded on Books Not Included in Return	
Tax Exempt Interest Income	(508,730)
Change in Cash Surrender Value	(186,842)
Flow-through AFUDC Equity	(13,602,559)
Dividend Received Deduction	(85,824)
Equity-based Compensation and Dividends	(4,655,805)
Flow-through Cost of Removal	(52,021,287)
Flow-through Unamortized Debt	(329,236)
Total Line 15	($71,390,283)
8. Deductions on Return Not Charged Against Book Income	
ACCRUED OTHER	(3,236,707)
ACCRUED OTHER - REC OBLIGATION	(1,607,987)
ACCRUED OTHER - PSA4	(209,596)
ASSET RETIREMENT OBLIGATION	(532,399)
CASUALTY LOSS	(11,754,903)
DEFERRED COMPENSATION	(501,550)
DEPRECIATION EXPENSE - TAX	(210,447,925)
DEPRECIATION EXPENSE - TAX BONUS	(11,961,626)
FASB 112	(1,579,627)
GAIN (LOSS) ON SALE OF ASSETS	(4,818,343)
HEDGING	(43,929,133)
INSURANCE PROVISION	(1,787,002)
OPEB / FASB 106	(86,629,649)
PENSION COST	(36,509,817)
REG ASSET - ENVIRONMENTAL	(38,216,811)
REG ASSET - PROPERTY TAXES	(10,550,254)
REG ASSET - STORM COST	(61,957,574)
REG LIABILITY - BONUS DEPRECIATION	(5,292,914)
REPAIRS DEDUCTION	(106,665,219)
RESERVE - OBSOLETE INVENTORY	(282,178)
RESERVE - SEVERANCE	(443,533)
UNBILLED REVENUE	(8,721,016)
VACATION ACCRUAL	($1,107,621)
SHARE BASED COMP	(900,007)
CHARITABLE CONTRIB LIMITATION	(206,212)
Total Line 20	($649,849,603)

Name of Respondent Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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 known, 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 under the appropriate heading of "Federal," "State," and "Local" in such manner that the total tax for each State and subdivision can readily be ascertained.

		BALANCE BEGINNING OF YEAR				
Line No.	Kind of Tax (See Instruction 5) (a)	Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	Federal:					
2	Income Taxes	$84,537,476		$40,408,175	$49,180,110	($37,121,590)
3	FICA Contribution	1,842,471		30,476,331	31,243,896	(54,029)
4	Federal Unemployment	2,121		178,842	177,226	
5						
6	Total	86,382,068	0	71,063,348	80,601,232	(37,175,619)
7	State:					
8	State Income Tax	31,634,330		9,549,675	14,792,269	
9	Franchise - Gross Earnings	(470,250)		24,295,171	23,113,066	
10	State Unemployment	8,207		428,315	420,686	
11	Sales and Use	2,554,182		38,109,750	39,989,781	2,244,573
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22	Total	33,726,469	0	72,382,911	78,315,802	2,244,573
23	Local:					
24	Municipal Gross Income	1,261,250		14,904,389	14,838,378	
25	Real Estate	20,952		223,092,522	223,053,926	
26						
27						
28						
29	Total	1,282,202	0	237,996,911	237,892,304	0
30	Other (list):					
31						
32	Other	(5,357)		336,161	330,786	
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	121,385,382	-	381,779,331	397,140,124	(34,931,046)

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. *If any tax covers more than 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 footnote. 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 (q) how the taxes were distributed.

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 (Show utility dept. where applicable and acct. charged.)				
(Taxes Accrued Account 236) (g)	Prepaid Taxes (Incl. in Acct. 165) (h)	Electric (Account 408.1,409.1) (i)	Gas (Account 408.1,409.1) (j)	Other Utility Depts. (Account 408.1,409.1) (k)	Other Utility Operating Income (Account 408.1,409.1) (l)	Line No.
						1
$38,643,951		$28,851,151	13,629,594			2
1,020,877		19,941,264	4,088,504			3
3,737		(10,960)	25,920			4
						5
39,668,565	0	48,781,455	17,744,018	0	0	6
						7
26,391,736		6,902,209	3,163,265			8
711,855		18,726,477	5,568,694			9
15,836		0				10
2,918,724		26,160				11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
30,038,151	0	25,654,846	8,731,959	0	0	22
						23
1,327,261		11,948,261	2,956,128			24
88,148	28,600	177,550,920	44,983,177			25
						26
						27
						28
1,415,409	28,600	189,499,181	47,939,305	0	0	29
						30
						31
18		315,044	159,093			32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
71,122,143	28,600	264,250,526	74,574,375	-	-	44

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

DISTRIBUTION OF TAXES CHARGED (Show utility dept. where applicable and acct. charged.)

Line No.	Kind of Tax (See Instruction 5) (a)	Other Income and Deductions (Account 408.2,409.2) (m)	Extraordinary Items (Account 409.3) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	Other (q)
1	Federal:					
2	Income Taxes	($2,072,570)				
3	FICA Contribution				6,446,563	
4	Federal Unemployment				163,882	
5						
6	Total	(2,072,570)	0	0	6,610,445	0
7	State:					
8	State Income Tax	(515,799)				
9	Franchise - Gross Earnings					
10	State Unemployment				428,315	
11	Sales and Use				38,083,590	
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22	Total	(515,799)	0	0	38,511,905	0
23	Local:					
24	Municipal Gross Income					
25	Real Estate	558,425				
26						
27						
28						
29	Total	558,425	0	0	0	0
30	Other (list):					
31						
32	Other				(137,976)	
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	($2,029,944)	$0	$0	$44,984,374	$0

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) for Electric, Gas, Common, and non-utility respectively

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	$11,422,554		506,804	420	1,059,468	
6							
7							
8							
9							
10							
11							
12	SUBTOTAL	$11,422,554		$506,804		$1,059,468	$0
13	Other Utility						
14							
15	4%	83,746			420	7,900	
16							
17	10%	2,840,695			420	267,971	
18							
19							
20							
21							
22							
23							
24	SUBTOTAL	$2,924,441		$0		$275,871	$0
25	Common Utility						
26	3%						
27	4%						
28	7%						
29	3%						
30							
31							
32							
33							
34							
35							
36	SUBTOTAL	$0		$0		$0	$0
37	Nonutility						
38	3%						
39	4%						
40	7%						
41	10%						
42							
43							
44							
45							
46							
47	SUBTOTAL	$0		$0		$0	$0
48	TOTAL	$14,346,995		$506,804		$1,335,339	$0

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) for Electric, Gas, Common, and non-utility respectively (Continued)

Balance at End Year (h)	Average Period of Allocation to Income (i)	Adjustment Explanation	Line No.
			1
			2
			3
			4
$10,869,890	35 Years		5
			6
			7
			8
			9
			10
			11
$10,869,890			12
			13
			14
75,846	44 Years		15
			16
2,572,724	44 Years		17
			18
			19
			20
			21
			22
			23
$2,648,570			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
$0			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
$0			47
$13,518,460			48

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

OTHER DEFERRED 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 of End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description of 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	Energy Service Company Deposits	1,488,438	131/232	851,213	623,253	1,260,478
2						
3	Executive Retirement Plan	1,042,196	Various	594,092	92,542	540,646
4						
5	Nuclear Fuel Disposal Costs	169,812,722	431		3,174,423	172,987,145
6						
7	Other Post Employment Benefit Lial	28,122,893	Various	18,197,182	16,617,554	26,543,265
8						
9	Long Term Interest Payable	25,661,493	431	1,558,192	11,930,244	36,033,545
10						
11	Def Cr - Sales Tax Acc	9,360,137	431/408.1	1,469,266	2,341,013	10,231,884
12						
13	FIN 48 FIT/SIT	116,464,307	Various	13,620,856	28,224,261	131,067,712
14						
15	Storm Reserve	1,080,593	456	45,397	1,558,630	2,593,826
16						
17	Deferred Revenue	365,580	454/242	101,769	79,483	343,294
18						
19	Mohawk Valley Edge - CIAC	4,819,686	456	1,986,512	3,478,578	6,311,752
20						
21	All Other	(133,484,973)	Various	143,746,173	134,309,804	(142,921,342)
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
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34						
35						
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41						
42						
43						
44						
45						
46						
47	TOTAL	$224,733,072		$182,170,652	$202,429,785	$244,992,205

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited To Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited To Account 411.1 (d)
1	Account 282			
2	Electric	$1,305,014,102	$40,540,228	
3	Gas	324,917,115	8,090,225	
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,629,931,217	48,630,453	0
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	$1,629,931,217	$48,630,453	$0
10	Classification of TOTAL			
11	Federal Income Tax	$1,395,417,973	$37,285,458	
12	State Income Tax	234,513,244	11,344,995	
13	Local Income Tax			

NOTES

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

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

3. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits		Balance at End of Year	
Amounts Debited To Account 410.2	Amounts Credited To Account 411.2	Account Credited	Amount	Account Debited	Amount		Line No.
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182/254	$0	182/254	$4,531,545	$1,350,085,875	2
		182/254	0	182/254	1,005,947	334,013,287	3
							4
0	0		0		5,537,492	1,684,099,162	5
							6
							7
							8
$0	$0		$0		$5,537,492	$1,684,099,162	9
							10
		182/254		182/254	$4,663,784	1,437,367,215	11
		182/254		182/254	873,708	246,731,947	12
							13

NOTES (Continued)

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

ACCUMULATED DEFERRED 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 Subdivisions (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	Regulatory Assets - Environmental	$64,816,009	$8,933,179	
4	Reg Assets - Pension and OPEB	30,521,557	(30,521,557)	
5	Regulatory Assets - Other	42,296,991	(40,006,034)	
6	Other Deferred Tax Liabilities	859,756	1,809,384	
7	Pension, OPEB and other employee benefits	13,222,651	29,362,715	
8				
9	TOTAL Electric (Total of lines 3 thru 8)	$151,716,964	($30,422,313)	$0
10	Gas			
11	Regulatory Assets - Environmental	$11,438,119	$1,576,444	
12	Reg Assets - Pension and OPEB	6,251,403	(6,251,403)	
13	Regulatory Assets - Other	18,253,543	(10,548,301)	
14	Other Deferred Tax Liabilities	3,315,505	(2,768,814)	
15	Pension, OPEB and other employee benefits	2,779,334	5,921,384	
16				
17	TOTAL Gas (Total of lines 11 thru 16)	$42,037,904	($12,070,690)	$0
18	Other (Specify)			
19	TOTAL (Acct 283) (Enter Total of Lines 9,17 and 18)	$193,754,868	($42,493,003)	$0
20	Classification of TOTAL			
21	Federal Income Tax	$151,647,463	($32,673,573)	
22	State Income Tax	42,107,405	(9,819,430)	
23	Local Income Tax			

NOTES

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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

3. Provide in the space below explanations for pages 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	Amounts Credited To Account 411.2	Acct. Credited	Amount	Acct. Debited	Amount	Balance at End of Year	Line No.
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						$73,749,188	3
						-	4
		182/254		182/254	5,195,758	7,486,715	5
					50,098	2,719,238	6
						42,585,366	7
							8
$0	$0		$0		$5,245,856	$126,540,507	9
							10
						$13,014,563	11
						-	12
				182/254	1,064,191	8,769,433	13
					10,261	556,952	14
						8,700,718	15
							16
$0	$0		$0		$1,074,452	$31,041,666	17
							18
$0	$0		$0		$6,320,308	$157,582,173	19
							20
				182/254	$4,989,730	123,963,620	21
				182/254	1,330,578	33,618,553	22
							23

NOTES (Continued)

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (details) called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $100,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in a footnote, for each line item, the regulatory citation where authorization for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance End of Year (f)
1	FAS 109	983,467,934	182/190/282/283	236,751,289	29,275,234	775,991,879
2	Energy Efficiency - Gas EEPS deferral	-	254/495	33,927	6,146,096	6,112,169
3	GAS Refund	403,469				403,469
4	Deferred Gas Cost	-	182/254/804	29,710,733	29,710,733	-
5	Pipeline Refunds	55	254	55		-
6	Gas Adjustment Clause (GAC) Imbalance Refund	3,122,550	431/804	3,171,805	9,681,564	9,632,309
7	Temporary State Assessment 18-A	502,843	419/928	9,294	636,377	1,129,926
8	Transportation Adjustment Clause Imbalance Refund	158,199	431/804	253,938	95,739	-
9	Commodity Timing Impact Deferral	-	456	41,558,630	41,558,630	-
10	RPS Program Cost Deferred	-			17,623,450	17,623,450
11	CES Def Supply	-	555	4,414,815	4,414,815	-
12	Exc Resv Tax Elec	-			17,948,000	17,948,000
13	Exc Resv Tax Gas	-			4,534,000	4,534,000
14	Energy Efficiency Surcharge Gas	3,963,992	495/431	1,161,947	5,609,938	8,411,983
15	Energy Efficiency Surcharge Electric	15,472,736	431/456	7,705,676	23,919,496	31,686,556
16	OBR EE Fund Oblig	7,257,423	908	8,001,019	5,755,231	5,011,635
17	NIMO MFC-Electric	-	431/456	228,312	570,921	342,609
18	NIMO RDM - Electric	0	456	14,309,214	51,748,618	37,439,404
19	Deferred Rate Case True Up	-			29,239,860	29,239,860
20	Capital Tracker	5,201,772	254/495	5,201,772		-
21	Affordability Program - Electric	3,012,009	456	32,400	203,046	3,182,655
22	Generation Stranded Cost Adjustments	3,862,937	254	1,966,851	4,741,272	6,637,358
23	Low Income Program - G	2,761,953	495	1,011,879	3,301,255	5,051,329
24	Int SBC Costs Def	-	431	635,097	1,692,358	1,057,261
25	OffSys Sales-Profit Deferral	543,046	254	2,432,305	2,956,784	1,067,525
26	Electric Supply Reconciliation Mechanism (ESRM)	0	456	38,439,021	38,439,021	-
27	Excess Storm Reserve	170,138,977	182/254	194,638,977	24,500,000	-
28	Capital Tracker - Electric	13,269,953	182/254/456	13,336,570	66,617	-
29	NUP-FY18-E-15-M-0744	(53,311,227)	254/456	19,638,461	72,949,688	-
30	NUP-FY18-G-15-M-0744	(11,897,236)	254/495	4,588,291	16,485,527	-
31	Paige St Settlement	498,419	892	11,232		487,187
32	Debt True Up - Electric	56,696,172	182/254/456	49,816,997	3,049,974	9,929,149
33	Consumer Service Advocate	90,479	254	64,160		26,319
34	Deferral Carry Chrg 10-E-0050	82,750,585	254/419/431	92,894,347	33,354,954	23,211,192
35	Proceeds from Sale of Emissions Allowance -Albany	1,435,234	254	1,261,808		173,426
36	Clean Air Act - Roseton	135,179	254	119,052		16,127
37	Customer Service System Conversion Savings Gas	68,593	254	51,907		16,686
38	NIMO-Gas Net Revenue Mechanism	321,733	182/495	466,735	145,002	-
39	Unbilled Gas Revenue	20,106,709	495	155,270,052	153,175,983	18,012,640
40	Electric Customer Service Penalty	17,328,766	254/456	13,755,319		3,573,447
41	Gas Contingency Reserve	407,326	254	306,173		101,153
42	**From Insert Page A**	498,040,535		559,657,591	480,511,242	418,894,186
43	**From Insert Page B**	473,758,036		326,342,487	388,400,387	535,815,936
44	TOTAL	2,299,569,151		$1,829,250,138	$1,502,441,812	$1,972,760,825

Insert

If applicable, see insert page below:

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance End of Year (f)
1	Gas Customer Service Penalty	28,954,891	407/495	28,345,000	6,085,000	6,694,891
2	Loss on Sale of Building	269				269
3	System Benefit Charge Program Deferred	-			13,573,321	13,573,321
4	State Regulatory Liability (FAS 109)	57,486,030	182/407	24,342,978	11,379,812	44,522,864
5	Diana Dolgeville - IPP Settlement	3,500,128	254	2,495,100		1,005,028
6	Merchant Function Charge - Gas	-	495	65,585	223,889	158,304
7	Site Investigation and Remediation Expenditure Def-Gas	11,163,139	254	7,512,917	3,825,534	7,475,756
8	NIMO-Trnsm Rev AdjCl	110,352,453	254/431/456	147,573,610	57,304,562	20,083,405
9	NYS Sales Tax Refund	1,200,000	254	868,696		331,304
10	Economic Development Fund - Electric	90,302,612	254/456	67,752,902	3,816,028	26,365,738
11	Gross Receipts Tax Customer Refund -2000-Gas	15,386	254	11,284		4,102
12	Gas Millenium Fund Deferral	-	495/880/930	631,775	1,734,735	1,102,960
13	Bonus Depriciation Adj. Electric (15-M-0744)	9,445,702	254	6,914,278	2,301,199	4,832,623
14	Bonus Depreciation Adjustment - Gas (12-G-0202)	21,897	254	16,550		5,347
15	Int Reserve CarryChg	50,829,108	254	36,235,265		14,593,843
16	Gas Futures - Gas Supply	527,995	176/186	3,390,416	2,862,421	-
17	KeySpan Merger Savings - Gas	62,806	254	47,392		15,414
18	Electric Swaps - Electric Supply	7,446,356	175/176	66,390,873	82,651,512	23,706,995
19	Voltage Migration Fee Deferral	7,504	254/407	7,960	456	-
20	RDM Rev Decoupling - Gas	-	419/495	11,388,189	12,783,057	1,394,868
21	Long Term Debt True-Up - Gas	19,279,477	254/495	14,966,563	745,020	5,057,934
22	Federal Tax Refund 1991-1995	3,723,054	254	2,800,696		922,358
23	Curtailment	316,134	254	226,179		89,955
24	Oswego PPA Reg Liab	5,802,754	555	1,542,406	362,545	4,622,893
25	NYPA Hydropower Benefit	25,588	456	1,226,900	1,248,086	46,774
26	Pension Expense deferred-Electric	(23,949,366)	926	4,916,280	28,865,646	-
27	OPEB Expense deferred-Electric	75,616,335	254	39,191,602	62,836,975	99,261,708
28	Low Income Allowance Discount Program - Electric	9,069,787	456	7,393,916	9,938,482	11,614,353
29	Site Investigation and Remediation Expenditures Deferre	71,180,832	254/930	45,956,785	21,641,133	46,865,180
30	Legacy Transition Charge	-	456	16,967,598	16,967,598	-
31	Dunkirk II Settlement Deferral - Excess	1,331,592	456	70	13,999	1,345,521
32	NYPA Replacement Power & Expansion Power	4,927,507	254	3,513,100		1,414,407
33	NMPC - 18 A Ass. Gas	319,628	419/928	371	303,978	623,235
34	Hydro One Network	1,887,763	407	1,887,763		-
35	Miscellaneous Penalties	443,402	254	333,255		110,147
36	Case 08-G-0609 Joint Proposal Amortization	2,895,907	254	2,178,569		717,338
37	Demand Response Programs	223,803	182/431/456	2,325,230	2,101,427	-
38	NUPD - Mech-Elec-15-M-0744 Contra Liability	(39,425,999)	254		39,425,999	-
39	NUPD - Mech-Gas-15-M-0744 Contra Liability	(7,349,364)	495	31,789	7,381,153	-
40	Self-Direct Elec	405,425	431/456	139,905	366,205	631,725
41	Rate Plan Settlement Credit Elec		407	4,650,000	44,880,000	40,230,000
42	Rate Plan Settlement Credit Gas				28,420,000	28,420,000
43	LEDCap Inv Trk-Elec		456	21,644	268,741	247,097
44	Walk-in Pymt Fee-ele		456	147,851	358,328	210,477
45	Walk-in Pymt Fee-gas		903	54,685	132,368	77,683
46	Veget Mgmt Cost-Elec		456	4,739,838	14,423,581	9,683,743
47	Pltfm SrvcRev Sharng		456	6,225	25,295	19,070
48	Net Utility Plant - 17-G-0239		495	447,601	1,263,157	815,556
49	TOTAL	498,040,535		$559,657,591	$480,511,242	$418,894,186

Next Page is 300

OTHER REGULATORY LIABILITIES (Account 254)

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance End of Year (f)
1	Economic Development - Gas	7,708,330	254/495	6,406,748	2,028,722	3,330,304
2	Economic Develop Grant Program - Gas	3,237,826			995,440	4,233,266
3	Economic Develop Grant Program - Electric	4,714,778	456	2,044,725	1,812,512	4,482,565
4	AffordAbility Program - Gas	587,240	495	11,280	88,040	664,000
5	Property Tax Exp Def - Gas	11,258,788	254/407	11,391,755	841,501	708,534
6	Variable Pay Deferral - Gas	363,279	254	324,228		39,051
7	NYPA Discount Rec De	2,692,035	254	998,753	343,791	2,037,073
8	Trans Tower Painting	75,841	254	22,812	50,067	103,096
9	Sub-Trans Tower Pain	1,116,248	254	846,908	2,249	271,589
10	Trans Footer Insp Ex	29,831	254	29,831	0	-
11	Sub-Trans Footer Ins	107,658	254	81,269	928	27,317
12	FIT Repair Costs	30,113,000	254	28,118,719		1,994,281
13	12E0201 DefCr Amrt-E		456	86,040,605	200,403,569	114,362,964
14	12G0202 DefCr Amrt-G		495	21,009,113	56,123,000	35,113,887
15	Bonus Depreciation Adjustment (15-M-0744)	1,527,691	254	987,729	324,444	864,406
16	Merchant Function Charge (MFC) - Imbalance	22,786	431/495	94,406	71,620	-
17	NMPC Gas CC Chrg Def	24,073,431	182/254	20,390,153	7,091,657	10,774,935
18	System Performance Adjustment				23,544	23,544
19	Excess Voltage Test	15,222,837	254	15,358,482	932,372	796,727
20	Clean Energy Fund Gas	8,756,809	254/431/495	12,013,242	8,673,633	5,417,200
21	Clean Energy Fund Electric	362,149,628	182/431/456	113,978,390	83,377,859	331,549,097
22	Spier Falls Transm		571	86,751	1,158,053	1,071,302
23	Clean Energy Fund Interest -Ga		254	31,594	139,491	107,897
24	Clean Energy Fund Interest -Elec		254/431	2,101,482	12,882,867	10,781,385
25	EEPS Interest-Elec		431	3,973,512	8,836,009	4,862,497
26	SBC Interest Deferral				1,362,406	1,362,406
27	RPS Interest Deferral				836,613	836,613
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	473,758,036		$326,342,487	$388,400,387	$535,815,936

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

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 and MWh for each prescribed account and/or category, and manufactured gas revenues in total.
3. Report number of customers for each prescribed account and/or category column (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except 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 year (columns (c), (e), and (g)), are not derived from previously previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	Bundled		
3	(440) Residential Sales	$ 1,295,349,921	$ 1,244,399,075
4	(442) Commercial and Industrial Sales		
5	Small (or Commercial) (See Instr. 6)	330,455,990	294,245,175
6	Large (or Industrial) (See Instr. 6)	57,910,684	49,816,324
7	(444) Public Street and Highway Lighting	20,216,814	19,393,340
8	(445) Other Sales to Public Authorities		
9	(446) Sales to Railroads and Railways		
10	(448) Interdepartmental Sales		
11	TOTAL Sales to Ultimate Consumers	1,703,933,409	1,607,853,914
12	(447) Sales for Resale	596,785	556,778
13	TOTAL Sales of Electricity	1,704,530,194	1,608,410,692
14	(Less) (449.1) Provision for Rate Refunds		
15	TOTAL Revenues Net of Provision for Refunds	1,704,530,194	1,608,410,692
16	Other Operating Revenues		
17	(450) Forfeited Discounts	12,630,792	12,561,488
18	(451) Miscellaneous Service Revenues	6,485,183	3,822,718
19	(453) Sales of Water and Water Power		
20	(454) Rent from Electric Property	14,711,678	16,911,855
21	(455) Interdepartmental Rents		
22	(456) Other Electric Revenues	66,519,088	(50,698,267)
23	(456.1) Revenues from Transmission of Electricity of Others	206,453,609	211,023,642
24	(456.2) Revenues from Distribution of Electricity of Others*		
25	Residential Sales	151,732,459	159,754,705
26	Commercial and Industrial Sales		
27	Small (or Commercial) (See Instr. 6)	332,848,152	369,465,303
28	Large (or Industrial) (See Instr. 6)	106,069,884	115,441,636
29	Public Street and Highway Lighting		
30	Other Sales to Public Authorities		
31	Sales to Railroads and Railways		
32	Interdepartmental Sales		
33	Other		
34	TOTAL Sales to Ultimate Consumers	590,650,495	644,661,644
35	(457.1) Regional Control Services Revenues		
36	(457.2) Miscellaneous Revenues		
37			
38	TOTAL Other Operating Revenues	897,450,845	838,283,080
39	TOTAL Electric Operating Revenues	2,601,981,039	2,446,693,772

*** Note: Account (456.2) Revenues from Distribution of Electricity of Others should be separately identified by subcategories on lines 25 - 33. Items recorded on Line 33 - Other should be footnoted with a description.**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original	(Mo, Da, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

ELECTRIC OPERATING REVENUES (ACCOUNT 400) (Continued)

5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2
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 basis of classification in a footnote).
7. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases 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		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
[redacted]				1
				2
9,952,519	9,134,204	1,269,781	1,243,100	3
[redacted]				4
3,340,677	3,089,384	104,751	102,134	5
907,388	893,575	546	542	6
67,086	67,588	2,892	2,922	7
				8
				9
				10
14,267,670	13,184,751	1,377,970	1,348,698	11
6,215	5,906	135	135	12
14,273,885	13,190,657	1,378,105	1,348,833	13
				14
14,273,885	13,190,657	1,378,105	1,348,833	15
[redacted]				16
				17
				18
				19
				20
				21
				22
				23
[redacted]				24
2,116,344	2,113,085	$231,640	$250,598	25
[redacted]				26
9,391,153	9,346,525	$68,421	$69,264	27
9,518,591	9,054,676	$1,026	$1,037	28
				29
				30
				31
				32
				33
21,026,088	20,514,286	$301,087	$320,899	34
				35
				36
				37
[redacted]				38
				39

Line 12, Column (b) includes $ 0 of unbilled revenues.

Line 12 Column (d) includes 0 MWH relating to unbilled revenues.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original	(Mo, Da, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

SALES BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold and/or distribution of electricity sold to others, revenue, number of customers, average KWh per customer, and average revenue per KWh, excluding data 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," pages 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. For each rate schedule, provide the required information specified below.
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	SCH. 214-S.C.1	2,004	$469,953	1,768	1,133	0.2345
2	SCH. 207-S.C.1	9,777,486	1,278,658,636	1,262,782	7,743	0.1308
3	SCH. 207-S.C.1C	163,955	14,712,962	3,468	47,277	0.0897
4	SCH. 207-S.C.2 DEMAND	2,033	247,045	54	37,648	0.1215
5	SCH. 207-S.C.2 NON-DEMAND	7,041	1,261,325	1,709	4,120	0.1791
6	RESIDENTIAL TOTAL (440)	9,952,519	1,295,349,921	1,269,781	7,838	0.1302
7						
8	SCH. 214-S.C.1	12,049	2,559,652	3,391	3,553	0.2124
9	SCH. 207-S.C.2 DEMAND	1,719,771	178,754,115	24,205	71,050	0.1039
10	SCH. 207-S.C.2 NON-DEMAND	416,491	48,163,273	76,597	5,437	0.1156
11	SCH. 207-S.C.3	1,127,756	100,028,427	1,007	1,119,917	0.0887
12	SCH. 207-S.C.3A	540,456	34,563,815	15	36,030,400	0.0640
13	SCH. 207-S.C.4	221,509	12,677,199	59	3,754,390	0.0572
14	SCH. 207-S.C.7	45,071	2,908,047	22	2,048,682	0.0645
15	SCH. 207-S.C.11					
16	SCH. 207-S.C.12	164,962	8,712,146	1	164,962,000	0.0528
17	PASNY CONTRACTS NS-1					
18	COMMERCIAL & INDUSTRIAL TOTAL (442	4,248,065	388,366,674	105,297	40,344	0.0914
19						
20	214-S.C.2	56,758	18,674,435	842	67,409	0.3290
21	214-S.C.3	1,898	210,619	133	14,271	0.1110
22	SPECIAL CONTRACTS	8,430	1,331,760	1,917	4,397	0.1580
23	PUBLIC STREET & HIGHWAY TOTAL (444	67,086	20,216,814	2,892	23,197	0.3014
24						
25	Other Revenues					
26	Forfeited Discounts		12,630,792			
27	Miscellaneous Service Revenue		6,485,183			
28	Rent from Electric Properties		14,711,678			
29	Other Electric Revenues		66,519,088			
30	Revenues from Trans of Electricity of Others		206,453,609			
31	Revenues from Dist of Electricity of Others		590,650,495			
32	Total Other Revenues		897,450,845			
33						
34						
35						
36						
37						
38						
39						
40						
41	Total Billed	14,267,670	2,601,384,254	1,377,970	10,354	0.1823
42	Total Unbilled Rev. (See Instr. 6)					
43	TOTAL	14,267,670	$2,601,384,254	1,377,970	10,354	0.1823

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original	(Mo, Da, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

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 (pages 326-327).

2. Enter the name of the purchaser 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 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 (ie., 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 long-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 seller 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 the 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 Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)
1					
2	borderline sales:				
3	Central Hudson Gas & Electric	RQ	NM-41		
4	Central Vermont Public	RQ	NM-254		
5	Delaware County Electric	RQ	NM-256		
6	Pensylvania Electric (GPU)	RQ	NM-185		
7	New York State Electric & Gas	RQ	NM-37		
8	Rochester Gas & Electric	RQ	NM-44		
9					
10	New York Independent System Operator	OS	ISO-MKT-SVC		
11					
12	subtotal rq				
13	subtotal non rq				
14	Total				

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.
AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RG 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 (g) 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 megawatthours 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 adjustment, 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, line 24.
10. Footnote entries as required and provide explanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h + i + j) (k)	Line No.
					1
					2
102		13,592		13,592	3
29		4,195		4,195	4
2		521		521	5
294		34,436		34,436	6
5,228		480,615		480,615	7
560		63,426		63,426	8
					9
					10
					11
6,215		596,785		596,785	12
0		0		0	13
6,215	0	596,785	0	596,785	14

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

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		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	0	0
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of lines 15 thru 19)	0	0
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 and 20)	0	0
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
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		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	0	0
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	0	0
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)	0	0
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of lines 44 thru 49)	$0	$0

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.		Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter total of lines 53 thru 57)	0	0
59	TOTAL Power Production Expenses-Hydraulic Power (Enter total of lines 50 and 58)	0	0
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(548.1) Operation of Energy Storage Equipment		
66	(549) Miscellaneous Other Power Generation Expenses		
67	(550) Rents		
68	TOTAL Operation (Enter total of lines 62 thru 67)	0	0
69	Maintenance		
70	(551) Maintenance Supervision and Engineering		
71	(552) Maintenance of Structures		
72	(553) Maintenance of Generating and Electric Plant		
73	(553.1) Maintenance of Energy Storage Equipment		
74	(554) Maintenance of Miscellaneous Other Power Generation Plant		
75	TOTAL Maintenance (Enter Total of Lines 70 thru 75)	0	0
76	TOTAL Power Production Expenses--Other Power (Enter Total of Lines 70 and 75)	0	0
77	E. Other Power Supply Expenses		
78	(555) Purchased Power	740,000,496	702,730,223
79	(555.1) Power Purchased for Storage Operations		
80	(556) System Control and Load Dispatching		
81	(557) Other Expenses	35,708	
82	TOTAL Other Power Supply Expenses (Enter Total of Lines 78 thru 81)	740,036,204	702,730,223
83	TOTAL Power Production Expenses (Enter total of lines 21, 41, 59, 76, and 82)	740,036,204	702,730,223
84	2. TRANSMISSION EXPENSES		
85	Operation		
86	(560) Operation Supervision and Engineering	2,283,957	2,115,929
87	(561.1) Load Dispatch - Reliability	165,673	138,877
88	(561.2) Load Dispatch - Monitor and Operate Transmission System	5,614,388	5,502,862
89	(561.3) Load Dispatch - Transmission Service and Scheduling		
90	(561.4) Scheduling, System Control and Dispatch Services	3,111,507	2,586,321
91	(561.5) Reliability, Planning and Standards Development	409,524	367,072
92	(561.6) Transmission Service Studies		
93	(561.7) Generation Interconnection Studies		
94	(561.8) Reliability, Planning and Standards Development Services	873,066	741,043
95	(562) Station Expenses	2,374,982	2,692,341
96	(562.1) Operation of Energy Storage Equipment		
97	(563) Overhead Lines Expenses	1,910,038	2,422,462
98	(564) Underground Lines Expenses	188,030	195,058
99	(565) Transmission of Electricity by Others		
100	(566) Miscellaneous Transmission Expenses	6,246,480	5,888,781
101	(567) Rents	7,325,605	12,072,795
102	TOTAL Operation (Enter total of lines 86 thru 101)	30,503,250	34,723,541
103	Maintenance		
104	(568) Maintenance Supervision and Engineering	1,341,272	1,415,793
105	(569) Maintenance of Structures		
106	(569.1) Maintenance of Computer Hardware	0	428
107	(569.2) Maintenance of Computer Software	0	66,212
108	(569.3) Maintenance of Communication Equipment	2,208	11,435
109	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	(222,580)	681,666
110	(570) Maintenance of Station Equipment	4,764,819	4,232,157
111	(570.1) Maintenance of Energy Storage Equipment		
112	(571) Maintenance of Overhead Lines	43,650,456	35,821,832
113	(572) Maintenance of Underground Lines	16,793	300,196
114	(573) Maintenance of Miscellaneous Transmission Plant	983,942	1,410,632
115	TOTAL Maintenance (Enter total of lines 104 thru 115)	50,536,910	43,940,351
116	TOTAL Transmission Expenses (Enter total of lines 102 and 115)	81,040,160	78,663,892

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
117	3. REGIONAL MARKET EXPENSES		
118	Operation		
119	(575.1) Operation Supervision		
120	(575.2) Day Ahead and Real Time Market Facilitation		
121	(575.3) Transmission Rights Market Facilitation		
122	(575.4) Capacity Market Facilitation		
123	(575.5) Ancillary Services Market Facilitation		
124	(575.6) Market Monitoring and Compliance		
125	(575.7) Market Facilitation, Monitoring and Compliance Services	5,411,455	4,678,558
126	(575.8) Rents		
127	TOTAL Operation (Enter total of lines 119 thru 126)	5,411,455	4,678,558
128	Maintenance		
129	(576.1) Maintenance of Structures and Improvements		
130	(576.2) Maintenance of Computer Hardware		
131	(576.3) Maintenance of Computer Software		
132	(576.4) Maintenance of Communication Equipment		
133	(576.5) Maintenance of Miscellaneous Market Operation Plant		
134	TOTAL Maintenance (Lines 129 thru 133)	0	0
135	TOTAL Regional Transmission and Market Op Expenses (Total 127 and 134)	5,411,455	4,678,558
136	4. DISTRIBUTION EXPENSES		
137	Operation		
138	(580) Operation Supervision and Engineering	8,130,624	11,773,615
139	(581) Load Dispatching	9,218,672	9,110,486
140	(582) Station Expenses	6,592,391	6,714,054
141	(583) Overhead Line Expenses	11,385,825	18,580,933
142	(584) Underground Line Expenses	6,932,735	6,423,330
143	(584.1) Operation of Energy Storage Equipment		
144	(585) Street Lighting and Signal System Expenses	772,439	639,048
145	(586) Meter Expenses	12,298,898	13,916,440
146	(587) Customer Installations Expenses	6,866,419	7,125,244
147	(588) Miscellaneous Expenses	40,948,655	44,352,297
148	(589) Rents	76,045	740,531
149	TOTAL Operation (Enter Total of lines 138 thru 148)	103,222,703	119,375,978
150	Maintenance		
151	(590) Maintenance Supervision and Engineering	2,863,231	2,798,373
152	(591) Maintenance of Structures	1,561,572	1,849,059
153	(592) Maintenance of Station Equipment	7,507,456	7,361,587
154	(592.1) Maintenance of Structures and Equipment		
155	(592.2) Maintenance of Energy Storage Equipment		
156	(593) Maintenance of Overhead Lines	186,380,412	140,218,006
157	(594) Maintenance of Underground Lines	9,562,806	8,538,693
158	(595) Maintenance of Line Transformers	1,679,094	2,176,107
159	(596) Maintenance of Street Lighting and Signal Systems	6,159,541	5,830,281
160	(597) Maintenance of Meters	620,792	245,353
161	(598) Maintenance of Miscellaneous Distribution Plant	3,592,002	3,946,951
162	TOTAL Maintenance (Enter Total of lines 151 thru 162)	219,926,906	172,964,410
163	TOTAL Distribution Expenses (Enter Total of lines 149 and 162)	323,149,609	292,340,388
164	5. CUSTOMER ACCOUNTS EXPENSES		
165	Operation		
166	(901) Supervision	2,665,983	2,049,558
167	(902) Meter Reading Expenses	2,645,147	2,277,159
168	(903) Customer Records and Collection Expenses	39,930,319	38,769,969
169	(904) Uncollectible Accounts	35,873,187	30,824,983
170	(905) Miscellaneous Customer Accounts Expenses	2,853,510	3,242,359
171	TOTAL Customer Accounts Expenses (Enter Total of lines 165 thru 170)	83,968,146	77,164,028
172	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
173	Operation		
174	(907) Supervision	273,003	108,008
175	(908) Customer Assistance Expenses	213,600,629	57,958,464
176	(909) Information and Instructional Expenses	8,493,639	3,755,987
177	(910) Miscellaneous Customer Service and Information Expenses	2,176,777	1,172,870
178	TOTAL Cust. Service and Informational Expenses (Enter Total of Lines 174 thru 177)	224,544,048	62,995,329
179	7. SALES EXPENSES		
180	Operation		
181	(911) Supervision	163,621	
182	(912) Demonstrating and Selling Expenses	338,497	173,514
183	(913) Advertising Expenses	585,513	493,914
184	(916) Miscellaneous Sales Expenses	47,534	12,482
185	TOTAL Sales Expenses (Enter Total of lines 181 thru 184)	1,135,165	679,910
186	8. ADMINISTRATIVE AND GENERAL EXPENSES		
187	Operation		
188	(920) Administrative and General Salaries	70,114,598	70,886,299
189	(921) Office Supplies and Expenses	60,723,332	67,526,694
190	(Less) (922) Administrative Expenses Transferred-Credit	23,872,297	

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
191	8. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
192	(923) Outside Services Employed	$15,521,851	$25,184,142
193	(924) Property Insurance	$2,796,065	3,719,672
194	(925) Injuries and Damages	$8,790,864	10,565,357
195	(926) Employee Pensions and Benefits	$100,658,115	92,356,485
196	(927) Franchise Requirements		
197	(928) Regulatory Commission Expenses	$9,297,198	22,129,461
198	(929) (Less) Duplicate Charges-Cr.		
199	(930.1) General Advertising Expenses	0	2,105
200	(930.2) Miscellaneous General Expenses	44,494,026	40,852,488
201	(931) Rents	37,054,108	34,724,478
202	TOTAL Operation (Enter Total of lines 188 thru 201)	325,577,860	367,947,181
203	Maintenance		
204	(935) Maintenance of General Plant	2,223,708	3,286,138
205	TOTAL Administrative and General Expenses (Enter total of lines 202 and 204)	327,801,568	371,233,319
206	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 83, 116, 163, 171, 178, 185 and 205)	$1,787,086,355	$1,590,485,647

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/31/2018
2. Total Regular Full-Time Employees	3,827
3. Total Part-Time and Temporary Employees	3
4. Total Employees	3,830

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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 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 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 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 seller 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 the 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.
   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-

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 (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	Megawatthours Purchased (Excluding for Energy Storage) (g)
1	Non - Associated Utilities						
2	Central HudsonGas & Elec Corp	RQ					
3	New York State Elec & Gas Corp.	RQ					
4	Rochester Gas & Elec Corp	RQ					
5							
6	Other Non-Utilities						
7	Black River Hydro C/O Enel - Denley-Old Generation	LU	NM-342				
8	AHDC Hudson Falls	LU	NM-863				
9	AHDC South Glens Falls	LU	NM-862				
10	Ampersand - Alder Creek Hyrdro (Kayuta)	LU	NM-1833				
11	Azure Mountain	LU	NM-1784				
12	KEI Power Mgmt - Battenkill Hydro Inc (upper)	LU	NM-410				
13	From Insert Page						
14	Total						

If applicable, see insert pages below:

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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

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.
AD - for out-of-period adjustment. Use this code for any accounting adjustment 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 services involving demand charges imposed on a monthly (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 (1) includes 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 totaled 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.

Megawatthours	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Purchased Purchased for Energy Storage (h)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
							1
220				6,085		6,085	2
3,133				316,586		316,586	3
915				108,013		108,013	4
-				-		0	5
-				-		0	6
1,257			-	81,692	-	81,692	7
201,703			-	9,652,676	-	9,652,676	8
76,907			-	6,624,449	-	6,624,449	9
1,313			1,388	36,412	-	37,800	10
2,443			-	61,276	4,227	65,503	11
-			-	13	-	13	12
						0	13
14,817,660			69,830,727	602,407,043	67,762,726	740,000,496	14

PURCHASED POWER (Account 555)
(INCLUDING POWER EXCHANGES)

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 (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	Megawatthours Purchased (Excluding for Energy Storage) (g)
1	Eagle Creek - Lower Beaver Falls	LU	NM-360				
2	Eagle Creek - Upper Beaver Falls	LU	NM-361				
3	Lyonsdale Associates	OS	NM-297				
4	Silverstreet Hydro - Burt Dam Power Company	LU	NM-1379				
5	Dunn Paper - Cellu-Tissue Corp - Natural Dam	LU	NM-294				
6	Eagle Creek - Champlain Spinners - Power Co	LU	NM-672				
7	Ampersand - Christine Falls	LU	NM-1834				
8	Enel - Copenhagen Hydro - High Falls - - 845"A"	LU	NM-845				
9	Ampersand - Cranberry Lake Hydro	LU	NM-1830				
10	Black River C/O Enel - Denley - New Generation	LU	NM-341				
11	Enel - Dexter Hydro - HDG - - 845"C"	LU	NM-845				
12	Enel - Diamond Island Hydro - - 845"F"	OS	NM-845				
13	Edison Hydroelectric	LU	NM-1671				
14	Empire Hydro	LU	NM-315				
15	Erie Blvd Hydropower L.P. (Hewittville)	LU	NM-277H				
16	Erie Blvd Hydropower L.P. (Unionville)	SF	NM-277U				
17	FINCH PAPER LLC	LU	NM-1670				
18	Ampersand - Forestport Hydro	LU	NM-1831				
19	Fort Miller Hydro	LU	NM-367				
20	Fortis USEnergy (Diana)	LU	NM-1527				
21	FortisUS Energy Corporation (Dolgeville)	LU	NM-1528				
22	FortisUS Energy Corporation(Moose River)	LU	NM-1414				
23	FortisUS Energy Corporation (Phil.Hydro)	LU	NM-1415				
24	Enel - Fowler Hydro	SF	NM-196				
25	Enel - Hailesboro Hydro #3 - - 845"B"	LU	NM-845				
26	Enel - Hailesboro Hydro #4 - - 845 "G"	LU	NM-845				
27	Enel - Haliesboro Hydro #6 - - 845 "D"	LU	NM-845				
28	City of Oswego - High Dam	LU	NM-805				
29	Hollingsworth & Vose-Upper	LU	NM-1547				
30	Hollingsworth & Vose-Lower	LU	NM-1546				
31	Ampersand - Hollow Dam Hydro	LU	NM-1378				
32	Enel - Lachute Hydro - - 420 & 421	LU	NM-420				
33	Lake Algonquin Hydro	LU	NM-458				
34	Little Falls Hydro	SF	NM-307				
35	Middle Falls	LU	NM-548				
36	Ampersand - MT IDA Associates	LU	NM-1787				
37	Eagle Creek - Newport Hydro	SF	NM-484				
38	OAKVALE CONSTRUCTION LTD.	LU	NM-1692				
39	Northline Energy - Wave Hydro	LU	NM-1638				
40	Ampersand - Ogdensburg Hydro	LU	NM-1832				
41	Curtis Palmer Hydroelectric	LU	NM-338				
42	Eagle Creek - Phoenix Hydro	OS	NM-618				
43	Black River Hydro C/O Enel - Port Leyden-Kelpytown Rd	LU	NM-343				
44	Enel - Pyrites - New Hydro	LU	NM-362				
45	Riverrat Glass & Electric	OS	NM-1783				
46	Rock City Falls - Cotterell Paper	OS	NM-477				
47	Sandy Hollow Hydro	LU	NM-383				
48	Stevens and Thompson (Dahowa)	LU	NM-1856				
49	Stillwater Hydro	LU	NM-369				
50	Total						

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

Megawatthours Purchased Purchased for Energy Storage (h)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
9,120			14,612	153,916	-	168,528	1
4,765			8,227	76,176	-	84,403	2
8,696			-	695,667	-	695,667	3
457			-	14,286	950	15,236	4
-			-	20	2	22	5
809			-	26,070	1,490	27,560	6
662			439	29,252	-	29,691	7
7,303			-	1,206,644	-	1,206,644	8
1,515			1,862	46,636	-	48,498	9
4,839			-	314,549	-	314,549	10
18,805			-	3,107,134	-	3,107,134	11
5,106			-	843,685	-	843,685	12
490			-	13,579	848	14,427	13
4,817			6,155	206,533	-	212,688	14
13,209			29,216	401,605	-	430,821	15
12,479			33,143	384,957	-	418,100	16
191			1,469	5,022	-	6,491	17
7,232			11,861	198,883	-	210,744	18
22,662			-	2,016,872	-	2,016,872	19
6,598			-	196,480	11,208	207,688	20
1,217			-	37,232	453	37,685	21
47,396			-	1,369,812	79,409	1,449,221	22
10,197			-	312,921	16,882	329,803	23
4,312			-	225,589	-	225,589	24
3,724			-	615,235	-	615,235	25
10,258			-	1,694,935	-	1,694,935	26
4,223			-	697,696	-	697,696	27
28,486			-	979,732	-	979,732	28
-			-	(971)	971	0	29
693			-	22,826	-	22,826	30
2,821			-	86,256	5,005	91,261	31
30,179			27,503	1,051,473	-	1,078,976	32
1,582			-	94,919	-	94,919	33
57,914			-	6,896,964	-	6,896,964	34
12,525			22,268	383,486	-	405,754	35
8,850			26,018	307,518	-	333,536	36
5,881			-	352,871	-	352,871	37
1,956			-	47,287	3,284	50,571	38
17			-	1,829	109	1,938	39
9,164			21,456	269,596	-	291,052	40
320,948			-	42,807,967	-	42,807,967	41
10,370			-	954,599	-	954,599	42
16,002			-	1,040,105	-	1,040,105	43
23,507			-	1,604,009	-	1,604,009	44
-			-	(1)	-	(1)	45
10			-	401	-	401	46
4			-	131	-	131	47
30,292			39,293	991,485	-	1,030,778	48
6,508			-	514,119	-	514,119	49
14,817,660			69,830,727	602,407,043	67,762,726	740,000,496	50

PURCHASED POWER (Account 555)
(INCLUDING POWER EXCHANGES)

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 (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	Megawatthours Purchased (Excluding for Energy Storage) (g)
1	GR Catalyst One - Stillwater Hydro	OS	NM-617				
2	Ampersand - Tannery Island Power Company	LU	NM-380				
3	Enel - Theresa Hydro - - 845 "E"	OS	NM-845				
4	KEI Power Mgmt - Union Falls Hydropower LTD Partnership	OS	NM-429				
5	Mohawk Valley Water Authority - Utica Water Board - Sand Road	OS	NM-670				
6	Mohawk Valley Water Authority - Utica Water Board - Trenton Falls	LU	NM-669				
7	Enel - Valatie Falls Hydro	LU	NM-679				
8	Valley Falls Hydro	OS	NM-368				
9	EGPNA Renewable Energy Partners - Victory Mills Hydro	LU	NM-453				
10	Village of Saranac Lake, Inc.	OS	NM-913				
11	Watertown, City of (Contract Plant)	LU	NM-662				
12	Watervliet Hydro	LU	NM-393				
13	Northbrook Carthage - West End Dam	LU	NM-1825				
14	Albany Engineering Inc	OS	NM-1368				
15	Ampersand Long Falls - Wamco	LU	NM-575				
16	General Mills	LU	NM-1411				
17	Onondaga Co Resource Recovery	LU	NM-320				
18	Oswego Cty Energy Recovery	LU	NM-358				
19	Fortistar North Tonowanda, Inc. (oxbow)	LU	NM-498				
20	US Gypsum Company	OS	NM-1691				
21	Allied Frozen Storage	LU	NM-1607				
22	Burrstone Energy Center (Luke)	LU	NM-1673				
23	Burrstone Energy Center (Utica)	LU	NM-1672				
24	St Elizabeth Medical Center	LU	NM-1756				
25	Albany Engineering Corp - Stuyvesant Falls Hydro	LU	NM-1764				
26	Sustainable Bioelectric LLC	LU	NM-1796				
27	Gloversville Johnstown Joint Waste water treatment Facility	LU	NM-1824				
28	Re Energy Black River LLc	LU	NM-1836				
29							
30	Municipalities						
31	Brockton, Village of	RQ					
32	Frankfort Power & Light	RQ					
33	Richmondville Power & Light	RQ					
34	Wellsville, City of	RQ					
35	New York Power Authority - Niagara	OS	NM-76				
36	Albany Engineering - Green Island Power Authority	LF	NM-1305				
37		IU					
38							
39	WINDMILL GENERATION						
40							
41	FARM WASTE						
42	Walker Farms	OS					
43							
44	PHOTOVOLTAIC GENERATION						
45	Distributed Generation Avoided Costs						
46	VDER - Energy Component						
47	VDER - Capacity Component						
48	VDER - Enivornmental Component						
49							
50	Total						

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

Megawatthours Purchased Purchased for Energy Storage (h)	POWER EXCHANGES Megawatthours Received (h)	POWER EXCHANGES Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
13,394			-	1,306,405	-	1,306,405	1
6,394			-	183,482	11,595	195,077	2
5,825			-	962,531	-	962,531	3
8,041			22,562	141,736	-	164,298	4
1,450			1,097	43,627	-	44,724	5
667			3,817	17,954	-	21,771	6
347			-	9,566	662	10,228	7
7,074			-	495,153	-	495,153	8
6,588			-	395,255	-	395,255	9
524			497	13,562	-	14,059	10
11,264			-	2,441,021	-	2,441,021	11
2,705			-	97,971	4,194	102,165	12
21,435			46,736	614,425	-	661,161	13
20,735			-	755,557	37,573	793,130	14
4,855			13,668	108,187	-	121,855	15
1,567			3,504	61,484	-	64,988	16
212,050			410,102	5,072,818	-	5,482,920	17
4,285			-	239,282	-	239,282	18
-			-	(427,124)	-	(427,124)	19
1,152			3,030	38,157	-	41,187	20
60			3	2,866	-	2,869	21
925			801	47,463	-	48,264	22
125			454	4,239	-	4,693	23
407			446	15,613	-	16,059	24
19,032			-	652,067	30,170	682,237	25
882			-	24,967	1,335	26,302	26
1,207			3,016	49,459	-	52,475	27
203,428			481,894	6,029,603	-	6,511,497	28
-			-	-	-	-	29
-			-	-	-	-	30
31			-	1,827	-	1,827	31
363			-	29,870	-	29,870	32
90			-	8,603	-	8,603	33
25			-	1,492	-	1,492	34
191,625			-	9,528,596	-	9,528,596	35
39,462			82,139	1,482,342	-	1,564,481	36
-				-		-	37
-				-		-	38
-				-		-	39
-				-		0	40
-				-		0	41
-				-		0	42
-				-		0	43
-				-		0	44
9,962				334,061		334,061	45
218				8,089		8,089	46
				3,062		3,062	47
				5,274		5,274	48
						-	49
14,817,660			69,830,727	602,407,043	67,762,726	740,000,496	50

PURCHASED POWER (Account 555)
(INCLUDING POWER EXCHANGES)

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 (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	Megawatthours Purchased (Excluding for Energy Storage) (g)
1	RTO/ISO						
2	New York State ISO	EX	ISO-MKT-SVC				
3							
4	Energy Marketers	OS					
5	Constellation Zone F Swap	OS					
6	Covanta Niagara LP	OS					
7	NextEra Marketing	OS					
8	BP Energy	OS					
9	Exelon Generating	OS					
10	PSEG Marketing	OS					
11	Evolution Marketing	OS					
12	TFS Energy Futures	OS					
13	Dynegy Inc.						
14	NYSERDA						
15	Con Edison						
16	Canadian Niagara Power						
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48							
49							
50	Total						

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

Megawatthours Purchased Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
						0	1
12,952,784			52,234,340	479,612,506	24,205,902	556,052,748	2
						0	3
					-	-	4
			-	1,808,806	-	1,808,806	5
			-	-	-	-	6
			1,812,000	-	-	1,812,000	7
			6,688,000	-	-	6,688,000	8
			4,190,000	-	-	4,190,000	9
-			2,243,000	-	-	2,243,000	10
-			28,522	-	-	28,522	11
			37,248	-	-	37,248	12
			800,000			800,000	13
					43,346,457	43,346,457	14
			622,000			622,000	15
			(143,059)			(143,059)	16
							17
							18
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							20
							21
							22
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							43
							44
							45
							46
							47
							48
							49
14,817,660			69,830,727	602,407,043	67,762,726	740,000,496	50

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

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, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in columns (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:

LF - for long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.
OS - for other transmission service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm transmission service, regardless of the length of the contract. 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.

Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistical Classification (d)
1	NYPA (TSC)	NYPA	NYPA NYS Municipal Customers	OS
2	NYPA	NYPA	Niagara Frontier Transit Authority	OLF
3	NYPA	NYPA	NYPA NYS Municipal Customers	OLF
4	NYPA	NYPA	Consolidated Edison	OS
5	Central Hudson Gas & Electric	Central Hudson Gas & Electric	Central Hudson Gas & Electric	OLF
6	Central Hudson Gas & Electric	Central Hudson Gas & Electric	Central Hudson Gas & Electric	OS
7	LIPA	NYPA	LIPA	OLF
8	LIPA	LIPA	LIPA	OLF
9	NYSEG	NYSEG	NYSEG	OLF
10	City of Watertown	City of Watertown	City of Watertown	OLF
11	Selkirk Co-Gen	Selkirk Co-Gen	Consolidated Edison	OLF
12	Sithe Independence	Sithe Independence	Consolidated Edison	OLF
13	Indeck	Indeck	Consolidated Edison	OLF
14	Muni Wheels / OATT	Various	Various	OS
15	RG&E Tx Capacity Charge	Various	Various	OLF
16	ISO External Trans. TSC	Various	Various	OS
17	NYMPA, Misc Villages, Jamestown, Griffiss (T	Various	Various	OS
18	New York Power Authority	New York Power Authority	New York Power Authority	OS
19	Brookfield Renewable	Support	Support	OS
20	Carthage	Support	Support	OS
21	City of Oswego	Support	Support	OS
22	City of Salamanca	Support	Support	OS
23	Sithe	Support	Support	OS
24	Indeck Olean	Support	Support	OS
25	Lake Colby	Support	Support	OS
26	Marcy Facts	Support	Support	OS
27	Rensselaer Generating	Support	Support	OS
28	American Ref-Fuel Covanta	Support	Support	OS
29	South Glens Falls	Support	Support	OS
30	Copenhagen Associates	Support	Support	OS
31	Lyonsdale Biomass, LLC	Support	Support	OS
32	Northern Electric Power	Support	Support	OS
33	Hydro Development Group	Support	Support	OS
34	Canadian Niagara Power	Support	Support	OS
35				
36	From Insert Page			
37	Total			

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.
FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.
LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.
OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.
SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.
NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

FERC Rate Schedule or Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatthours Received (i)	TRANSFER OF ENERGY Megawatthours Delivered (j)	Line No.
NYISO OATT	Various	NYPA NYS Muni		89,496	89,496	1
136	Various	Niagara Frontier				2
18	Various	NYPA NYS Muni	8			3
180	Various	Crescent Vischer				4
141	Nine Mile 2 Station	Central Hudson Gas	103			5
55	North Catskill	North Catskill				6
142	Fitzpatrick	Consolidated Edison	142			7
142	Nine Mile 2 Station	Consolidated Edison	206			8
165	Various	Various	464			9
174	Watertown Hydro	Watertown Muni		11,314	11,314	10
171	Selkirk Station	Consolidated Edison				11
178	Sithe Station	Consolidated Edison				12
175	Indeck Station	Consolidated Edison				13
NYISO OATT	Various	Various				14
178	Various	Various				15
NYISO OATT	Various	Various		291,134	291,134	16
NYISO OATT	N/A	Various		2,820,314	2,820,314	17
NYISO OATT	Edic Substation	Edic Substation				18
ER09-1276	Brookfield Renewable	Brookfield Renewable				19
ER08-1175	Carthage	Carthage				20
CLA 25.1.5.021	City of Oswego	City of Oswego				21
ER95-574	City of Salamanca	City of Salamanca				22
ER15-2127	Sithe	Sithe				23
ER99-4238	Indeck Olean	Indeck Olean				24
ER09-1503	Lake Colby	Lake Colby				25
CLA 25.1.6.005	Marcy Facts	Marcy Facts				26
ER07-1096	Rensselaer Generating	Rensselaer Generating				27
ER07-1285	American Ref-Fuel Gt	American Ref-Fuel Gt				28
QF/ PPA -862- 93-65	Existing Circuit at Glens Falls –	High Side of GSU at the facility				29
ER17-1703-000	Middle Road Station	Middle Road Station				30
SA No. 1152	Lyonsdale facility	Burrows paper tap				31
QF/ PPA863	Existing Circuit - Mohican	High side of GSU at the facility				32
CLA 036-25.1-3.159.1	Fowler Facilities	Fowler Facilities				33
CLA 036-25.28.014	Fort Erie	Fort Erie				34
						35
						36
			923	3,212,258	3,212,258	37

Name of Responder	This Report is:	Date of Report	Year of Report
Niagara Mohawk Po	(1) [ ] An Original	(Mo, Da, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred 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 columns (i) and (j) the total megawatthours received and delivered.
9. In columns (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 re to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rend including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in colu the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero ("0 column (n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy service rendered.
10. Provide total amounts in columns (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amou columns (i) and (j) must be reported as Transmission Received and Delivered 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.
		$657,545	$657,545	1
			0	2
		21,352	21,352	3
			0	4
2,175,360			2,175,360	5
		195,300	195,300	6
2,999,040			2,999,040	7
4,350,720			4,350,720	8
9,354,240			9,354,240	9
		83,543	83,543	10
			0	11
			0	12
			0	13
			0	14
319,896			319,896	15
		2,076,066	2,076,066	16
		20,623,640	20,623,640	17
		1,021,388	1,021,388	18
		22,952	22,952	19
		5,681	5,681	20
		6,200	6,200	21
		2,400	2,400	22
		(75,240)	(75,240)	23
		(24,637)	(24,637)	24
		4,436	4,436	25
		193,429	193,429	26
		73,455	73,455	27
		24,074	24,074	28
		2,523	2,523	29
		18,987	18,987	30
		2,430	2,430	31
		8,411	8,411	32
		26,249	26,249	33
		100,362	100,362	34
				35
			0	36
$19,199,256	$0	$25,070,546	$44,269,802	37

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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 9e) 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 Tariff (d)	Total Revenue (e)
1	NiMo - TCC Auction Revenue	FNS	NYISO OATT	49,910,803	177,145,380
2	NiMo - Congestion Revenue	FNS	NYISO OATT		
3	NiMo - Congestion Balancing	FNS	NYISO OATT	(8,805,343)	(16,209,474)
4	NiMo - TCC Monthly Revenue	FNS	NYISO OATT	221,462	1,247,901
5					
6					
7					
8					
9					
10					
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40	TOTAL			41,326,922	162,183,807

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC and GAS)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	
5	Other Expenses (List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less than $5,000 by classes if the number of items so grouped is shown).	
6	Electric	
7	Research and Development Activities	$1,482,328
8	Environmental activities Expenses	29,415,750
9	Meter Data Services	1,667,268
10	Expense as Built	7,998,368
11	Computer Network	1,745,517
12	Other	2,184,795
13		
14	Subtotal	44,494,026
15		
16		
17	Gas	
18	Research and Development Activities	1,427,561
19	Environmental activities Expenses	5,190,750
20	Expense as Built	154,144
21	Computer Network	112,416
22	Other	177,406
23		
24	Subtotal	7,062,277
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51	Total	$51,556,303

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original	(Mo, Da, Yr)	
	(2) [ ] A Resubmission	April 17, 2019	December 31, 2018

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition 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 B 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 subaccounts used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a 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 (Acct. 404) (d)	Amortization of Other Electric Plant (Acct. 405) (e)	Total (f)
1	Intangible Plant				$321,454	$321,454
2	Steam Production Plant					0
3	Nuclear Production Plant					0
4	Hydraulic Production Plant-Conventional	32,543				32,543
5	Hydraulic Production Plant-Pumped Storage					0
6	Other Production Plant	80,707				80,707
7	Transmission Plant	64,476,570		432,420		64,908,990
8	Distribution Plant	145,912,815		550,220		146,463,035
9	Regional Transmission and Market Operation					0
10	General Plant	12,144,229				12,144,229
11	Common Plant-Electric	6,992,236				6,992,236
12	TOTAL	$229,639,100	$0	$982,640	$321,454	$230,943,194

B. Basis for Amortization Charges

Base and Rates for Amortization of Electric Plant(404 & 405)

Utility Account	Base	Rate
Account 404		
NIMO 101/106 35040	32,168	1.31%
NIMO 101/106 36015	147	1.33%
NIMO 101/106 36025	38,284	1.33%
Account 405		
36 101 30200 HUDSON FALLS RESERVOIR	2,417	5.56%
36 101 30200 SOUTH GLENS FALLS HYDR	251	5.94%
30200 Total	2,667	5.59%

*Base is calculated in thousands

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

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)
1	**Intangible Plant**						
2	30200	6,358					
3	30300	1,269					
4	**Subtotal**	**7,627**					
5							
6	**Hydraulic Production Plant**						
7	330						
8	**Subtotal**	**0**					
9							
10	**Other Production Plant**						
11	34600	1,854			4.540%		
12	**Subtotal**	**1,854**					
13							
14	**Transmission**						
15	35000	3,480					
16	35010	7,083					
17	35020	1,722					
18	35030	62,685					
19	35040	33,067	75	1.200%	1.320%	H5	37.22
20	35200	48,709	55	-33.000%	2.420%	R2.5	33.09
21	35300	1,216,255	45		2.530%	L0.5	
22	35310	2,967	45		2.530%	L0.5	
23	35355	51,759	25	-5.000%	4.200%	H5	7.12
24	35400	121,323	75	-35.000%	1.800%	R4	29.38
25	35500	850,940	65	-45.000%	2.230%	R2.5	52.08
26	35600	927	80		1.690%	R2.5	
27	35610	241,779	80		1.690%	R2.5	
28	35620	335,375	80		1.690%	R2.5	
29	35630	96			4.520%		
30	35710	12,056	85		1.240%	R3	
31	35720	30,211	85		1.240%	R3	
32	35800	147,264	80	-27.000%	1.590%	R3	53.75
33	35900	10,259	75	0.000%	1.330%	H4	59.95
34	**Subtotal**	**3,177,957**					
35							
36	**Distribution**						
37	36000	32					
38	36010	10,286					
39	36015	147	75		1.330%		
40	36020	463					
41	36025	44,091	75		1.330%		
42	36100	49,587	80	-33.000%	1.660%	R2.5	53.57
43	36200	720,684	60		1.920%		
44	36210	2,879	60		1.920%		
45	36255	89,114	25	-5.000%	4.200%	S3	8.22
46	36400	1,191,823	65	-20.000%	1.850%	R1.5	51.45
47	36500	1,323,550	60	-40.000%	2.330%	R4	38.15
48	36503	2,735	22		4.520%	L1	
49	36610	116,093	70		1.660%	R0.5	
50	36620	98,993	70		1.660%	R0.5	
51	36710	688,005	75	-30.000%	1.730%	R3	59.92
52	36810	72,894	40		2.650%	R1.5	
53	36820	583,365	40		2.650%	R1.5	
54	36830	354,929	40	-35.000%	3.380%	R2	24.44
55	36910	335,190	55	-45.000%	2.640%	R4	33.49
56	36920	9,783	85	-5.000%	1.240%	H4	48.11
57	36921	163,896	85	-20.000%	1.410%	H2.5	60.61
58	37010	62,212	20	-25.000%	6.250%	H0.5	15.88
59	37020	56,198	20	-25.000%	6.250%	H0.5	16.51
60	37030	20,927	20	-1.000%	5.050%	H3	12.87
61	37035	32,592	20	-1.000%	5.050%	H3	9.03
62	37100	7,788	42	-11.000%	2.640%	R1.5	25.01
63	37130	56			2.640%		
64	37310	43,499	60	-30.000%	2.170%	H1.5	
65	37311	47,128	20	-30.000%	6.500%	S3	10.80
66	37320	130,776	60	-30.000%	2.170%	H1.5	
67	37321	53,510	20	-30.000%	6.500%	S3	10.42
68	37330	2,144	25	-30.000%	5.200%	S3	0.00
69	37400	1,694					
70	**Subtotal**	**6,317,063**					
71							
72	**General:**						
73	38900	2,339					
74	38910	2					
75	39000	110,265	45	-13.000%	2.510%	H0.5	36.19
76	39100	1,746	22		4.550%	SQ	
77	39110	1,112	22	0.000%	4.550%	SQ	
78	39120	5,187	5	0.000%	20.000%	SQ	
79	39200	56	15		3.333%		
80	39222	8,007	15	50.000%	3.330%	SQ	14.50
81	39300	60	22	0.000%	4.550%	SQ	1.00
82	39400	6,548	22	0.000%	4.550%	SQ	
83	39410	2,511	22		4.550%	SQ	
84	39420	38,837	22		4.550%	SQ	
85	39500	12,632	22	0.000%	4.550%	SQ	
86	39600	279	22	0.000%	4.550%	SQ	16.71
87	39710	4,380	22	0.000%	4.550%	SQ	
88	39720	43,429	8	0.000%	12.500%	SQ	
89	39730	9,296	22	0.000%	4.550%	SQ	
90	39735	49	22		4.550%	SQ	
91	39750	6,682	22	0.000%	4.550%	SQ	10.50
92	39760	6,444	22	0.000%	4.550%	SQ	7.42
93	39800	9,009	22	0.000%	4.550%	SQ	
94	39801	632	22	0.000%	4.550%	SQ	1.00
95	39810	763	22	0.000%	0.05	SQ	
96	39855	183	22		0.05	SQ	
97	39856	31,661					
98	**Subtotal**	**302,109**					
99							
100	**Total**	**9,806,610**					
101							

Next Page is 340

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430)-For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431)-Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Miscellaneous Amortization (Account 425)	
2		
3		
4		
5		
6		
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8		
9		
10	Total	$0
11	Donations (Account 426.1)	
12	AMERICAN RED CROSS OF CENTRAL MASS	$113,558
13	HEARTSHARE HUMAN SERVICES OF NEW YO	250,000
14	UNITED WAY OF BUFFALO & ERIE CO.	151,909
15	UNITED WAY OF CENTRAL NEW YORK INC	398,275
16	Donations (Less than 5%)	1,582,625
17		
18		
19		
20		
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41	Total	$2,496,367

If applicable, see insert pages below:

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Line No.	Item (a)	Amount (b)
1	Life Insurance (Account 426.2)	
2	Miscellaneous	$129,923
3		
4		
5		
6		
7	Total	$129,923
8	Penalties (Account 426.3)	
9	Penalties	$43,715
10		
11		
12		
13		
14		
15	Total	$43,715
16	Expenditures for Certain Civic, Political, and Related Activities (Account 426.4)	
17	Lobbying	$570,347
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52	Total	$570,347

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Line No.	Item (a)	Amount (b)
1	Other Deductions (Account 426.5)	
2	Legal Fee Accrual	$6,600,000
3	Miscellaneous (Less than 5%)	1,278,837
4		
5		
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12		
13		
14		
15	Total	$7,878,837
16	Interest on Debt to Associated Companies (Account 430)	
17		$0
18		
19		
20		
21		
22		
23		
24		
25		
26	Total	$0
27	Other Interest Expense (Account 431)	
28	Interest Charges FIN 48	$10,261,223
29	Community Carrying Charge	5,805,311
30	Miscellaneous (Less than 5%)	25,755,357
31		
32		
33		
34		
35	Total	$41,821,891
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Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

REGULATORY COMMISSION EXPENSES FOR ELECTRIC AND GAS

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party. Identify this expense as Electric, Gas or Common.

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 Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 Beginning of Year (e)
1	Public Service Commission of the State of				
2	New York:				
3					
4	Expense of the NYPSC	10,311,842		10,311,842	(822,473)
5	General and Temporary Assessments 18-A				
6					
7	Rate Case Expenses Deferred				
8	Amortization (Apr 2018 - Mar 2021)				1,353,665
9					
10					
11	Management Audit Expense Deferred				
12	Amortization (Apr 2018 - Mar 2023)				
13					
14					
15	MISCELLANEOUS:				
16					
17	Miscellaneous FERC and PSC expenses relating		1,052,406	1,052,406	
18	to permit fees, regulatory requirements, legal				
19	fees, environmental activities, and other				
20	various matters.				
21					
22					
23					
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42					
43					
44					
45	TOTAL	$10,311,842	$1,052,406	$11,364,248	$531,192

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

REGULATORY COMMISSION EXPENSES FOR ELECTRIC AND GAS (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			
Charged Currently 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
electric	928	8,215,028				(1,753,161)	4
gas	928	2,096,814					5
							6
							7
electric	928		(88,575)		369,750	847,960	8
gas	928		(72,470)		297,000		9
							10
							11
electric	928		(112,399)		50,400	76,340	12
gas	928		(23,941)		9,600		13
							14
							15
							16
electric	928	862,994					17
gas	928	189,412					18
							19
							20
							21
							22
							23
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							43
							44
		$11,364,248	(297,385)		$726,750	($828,861)	45

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Electric and Gas)

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 on by the respondent in which there is a sharing of costs 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 and Gas 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) System Planning, Engineering and Operation
  (3) Transmission
    a. Overhead
    b. Underground
  (4) Distribution
  (5) Regional Transmission and Market Operation
  (6) Environment (other than equipment)
  (7) Other (Classify and include items in excess of $50,000.)
  (8) Total Cost Incurred
B. Electric and Gas R, D & D Performed Externally
  Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Other	R&D Related Activities
2		
3		
4		R&D Operations
5		$25,335 in Transmission - Internal
6		$336,252 in Transmission - External
7		
8		
9		
10		
11		
12		
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14		
15		
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35		
36		
37		
38	Total	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(1) Research Support to the Electrical Research Council or the Electric Power Research Institute
(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 $5,000 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 accumulation 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)	Amount (f)	Unamortized Accumulation (g)	Line No.
151,668	2,758,221	930.2	2,909,889		1
					2
					3
					4
					5
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					34
					35
					36
					37
$151,668	$2,758,221		$2,909,889	$0	38

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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			
4	Transmission	301,861		
5	Regional Market			
6	Distribution	71,888,394		
7	Customer Accounts	22,843,452		
8	Customer Service and Informational	10,663,337		
9	Sales	529,357		
10	Administrative and General	57,206,156		
11	TOTAL Operation (Enter Total of lines 3 thru 9)	163,432,557		
12	Maintenance			
13	Production			
14	Transmission	37,505		
15	Regional Market			
16	Distribution	73,788,420		
17	Administrative and General			
18	TOTAL Maint. (Total of lines 12 thru 15)	73,825,925		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 12)	0		
21	Transmission (Enter Total of lines 4 and 14)	339,366		
22	Regional Market (Enter Total of lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	145,676,814		
24	Customer Accounts (Transcribe from line 7)	22,843,452		
25	Customer Service and Informational (Transcribe from line 8)	10,663,337		
26	Sales (Transcribe from line 9)	529,357		
27	Administrative and General (Enter Total of lines 10 and 17)	57,206,156		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	237,258,482	(209,055)	237,049,427
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production - Natural Gas (Including Expl. and Dev.)			
33	Other Gas Supply	7,724		
34	Storage, LNG Terminaling and Processing	1,140,810		
35	Transmission	1,140,127		
36	Distribution	19,608,921		
37	Customer Accounts	5,981,642		
38	Customer Service and Informational	2,631,981		
39	Sales	409,229		
40	Administrative and General	16,602,270		
41	TOTAL Operation (Enter Total of lines 28 thru 37)	47,522,704		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production - Nat. Gas			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	802,736		
48	Distribution	10,380,337		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 40 thru 46)	11,183,073		

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas (Continued)			
51	Total Operation and Maintenance			
52	Production - Manufactured Gas (Enter Total of lines 28 and 40)	0		
53	Production - Nat. Gas (Including Expl. and Dev.) (Total of lines 29 and 41)	0		
54	Other Gas Supply (Enter Total of lines 30 and 42)	7,724		
55	Storage, LNG Terminaling and Processing (Total of lines 31 and 43)	1,140,810		
56	Transmission (Lines 32 and 44)	1,942,863		
57	Distribution (Lines 33 and 45)	29,989,258		
58	Customer Accounts (Line 34)	5,981,642		
59	Customer Service and Informational (Line 35)	2,631,981		
60	Sales (Line 36)	409,229		
61	Administrative and General (Lines 37 and 46)	16,602,270		
62	TOTAL Operation and Maint. (Total of lines 49 thru 58)	58,705,777	(43,337)	58,662,440
63	Other Utility Departments			0
64	Operation and Maintenance			0
65	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	295,964,259	(252,392)	295,711,867
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	148,350,341	6,514,863	154,865,204
69	Gas Plant	34,646,385	1,881,276	36,527,661
70	Other			0
71	TOTAL Construction (Total of lines 65 thru 67)	182,996,726	8,396,139	191,392,865
72	Plant Removal (By Utility Departments)			
73	Electric Plant			0
74	Gas Plant			0
75	Other			0
76	TOTAL Plant Removal (Total of lines 70 thru 72)	0	0	0
77	Other Accounts (Specify):			
78	Other work in progress (174)	10,873,919	5,730	10,879,649
79				
80	Misc Income Deductions	233,637	0	233,637
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95				
96				
97				
98	TOTAL Other Accounts	11,107,556	5,730	11,113,286
99	TOTAL SALARIES AND WAGES	490,068,541	8,149,477	498,218,018

Name of Respondent	This Report is:	Date of Report	Year of Report
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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.

Acct. No.	Item	Beginning Balance	Additions	Retirements	Transfers	Adjustments	Ending Balance
301	Organization						$0
302	Franchises & Consents						0
303	Miscellaneous Intangible Plant						
	Total Intangible Plant	0	0	0	0		0
	Other (Specify)						
	Total Other	0	0	0	0		0
389	Land & Land Rights	5,274,371	(35,538)	0	0		5,238,833
390	Structures & Improvements	211,677,424	8,090,358	(1,107,779)	0	(214,111)	218,445,892
391	Office Furniture & Equipment	14,041,239	16,486	(2,861,603)	0		11,196,122
392	Transportation Equipment	4,931,995	0	0	0		4,931,995
393	Stores Equipment	1,142,478	0	(140,647)	0		1,001,831
394	Tools, Shop & Garage Equipmt.	4,245,913	0	(254,996)	0		3,990,917
395	Laboratory Equip	0	0	0	0		0
396	Power Operated Equipment	0	0	0	0		0
397	Communication Equipment	29,272,643	24,807	(226,682)	0		29,070,768
398	Misc. Equipment	512,315	0	(4,237)	0		508,078
399	Other Tangible Property	616,919	0	(567,445)	0	1,013,490	1,062,964
	Total General Plant	271,715,297	8,096,113	(5,163,389)	0	799,379	275,447,400
	Total Common Utility Plant	$271,715,297	$8,096,113	($5,163,389)	$0	$799,379	$275,447,400

Departmental Allocation of Common Items

Name of Respondent	This Report is:	Date of Report	Year of Report
Niagara Mohawk Power Corporation	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 17, 2019	December 31, 2018

COMMON UTILITY PLANT AND EXPENSES (CONTINUED)

RESERVE FOR DEPRECIATION OF COMMON UTILITY PLANT

Balance January 1, 2018	$91,110,247	
Depreciation and Amortization Provisions for year charged to:		
Depreciation - Electric	6,995,052	
Depreciation - Gas	1,432,721	
Total Depreciation and Amortization Provisions	8,427,773	
Net Charges for Plant Retired:		
Book Cost of Plant Retired	(5,163,387)	
Cost of Removal	(996,602)	
Net Charges for Plant Retired	(6,159,989)	
Other Debit or Credit Items:		
Asset Retirement Obligation Adjustment	799,735	
Net increase in Retirement Work in Progress	(78,079)	
Transfer of Provisions to Electric Department		
Balance December 31, 2018	$94,099,687	Page 201 line 22 column (h)

Common Utility Expenses and Departmental Allocation

Depreciation Expense
Allocation Factors to Common Plant Assets

17% Gas Segment
83% Electric Segment

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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)	$ 150,823,543	$ 79,213,768	$ 134,979,182	$ 112,681,202
3	Net Purchases (Account 555.1)				
4	Net Sales (Account 447)				
5	Transmission Rights				
6	Ancillary Services	6,949,849	7,182,008	6,105,232	6,521,510
7	Other Items (list separately)				
8	Installed Capacity	2,514,190	16,873,599	25,377,808	7,490,563
9					
10					
11					
12					
13					
14					
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45					
46					
47	TOTAL	160,287,582	103,269,375	166,462,222	126,693,275

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year/Period of Report December 31, 2018

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 purchase and sol 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 regulations 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 purchase and sold during the year.

(5) On line 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 Purchase 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 Unit (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	15,351,155	mwh	$ 8,057,987			
2	Reactive Supply and Voltage		mwh	5,679,927		MVAr	
3	Regulation and Frequency Response		mwh	2,193,493			
4	Energy Imbalance		mwh				
5	Operating Reserve - Spinning		mwh	8,891,098			
6	Operating Reserve - Supplement		Combined w/line 5				
7	Other		mwh	113,467			
8	Total (Lines 1 thru 7)	15,351,155		24,935,972	0		$ -

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year/Period of Report December 31, 2018

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)	Film Network Service for Self (e)	Film Network Service for Others (f)	Long-Term Film Point-to-point Reservation (g)	Other Long-Term Film Service (h)	Short-Term Film Point-to-point Reservation (i)	Other Services (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1	-			-	-	-	0	0	
5	April	5,585	6	12	4,115	573	897			
6	May	6,675	30	18	5,201	541	933			
7	June	7,116	18	14	5,598	585	933			
8	Total for Quarter 2	19,376			14,914	1,699	2763	0	0	
9	July	7,604	2	14	6,186	485	933			
10	August	7,544	6	15	6,117	494	933			
11	September	7,428	5	19	6,023	472	933			
12	Total for Quarter 3	22,576			18,326	1,451	2,799	0	0	
13	October	6,136	9	20	4,729	474	933			
14	November	6,145	7	18	4,732	516	897			
15	December	6,090	11	18	4,538	655	897			
16	Total for Quarter 4	18,371			13,999	1,645	2,727	0	0	
17	Total Year to Date/Year	60,323			47,239	4,795	8,289	0	0	

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year/Period of Report December 31, 2018

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	0			0	0	0	0	0	
5	April									
6	May									
7	June									
8	Total for Quarter 2	0			0	0	0	0	0	
9	July									
10	August									
11	September									
12	Total for Quarter 3	0			0	0	0	0	0	
13	October									
14	November									
15	December									
16	Total for Quarter 4	0			0	0	0	0	0	
17	Total Year to Date/Year	0			0	0	0	0	0	

Name of Respondent	This Report is:	Date of Report	Year of Report
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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)	Megawatthours (b)	Line No.	Item (a)	Megawatthours (b)
1	SOURCES OF ENERGY		22	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		23	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,267,670
3	Steam				
4	Nuclear		24	Requirements Sales for Resale (See Instruction 4, page 311.)	6,215
5	Hydro - Conventional				
6	Hydro - Pumped Storage		25	Non-Requirements Sales for Resale (See Instruction 4, page 311.)	
7	Other				
8	Less Energy for Pumping		26	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	0	27	Energy Used by the Company (Electric Department Only, Excluding Station Use)	17,328
10	Purchases	14,817,660	28	Total Energy Losses	526,223
11	Purchases for Energy Storage		29	Total Energy Stored	
12	Power Exchanges:		30	TOTAL (Enter Total of Lines 22 Through 29)(MUST EQUAL LINE 21)	14,817,436
13	Received				
14	Delivered				
15	Net Exchanges (Line 12 minus line 13)	0			
16	Transmission for Other (Wheeling)				
17	Received	3,212,258			
18	Delivered	3,212,258			
19	Net Transmission for Other (Line 16 minus line 17)	0			
20	Transmission by Other Losses				
21	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	14,817,660			

MONTHLY PEAKS AND OUTPUT

1. 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 in column (b) the system's energy output for each month such that the total on line 41 matches the total on line 20.
3. Report in column (c) a monthly breakdown of the Non-Requirements Sales for Resale reported on line 24. Include in the monthly amounts any energy losses associated with the sales so that the total of line 41 exceeds the amount on line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales for Resale.
4. Report in column (d) the system's monthly maximum megawatt load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c).
5. Report in columns (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-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instruction 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
31	January	1,393,554	394	6,024	5	HE 18
32	February	1,150,082	935	5,500	7	HE 8
33	March	1,202,285	332	5,101	8	HE 19
34	April	1,102,160	736	4,688	6	HE 12
35	May	1,076,029	445	5,766	30	HE 18
36	June	1,112,091	583	6,112	18	HE 14
37	July	1,426,552	370	6,495	16	HE 15
38	August	1,497,582	630	6,610	6	HE 15
39	September	1,201,364	623	6,500	5	HE 19
40	October	1,051,295	416	5,197	9	HE 20
41	November	1,247,125	371	5,238	27	HE 18
42	December	1,357,317	609	5,193	11	HE 18
43	TOTAL	14,817,436	6,444			

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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 Structures of Line Designated (f)	Length (Pole Miles): On Structures of Another Line (g)	Number of Circuits (h)
1	Clay	Dewitt	345.00		Lattice, Wood	15.08		1
2								
3	Dewitt	Lafayette	345.00		Steel, Wood, Lattice	8.31		1
4								
5	Nine Mile Point 1	Clay	345.00		Wood, Lattice, Steel	27.56		1
6								
7	Nine Mile Point 1	Scriba	345.00		Lattice, Steel	0.40		1
8								
9	Oswego	Lafayette	345.00		Wood, Lattice, Steel	48.55		1
10								
11	Oswego	Volney	345.00		Wood, Steel, Lattice	13.41		1
12								
13	Oswego	Volney	345.00		Wood, Steel, Lattice	13.41		1
14								
15	Scriba	Volney	345.00		Wood, Lattice, Steel	8.82		1
16								
17	Scriba	Volney	345.00		Wood, Steel	8.87		1
18								
19	Volney	Clay	345.00		Wood, Lattice, Steel	18.47		1
20								
21	Independence	Scriba	345.00		Steel	2.79		1
22								
23	Edic	New Scotland	345.00		Lattice, Steel, Wood	83.62		1
24								
25	Marcy	New Scotland	345.00		Steel, Lattice, Wood	83.91		1
26								
27								
28								
29	Volney	Marcy	345.00		Lattice, Wood, Steel	65.56		1
30								
31								
32								
33	Alps	Berkshire	345.00		Wood, Lattice	8.88		1
34								
35	Leeds	Hurley	345.00		Unknown	0.18		1
36					Total	5,765.03	0.00	383

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
216.7 KIWI ACSR	$900,555	$5,049,249	$5,949,804					1
								2
2 - 1192.5 BUNTING ACSR	541,168	5,074,079	5,615,247					3
								4
216.7 KIWI ACSR	1,220,182	5,292,053	6,512,235					5
								6
216.7 KIWI ACSR	0	442,025	442,025					7
								8
2 - 1192.5 BUNTING ACSR	5,625,110	20,896,361	26,521,471					9
								10
2 - 1192.5 BUNTING ACSR	1,743,552	3,815,061	5,558,613					11
								12
2 - 1192.5 BUNTING ACSR	0	4,197,269	4,197,269					13
								14
216.7 KIWI ACSR	208,643	3,891,599	4,100,242					15
								16
2 - 1192.5 BUNTING ACSR	0	0	0					17
								18
216.7 KIWI ACSR	0	887,691	887,691					19
								20
2 - 795 DRAKE ACSR	0	27,103,218	27,103,218					21
								22
2 - 795 DRAKE ACSR	2,627,756	37,619,494	40,247,250					23
								24
2 - 1192.5 BUNTING ACSR	2,322,341	29,633,497	31,955,838					25
2 - 1351.5 DIPPER ACSR	0	0						26
4 - 1351.5 DIPPER ACSR	0	0						27
								28
2 - 1192.5 BUNTING ACSR	2,640,639	84,286	2,724,925					29
2 - 1431 BOBOLINK ACSR	0	0						30
4 - 1351.5 DIPPER ACSR	0	0						31
								32
2 - 1192.5 BUNTING ACSR			0					33
								34
2 - 1033.5 ORTOLAN ACSR	0	59,438	59,438					35
	34,297,795	389,404,198	423,701,993	$0	$0	$0	$0	36

If applicable, see insert pages below

TRANSMISSION LINE STATISTICS (Continued)

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 Structures of Line Designated (f)	Length (Pole Miles) On Structures of Another Line (g)	Number of Circuits (h)
1	Athens	Pleasant Valley	345		Lattice, Steel	39.17		1
2								
3								
4	Leeds	Pleasant Valley	345.00		Lattice, Wood, Steel	38.76		1
5								
6								
7	New Scotland	Alps	345.00		Wood, Steel, Lattice	30.65		1
8								
9								
10	New Scotland	Leeds	345.00		Lattice	25.73		1
11								
12	New Scotland	Leeds	345.00		Lattice, Wood	25.86		1
13								
14	Reynolds Road	Alps	345.00		Wood, Lattice, Steel	11.09		1
15								
16	Independence	Clay	345.00		Steel, Wood, Lattice	29.14		1
17								
18	Leeds	Athens	345.00		Steel	0.49		1
19								
20	Reynolds Road	Empire	345.00		Steel	8.12		1
21								
22	Lafayette	Clarks Ciorner	345.00		Wood, Lattice, Steel	38.59		1
23								
24	Stolle Road	Five Mile Road	345.00		Wood, Lattice, Steel	25.17		1
25								
26	Pierce Brook (FE)	Five Mile Road	345.00		Wood, Steel, Lattice	12.34		1
27								
28	Beck	Packard	230.00		Lattice, Wood	4.1		1
29								
30								
31	Dunkirk	South Ripley	230.00		Wood, Lattice	31.41		1
32								
33								
34	South Ripley	Erie	230.00		Wood	0.15		1
35								
36	Gardenville	Dunkirk	230.00		Wood, Lattice, Steel	47.39		1
37								
38								
39	Gardenville	Dunkirk	230.00		Wood, Lattice, Steel	47.16		1
40								
41								
42	Huntley	Gardenville	230.00		Lattice, Steel	20.19		1
43								
44								
45	Huntley	Gardenville	230.00		Lattice, Steel	20.3		1
46								
47								
48	Niagara	Packard	230.00		Lattice	3.37		1
49								
50	Niagara	Packard	230.00		Lattice	3.42		1
51								
52								
53					Total	5,765.03	0.00	383

TRANSMISSION LINE STATISTICS (Continued)

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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
2 - 795 DRAKE ACSR	0	435,469	435,469					1
2 - 795 MALLARD ACSR								2
								3
2 - 795 MALLARD ACSR	0	0	0					4
2 - 795 DRAKE ACSR								5
								6
2 - 1192.5 BUNTING ACSR	2,587,038	19,671,534	22,258,572					7
3 - 1590 LAPWING ACSR								8
								9
2 - 795 DRAKE ACSR	2,018,970	12,948,389	14,967,359					10
								11
2 - 795 DRAKE ACSR	0	0	0					12
								13
2 - 1192.5 BUNTING ACSR	608,370	4,720,459	5,328,829					14
								15
2 - 1192.5 BUNTING ACSR	0	0	0					16
								17
2 - 795 DRAKE ACSR	153,716	38,568,281	38,721,997					18
								19
Unknown	0	0	0					20
								21
2 - 1192.5 BUNTING ACSR	0	0	0					22
								23
2 - 1192.5 BUNTING ACSR	0	46,413	46,413					24
								25
2 - 1192.5 BUNTING ACSR	0	0	0					26
								27
1158.4 ACSR	26,140	516,760	542,900					28
1192.5 BUNTING ACSR	0	0						29
								30
1192.5 BUNTING ACSR	586,893	3,325,951	3,912,844					31
1192.5 GRACKLE ACSR	0	0						32
								33
1192.5 BUNTING ACSR	0	194,637	194,637					34
								35
1192.5 BUNTING ACSR	3,618,873	8,726,511	12,345,384					36
1192.5 GRACKLE ACSR	0	0						37
								38
1192.5 BUNTING ACSR	0	0	0					39
1192.5 GRACKLE ACSR	0	0						40
								41
1192.5 GRACKLE ACSR	1,053,702	9,035,107	10,088,809					42
795 COOT ACSR	0	0						43
								44
1192.5 GRACKLE ACSR	0	0	0					45
795 COOT ACSR	0	0						46
								47
1431 ACSR	68,648	574,375	643,023					48
								49
1431 ACSR	0	347,181	347,181					50
								51
								52
	34,297,795	389,404,198	423,701,993	0	0	0	0	53

TRANSMISSION LINE STATISTICS (Continued)

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 Structures of Line Designated (f)	Length (Pole Miles) On Structures of Another Line (g)	Number of Circuits (h)
1	Packard	Huntley	230.00		Lattice, Wood, Steel	12.31		1
2								
3								
4								
5	Packard	Huntley	230.00		Lattice, Steel	12.08		1
6								
7								
8								
9	Adirondack	Porter	230.00		Wood, Steel, Lattice	54.33		1
10								
11								
12	Edic	Porter	230.00		Lattice, Wood	0.42		1
13								
14								
15	Porter	Rotterdam	230.00		Wood, Steel	71.71		1
16								
17								
18								
19	Porter	Rotterdam	230.00		Wood, Steel	72.09		1
20								
21								
22								
23	Adirondack	Chases Lake	230.00		Wood	11.05		1
24								
25	Chases Lake	Porter	230.00		Wood, Steel, Lattice	43.41		1
26								
27								
28	Rotterdam	Eastover	230.00		Wood, Steel, Lattice	23.52		1
29								
30								
31	Eastover	Bear Swamp	230		Wood, Steel	20.42		1
32								
33								
34								
35	Huntley	Elm	230		Underground	7.90		1
36	Elm	Seneca	230		Underground	3.16		1
37	Elm	Seneca	230		Underground	3.03		1
38	Seneca	Gardenville	230		Underground	3.00		1
39	Seneca	Gardenville	230		Underground	3.10		1
40	Elm Street Bus Tie		230		Underground	0.04		1
41	Conklin	Bailey (North)	230		Underground	0.30		1
42	Conklin	Bailey (South)	230		Underground	0.30		1
43								
44	Various		115		Various	4,519.74		298
45			115		Underground	32.70		30
46								
47								
48								
49								
50								
51								
52								
53					Total	5,765.03	0.00	383

TRANSMISSION LINE STATISTICS (Continued)

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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
1158.4 ACSR	1,239,863	5,145,759	6,385,622					1
1192.5 GRACKLE ACSR								2
795 COOT ACSR								3
								4
1158.4 1158.4 ACSR	0	0	0					5
795 COOT ACSR								6
1192.5 GRACKLE ACSR								7
								8
1431 BOBOLINK ACSR	0	4,013,534	4,013,534					9
795 COOT ACSR								10
								11
2 - 795 COOT ACSR	0	385,250	385,250					12
216.7 KIWI ACSR								13
								14
1431 BOBOLINK ACSR	788,373	6,420,719	7,209,092					15
795 COOT ACSR								16
795 DRAKE ACSR								17
								18
1431 BOBOLINK ACSR	178,309	13,730,293	13,908,602					19
795 DRAKE ACSR								20
795 COOT ACSR								21
								22
795 COOT ACSR	0	0	0					23
								24
1431 BOBOLINK ACSR	0	0	0					25
795 COOT ACSR								26
								27
1033.5 ORTOLAN ACSR	1,145,797	14,631,070	15,776,867					28
1113 FINCH ACSR								29
								30
1033.5 ORTOLAN ACSR								31
1113 FINCH ACSR								32
795 COOT ACSR								33
								34
2500 AL								35
750 Copper								36
750 Copper								37
1500 Copper								38
1500 Copper								39
2000 Copper	0	17,710	17,710					40
2500 Copper								41
2500 Copper								42
								43
Various	2,393,157	101,875,391	104,268,548					44
Various	0	28,085	28,085					45
								46
								47
								48
								49
								50
								51
								52
	34,297,795	389,404,198	423,701,993	0	0	0	0	53

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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	Akwesasne Station 825	Trans-Unattended	115.00	5.04	
2	Akwesasne Station 825	Trans-Unattended	115.00	34.50	
3	Albany High School Station 403	Dist-Unattended	34.40	13.80	
4	Albion Station 80	Dist-Unattended	34.40	4.80	
5	Albion Station 80	Dist-Unattended	34.50	4.80	
6	Alder Creek Station 701	Dist-Unattended	43.80	5.00	
7	Alder Creek Station 701	Dist-Unattended	43.80	13.80	
8	Altamont Station 283	Dist-Unattended	115.00	13.80	
9	Andover Station 09	Trans-Unattended	34.50	4.80	
10	Andover Station 09	Trans-Unattended	110.00	34.50	
11	Antwerp Station 801	Dist-Unattended	23.00	4.80	
12	Arnold Pit 4746	Dist-Unattended	23.00	0.48	
13	Arnold Station 656	Dist-Unattended	43.80	4.40	
14	Arnold Station 656	Dist-Unattended	43.80	13.80	
15	Ash Street Station 223	Trans-Unattended	34.40	4.40	
16	Ash Street Station 223	Trans-Unattended	34.50	4.40	
17	Ash Street Station 223	Trans-Unattended	110.00	34.50	
18	Ash Street Station 223	Trans-Unattended	115.00	12.50	
19	Ash Street Station 223	Trans-Unattended	115.00	12.50	12.50
20	Ash Street Station 223	Trans-Unattended	115.00	13.80	
21	Ash Street Station 223	Trans-Unattended	115.00	34.50	
22	Ashley Station 331 (Port PDS 7 East)	Dist-Unattended	34.50	13.20	
23	Attica Station 12	Dist-Unattended	34.50	4.80	
24	Ausable Forks Station 846	Dist-Unattended	46.00	5.00	
25	Avenue A Station 291	Dist-Unattended	34.40	4.40	
26	Avon Station 43	Dist-Unattended	34.50	4.80	
27	Baker Street Station 150	Dist-Unattended	115.00	13.20	
28	Ballina Station 221	Dist-Unattended	34.50	13.20	7.97
29	Ballston Station 12	Trans-Unattended	34.40	4.16	
30	Ballston Station 12	Trans-Unattended	110.00	34.40	13.80
31	Ballston Station 12	Trans-Unattended	113.00	13.80	
32	Balmat Station 904	Trans-Unattended	23.00	4.80	
33	Balmat Station 904	Trans-Unattended	115.00	23.00	
34	Barker Station 78	Dist-Unattended	34.50	4.80	
35	Bartell Road Station 325	Dist-Unattended	115.00	13.80	
36	Basom Station 15	Dist-Unattended	34.50	4.80	
37	Batavia Station 01	Trans-Unattended	115.00	13.20	
38	Batavia Station 01	Trans-Unattended	115.00	13.80	
39	Batavia Station 01	Trans-Unattended	115.00	34.50	
40	Total on page				

If applicable, see insert page below

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Battenkill Station 342	Trans-Unattended	110.00	34.40	13.80
2	Battenkill Station 342	Trans-Unattended	115.00	13.20	
3	Belmont Station 260	Dist-Unattended	115.00	13.80	
4	Belmont Station 260	Dist-Unattended	116.00	13.80	
5	Bemus Point Station 159	Dist-Unattended	34.40	5.00	
6	Bennett Road Station 99	Dist-Unattended	115.00	13.80	
7	Berry Road Station 153	Dist-Unattended	115.00	13.80	
8	Bethlehem Station 21	Trans-Unattended	115.00	13.80	
9	Bethlehem Station 21	Trans-Unattended	115.00	34.40	5.00
10	Bethlehem Station 21	Trans-Unattended	115.00	34.40	13.80
11	Birch Avenue Station 322	Dist-Unattended	34.40	13.80	
12	Black River Station 70	Trans-Unattended	115.00	23.00	
13	Bloomingdale Station 841	Dist-Unattended	46.00	4.80	
14	Blue Stores Station 303	Dist-Unattended	113.00	13.80	
15	Bolton Station 284	Dist-Unattended	34.40	13.80	
16	Bombay Station 897	Dist-Unattended	34.40	5.00	
17	Boonville Station 707	Trans-Unattended	115.00	23.00	
18	Boonville Station 707	Trans-Unattended	115.00	46.00	
19	Boonville Station 707	Trans-Unattended	115.00	48.00	
20	Boyntonville Station 333	Dist-Unattended	110.00	13.80	
21	Brady Station 957	Dist-Unattended	115.00	13.80	
22	Brasher Station 851	Dist-Unattended	34.40	5.00	
23	Bremen Station 815	Dist-Unattended	115.00	13.80	
24	Brewerton Station 7	Dist-Unattended	34.40	5.00	
25	Bridge Street Station 295	Dist-Unattended	115.00	13.80	
26	Bridgeport Station 168	Dist-Unattended	113.00	13.80	
27	Brier Hill Station 953	Dist-Unattended	22.00	5.00	
28	Brigham Road Station 64	Dist-Unattended	69.00	13.80	
29	Bristol Hill Station 109	Trans-Unattended	115.00	34.50	
30	Brockport Station 74	Trans-Unattended	115.00	13.80	
31	Brockport Station 74	Trans-Unattended	115.00	34.50	
32	Brook Road Station 369	Dist-Unattended	115.00	13.80	
33	Brook Road Station 369	Dist-Unattended	115.00	34.50	
34	Browns Falls Station 711	Trans-Unattended	115.00	34.50	
35	Brunswick Station 264	Dist-Unattended	34.40	13.80	
36	Buckley Corners Station 454	Dist-Unattended	113.00	13.80	
37	Burdeck Street Station 265	Dist-Unattended	113.00	13.80	
38	Burgoyne Avenue Station 337	Dist-Unattended	115.00	13.80	
39	Busti Station 68	Dist-Unattended	34.40	5.00	
40	Butler Station 362	Dist-Unattended	113.00	13.80	
41	Butternut Station 255	Dist-Unattended	113.00	13.80	
42	Butts Road Station 72	Dist-Unattended	34.40	13.80	
43	Butts Road Station 72	Dist-Unattended	34.50	13.20	
44	Byron Station 18	Dist-Unattended	34.50	4.80	
45	Camillus Station 10	Dist-Unattended	34.50	4.40	
46	Canawagus Station	Dist-Unattended	34.50	0.48	
47	Cardiff Station 13	Dist-Unattended	34.50	2.40	
48	Caroga Lake Station 219	Dist-Unattended	22.90	5.00	
49	Carthage Station 717	Dist-Unattended	23.00	4.80	
50	Cascade Tissue Station	Dist-Unattended	34.50	4.16	
51	Cassadaga Station 61	Dist-Unattended	34.50	4.80	
52	Cattaraugus Station 15	Dist-Unattended	34.50	4.80	
53	Cavanaugh Road Station 616	Dist-Unattended	115.00	13.80	
54	Cazenovia Station 220	Dist-Unattended	34.50	4.80	
55	Cedar Station 453	Dist-Unattended	115.00	13.20	
56	Center Street Station 379	Dist-Unattended	115.00	13.20	
57	Central Square Station 15	Dist-Unattended	34.40	5.00	
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SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Chadwicks Station 668	Dist-Unattended	115.00	13.80	
2	Charley Lake Station 254	Dist-Unattended	23.00	2.40	
3	Chasm Falls Station 852	Trans-Unattended	34.50	13.20	
4	Chautauqua Station 57	Dist-Unattended	34.50	4.80	
5	Chestertown Station 42	Dist-Unattended	34.50	13.20	
6	Chittenango Station 16	Dist-Unattended	34.40	5.00	
7	Chrisler Avenue Station 257	Dist-Unattended	34.50	4.16	
8	Church Street Station 43	Dist-Unattended	115.00	13.80	
9	Church Street Station 43	Dist-Unattended	116.00	13.80	
10	Clay Station 229	Trans-Unattended	345.00	120.00	13.80
11	Cleveland Station 11	Dist-Unattended	34.50	4.60	
12	Clinton Road Station 366	Dist-Unattended	113.00	13.80	
13	Clinton Station 604	Dist-Unattended	43.80	13.80	
14	Cloverbank Station 91	Dist-Unattended	115.00	13.20	
15	Clymer Station 55	Dist-Unattended	34.50	4.80	
16	Cobleskill Station 214	Dist-Unattended	69.00	4.80	
17	Coffeen Street Station 760	Trans-Unattended	113.00	13.80	
18	Coffeen Street Station 760	Trans-Unattended	115.00	13.80	
19	Coffeen Street Station 760	Trans-Unattended	115.00	24.00	
20	Collins Station 83	Dist-Unattended	34.40	5.04	
21	Collinsville Station 716	Dist-Unattended	22.90	5.00	
22	Colosse Station 321	Dist-Unattended	34.40	13.80	
23	Colvin Avenue Station 313	Dist-Unattended	34.50	4.16	
24	Commerce Avenue Station 235	Dist-Unattended	34.40	13.80	
25	Comstock Station 48	Dist-Unattended	115.00	5.00	
26	Conesus Lake Station 52	Dist-Unattended	34.40	5.04	
27	Conkling Station 652	Dist-Unattended	43.80	4.40	
28	Constantia Station 19	Dist-Unattended	34.50	4.16	
29	Coolidge Ventures Station 268	Dist-Unattended	115.00	13.20	
30	Corfu Station 22	Dist-Unattended	34.50	4.80	
31	Corinth Station 285	Dist-Unattended	34.40	13.20	
32	Corliss Park Station 338	Dist-Unattended	34.40	4.16	
33	Corning Station 970	Dist-Unattended	115.00	13.80	
34	Cortland Line Station 277	Dist-Unattended	34.50	4.40	
35	Cortland Station 502	Dist-Unattended	34.40	5.00	
36	Cortland Station 502	Dist-Unattended	34.50	5.00	
37	Cortland Station 502	Dist-Unattended	110.00	34.50	
38	Cortland Station 502	Dist-Unattended	113.00	34.50	
39	Cross Street Pump	Dist-Unattended	34.50	4.16	
40	Cross Street Pump	Dist-Unattended	34.50	5.00	
41	Crouse Hinds Station 239	Dist-Unattended	34.40	13.20	
42	Crown Point Station 249	Dist-Unattended	115.00	13.80	
43	Cuba Lake Station 37	Dist-Unattended	34.50	4.80	
44	Cuba Station 05	Dist-Unattended	34.40	5.04	
45	Curry Road Station 365	Dist-Unattended	113.00	13.80	
46	Curry Road Station 365	Dist-Unattended	115.00	13.20	
47	Curry Road Station 365	Dist-Unattended	115.00	13.80	
48	Curtis Street Station 224	Trans-Unattended	110.00	34.50	
49	Darien Station 16	Dist-Unattended	34.50	4.80	
50	David Station 979	Dist-Unattended	22.30	5.00	
51	Debalso Station 684	Dist-Unattended	115.00	13.80	
52	Deerfield Station 606	Trans-Unattended	115.00	13.80	
53	Deerfield Station 606	Trans-Unattended	115.00	46.00	
54	Dekalb Station 984	Dist-Unattended	115.00	13.80	
55	Delameter Station 93	Dist-Unattended	115.00	13.80	
56	Delanson Station 269	Dist-Unattended	67.00	13.80	
57	Delaware Avenue Station 330	Dist-Unattended	34.40	4.40	
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SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Delaware Avenue Station 330	Dist-Unattended	34.40	13.80	
2	Delevan Station 11	Dist-Unattended	34.50	4.80	
3	Delmar Station 279	Dist-Unattended	34.40	5.00	
4	Delphi Station 262	Dist-Unattended	113.00	13.80	
5	Depot Road Station 425	Dist-Unattended	34.50	13.20	
6	Dewitt Station 241	Trans-Unattended	345.00	120.00	13.80
7	Dexter Station 726	Dist-Unattended	23.00	4.80	
8	Dorwin Station 26	Dist-Unattended	34.40	4.40	
9	Dugan Road Station 22	Dist-Unattended	115.00	13.20	
10	Dugan Road Station 22	Dist-Unattended	115.00	13.80	
11	Duguid Station 265	Dist-Unattended	115.00	13.80	
12	Dunkirk Station	Trans-Unattended	115.00	34.50	
13	Dunkirk Station	Trans-Unattended	230.00	120.00	13.20
14	E. J. West Station 38	Trans-Unattended	115.00	13.80	
15	Eagle Bay Station 382	Dist-Unattended	43.80	5.00	
16	Eagle Harbor Station 92	Dist-Unattended	34.50	4.80	
17	East Batavia Station 28	Dist-Unattended	115.00	13.80	
18	East Dunkirk Station 63	Dist-Unattended	115.00		
19	East Fulton Station 100	Dist-Unattended	34.40	2.50	
20	East Golah Station 51	Dist-Unattended	66.00	34.50	
21	East Golah Station 51	Dist-Unattended	115.00	13.80	
22	East Molloy Road Station 151	Dist-Unattended	115.00	13.50	
23	East Norfolk Station 913	Trans-Unattended	23.00	4.80	
24	East Oswegatchie Station 982	Trans-Unattended	115.00	24.00	
25	East Otto Station 28	Dist-Unattended	34.50	4.80	
26	East Pulaski Station 324	Dist-Unattended	110.00	13.80	
27	East Schodack Station 447	Dist-Unattended	34.50	4.80	
28	East Springfield Station 477	Dist-Unattended	115.00	13.80	
29	East Watertown Station 817	Dist-Unattended	113.00	13.80	
30	East Worcester Station 060	Dist-Unattended	34.50	13.20	
31	Eastover Road Station 2931	Trans-Unattended	230.00	115.00	13.80
32	Eastover Road Station 2931	Trans-Unattended	230.00	120.00	13.80
33	Eden Center Station 88	Dist-Unattended	34.40	4.50	
34	Edic Station 662	Trans-Unattended	345.00	120.00	13.80
35	Edic Station 662	Trans-Unattended	345.00	230.00	13.20
36	Edwards Station 916	Dist-Unattended	34.40	5.00	
37	Elba Station 20	Dist-Unattended	34.50	4.80	
38	Elbridge Station 312	Trans-Unattended	115.00	34.50	
39	Elbridge Station 312	Trans-Unattended	345.00	120.00	13.80
40	Ellicott Station 65	Dist-Unattended	34.40	5.00	
41	Elm Street Station	Trans-Unattended	240.00	24.00	
42	Elm Street Station 898	Dist-Unattended	34.40	5.00	
43	Elnora Station 344	Dist-Unattended	115.00	13.80	
44	Elsmere Station 407	Dist-Unattended	34.40	4.80	
45	Emerald Equipment Systems Station 234	Dist-Unattended	34.50	13.20	
46	Emmet Street Station 256	Dist-Unattended	34.40	4.20	
47	Emmet Street Station 256	Dist-Unattended	34.50	4.16	
48	Ephratah Station 18	Trans-Unattended	69.00	4.80	
49	Ephratah Station 18	Trans-Unattended	69.00	23.00	13.20
50	Euclid Station 267	Dist-Unattended	115.00	13.80	
51	Everett Road Station 420	Dist-Unattended	115.00	13.80	
52	Fabius Station 55	Dist-Unattended	34.40	5.00	
53	Fairdale Station 135	Dist-Unattended	34.40	5.00	
54	Farmersville Station 27	Dist-Unattended	34.50	4.80	
55	Farnan Road Station 476	Dist-Unattended	34.50	13.80	
56	Fayette Street Station 28	Dist-Unattended	34.40	4.40	
57	Fine Station 978	Dist-Unattended	34.50	5.00	
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SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Finley Lake Station 71	Dist-Unattended	34.40	5.00	
2	Firehouse Road Station 449	Dist-Unattended	115.00	13.80	
3	Fisher Avenue Station 270	Dist-Unattended	34.50	13.80	4.16
4	Five Mile Road 1325	Trans-Unattended	345.00	120.00	13.80
5	Florida Station 501	Dist-Unattended	69.00	13.80	
6	Fly Road Station 261	Dist-Unattended	115.00	13.80	7.97
7	Fort Covington Station 896	Trans-Unattended	34.40	13.80	
8	Fort Gage Station 319	Dist-Unattended	34.40	13.80	
9	Forts Ferry Station 459	Dist-Unattended	115.00	13.20	
10	Frankfort Station 677	Dist-Unattended	43.80	4.16	
11	Frankhauser Substation 995	Dist-Unattended	115.00	13.80	
12	Franklin Falls Station 843	Trans-Unattended	46.00	4.80	
13	Franklinville Station 24	Dist-Unattended	34.40	5.04	
14	French Creek Station 56	Dist-Unattended	34.40	13.80	1.60
15	French Mountain Station 1054	Dist-Unattended	34.40	13.80	
16	Frewsburg Station 69	Dist-Unattended	34.50	4.80	
17	Front Street Station 360	Dist-Unattended	113.00	13.80	
18	Front Street Station 360	Dist-Unattended	115.00	13.80	
19	Fuller Realty Station	Dist-Unattended	19.05	4.16	
20	Gabriels Station 835	Dist-Unattended	46.00	4.80	
21	Galeville Station 213	Dist-Unattended	34.40	4.36	
22	Gardenville (New) 230 Station	Trans-Unattended	230.00	120.00	13.20
23	Gardenville (New) 230 Station	Trans-Unattended	230.00	120.00	13.80
24	Gasport Station 90	Dist-Unattended	34.50	5.04	
25	Genesee Street Station 260	Dist-Unattended	34.40	4.40	
26	Geneseo Station 55	Dist-Unattended	34.50	13.20	
27	Gibson Station 106	Trans-Unattended	13.20	12.00	
28	Gibson Station 106	Trans-Unattended	115.00	12.00	
29	Gilbert Mills Station 247	Dist-Unattended	110.00	13.80	
30	Gilmantown Road Station 154	Dist-Unattended	23.00	13.20	
31	Gilpin Bay Station 956	Dist-Unattended	46.00	4.80	
32	Glens Falls Hospital Station 414	Dist-Unattended	34.40	4.40	
33	Glens Falls Hospital Station 414	Dist-Unattended	34.50	4.80	
34	Glens Falls Station 75	Trans-Unattended	34.50	4.16	
35	Glenwood Station 227	Dist-Unattended	34.40	4.40	
36	Gloversville Station 72	Dist-Unattended	69.00	4.16	13.20
37	Gloversville Station 72	Dist-Unattended	69.00	13.80	
38	Golah Station	Trans-Unattended	69.00	34.50	
39	Golah Station	Trans-Unattended	115.00	34.50	
40	Granby Center Station 293	Dist-Unattended	34.40	13.80	
41	Grand Street Station 433	Dist-Unattended	69.00	13.20	
42	Greenbush Station 78	Trans-Unattended	113.00	13.80	
43	Greenbush Station 78	Trans-Unattended	115.00	13.20	
44	Greenbush Station 78	Trans-Unattended	115.00	34.50	5.00
45	Greenbush Station 78	Trans-Unattended	115.00	34.50	13.80
46	Greenhurst Station 60	Dist-Unattended	34.50	4.80	
47	Grooms Road Station 345	Dist-Unattended	115.00	13.80	
48	Groveland Station 41	Dist-Unattended	34.50	4.80	
49	Guilford Mills	Dist-Unattended	46.00	4.16	
50	Hague Road Station 418	Dist-Unattended	115.00	13.80	
51	Hammond Station 370	Dist-Unattended	22.90	4.80	
52	Hancock Station 137	Dist-Unattended	34,500.00	2.40	
53	Hanson 1 - General Crush - TS 4504	Dist-Unattended	34.50	0.48	
54	Hanson Aggregate - Middleville	Dist-Unattended	46.00	4.80	
55	Hanson Station 738	Dist-Unattended	23.00	2.40	
56	Harper Station	Trans-Unattended	12.00	4.80	
57	Harper Station	Trans-Unattended	115.00	12.00	
58	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Harris Road Station 235	Trans-Unattended	110.00	34.50	
2	Harris Road Station 235	Trans-Unattended	115.00	13.80	
3	Hartfield Station 79	Trans-Unattended	113.00	13.80	
4	Hartfield Station 79	Trans-Unattended	115.00	34.50	
5	Headson Station 146	Trans-Unattended	116.00	34.50	
6	Hedley Park Place Station	Dist-Unattended	34.50	4.16	
7	Hemlock Station 38	Dist-Unattended	34.50	13.20	
8	Hemstreet Station 328	Dist-Unattended	115.00	13.80	
9	Henry Street Station 316	Dist-Unattended	34.40	4.20	
10	Henry Street Station 316	Dist-Unattended	34.40	4.40	
11	Higley Station 473	Trans-Unattended	110.00	13.80	
12	Hill Street Station 311	Dist-Unattended	69.00	4.20	
13	Hinsdale Station 218	Dist-Unattended	34.50	4.40	
14	Hoag Station 221	Dist-Unattended	34.50	7.62	
15	Homer Hill Switch Structure	Trans-Unattended	115.00	34.50	
16	Homer Station 129	Dist-Unattended	34.50	4.80	
17	Hoosick Station 314	Trans-Unattended	113.00	13.80	
18	Hoosick Station 314	Trans-Unattended	115.00	34.50	13.80
19	Hopkins Road Station 253	Dist-Unattended	115.00	13.80	
20	Hudson Falls Station 88	Dist-Unattended	34.50	13.80	
21	Hudson Station 87	Trans-Unattended	115.00	13.80	7.97
22	Hudson Station 87	Trans-Unattended	115.00	34.50	5.00
23	Huntley Station	Trans-Unattended	115.00	23.80	
24	Indian Lake Station 310	Dist-Unattended	19.92	4.80	
25	Indian River Station 323	Dist-Unattended	115.00	13.20	
26	Indian River Station 323	Dist-Unattended	115.00	23.00	
27	Industry Station 47	Dist-Unattended	34.50	4.80	
28	Inghams Station 20	Trans-Unattended	113.00	13.80	
29	Inghams Station 20	Trans-Unattended	115.00	46.00	
30	Inghams Station 20	Trans-Unattended	115.00	115.00	
31	Inman Road Station 370	Dist-Unattended	113.00	13.80	
32	Inman Road Station 370	Dist-Unattended	115.00	13.80	
33	Iroquois Rock Station	Dist-Unattended	34.50	0.48	
34	Jewett Road Station 291	Dist-Unattended	34.40	13.80	2.40
35	Johnson Road Station 352	Dist-Unattended	115.00	13.80	
36	Johnstown Station 61	Dist-Unattended	67.00	4.40	
37	Johnstown Station 61	Dist-Unattended	69.00	4.20	4.80
38	Juniper Station 500	Dist-Unattended	34.50	13.20	
39	Karner Station 317	Dist-Unattended	34.40	4.40	
40	Kenmore Terminal Station 158	Dist-Unattended	115.00	23.00	
41	Kensington Terminal Station	Trans-Unattended	115.00	23.00	
42	Kensington Terminal Station	Trans-Unattended	115.00	23.70	
43	Kilian Manufacturing Corporation - TS 2296	Dist-Unattended	34.40	0.24	
44	Kilian Manufacturing Corporation - TS 2296	Dist-Unattended	34.50	0.24	
45	Knapp Road Station 226	Dist-Unattended	115.00	13.80	
46	Knights Creek Station 06	Dist-Unattended	34.50	4.80	
47	Labrador Station 230	Trans-Unattended	34.50	13.80	
48	Labrador Station 230	Trans-Unattended	115.00	34.50	
49	Lake Colby Station 927	Trans-Unattended	110.00	46.00	
50	Lake Colby Station 927	Trans-Unattended	115.00	13.80	
51	Lake Colby Station 927	Trans-Unattended	115.00	15.00	
52	Lake Colby Station 927	Trans-Unattended	115.00	46.00	
53	Lake Road No. 2 Station 299	Dist-Unattended	115.00	13.80	
54	Lakeview Station 182	Dist-Unattended	115.00	13.20	
55	Lakeville Station 40	Dist-Unattended	34.50	4.80	
56	Langford Station 180	Dist-Unattended	34.50	13.80	
57	Lansingburgh Station 93	Dist-Unattended	13.20	4.16	
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SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lansingburgh Station 93	Dist-Unattended	34.50	13.20	
2	Lapp Station 26	Dist-Unattended	115.00	4.40	
3	Latham Station 282	Dist-Unattended	34.40	13.80	
4	Lawrence Avenue Station 976	Dist-Unattended	115.00	13.20	
5	Leeds Station 377	Trans-Unattended	345.00	18.00	
6	Lehigh Station 669	Dist-Unattended	115.00	13.80	
7	Leray Station 813	Dist-Unattended	23.00	4.80	
8	Levant Station 98	Dist-Unattended	34.50	4.80	
9	Levitt Station 665	Dist-Unattended	110.00	5.00	
10	Liberty Street Station 94	Dist-Unattended	34.40	4.36	
11	Liberty Street Station 94	Dist-Unattended	34.40	4.40	
12	Liberty Street Station 94	Dist-Unattended	34.50	13.80	
13	Lighthouse Hill Station 61	Trans-Unattended	115.00	34.50	
14	Lima Station 36	Dist-Unattended	34.50	4.80	
15	Linden Station 21	Dist-Unattended	34.50	4.80	
16	Lisbon Station 963	Dist-Unattended	22.00	5.00	
17	Little River Station 955	Dist-Unattended	115.00	13.20	
18	Little River Station 955	Dist-Unattended	115.00	24.00	
19	Livingston Correctional Station 130	Dist-Unattended	34.50	13.20	
20	Livonia Station 37	Dist-Unattended	34.50	4.80	
21	Lockport Station	Trans-Unattended	115.00	12.00	
22	Loon Lake Station 837	Dist-Unattended	46.00	4.80	
23	Lords Hill Station 150	Dist-Unattended	34.40	5.00	
24	Lorings Station 276	Dist-Unattended	34.40	13.80	
25	Lowville Station 773	Trans-Unattended	110.00	24.00	
26	Lowville Station 773	Trans-Unattended	115.00	13.80	
27	Lyme Station 733	Dist-Unattended	115.00	13.80	
28	Lyndonville Station 95	Dist-Unattended	34.50	4.80	
29	Lynn Street Station 320	Dist-Unattended	34.50	13.20	
30	Lysander Station 297	Dist-Unattended	113.00	13.80	
31	Machias Station 13	Trans-Unattended	34.50	4.80	
32	Machias Station 13	Trans-Unattended	115.00	34.50	
33	Madison Station 654	Dist-Unattended	110.00	5.00	
34	Mallory Road Station 40	Trans-Unattended	110.00	34.50	
35	Mallory Road Station 40	Trans-Unattended	113.00	34.50	
36	Malone Station 895	Trans-Unattended	115.00	13.80	
37	Malone Station 895	Trans-Unattended	115.00	34.50	
38	Malta Station 443	Dist-Unattended	115.00	13.80	
39	Maplehurst Station 04	Dist-Unattended	34.40	5.04	
40	Maplewood Station 307	Trans-Unattended	115.00	13.80	
41	Maplewood Station 307	Trans-Unattended	115.00	34.40	13.80
42	Market Hill Station 324	Dist-Unattended	67.00	4.40	
43	Market Hill Station 324	Dist-Unattended	69.00	4.40	
44	Marshville Station 299	Trans-Unattended	110.00	67.00	13.80
45	Marshville Station 299	Trans-Unattended	115.00	69.00	23.00
46	Mayfield Station 356	Dist-Unattended	67.00	13.80	
47	McAdoo Station 914	Dist-Unattended	115.00	13.80	
48	McClellan Street Station 304	Dist-Unattended	34.50	13.20	
49	McCrea Street Station 272	Dist-Unattended	33.00	4.80	
50	McGraw Station 228	Dist-Unattended	34.40	5.00	
51	McGraw Station 228	Dist-Unattended	34.50	5.00	
52	Mcintosh Box & Pallet Corporation - TS 2766	Dist-Unattended	34.50	0.48	
53	McIntyre Station 969	Trans-Unattended	110.00	24.00	
54	McIntyre Station 969	Trans-Unattended	115.00	23.00	
55	McKownville Station 327	Dist-Unattended	113.00	13.80	
56	McKownville Station 327	Dist-Unattended	115.00	13.20	
57	Meco Station 318	Dist-Unattended	69.00	23.00	
58	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Meco Station 318	Trans-Unattended	69.00	13.20	
2	Meco Station 318	Trans-Unattended	113.00	67.00	5.00
3	Menands Station 101	Trans-Unattended	13.80	3.40	
4	Menands Station 101	Trans-Unattended	110.00	4.36	
5	Menands Station 101	Trans-Unattended	110.00	34.40	8.66
6	Menands Station 101	Trans-Unattended	115.00	13.80	
7	Menands Station 101	Trans-Unattended	115.00	34.50	5.00
8	Merrillsville Station 838	Dist-Unattended	46.00	2.40	
9	Mexico Station 43	Dist-Unattended	34.40	5.00	
10	Middleburg Station 390	Dist-Unattended	67.00	13.80	
11	Middleport Station 77	Dist-Unattended	34.50	4.80	
12	Middleville Station 666	Dist-Unattended	43.80	4.20	
13	Midler Station 145	Dist-Unattended	34.40	4.40	
14	Midstate Construction Company Station 148	Dist-Unattended	34.50	2.40	
15	Midstate Construction Company Station 148	Dist-Unattended	34.50	2.40	0.24
16	Midstate Correctional Facility	Dist-Unattended	46.00	2.40	
17	Mill Street Station 748	Trans-Unattended	23.00	5.00	
18	Miller Street Station 117	Dist-Unattended	34.50	4.80	
19	Milton Avenue Station 266	Dist-Unattended	113.00	13.80	
20	Milton Avenue Station 266	Dist-Unattended	115.00	13.80	
21	Mine Road Station 777	Trans-Unattended	34.40	23.00	
22	Minoa Station 44	Dist-Unattended	34.40	5.00	
23	MOBILE SUB 7991 CENTRAL	Dist-Unattended	115.00	13.20	
24	MOBILE SUB 8 CENTRAL	Dist-Unattended	115.00	13.20	
25	Mohican Station 247	Trans-Unattended	113.00	34.40	5.00
26	Mohican Station 247	Trans-Unattended	115.00	34.50	
27	Moira Station 859	Dist-Unattended	34.40	5.00	
28	Monarch Machine Tool Station 264	Dist-Unattended	34.40	2.40	
29	Morristown Station 933	Dist-Unattended	23.00	5.04	
30	Mortimer Station	Trans-Unattended	115.00	63.00	11.50
31	Mountain Station	Trans-Unattended	115.00	34.50	
32	Mumford Station 50	Dist-Unattended	115.00	13.20	
33	Nassau Station 113	Dist-Unattended	34.40	19.80	
34	New Haven Station 256	Dist-Unattended	113.00	13.80	
35	New Krumkill Station 421	Dist-Unattended	13.80	4.40	
36	New Krumkill Station 421	Dist-Unattended	113.00	13.80	
37	New Scotland Station 325	Trans-Unattended	345.00	120.00	13.80
38	New Walden Station	Trans-Unattended	115.00	34.50	
39	Newark Station 300	Dist-Unattended	34.50	13.20	
40	Newton Falls Station 774	Dist-Unattended	34.50	2.40	
41	Newtonville Station 305	Dist-Unattended	34.40	2.50	
42	Nicholville Station 860	Trans-Unattended	34.50	4.80	
43	Nicholville Station 860	Trans-Unattended	115.00	34.50	
44	Nile Station	Trans-Unattended	115.00	34.50	
45	Niles Station 294	Dist-Unattended	34.40	13.80	
46	Norfolk Station 934	Trans-Unattended	115.00	24.00	
47	North Akron Station	Trans-Unattended	115.00	34.50	
48	North Angola Station	Trans-Unattended	115.00	34.50	
49	North Ashford Station 36	Trans-Unattended	34.50	4.80	
50	North Bangor Station 864	Dist-Unattended	34.40	5.00	
51	North Bombay Station 866	Dist-Unattended	34.50	13.20	
52	North Carthage Station 816	Dist-Unattended	115.00	13.20	
53	North Carthage Station 816	Dist-Unattended	115.00	23.00	
54	North Chautauqua Station	Dist-Unattended	34.50	4.80	
55	North Collins Station 92	Dist-Unattended	34.50	4.80	
56	North Creek Station 122	Dist-Unattended	115.00	13.80	
57	North Eden Station 82	Dist-Unattended	34.50	13.20	
58	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	North Gouverneur Station 983	Dist-Unattended	115.00	13.80	
2	North Lakeville Station	Trans-Unattended	115.00	34.50	
3	North Lawrence Station 861	Dist-Unattended	34.00	5.00	
4	North LeRoy Station	Trans-Unattended	115.00	34.50	
5	North LeRoy Station 04	Dist-Unattended	115.00	13.20	
6	North Olean Station 30	Dist-Unattended	34.50	4.80	
7	North Troy Station 123	Trans-Unattended	115.00	13.80	
8	North Troy Station 123	Trans-Unattended	115.00	34.50	
9	Northville Station 332	Dist-Unattended	69.00	13.80	
10	Northville Station 332	Dist-Unattended	69.00	23.00	
11	Norwood Station 936	Trans-Unattended	23.00	4.80	
12	Oak Hill Station 62	Dist-Unattended	34.50	4.80	
13	Oakfield Station 03	Trans-Unattended	34.50	4.80	
14	Oakfield Station 03	Trans-Unattended	115.00	34.50	
15	Oakwood Ave Station 232	Dist-Unattended	115.00	13.80	
16	Oathout Station 402	Dist-Unattended	34.40	13.80	
17	Ogdenbrook Station 423	Dist-Unattended	115.00	13.80	
18	Ogdensburg Station 938	Trans-Unattended	115.00	13.80	
19	Ogdensburg Stone Station 932	Dist-Unattended	23.00	0.48	
20	Ogdensburg Stone Station 932	Dist-Unattended	23.00	5.00	
21	Old Forge Station 383	Dist-Unattended	46.00	4.80	
22	Oneida Station 501	Trans-Unattended	115.00	13.80	
23	Orangeville Station 19	Dist-Unattended	34.50	4.80	
24	Oswego Switch Yard	Trans-Unattended	115.00	34.50	
25	Oswego Switch Yard	Trans-Unattended	345.00	120.00	13.80
26	Otten Station 412	Dist-Unattended	115.00	5.00	
27	Packard Station	Trans-Unattended	230.00	120.00	13.20
28	Paloma Station 254	Dist-Unattended	115.00	13.80	
29	Panama Station 70	Dist-Unattended	34.50	4.80	
30	Parish Station 49	Dist-Unattended	34.40	5.00	
31	Parishville Station 939	Trans-Unattended	4.80	2.40	
32	Park Street Station 144	Dist-Unattended	34.40	4.36	
33	Partridge Street Station 128	Dist-Unattended	34.40	4.40	
34	Patroon Station 323	Trans-Unattended	110.00	34.40	13.80
35	Patroon Station 323	Trans-Unattended	115.00	13.20	
36	Paul Smiths Station 384	Dist-Unattended	46.00	4.80	
37	Peat Street Station 250	Dist-Unattended	113.00	13.80	
38	Pebble Hill Station 290	Trans-Unattended	115.00	13.80	
39	Pebble Hill Station 290	Trans-Unattended	116.00	34.50	
40	Peckham Materials	Dist-Unattended	34.40	0.24	
41	Perryville Station 50	Dist-Unattended	34.40	2.50	
42	Peterboro Station 514	Dist-Unattended	115.00	13.20	
43	Peterboro Station 514	Dist-Unattended	115.00	13.80	
44	Petrolia Station 19	Dist-Unattended	34.50	4.80	
45	Phoenix Station 51	Dist-Unattended	34.40	5.00	
46	Piercefield Station 502	Trans-Unattended	43.80	2.40	
47	Pine Grove Station 59	Dist-Unattended	115.00	13.80	
48	Pinebush Station 371	Dist-Unattended	113.00	13.80	
49	Pinebush Station 371	Dist-Unattended	115.00	13.80	
50	Pleasant Station 664	Dist-Unattended	43.80	4.40	
51	Poland Station 621	Dist-Unattended	43.60	13.80	
52	Poland Station 66	Dist-Unattended	34.50	4.80	
53	Pompey Station 120	Dist-Unattended	34.50	4.80	
54	Port Henry Station 385	Dist-Unattended	113.00	13.80	
55	Port Leyden Station 755	Dist-Unattended	23.00	5.00	
56	Portage Street Station 754	Dist-Unattended	23.00	5.00	
57	Porter Station 657	Trans-Unattended	230.00	115.00	13.20
58	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Porter Station 657	Trans-Unattended	230.00	120.00	13.80
2	Pottersville Station 424	Dist-Unattended	34.40	13.20	
3	Price Corners Station 14	Dist-Unattended	34.40	13.80	2.63
4	Prospect Hill Station 413	Dist-Unattended	113.00	13.80	
5	Queensbury Station 295	Trans-Unattended	110.00	34.40	
6	Queensbury Station 295	Trans-Unattended	115.00	13.80	
7	Raquette Lake Station 398	Dist-Unattended	43.80	5.00	
8	Raybrook Station 839	Dist-Unattended	115.00	13.80	
9	RAYMOUR & FLANIGAN	Dist-Unattended	34.40	0.48	
10	RAYMOUR & FLANIGAN	Dist-Unattended	34.50	0.48	
11	Renaissance Drive Station 229	Dist-Unattended	115.00	13.80	
12	Rensselaer Station 132	Trans-Unattended	34.50	13.20	
13	Reservoir Station 103	Dist-Unattended	34.40	5.04	
14	Reynolds Road Station 334	Trans-Unattended	115.00	13.80	
15	Reynolds Road Station 334	Trans-Unattended	345.00	120.00	13.80
16	Richmond Station 32	Dist-Unattended	34.50	13.80	
17	Ridge Road Station 219	Dist-Unattended	34.50	4.80	
18	Ridge Station 142	Trans-Unattended	115.00	34.50	
19	Riparius Station 293	Dist-Unattended	34.40	19.80	
20	Ripley Station 53	Dist-Unattended	34.50	4.80	
21	Riverside Station 288	Dist-Unattended	13.20	4.16	
22	Riverside Station 288	Dist-Unattended	13.20	12.00	
23	Riverside Station 288	Dist-Unattended	34.40	5.04	
24	Riverside Station 288	Dist-Unattended	34.40	13.80	
25	Riverside Station 288	Dist-Unattended	34.50	0.48	
26	Riverside Station 288	Dist-Unattended	34.50	4.80	
27	Riverside Station 288	Dist-Unattended	67.00	13.80	
28	Riverside Station 288	Dist-Unattended	68.80	34.40	
29	Riverside Station 288	Dist-Unattended	110.00	13.80	
30	Riverside Station 288	Dist-Unattended	113.00	34.40	
31	Riverside Station 288	Dist-Unattended	113.00	67.00	13.80
32	Riverside Station 288	Dist-Unattended	115.00	13.80	
33	Riverside Station 288	Dist-Unattended	115.00	13.80	7.97
34	Riverside Station 288	Dist-Unattended	115.00	34.40	
35	Riverside Station 288	Dist-Unattended	115.00	34.40	13.80
36	Riverview Station 847	Dist-Unattended	43.80	4.80	
37	Roberts Road Station 154	Dist-Unattended	115.00	13.20	
38	Rock City Falls Station 404	Dist-Unattended	34.50	4.80	
39	Rock City Station 623	Dist-Unattended	43.80	4.40	
40	Rock Cut Station 286	Dist-Unattended	115.00	13.80	
41	Rock Cut Station 286	Dist-Unattended	116.00	13.80	
42	Rome Station 762	Trans-Unattended	115.00	13.80	
43	Rosa Road Station 137	Trans-Unattended	113.00	13.80	
44	Rosa Road Station 137	Trans-Unattended	115.00	34.50	
45	Rotterdam Station 138	Trans-Unattended	113.00	68.00	13.80
46	Rotterdam Station 138	Trans-Unattended	115.00	13.80	
47	Rotterdam Station 138	Trans-Unattended	115.00	34.40	13.80
48	Rotterdam Station 138	Trans-Unattended	115.00	34.50	13.80
49	Rotterdam Station 138	Trans-Unattended	230.00	115.00	13.80
50	Rotterdam Station 138	Trans-Unattended	230.00	120.00	13.80
51	Royalton Station 98	Dist-Unattended	34.50	4.80	
52	Ruth Road Station 381	Dist-Unattended	113.00	13.80	
53	S/C - Batavia	Trans-Unattended	34.50	4.80	
54	S/C - Campion Road	Dist-Unattended	12.00	0.48	
55	S/C - Campion Road	Dist-Unattended	44.00	4.16	
56	S/C - Eastern Region Warehouse - Clifton Park	Dist-Unattended	34.50	4.16	
57	S/C - Fredonia	Dist-Unattended	34.50	13.80	
58	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	S/C - Henry Clay Blvd.	Dist-Unattended			
2	S/C - Henry Clay Blvd.	Dist-Unattended	34.40	4.36	
3	S/C - Henry Clay Blvd.	Dist-Unattended	34.40	4.80	
4	S/C - Henry Clay Blvd.	Dist-Unattended	34.50	2.40	
5	S/C - Henry Clay Blvd.	Dist-Unattended	34.50	4.80	
6	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	5.04	
7	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	7.97	
8	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	13.20	
9	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	13.80	
10	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	23.00	
11	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	26.50	
12	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	34.50	
13	S/C - Henry Clay Blvd.	Dist-Unattended	115.00	46.00	
14	S/C - Henry Clay Blvd.	Dist-Unattended	34,400.00	5,040.00	
15	S/C - Potsdam	Dist-Unattended	23.00	4.80	
16	S/C - Potsdam	Dist-Unattended	23.00	5.04	
17	S/C - Potsdam	Dist-Unattended	34.40	5.00	
18	S/C - Potsdam	Dist-Unattended	115.00	4.80	
19	S/C - South Watertown	Dist-Unattended	23.00	4.80	
20	Saint Johnsville Station 335	Dist-Unattended	110.00	13.80	4.80
21	Saint Johnsville Station 335	Dist-Unattended	110.00	13.80	5.00
22	Saint Regis Station 977	Dist-Unattended	34.50	4.80	
23	Salisbury Station 678	Dist-Unattended	110.00	13.80	
24	Salisbury Station 678	Dist-Unattended	113.00	13.80	
25	Sanborn Station	Trans-Unattended	115.00	34.50	
26	Sand Creek Station 452	Dist-Unattended	115.00	13.20	
27	Sand Road Station 131	Dist-Unattended	34.40	4.40	
28	Sandy Creek Station 66	Dist-Unattended	34.50	13.80	
29	Saratoga Station 142	Dist-Unattended	33.00	4.20	
30	Saratoga Station 142	Dist-Unattended	34.40	13.80	
31	Sawyer Avenue Station	Trans-Unattended	23.00	13.30	
32	Sawyer Avenue Station	Trans-Unattended	230.00	23.00	
33	Schenevus Station 261	Dist-Unattended	22.00	4.80	
34	Schodack Station 451	Dist-Unattended	115.00	13.80	
35	Schoharie Station 234	Trans-Unattended	67.00	13.80	
36	Schroon Lake station 429	Dist-Unattended	34.40	13.80	
37	Schuyler Station 663	Trans-Unattended	110.00	43.80	
38	Schuyler Station 663	Trans-Unattended	115.00	13.80	
39	Schuylerville Station 39	Trans-Unattended	34.40	4.80	
40	Scofield Road Station 450	Dist-Unattended	113.00	13.80	
41	Scotia Station 255	Dist-Unattended	34.50	4.16	
42	Sealright Station 273	Dist-Unattended	113.00	2.40	
43	Selkirk Station 149	Dist-Unattended	34.40	13.80	
44	Seminole Station 339	Dist-Unattended	34.40	4.40	
45	Seneca Terminal Station	Trans-Unattended	115.00	23.00	
46	Sentinel Heights Station 128	Dist-Unattended	33.00	2.30	
47	Seventh Avenue Station 244	Dist-Unattended	34.50	4.20	
48	Seventh North Street Station 231	Dist-Unattended	34.40	5.00	
49	Sewalls Island Station 766	Trans-Unattended	23.00	4.80	
50	Shaleton Station 81	Trans-Unattended	115.00	34.50	
51	Sharon Station 363	Dist-Unattended	69.00	13.20	
52	Shelby Station 76	Dist-Unattended	115.00	13.20	
53	Shelby Station 76	Dist-Unattended	115.00	13.80	
54	Sheppard Road Station 29	Dist-Unattended	34.40	13.80	
55	Sheppard Road Station 29	Dist-Unattended	34.50	13.20	
56	Sherman Station 333	Dist-Unattended	46.00	13.80	
57	Sherman Station 54	Dist-Unattended	34.50	4.80	
58	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Shore Road Station 281	Dist-Unattended	34.40	4.80	
2	Silver Lake Station 845	Dist-Unattended	46.00	2.40	
3	Sinclairville Station 72	Dist-Unattended	34.50	4.80	
4	Smith Bridge Station 464	Dist-Unattended	115.00	13.80	
5	Solvay Station 57	Trans-Unattended	110.00	34.50	
6	Solvay Station 57	Trans-Unattended	115.00	34.50	
7	Solvay Station 57	Trans-Unattended	116.00	33.00	
8	Solvay Station 57	Trans-Unattended	116.00	34.50	
9	Sonora Way Station 4381	Dist-Unattended	115.00	13.80	
10	Sorrell Hill Station 269	Dist-Unattended	115.00	13.80	
11	South Dow Station	Trans-Unattended	115.00	34.50	
12	South Philadelphia Station 764	Dist-Unattended	23.00	4.80	
13	South Randolph Station 32	Dist-Unattended	34.50	4.80	
14	South Street Station 297	Dist-Unattended	34.40	13.20	
15	South Washington Street Station 614	Dist-Unattended	46.00	13.80	
16	South Wellsville Station 23	Dist-Unattended	34.50	4.80	
17	Southland Station 84	Dist-Unattended	34.50	4.80	
18	Southwood Station 244	Dist-Unattended	110.00	13.80	
19	Spencer Haley	Dist-Unattended	34.50	0.48	
20	Spier Falls Station 34	Trans-Unattended	115.00	34.40	5.00
21	Springfield Station 167	Dist-Unattended	34.40	4.16	
22	Springfield Station 167	Dist-Unattended	34.50	4.40	
23	Star Lake Station 727	Dist-Unattended	34.40	5.00	
24	Starr Road Station 334	Dist-Unattended	115.00	13.80	
25	Station 021	Dist-Unattended	23.00	4.16	
26	Station 022	Dist-Unattended	23.00	4.40	
27	Station 023	Dist-Unattended	22.90	4.36	
28	Station 024	Dist-Unattended	23.00	4.40	
29	Station 025	Dist-Unattended	22.00	4.30	
30	Station 025	Dist-Unattended	23.00	4.33	
31	Station 026	Dist-Unattended	23.00	4.40	
32	Station 027	Dist-Unattended	22.90	4.30	
33	Station 028	Dist-Unattended	23.00	4.40	
34	Station 029	Dist-Unattended	22.90	4.36	
35	Station 030	Dist-Unattended	22.00	4.30	
36	Station 031	Dist-Unattended	22.00	4.30	
37	Station 031	Dist-Unattended	22.90	4.36	
38	Station 032	Dist-Unattended	23.00	4.16	
39	Station 032	Dist-Unattended	23.00	4.33	
40	Station 033	Dist-Unattended	23.00	4.36	
41	Station 034	Dist-Unattended	22.00	4.30	
42	Station 034	Dist-Unattended	23.00	4.16	
43	Station 034	Dist-Unattended	23.00	4.30	
44	Station 035	Dist-Unattended	22.00	4.30	
45	Station 035	Dist-Unattended	23.00	4.30	
46	Station 036	Dist-Unattended	2.29	4.36	
47	Station 036	Dist-Unattended	23.00	4.40	
48	Station 037	Dist-Unattended	22.90	4.30	
49	Station 038	Dist-Unattended	22.00	4.30	
50	Station 039	Dist-Unattended	22.90	4.40	
51	Station 040	Dist-Unattended	23.00	4.16	
52	Station 041	Dist-Unattended	23.00	4.16	
53	Station 042 MITS	Dist-Unattended	34.50	13.80	
54	Station 043	Dist-Unattended	22.90	4.16	
55	Station 043	Dist-Unattended	22.90	4.36	
56	Station 043	Dist-Unattended	23.00	4.16	
57	Station 044	Dist-Unattended	22.90	4.36	
58	Station 045	Dist-Unattended	22.00	4.30	
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SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Station 045	Dist-Unattended	23.00	4.16	
2	Station 046	Dist-Unattended	2.29	4.36	
3	Station 046	Dist-Unattended	22.90	4.36	
4	Station 046	Dist-Unattended	23.00	4.40	
5	Station 047	Dist-Unattended	23.00	4.36	
6	Station 048	Dist-Unattended	22.40	4.40	
7	Station 048	Dist-Unattended	22.90	4.40	
8	Station 049	Dist-Unattended	22.90	4.40	
9	Station 050	Dist-Unattended	22.90	4.40	
10	Station 050	Dist-Unattended	23.00	4.36	
11	Station 051	Dist-Unattended	22.00	4.30	
12	Station 052	Dist-Unattended	23.00	4.16	
13	Station 053	Dist-Unattended	22.00	4.30	
14	Station 054	Dist-Unattended	115.00	4.30	
15	Station 054	Dist-Unattended	115.00	4.33	
16	Station 055	Dist-Unattended	115.00	4.30	
17	Station 056	Dist-Unattended	22.90	4.30	
18	Station 057	Dist-Unattended	22.90	4.40	
19	Station 058	Dist-Unattended	34.40	4.36	
20	Station 058	Dist-Unattended	34.40	4.40	
21	Station 059	Dist-Unattended	22.00	4.30	
22	Station 059	Dist-Unattended	23.00	4.16	
23	Station 060 - Getzville	Trans-Unattended	115.00	13.80	
24	Station 061	Dist-Unattended	115.00	4.16	
25	Station 061	Dist-Unattended	115.00	4.36	
26	Station 063	Dist-Unattended	22.90	4.36	
27	Station 063	Dist-Unattended	23.00	4.16	
28	Station 064 - Grand Island	Dist-Unattended	113.00	13.80	
29	Station 066	Dist-Unattended	34.50	4.80	
30	Station 067	Dist-Unattended	34.50	4.16	
31	Station 068	Dist-Unattended	23.00	4.16	
32	Station 071 - South Newfane	Dist-Unattended	34.40	5.04	
33	Station 074	Dist-Unattended	22.90	4.36	
34	Station 074	Dist-Unattended	23.00	4.16	
35	Station 076 - Shawnee Road	Dist-Unattended	115.00	13.80	
36	Station 077	Dist-Unattended	23.00	4.16	
37	Station 078	Trans-Unattended	115.00	4.30	23.00
38	Station 078	Trans-Unattended	115.00	23.00	
39	Station 079	Dist-Unattended	22.00	4.33	
40	Station 079	Dist-Unattended	23.00	4.16	
41	Station 080 - Eighth Street	Dist-Unattended	12.00	4.16	
42	Station 081 - Beech Avenue	Dist-Unattended	12.00	4.16	
43	Station 082 - Eleventh Street	Dist-Unattended	11.00	11.00	
44	Station 082 - Eleventh Street	Dist-Unattended	11.40	5.04	
45	Station 082 - Eleventh Street	Dist-Unattended	12.00	4.16	
46	Station 082 - Eleventh Street	Dist-Unattended	12.00	4.80	
47	Station 083 - Welch Avenue	Dist-Unattended	12.00	4.16	
48	Station 085 - Stephenson Avenue	Dist-Unattended	12.00	4.80	
49	Station 086 - Lewiston Heights	Dist-Unattended	34.50	4.80	
50	Station 087 - Lewiston	Dist-Unattended	34.50	4.80	
51	Station 088 - Youngstown	Dist-Unattended	34.40	5.04	
52	Station 089 - Ransomville	Dist-Unattended	34.50	4.80	
53	Station 093 - Wilson	Dist-Unattended	34.40	5.04	
54	Station 097 - Summit Park	Dist-Unattended	113.00	13.80	
55	Station 105 - Swann Road	Dist-Unattended	115.00	13.80	
56	Station 121 - Clinton	Dist-Unattended	34.50	4.80	
57	Station 122 - Tonawanda News	Dist-Unattended	23.00	4.16	
58	Station 124 - Almeda Ave	Dist-Unattended	34.50	4.16	
59	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Station 126 - Gibson St	Dist-Unattended	23.00	4.16	
2	Station 127 - Delaware Rd	Dist-Unattended	22.00	4.30	
3	Station 127 - Delaware Rd	Dist-Unattended	23.00	4.16	
4	Station 129 - Brompton Rd	Dist-Unattended	115.00	4.33	
5	Station 129 - Brompton Rd	Dist-Unattended	115.00	4.36	
6	Station 130	Dist-Unattended	115.00	13.80	
7	Station 132	Dist-Unattended	34.50	4.80	
8	Station 133 - Dupont	Dist-Unattended	115.00	4.16	
9	Station 139 - Martin Rd	Dist-Unattended	115.00	4.33	
10	Station 140	Dist-Unattended	115.00	13.80	
11	Station 142 - Ridge	Trans-Unattended	115.00	4.33	
12	Station 146 (Walden Ave)	Dist-Unattended	34.50	4.80	
13	Station 146 (Walden Ave)	Dist-Unattended	34.50	13.80	
14	Station 154	Dist-Unattended	115.00	4.16	
15	Station 155 - Worthington	Dist-Unattended	115.00	4.16	
16	Station 157	Dist-Unattended	23.00	4.16	
17	Station 160 - Summer St	Dist-Unattended	23.00	4.16	
18	Station 161 - Short St	Dist-Unattended	23.00	4.16	
19	Station 162	Dist-Unattended	23.00	4.16	
20	Station 170 - Newfane	Dist-Unattended	34.50	4.80	
21	Station 171 - Burt	Dist-Unattended	34.40	5.04	
22	Station 202	Dist-Unattended	23.00	4.16	
23	Station 203	Dist-Unattended	23.00	4.16	
24	Station 205	Dist-Unattended	23.00	13.20	
25	Station 206 - Tonawanda Creek	Dist-Unattended	115.00	13.20	
26	Station 206 - Tonawanda Creek	Dist-Unattended	115.00	13.80	
27	Station 207 - Slade Road	Dist-Unattended	34.40	13.80	
28	Station 208	Dist-Unattended	23.00	4.16	
29	Station 208	Dist-Unattended	23.00	4.40	
30	Station 209 - Long Rd	Dist-Unattended	115.00	13.20	
31	Station 210 - Military Road	Dist-Unattended	115.00	13.80	
32	Station 211 - Ayer Rd	Dist-Unattended	115.00	13.80	
33	Station 212	Dist-Unattended	115.00	13.20	
34	Station 213	Dist-Unattended	113.00	13.80	
35	Station 214 - Youngs St	Dist-Unattended	115.00	4.16	
36	Station 215 - Buffalo Avenue	Dist-Unattended	115.00	13.20	
37	Station 215 - Buffalo Avenue	Dist-Unattended	115.00	13.80	
38	Station 216 - Lockport Road	Dist-Unattended	115.00	13.80	
39	Station 217 - Walmore Rd	Trans-Unattended	113.00	13.80	
40	Station 219 - Park Club Ln	Trans-Unattended	115.00	13.20	
41	Station 224 - Sweethome Rd	Dist-Unattended	115.00	13.20	
42	Station 224 - Sweethome Rd	Dist-Unattended	115.00	13.80	
43	Stiles Station 58	Dist-Unattended	34.40	5.00	
44	Stittville Station 670	Dist-Unattended	113.00	13.80	
45	Stoner Station 358	Dist-Unattended	113.00	13.80	
46	Stow Station 52	Dist-Unattended	34.50	4.80	
47	Stuyvesant Station 977	Trans-Unattended	34.40	13.80	
48	Summit Station 347	Dist-Unattended	67.00	5.00	
49	Summit Station 347	Dist-Unattended	67.00	23.00	
50	Sunday Creek Station 876	Dist-Unattended	115.00	13.80	
51	Swaggertown Station 364	Dist-Unattended	115.00	13.20	
52	Sweden Station	Trans-Unattended	115.00	34.50	
53	Sycaway Station 372	Dist-Unattended	113.00	13.80	
54	Sycaway Station 372	Dist-Unattended	115.00	13.80	7.97
55	Taylorville Station 770	Trans-Unattended	115.00	23.00	
56	Teall Avenue Station 72	Trans-Unattended	115.00	13.80	7.97
57	Teall Avenue Station 72	Trans-Unattended	115.00	34.50	
58	Telegraph Road Station	Trans-Unattended	115.00	19.92	
59	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Telegraph Road Station	Trans-Unattended	115.00	34.50	
2	Temple Station 243	Dist-Unattended	113.00	13.80	
3	Temple Station 243	Dist-Unattended	115.00	13.80	
4	Terminal Station 651	Trans-Unattended	110.00	13.20	
5	Terminal Station 651	Trans-Unattended	115.00	13.80	7.97
6	Third Street Station 216	Dist-Unattended	34.40	5.00	
7	Thousand Islands Station 814	Dist-Unattended	115.00	13.20	
8	Tibbits Avenue Station 292	Dist-Unattended	34.40	4.40	
9	Tilden Station 73	Trans-Unattended	110.00	34.50	
10	Townline Station	Trans-Unattended	115.00	46.00	
11	Trinity Station 164	Dist-Unattended	13.80	4.36	
12	Trinity Station 164	Dist-Unattended	113.00	13.80	
13	Truxton Station 74	Dist-Unattended	33.00	4.60	
14	Truxton Station 74	Dist-Unattended	33.00	4.80	
15	Truxton Station 74	Dist-Unattended	34.50	4.80	
16	Tuller Hill Station 246	Dist-Unattended	110.00	13.80	
17	Tully Center Station 278	Dist-Unattended	115.00	13.80	
18	Tupper Lake Station 830	Dist-Unattended	46.00	7.00	
19	Turin Station 653	Trans-Unattended	115.00	13.80	
20	Union Falls Station 844	Trans-Unattended	44.00	2.40	
21	Union Street Station 376	Dist-Unattended	34.40	13.80	
22	Unionville Station 276	Dist-Unattended	34.50	13.20	
23	University Station 81	Dist-Unattended	115.00	13.80	
24	Vail Mills Station 392	Dist-Unattended	115.00	13.80	
25	Vail Mills Station 392	Dist-Unattended	115.00	69.00	13.80
26	Valkin Station 427	Dist-Unattended	115.00	13.80	
27	Valley Station 44	Dist-Unattended	115.00	13.80	
28	Valley Station 594	Dist-Unattended	115.00	4.16	
29	Valley Station 594	Dist-Unattended	115.00	46.00	
30	Vandalia Station 104	Dist-Unattended	34.50	13.20	
31	Veterans Hospital	Dist-Unattended	34.40	13.80	
32	Voorhees Station 83	Dist-Unattended	115.00	34.50	
33	Voorheesville Station 178	Dist-Unattended	115.00	13.80	
34	Walesville Station 331	Dist-Unattended	115.00	13.80	
35	Warrensburg Station 321	Dist-Unattended	115.00	13.80	
36	Warrensburg Station 321	Dist-Unattended	115.00	34.40	
37	Waterfront Health Care Station	Dist-Unattended	23.00	0.21	
38	Waterfront School Station 204	Dist-Unattended	23.00	4.16	
39	Waterport Station 73	Trans-Unattended	34.50	4.80	
40	Watt Street Station 380	Dist-Unattended	34.40	13.80	
41	Weaver Street Station	Dist-Unattended	34.50	13.20	
42	Weibel Avenue Station 415	Dist-Unattended	115.00	13.80	
43	Wells Station 208	Dist-Unattended	23.00	4.80	
44	West Adams Station 875	Dist-Unattended	115.00	13.80	
45	West Albion Station 79	Dist-Unattended	34.50	13.20	
46	West Cleveland Station 326	Dist-Unattended	34.40	13.20	
47	West Cleveland Station 326	Dist-Unattended	34.50	13.80	
48	West Hamlin Station 82	Dist-Unattended	115.00	13.80	
49	West Herkimer Station 676	Dist-Unattended	43.80	13.80	
50	West Monroe Station 274	Dist-Unattended	34.40	13.80	
51	West Olean Station 33	Dist-Unattended	115.00	13.80	
52	West Perrysburg Station 181	Dist-Unattended	34.50	13.80	
53	West Salamanca Station 16	Trans-Unattended	34.50	4.80	
54	West Seneca Storage Yard	Trans-Unattended	11.00	4.60	
55	West Seneca Storage Yard	Trans-Unattended	13.20	12.00	
56	West Seneca Storage Yard	Trans-Unattended	13.80	2.40	4.16
57	West Seneca Storage Yard	Trans-Unattended	22.00	4.30	
58	West Seneca Storage Yard	Trans-Unattended	22.90	4.36	
59	Total on page				

SUBSTATIONS (Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	West Seneca Storage Yard	Trans-Unattended	23.00	2.40	
2	West Seneca Storage Yard	Trans-Unattended	23.00	4.06	
3	West Seneca Storage Yard	Trans-Unattended	23.00	4.16	
4	West Seneca Storage Yard	Trans-Unattended	34.40	4.36	
5	West Seneca Storage Yard	Trans-Unattended	34.40	5.04	
6	West Seneca Storage Yard	Trans-Unattended	34.40	13.80	
7	West Seneca Storage Yard	Trans-Unattended	34.50	0.48	
8	West Seneca Storage Yard	Trans-Unattended	34.50	4.16	
9	West Seneca Storage Yard	Trans-Unattended	34.50	4.80	
10	West Seneca Storage Yard	Trans-Unattended	34.50	13.20	
11	West Seneca Storage Yard	Trans-Unattended	34.50	13.80	
12	West Seneca Storage Yard	Trans-Unattended	66.00	13.80	
13	West Seneca Storage Yard	Trans-Unattended	115.00	4.33	
14	West Seneca Storage Yard	Trans-Unattended	115.00	34.50	
15	West Seneca Storage Yard	Trans-Unattended	230.00	120.00	13.80
16	West Valley Station 25	Dist-Unattended	34.50	4.80	
17	Westvale Station 133	Dist-Unattended	34.50	4.16	
18	Westville Station 885	Dist-Unattended	34.40	5.00	
19	Westville Station 885	Dist-Unattended	34.50	5.00	
20	Wethersfield Station 23	Dist-Unattended	34.50	4.80	
21	Wetzel Road Station	Dist-Unattended	115.00	13.80	
22	Whitaker Station 296	Dist-Unattended	115.00	13.80	
23	White Lake Station 399	Dist-Unattended	43.80	5.00	
24	Whitehall Station 187	Trans-Unattended	115.00	13.20	
25	Whitesboro Station 632	Dist-Unattended	43.80	4.40	
26	Whitesville Station 101	Dist-Unattended	34.50	4.80	
27	Whitman Station 671	Trans-Unattended	115.00	34.50	
28	Willow Specialties Station 24	Dist-Unattended	34.50	4.80	
29	Wilton Station 329	Dist-Unattended	34.50	13.20	
30	Wine Creek Station 283	Dist-Unattended	116.00	13.80	
31	Wolf Road Station 344	Dist-Unattended	113.00	13.80	
32	Wolf Road Station 344	Dist-Unattended	115.00	13.80	
33	Woodard Station 233	Trans-Unattended	110.00	34.50	
34	Woodlawn Station 188	Trans-Unattended	110.00	34.40	
35	Woodlawn Station 188	Trans-Unattended	110.00	34.40	13.80
36	Worcester Station 189	Dist-Unattended	23.00	13.80	5.04
37	Yahnundasis Station 646	Trans-Unattended	113.00	46.00	
38	Yahnundasis Station 646	Trans-Unattended	115.00	13.20	
39	Yahnundasis Station 646	Trans-Unattended	115.00	46.00	
40	York Center Station 53	Dist-Unattended	69.00	13.20	
41	Youngmann Terminal Station	Trans-Unattended	115.00	34.50	
42					
43					
44					
45					
46					
47					
48					
49					
50					
51					
52					
53					
54					
55					
56					
57					
58					
59	Total on page				

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

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 Trans-formers in Service (g)	Number of Spare Trans-formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
10.00	1					1
20.00	1					2
3.75	1					3
3.75	1					4
3.75	1					5
1.50	3					6
3.75	1					7
12.00	1					8
1.00	1					9
20.00	1					10
3.75	1					11
0.30	3					12
5.00	1					13
5.00	1					14
15.00	2					15
7.50	1					16
30.00	1					17
24.00	1					18
24.00	1					19
40.00	2					20
30.00	1					21
7.50	1					22
7.50	1					23
2.50	1					24
10.00	2					25
3.75	1					26
15.00	1					27
5.60	1					28
0.00	0	1				29
30.00	1					30
16.00	1					31
1.50	1					32
7.50	1					33
3.75	1					34
15.00	1					35
3.00	2					36
20.00	1					37
24.00	1					38
30.00	2					39
	47	1		0	0	40

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SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Trans- formers in Service (g)	Number of Spare Trans- formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
30.00	1					1
12.00	1					2
20.00	1					3
18.00	1					4
3.75	1					5
25.40	2					6
15.00	1					7
15.00	1					8
30.00	1					9
30.00	1					10
10.00	1					11
15.00	1					12
2.50	1					13
12.00	1					14
10.00	1					15
2.50	1					16
7.50	1					17
20.00	1					18
20.00	4					19
7.50	1					20
15.00	1					21
6.00	3					22
5.00	1					23
3.75	1					24
18.00	1					25
13.40	1					26
1.00	1					27
10.00	1					28
20.00	1					29
28.40	2					30
30.00	2					31
40.00	2					32
30.00	1					33
15.00	4					34
7.50	1					35
7.50	1					36
12.00	1					37
15.00	1					38
1.50	1					39
12.00	1					40
12.00	1					41
5.25	1					42
3.75	1					43
3.00	2					44
3.75	3					45
1.50	1					46
1.80	3					47
2.50	1					48
6.00	3	1				49
2.50	1					50
3.75	1					51
2.50	1					52
15.00	1					53
3.75	3					54
25.00	1					55
15.00	1					56
2.50	1					57
	78	1		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans-formers in Service	Number of Spare Trans-formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (in MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
13.40	1					1
0.10	1					2
5.00	1					3
7.50	1					4
7.50	1					5
3.75	1					6
6.00	2					7
24.00	1					8
18.00	1					9
538.00	2	1				10
2.49	3					11
13.44	1					12
7.50	1					13
20.00	2					14
3.75	1					15
7.50	4					16
12.00	1					17
15.00	1					18
30.00	2					19
4.69	1					20
4.70	1					21
5.60	1					22
5.00	1					23
7.50	1					24
4.69	1					25
3.75	1					26
5.00	1					27
3.00	1					28
7.50	1					29
3.00	2					30
7.50	1					31
5.00	1					32
15.00	1					33
3.75	1					34
1.70	1					35
3.40	2					36
30.00	1					37
30.00	1					38
5.00	1					39
10.00	2					40
1.00	2					41
7.50	1					42
2.50	1					43
3.75	1					44
0.00	0	1				45
20.00	1					46
20.00	1					47
30.00	2					48
3.75	1					49
6.00	3					50
15.00	1					51
12.00	1					52
20.00	1					53
7.50	1					54
15.00	1					55
7.50	1					56
5.00	1					57
	72	2		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans-formers in Service	Number of Spare Trans-formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (in MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
10.00	1					1
3.00	2					2
13.30	2					3
7.50	1					4
10.00	1					5
514.00	2					6
2.50	3					7
5.00	1					8
15.00	1					9
15.00	1					10
20.00	1					11
50.00	2					12
150.00	2					13
6.00	1					14
3.75	3					15
2.50	1					16
40.00	2					17
20.00	2					18
3.75	1					19
0.00	0	1				20
35.00	2					21
15.00	1					22
3.00	3					23
7.50	1					24
2.50	1					25
7.50	1					26
3.75	1					27
6.00	1					28
12.00	1					29
5.00	1					30
200.00	1					31
200.00	1					32
3.75	1					33
1,385.60	4					34
304.00	1					35
1.00	1					36
3.00	2					37
20.00	1					38
448.00	1					39
2.50	1					40
225.00	4					41
5.01	3					42
15.00	1					43
7.50	1					44
5.00	1					45
3.00	1					46
3.00	1					47
5.10	3					48
5.00	1					49
40.00	2					50
15.00	1					51
2.49	3					52
2.50	1					53
2.50	3					54
0.50	1					55
24.00	2					56
1.00	1					57
	87	1		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Trans-formers in Service (g)	Number of Spare Trans-formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
2.50	1					1
15.00	1					2
12.00	1					3
268.80	1					4
15.00	1					5
20.00	1					6
5.00	1					7
5.00	1					8
15.00	1					9
3.75	1					10
48.00	2					11
0.50	2					12
3.75	1					13
5.00	1					14
5.00	1					15
5.00	1					16
24.00	1					17
24.00	1					18
3.00	3					19
1.28	1					20
5.00	1					21
250.00	2					22
200.00	1					23
3.75	1					24
5.00	1	1				25
3.75	1					26
0.00	0	3				27
50.00	2					28
7.50	1					29
5.00	1					30
5.00	1					31
2.83	1					32
3.75	1					33
5.00	1					34
5.00	1					35
8.40	1					36
15.00	1					37
15.00	2					38
25.00	1					39
5.00	1					40
5.00	1					41
18.00	1					42
20.00	1					43
30.00	1					44
30.00	1					45
2.50	1					46
48.00	2					47
0.75	1					48
3.75	1					49
13.40	1					50
3.75	1					51
3.00	3					52
2.50	3					53
1.50	3					54
3.00	3					55
2.50	6					56
64.00	2					57
	78	4		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans- formers in Service	Number of Spare Trans- formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (in MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20.00	1					1
44.00	2					2
7.50	1					3
15.00	1					4
60.00	2					5
2.50	3					6
4.20	1					7
10.00	1					8
5.00	1					9
5.00	1					10
5.00	1					11
10.00	1					12
5.00	1					13
5.00	1					14
15.00	2					15
7.50	3					16
7.50	1					17
20.10	3					18
38.00	2					19
5.00	1					20
40.00	2					21
30.00	1					22
37.50	1					23
3.00	3	1				24
15.00	1					25
15.00	1					26
1.00	1					27
7.50	1					28
20.00	1					29
155.90	1					30
18.00	1					31
20.00	1					32
1.00	3					33
10.00	1					34
24.00	2					35
5.00	1					36
10.00	1					37
3.75	1					38
10.00	2					39
26.88	2					40
90.00	3					41
30.00	1					42
0.67	2					43
0.33	1					44
15.00	1					45
1.50	1					46
1.50	1					47
7.50	1					48
18.00	1					49
13.40	1					50
49.60	1					51
20.10	1					52
12.00	1					53
15.00	1					54
3.75	1					55
5.00	1					56
5.00	2					57
	79	1		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans-formers in Service	Number of Spare Trans-formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (in MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
7.50	1					1
5.00	1					2
10.00	1					3
24.00	2					4
330.00	4					5
15.00	1	1				6
1.50	1					7
1.00	1					8
7.50	1					9
10.00	2					10
5.00	1					11
10.00	1					12
15.00	2					13
2.50	1					14
1.50	1					15
1.50	1					16
15.00	1					17
10.00	1					18
1.50	3					19
4.20	1					20
7.50	1					21
0.67	2					22
3.75	1					23
3.75	1					24
12.00	1					25
15.00	1					26
15.00	1					27
3.75	1					28
7.50	1					29
12.00	1					30
3.75	1					31
50.00	2					32
7.50	3	1				33
18.00	1					34
0.00	0	1				35
15.00	1					36
17.50	2					37
15.00	1					38
3.75	1					39
15.00	1					40
30.00	1					41
5.00	1					42
5.00	1					43
30.00	1					44
50.00	1					45
7.50	1					46
12.00	1					47
10.00	1					48
3.00	1					49
0.83	1					50
1.66	2					51
0.75	3					52
12.00	1					53
15.00	1					54
12.00	1					55
20.00	1					56
0.00	0	1				57
	71	4		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Trans- formers in Service (g)	Number of Spare Trans- formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
0.00	0	1				1
40.00	1					2
6.00	1					3
7.50	1					4
20.00	1					5
27.00	2					6
30.00	1					7
0.17	1					8
2.50	1					9
7.50	1					10
4.20	1					11
3.75	1					12
5.00	1					13
0.67	2					14
0.33	1					15
3.33	4					16
15.00	3					17
7.50	3					18
12.00	1					19
24.00	1					20
7.50	1					21
3.75	1					22
40.00	1					23
40.00	1					24
30.00	1					25
20.01	3					26
3.00	1					27
2.49	3					28
2.50	1					29
20.00	1					30
40.00	2					31
15.00	1					32
5.00	1					33
7.50	1					34
7.50	1					35
18.00	1					36
537.00	2					37
60.00	2					38
20.00	2					39
0.75	3					40
10.00	2					41
3.75	3					42
10.00	1	1				43
7.50	1					44
3.75	1					45
10.00	1					46
15.00	2					47
30.00	2					48
1.50	1					49
1.50	1					50
5.00	1					51
12.00	1					52
15.00	1					53
1.00	1					54
2.50	1					55
40.00	2					56
3.75	1					57
	81	2		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans-formers in Service	Number of Spare Trans-formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (in MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
12.00	1					1
25.00	1					2
2.50	1					3
15.00	1					4
12.00	1					5
3.75	3					6
15.00	1					7
60.00	2					8
10.00	1					9
10.00	1					10
3.75	3					11
2.50	1					12
3.75	1					13
28.00	1					14
30.00	2					15
10.00	1					16
32.00	2					17
15.00	1					18
0.50	1					19
0.30	2					20
8.75	4					21
48.00	2					22
2.50	1					23
30.00	3	1				24
448.00	1					25
3.75	1					26
150.00	2	1				27
36.00	2					28
1.50	1					29
3.00	1					30
1.00	2					31
5.00	1					32
20.00	2					33
30.00	1					34
15.00	1					35
2.50	1					36
12.00	1					37
20.00	1					38
20.00	1					39
1.50	3					40
3.00	1					41
15.00	1					42
24.00	1					43
3.00	3					44
5.00	1					45
0.99	3					46
44.00	2					47
12.00	1					48
15.00	1					49
10.00	2					50
10.00	1					51
2.50	1					52
2.49	3					53
7.50	1					54
2.50	3					55
5.00	1					56
534.00	2					57
	88	2		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Trans-formers in Service (g)	Number of Spare Trans-formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
0.00	0	1				1
7.50	1					2
3.75	1					3
12.00	1					4
30.00	1					5
48.00	2					6
0.99	3					7
15.00	1					8
8.30	1					9
1.00	2					10
40.00	2					11
10.00	1					12
5.04	1					13
30.00	2					14
400.00	1					15
7.50	1					16
3.30	3					17
40.00	2					18
3.75	1					19
3.75	1					20
0.00	0	1				21
0.00	0	1				22
0.00	0	1				23
0.00	0	2				24
0.00	0	1				25
0.00	0	1				26
0.00	0	1				27
0.00	0	1				28
24.00	1					29
40.00	1					30
0.00	0	1				31
0.00	0	1				32
24.00	1					33
40.00	1					34
0.00	0	1				35
0.50	1					36
13.40	1					37
3.75	1					38
5.60	1					39
24.00	1					40
18.00	1					41
36.00	2					42
12.00	1					43
30.00	1					44
33.60	1					45
15.00	1					46
20.00	1					47
20.10	3					48
267.00	1					49
616.00	2					50
3.00	2					51
18.00	1					52
0.00	0	1				53
0.00	0	2				54
0.00	0	1				55
0.00	0	1				56
0.00	0	1				57
	54	19		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans-formers in Service	Number of Spare Trans-formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (in MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
0.00	0	1				1
0.00	0	1				2
0.00	0	1				3
0.00	0	6				4
0.00	0	1				5
0.00	0	1				6
0.00	0	1				7
0.00	0	1				8
0.00	0	2				9
0.00	0	1				10
0.00	0	1				11
0.00	0	1				12
0.00	0	1				13
0.00	0	1				14
0.00	0	1				15
0.00	0	1				16
0.00	0	1				17
0.00	0	1				18
0.00	0	1				19
7.50	1					20
5.00	1					21
5.00	1					22
5.60	1					23
7.50	1					24
15.00	1					25
15.00	1					26
3.75	1					27
5.00	1					28
5.00	1					29
7.50	1					30
0.00	0	1				31
180.00	3	1				32
2.10	3					33
12.00	1					34
7.50	1					35
5.00	1					36
42.00	2					37
20.00	1					38
5.00	1					39
7.50	1					40
10.00	2					41
10.00	1					42
7.50	1					43
5.00	1					44
90.00	3	1				45
0.99	3					46
5.00	1					47
5.60	1					48
7.50	1					49
7.50	1					50
8.40	1					51
15.00	1					52
15.00	1					53
5.25	1					54
3.75	1					55
10.00	1					56
2.50	1					57
	47	28		0	0	58

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans-formers in Service	Number of Spare Trans-formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (in MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
5.00	1					1
0.33	1					2
2.50	1					3
15.00	1					4
25.00	5					5
15.00	3					6
10.00	2					7
10.00	2					8
15.00	1					9
15.00	1					10
40.00	2					11
5.00	1					12
1.50	1					13
10.00	1					14
5.00	1					15
3.75	1					16
3.75	1					17
12.00	1					18
0.50	3					19
50.00	1					20
5.00	1					21
5.00	1					22
3.75	1					23
30.00	2					24
15.00	4					25
14.80	4					26
15.00	4					27
15.00	4					28
7.50	3					29
2.50	1					30
15.00	4					31
15.00	4					32
15.00	4					33
15.00	4					34
10.00	4					35
7.50	3					36
2.50	1					37
2.50	1					38
7.50	3					39
15.00	4					40
5.00	2					41
2.50	1					42
2.50	1					43
7.50	3					44
2.50	1					45
3.75	1					46
11.25	3					47
15.00	4					48
10.00	4					49
15.00	4					50
15.00	4					51
10.00	4					52
10.00	1					53
3.75	1					54
3.75	1					55
7.50	2					56
15.00	4					57
2.50	1					58
	130	0		0	0	59

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Trans-formers in Service (g)	Number of Spare Trans-formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
7.50	3					1
3.75	1					2
3.75	1					3
7.50	2					4
11.25	3					5
7.50	2					6
7.50	2					7
15.00	4					8
7.50	2					9
3.75	1					10
10.00	4					11
15.00	4					12
7.50	3					13
7.50	1					14
7.50	1					15
7.50	2					16
11.25	3					17
11.25	3					18
4.20	1					19
11.25	3					20
5.00	2					21
2.50	1					22
24.00	2					23
7.50	1					24
7.50	1					25
4.20	1					26
9.37	2					27
24.00	2					28
1.50	1					29
7.50	2					30
10.00	4					31
3.75	1					32
2.50	1					33
5.50	2					34
27.00	2					35
9.45	2					36
15.00	2					37
85.00	4					38
2.50	1					39
5.00	2					40
10.50	3					41
10.50	3					42
3.50	1					43
3.50	1					44
0.00	0	1				45
3.50	1					46
10.50	3					47
10.50	3					48
4.69	1					49
3.75	1					50
3.75	1					51
3.75	1					52
7.50	1					53
24.00	2					54
30.00	2					55
2.50	3					56
11.88	4					57
17.44	4					58
	117	1		0	0	59

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa)	Number of Trans-formers in Service	Number of Spare Trans-formers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment	Number of Units	Total Capacity (in MVa)	Line No.
(f)	(g)	(h)	(i)	(j)	(k)	
5.00	2					1
2.50	1					2
5.00	2					3
7.50	1					4
7.50	1					5
40.00	2					6
3.75	1					7
12.50	1					8
7.50	2					9
36.00	2					10
7.50	1					11
1.50	1					12
3.75	1					13
7.50	2					14
7.50	1					15
5.00	1					16
11.70	3					17
11.25	3					18
5.50	2					19
5.25	1					20
3.75	1					21
3.75	1					22
1.50	1					23
15.00	4					24
15.00	1					25
15.00	1					26
3.75	1					27
3.75	1					28
7.45	2					29
15.00	1					30
40.00	2					31
40.00	2					32
30.00	2					33
7.50	1					34
7.50	1					35
20.00	1					36
20.00	1					37
15.00	1					38
13.40	1					39
5.00	1					40
20.00	1					41
20.00	1					42
5.01	3					43
7.50	1					44
12.00	1					45
2.50	1					46
10.00	1					47
7.50	1					48
7.50	1					49
2.50	1					50
12.00	1					51
15.00	1					52
12.00	1					53
15.00	1					54
20.00	1					55
24.00	1					56
60.00	2					57
30.00	1					58
	79	0		0	0	59

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Trans- formers in Service (g)	Number of Spare Trans- formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
30.00	1					1
48.00	2					2
26.90	1					3
27.00	1					4
24.00	1					5
3.75	1					6
30.00	2					7
5.00	1					8
40.00	2					9
30.00	1					10
7.50	1					11
67.20	2					12
0.25	1					13
1.16	4					14
0.33	1					15
5.00	1					16
15.00	1					17
13.00	1					18
15.00	1					19
0.50	3					20
7.50	1					21
10.00	1					22
12.00	1					23
15.00	1					24
30.00	1					25
12.00	1					26
35.00	2					27
15.00	2					28
30.00	3					29
5.00	1					30
15.00	2					31
7.50	1	1				32
15.00	1					33
15.00	1					34
10.00	1					35
30.00	1					36
0.75	1					37
3.75	1					38
3.75	1					39
7.50	1					40
10.00	1					41
40.00	2					42
2.50	1					43
15.00	1					44
9.80	2					45
0.50	1					46
1.00	2					47
20.00	1					48
5.00	1					49
5.00	1					50
27.00	2					51
5.00	1					52
1.50	1					53
0.00	0	1				54
0.00	0	4				55
0.00	0	1				56
0.00	0	1				57
0.00	0	2				58
	71	10		0	0	59

SUBSTATIONS (Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Trans-formers in Service (g)	Number of Spare Trans-formers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	Line No.
0.00	0	3				1
0.00	0	1				2
0.00	0	3				3
0.00	0	1				4
0.00	0	2				5
0.00	0	1				6
0.00	0	1				7
0.00	0	1				8
0.00	0	1				9
0.00	0	1				10
0.00	0	4				11
0.00	0	1				12
0.00	0	1				13
0.00	0	2				14
0.00	0	2				15
2.50	1					16
7.50	1					17
1.25	1					18
2.50	2					19
2.00	2					20
48.00	2					21
18.00	1					22
1.50	3					23
10.50	1					24
5.00	1					25
1.50	1					26
7.50	1					27
2.50	1					28
12.00	1					29
12.00	1					30
18.00	1					31
18.00	1					32
60.00	2					33
30.00	1					34
20.01	3					35
4.40	1					36
21.00	1					37
18.00	1					38
20.00	1					39
8.40	1					40
40.00	2					41
						42
						43
						44
						45
						46
						47
						48
						49
						50
						51
						52
						53
						54
						55
						56
						57
						58
	35	25		0	0	59

Name of Respondent Niagara Mohawk Power Corporation	This Report is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) April 17, 2019	Year of Report December 31, 2018

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.
2. Include watt-hour demand distribution meters, but not external demand meters.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other parties, explain basis of accounting for expenses 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.

Line No.	Item (a)	Number of Watt-Hour Meters (b)	LINE TRANSFORMERS Number (c)	LINE TRANSFORMERS Total Capacity (In MVa) (d)
1	Number at Beginning of Year	1,748,109	430,483	16,144
2	Additions During Year			
3	Purchases	28,622	13,769	516
4	Associated with Utility Plant Acquired			
5	TOTAL Additions (Enter Total of Lines 3 and 4)	28,622	13,769	516
6	Reductions During Year			
7	Retirements	18,124	0	0
8	Associated with Utility Plant Sold			
9	TOTAL Reductions (Enter Total of Lines 7 and 8)	18,124	0	0
10	Number at End of Year (Lines 1 + 5 - 9)	1,758,607	444,252	16,660
11	In Stock	7,935	11,155	418
12	Locked Meters on Customers' Premises			
13	Inactive Transformers on System			
14	In Customers' Use			
15	In Company's Use	1,750,672	433,097	16,242
16	TOTAL End of Year (Enter Total of lines 11 to 15. This line should equal line 10.)	1,758,607	444,252	16,660

Name of Respondent Niagara Mohawk Power Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Day, Yr) April 17, 2019	Year of Report December 31, 2018

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 services 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 a n allocations process, explain in a footnote.

Line No.	Description of the Non-Power Good or Services (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		NGUSA Service Company		372,174,175
3		Massachusetts Electric Company		921,421
4		KeySpan Gas East Corporation		270,328
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	**Non-power Goods or Services Provided for Affiliate**			
22		Massachusetts Electric Company		6,942,044
23		Boston Gas Company		6,863,738
24		Narragansett Electric Company		3,573,607
25		Brooklyn Union Gas		2,125,921
26		KeySpan Gas East Corporation		1,468,322
27		New England Power Company		803,965
28		Colonial Gas Company		742,551
29		NGUSA Service Company		469,635
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Comment Sheet

Please use this sheet to record any changes you made to this file. If you altered this file in anyway, except by entering data, you must record those changes here. You may also use this sheet to make any comments about this file or the joint cost file.

Item Number	Description	Schedule Number	Page Number
1	Changed formula on line 9 of the schedule to sum items 1-7 then subtract item 8 since benefits payments (item 7) is now shown as a negative number against the positive asset value.		32
2	Changed formula on line 52 column (h) of the schedule to show average per Dth of total revenues.		67
3	Added formula to line 24 column (c) to show total of line 23 in equivalent therms.		93

GENERAL INSTRUCTIONS

1. The completed original of this report form, properly filled out, shall be filed with the Public Service Commission, Albany, N.Y., on or before the 31st of March next following the end of the year to which the report applies. At least one additional copy shall be retained in the files of the reporting utility.

2. All utility companies upon which this report form is served are required by statute to complete and to file the report. The statute further provides that when any such report is defective or believed to be erroneous, the reporting utility shall be duly notified and given a reasonable time within which to make the necessary amendments or corrections.

3. All accounting terms and phrases used in this form are to be interpreted in accordance with the Uniform Systems of Accounts prescribed by this Commission. Whenever the term respondent is used, it shall be understood to mean the reporting utility.

4. If the report is made for a period other than the calendar year, the period covered must be clearly stated on the front cover and elsewhere throughout the report where the period covered is shown. When operations cease during the year because of the disposition of property the balance sheet and supporting schedules should consist of balances and items immediately prior to transfer (for accounting purposes). If the books are not closed as of that date, the data in the report should nevertheless be complete and the amounts reported should be supported by information set forth in, or as part of the books of account.

5. Every inquiry must be definitely answered. If "none" or "not applicable" states the fact, such an answer may be used. The annual report should be complete in itself. Reference to reports of previous years or to any paper or document should not be made in lieu of required entries except as specifically outlined.

6. Upon filing, the report may, if desired, be permanently bound. If it is so bound, the requirement for page by page identification of the reporting company set forth in paragraph 9 below, may be disregarded. Extra copies of any page will be furnished upon request.

7. If the utility conducts operations both within and without the State of New York, data should be reported so that there will be shown the quantities of commodities sold within this State, and (separately by accounts) the operating revenues from sources within this State, the operating revenue deductions applicable thereto and the plant investment as of the end of the year within this State.

8. All entries shall be made in black or dark blue except those of a contrary or opposite nature, which should be made in red or enclosed in parentheses. Inserts, if any, should be appropriately identified with the schedules to which they relate.

9. Insert the initials of the reporting utility and the year which the report covers in the space provided on each page.

10. Cents are to be omitted on all schedules except where they apply to averages and figures per unit where cents are important. The amounts shown on all supporting schedules shall agree with the item in the statement they support.

LIST OF SCHEDULES
SUPPLEMENTAL FILING FOR ELECTRIC AND GAS COMPANIES

RECONCILIATION BETWEEN FERC, PSC AND STOCKHOLDER'S ANNUAL REPORT

Attach herein (following this page) the respondent's latest annual report to stockholders. If such a report is not prepared, but if audited annual financial statements on which a certified public accountant expresses an opinion are regularly prepared and distributed to bondholders, banking institutions or security analysts, submit that.

If the respondent's annual report to stockholders or audited annual financial statements are prepared on a calendar year basis, the major financial statements contained therein, i.e., Balance Sheet, Income and Retained Earnings Statement and Statement of Cash Flows, shall be reconciled with the corresponding PSC and FERC statements. The reconciliation shall contain an explanation of all differences in reporting.

If the respondent's annual report to stockholders or audited annual financial statements are prepared on a fiscal year basis, then a statement shall be included stating that, except as noted, the major financial statements are prepared on the same basis as in this annual report to the Commission and are in conformity with this Commission's applicable Uniform System of Accounts.

If reports to stockholders or audited annual financial statements are not prepared, so state below:

Niagra Mohawk Power Corporation is not an SEC registrant. Therefore, no SEC Form 10K or annual report to shareholders is required or prepared. There are no audited financial statements as of December 31, 2016. The Company’s audited financial statements as of March 31 each year which are regularly prepared and distributed to bondholders, banking institutions, and/or security analysts are prepared in accordance with accounting principles generally accepted in the United States (US GAAP). US GAAP is a basis of accounting which is different from the Commission’s applicable Uniform System of Accounts. See footnote 1. for the primary differences.

RECONCILIATION BETWEEN FERC, PSC AND STOCKHOLDER'S ANNUAL REPORT (Continued)

($000s)

Note: A reconciliation between the PSC and FERC is only necessary if the net income difference is greater than .05%.

Line No.	Description	PSC USOA	Adjustments	FERC USOA					Consolidations Eliminations	Footnote Ref	Stockholder's Report
1	**Balance Sheet**										
2	Assets										
3	Total Net Utility Plant	9,042,248	1,289,132	10,331,380							
4											
5											
6											
7	Other Property & Investments										
8											
9											
10											
11	Current Assets										
12											
13											
14											
15	Deferred Debits										
16											
17											
18											
19											
20	Total	9,042,248	1,289,132	10,331,380	-	-	-	-	-		-
21	Liabilities & Capital										
22	Proprietary Capital	3,410,231	1,289,132	4,699,363							
23											
24											
25											
26	Long Term Debt										
27											
28	Other Noncurrent Liabilities										
29											
30											
31	Current & Accrued Liabilities										
32											
33											
34	Deferred Credits										
35											
36											
37											
38											
39	Operating Reserves										
40											
41	Income Taxes										
42											
43	Total	3,410,231	1,289,132	4,699,363	-	-	-	-	-		-

NEW YORK INTRASTATE REVENUES

Show for each department the amount of gross operating revenues derived from New York intrastate utility operations during the year. If these amounts differ from the corresponding revenue figures in the Income Statement, each such difference should be explained in sufficient detail to identify the amounts by detail revenue accounts. It is intended that the amounts shown hereunder shall represent the revenues subject to assessment under Section 18a of the Public Service Law.

Line No.	Description Account (a)	Revenues Intrastate (b)	Revenues Interstate (c)
1	Electric Utility	3,258,108,569	596,785
2	Gas Utility	858,639,212	5,790,551
3	Other Utility	2,224,611	
4			
5			
6			
7			
8			
9			
10	TOTALS	4,118,972,392	6,387,336

*Column (b) lines 1 and 2 include Electric Estimated ESCO Revenues of 656,724,315 and Gas Estimated ESCO Revenues of $241,286,462 for calendar year 2018. These amounts are being reported per Rate Case 09-M-0311.

INSTRUCTIONS FOR THE RATE OF RETURN AND RETURN ON COMMON EQUITY CALCULATION

COMPUTATIONS:

RETURN ON COMMON EQUITY

Net Operating Income	Page 114-115, Line 24, Column (e) Page 114-115, Line 24, Column (g) Page 114-115, Line 24, Column (i)
Interest Charges	Page 117, Line 66, Column (c) Allocate to electric, gas and other based on Net Utility Plant.
Preferred Stock Dividends	Page 118, Line 29, Column (c) Allocate to electric, gas and other based on Net Utility Plant.
Net Income Available for Common	Subtract Lines 2 and 3 from Line 1.
Adjusted Common Equity	Line 13 of this schedule Allocate to electric, gas and other based on Net Utility Plant.
Return on Common Equity	Divide Line 4 by Line 5.

TOTAL COMMON EQUITY

Common Stock	Page 112, Line 2: Columns (c) and (d).
Premium on Capital Stock	Page 112, Lines 4 through 8: Columns (c) and (d).
Capital Stock Expense	Page 112, Lines 9, 10: Columns (c) and (d).
Retained Earnings	Page 118, Lines 1 and 38: Column (c). Page 112, Line 12: Columns (c) and (d).
Total	Sum Lines 7 through 10.
Investment in Subsidiary Companies	Page 110, Lines 16 and 17: Columns (c) and (d).
Adjusted Common Equity	Subtract Line 12 from Line 11.

NET PLANT INVESTMENT

Net Plant - Electric	Page 200-201, Line 15: Column (c).
Net Plant - Gas	Page 200-201, Line 15: Column (d).
Net Plant - Other	Page 200-201, Line 15: Columns (e) through (g). Page 110, Line 14 minus Line 15: Columns (c) and (d).

RATE OF RETURN AND RETURN ON COMMON EQUITY CALCULATION

Line No.	Item	Total (a)	Electric (b)	Gas (c)	Other (d)
1	Net Operating Income	344,305,048	273,638,764	68,441,673	2,224,611
	Less:				
2	Interest Charges (1)	155,939,603	124,303,536	28,328,616	3,307,451
3	Preferred Stock Dividends (1)	(1,060,497)	(845,350)	(192,654)	(22,493)
4	Net Income Available for Common	189,425,942	150,180,578	40,305,711	(1,060,347)
5	Adjusted Common Equity (1)	3,266,134,144	2,603,520,947	593,339,080	69,274,116
6	Return on Common Equity	5.80%	5.77%	6.79%	-1.53%

Calculation of Common Equity

		Beginning of Year	End of Year		Average for Year
7	Common Stock	187,364,863	187,364,863		187,364,863
8	Premium on Capital Stock	1,773,485,310	1,810,363,763		1,791,924,537
9	Capital Stock Expense (Input as negative)	0	0		0
10	Retained Earnings	1,188,971,762	1,386,230,139		1,287,600,951
11	Total	3,149,821,935	3,383,958,765		3,266,890,350
12	Less: Investment in Subsidiary Companies	778,606	733,807		756,207
13	Adjusted Common Equity	3,149,043,329	3,383,224,958		3,266,134,144

Allocation of Net Plant between Electric, Gas and Other

		Beginning of Year	End of Year	Average for Year	Percentages
14	Net Plant - Electric	6,813,381,406	7,204,568,545	7,008,974,976	79.71%
15	Net Plant - Gas	1,544,637,142	1,650,035,650	1,597,336,396	18.17%
16	Net Plant - Other	185,343,991	187,643,633	186,493,812	2.12%
17	Total	8,543,362,539	9,042,247,828	8,792,805,184	100.00%

(1) It is acceptable to use the allocation method used in the company's last rate case proceeding. If this allocation method is used, please note "YES" here=================== YES

It should be noted that these calculated common equity returns are not intended as an evaluation of the reasonableness of the earnings of any utility under the jurisdiction of the Public Service Commission. Also, the earned rates of return reported here are not necessarily the same that would be computed in a formal rate proceeding. Differences may occur because the data in formal proceedings are analyzed in detail and adjustments are usually made to booked amounts.

MISCELLANEOUS PLANT DATA

Furnish a summary statement for each of the accounts listed here for each department and for Common Plant if a balance of $250,000 was carried therein at any time during the year. There should be shown a brief description and amounts, of transactions earned through each such account and, except to the extent that the information is shown elsewhere in this report, opening and closing balances. If any of the property involved has an income producing status during the year, the gross income and applicable expenses (suitably subdivided) should be reported.

104 Plant Leased to Others	See Below
105 Plant Held for Future Use	NONE
114 Plant Acquisition Adjustments	NONE
118 Other Utility Plant	NONE
108 Accumulated Provision for Depreciation of Plant Leased to Others	See Below
108 Accumulated Provision for Depreciation of Plant Held for Future Use	NONE
111 Accumulated Provision for Amortization of Plant Leased to Others	NONE
111 Accumulated Provision for Amortization of Plant Held for Future Use	NONE
111 Accumulated Provision for Abandonment of Leases	NONE
111 Accumulated Provision for Amortization of Other Gas Plant Held for Future Use	NONE
115 Accumulated Provision for Amortization of Plant Acquisition Adjustments	NONE
119 Accumulated Provision for Depreciation and Amortization of Other Utility Plant	NONE

104 - Plant Leased to Others

Balance - January 1, 2018	3,425,127
Balance - December 31, 2018	3,425,127

108 - Accumulated Provision for Depreciation of Plant Leased to Others

Balance - January 1, 2018	1,082,979
Additions	32,543
Balance - December 31, 2018	1,115,522

Investments (Account 123 and 124)

1. Report below investments greater than or equal to $250,000 in Accounts 123, Investment in Associated Companies and 124, Other Investments.

2. Provide a subheading for each account and list thereunder the information called for, observing the instructions below.

3. Investment in Securities - List and describe each security owned, giving name of issuer. For bonds give also principal amount, date of issue, maturity, and interest rate. For capital stock state number of shares, class and series of stock. Minor investments may be grouped by classes.

4. Investment Advances - Report separately for each person or company 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. Each note should be listed giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders or employees.

5. For any securities, notes, or accounts that were pledged, designate such securities, notes or accounts and in a footnote state the name of the pledgee and purpose of the pledge.

6. If commission approval was required for any advance made or security acquired, designate such fact and in a footnote give date of authorization and case number.

7. Interest and dividend revenues from investments should be reported in column (g), including such revenues from securities disposed of during the year.

8. 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 different from cost) and the selling price therefor, not including any dividend or interest adjustment includible in column (g).

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Book Cost Beginning Of Year (d)	Principal Amount or No. Of Shares End of Year (e)	Book Costs * End Of Year (f)	Revenues For Year (g)	Gain or Loss From Investment Disposed of (h)
1								
2	NM PROPERTIES, INC.							
3	$1 par value			778,606	3,075	733,807	(44,799)	
4								
5								
6								
7								
8	Totals (Account 123)			$778,606		$733,807	($44,799)	$0
9								
10								
11								
12	Cash Surrender Value on Officer Life							
13	Insurnce (National Wide Life Insurance)			5,882,286		6,472,690	590,404	
14								
15								
16	Totals (Account 124)			$5,882,286		$6,472,690	$590,404	$0

* If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference.

SPECIAL FUNDS (Accounts 125, 126, 128)
(Sinking Funds, Depreciation Fund, Other Special Funds)

1. For each fund which exceeds $250,000 at the end of the year, report the balance below. Aggregate all other funds. Indicate nature of any fund included in Account 128, Other Special Funds.

2. Explain, for each fund, any deductions other than withdrawals for the purpose for which the fund was created.

3. If the trustee of any fund is an associated company, give name of such associated company.

4. If assets other than cash comprise any fund, furnish a list of the securities or other assets, giving interest or dividend rate of each, cost to respondent, number of shares or principal amount, and book cost at end of year.

Line No.	Name of Fund and trustee if any (a)	Balance End of Year (b)
1		
2	None	
3		
4		
5		
6	Total (Account 125)	$0
7		
8	None	
9		
10		
11		
12		
13	Total (Account 126)	$0
14		
15	Supplemental Executive Retirement Plan	13,195,825
16	Rabbi Trust Investment	20,727,585
17		
18		
19		
20	Total (Account 128)	$33,923,410

SPECIAL DEPOSITS (Accounts 132, 133, 134)

1. For each fund which exceeds $250,000 at the end of the year, report the balance below. Aggregate all other funds.
2. If any deposit consists of assets other than cash, give a brief description of such assets.
3. If any deposit is held by an associated company, give name of company.

Line No.	Description and purpose of deposit (a)	Balance End of Year (b)
21	Other Special Deposits (Account 134):	
22	Release of Property Account (HSBC)	463,057
23	NYSDEC Trust Fund (Bank of NY)	2,270,553
24	Salmon River Escrow Account (HSBC) - Environmental reserve	-
25	CITI Group Energy Collateral	-
26	BP Energy Collateral	-
27	Exelon Collateral	-
28		
29		
30		
31		
32		
33		
34		
35		
36		
37	Total (Account 134)	$2,733,610

NOTES AND ACCOUNTS RECEIVABLE (Accounts 141, 142, 143)

Summary for Balance Sheet

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143). Disclose separately by footnote any capital stock subscriptions received included in Account 143, Other Accounts Receivable.

LINE NO.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)		
2	Customer Accounts Receivable (Account 142):		
3	Gas	146,100,174	169,148,529
4	Electric	316,847,503	310,153,698
5	Merchandising, Jobbing and Contract Work		
6	Other		
7	Other Accounts Receivable (Account 143)	65,398,251	55,756,400
8	Total (Accounts 142 and 143)	528,345,928	535,058,627
9	Less: Accumulated Provision for Uncollectible Accounts - Cr. (Account 144)	148,613,954	148,775,435
10	Total, Less Accumulated Provision for Uncollectible Accounts	$379,731,974	$386,283,192
11			
12			
13			
14			
15			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS-CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
2. Explain any important adjustments of subaccounts.
3. Entries with respect to officers and employees shall not include items for utility services.

LINE NO.	Item (a)	Utility Customers (b)	Merchandising, Jobbing and (c)	Officers and (d)	(e)	Total (f)
21	Balance Beginning of Year	$148,613,954				$148,613,954
22	Prov. for Uncollectibles for Year	43,873,258				43,873,258
23	Accounts Written Off	43,711,777				43,711,777
24	Collection of Accounts Written Off					
25	Adjustments (Explain)					
26						
27	Balance End of Year	$148,775,435	$0	$0	$0	$148,775,435

LINE NO.	
28	
29	4. Summarize the collection and write-off practices applied to overdue customers' accounts.
30	
31	
32	
33	
34	
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40	

RECEIVABLES FROM ASSOCIATED COMPANIES (Account 145 & 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.
2. Provide separate headings and totals for Accounts 145, Notes Receivable from Associated Companies.
3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year, including interest on notes held any time during the year. during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Debits (c)	Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	NGUSA Service Company	$182,917,175	$600,501,047	$182,917,175	$600,501,047	
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14	Totals (Account 145)	$182,917,175	$600,501,047	$182,917,175	$600,501,047	$0
15						
16						
17	NG USA Parent	$18,850,618	$10,599,362	$29,265,386	$184,594	
18	NGUSA Service Company	38,141,820	614,297,182	647,946,601	4,492,401	
19	NG Engineering Services, LLC	6,550,093	4,512,930	4,474,071	6,588,952	
20	Massachusetts Electric Company	8,364,949	40,488,565	48,734,791	118,723	
21	Other	561,598	1,220,141,544	1,220,444,139	259,003	
22						
23						
24						
25						
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46						
47						
48	Totals (Account 146)	$72,469,078	$1,890,039,583	$1,950,864,988	$11,643,673	$0

GAS STORED (ACCOUNTS 117, 164.1 AND 164.2)

1. Report below the information called for concerning inventory of gas stored.
2. The Uniform System of Accounts provides that inventory cost records be maintained on a consolidated basis for all storage projects with separate records showing the Dth of inputs and withdrawals and balance for each project, unless the storage projects are widely separated and the cost of gas therein varies significantly. If the respondent's inventory cost records are not maintained on a consolidated basis for all storage projects, furnish an explanation of the accounting followed and the reason for the deviation. Separate schedules on this schedule form should be furnished for each group of storage projects for which separate inventory cost records are maintained.
3. If during the year adjustment was made of the stored gas inventory, such as to correct for cumulative inaccuracies of gas measurements, furnish an explanation of the reason for the adjustment, the Dth and dollar amount of adjustment and account charged or credited.
4. Give a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
5. If the respondent uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock," or restoration of previous encroachment, including brief particulars of any such accounting during the year.
6. If respondent has provided accumulated provision for stored gas which may not eventually be fully recovered from any storage project furnish a statement showing: (a) date of Commission authorization of such accumulated provision (b) explanation of circumstances requiring such provision (c) basis of provision and factors of calculation (d) estimated ultimate accumulated provision accumulation (e) a summary showing balance of accumulated provision and entries during the year.

LINE NO.	DESCRIPTION (a)	NONCURRENT (b)	CURRENT (c)	LNG (d)	TOTAL (e)
1	BALANCE, BEGINNING OF YEAR		$26,965,736		$26,965,736
2					
3	GAS DELIVERED TO STORAGE				
4	(CONTRA ACCT. 809)		36,651,161		36,651,161
5	GAS WITHDRAWN FROM STORAGE				
6	(CONTRA ACCT.808)		28,251,837		28,251,837
7	OTHER DEBITS OR CREDITS (Explain)				
8					
9					
10					
11	BALANCE, END OF YEAR	$0	$35,365,060	$0	$35,365,060
12	Dth		14,581,497		14,581,497
13	AMOUNT PER Dth		2.43		2.43
14	State basis of segregation of inventory between current and noncurrent portions.				
15					
16	GAS DELIVERED TO STORAGE:				
17	Dth				14,952,718
18	AMOUNT PER Dth				2.45
19	Cost of gas delivered to storage:				Average
20	Specify: Own production (give production area, see Uniform System of Accounts);				
21	average system purchases; specific purchases (state which purchases)				
22	Does cost of gas delivered to storage include any expenses for use of respondent's				
23	transmission, storage, or other facilities? If so, give particulars and				
24	date of commission approval of the accounting.				
25					
26					
27	GAS WITHDRAWN FROM STORAGE:				
28	Dth - INCLUDES VOLUME OF Dth RELATED TO COST REPORTED ON LINE 6.				(12,725,760)
29	AMOUNT PER Dth				(2.22)
30	COST BASIS OF WITHDRAWALS:				Average
31	Specify: average cost, LIFO, FIFO, (Explain any change in inventory basis				
32	during year and give date of Commission approval of the change or approval				
33	of an inventory basis different from that referred to in the Uniform				
34	System of Accounts).				
35					
36					

PREPAYMENTS (ACCOUNT 165)

1. Give below the particulars called for concerning each prepayment.
2. Report all payments for undelivered gas on line 5 and complete schedule 34 showing particulars for gas prepayments.
3. Minor items may be grouped by classes, showing number of such items.

Line No.	Nature of Prepayment (a)	End of Year Balance (b)
1	Prepaid Insurance	$67,260
2	Prepaid Rents	3,211,540
3	Prepaid Taxes	52,413
4	Miscellaneous Prepayments: (specify:) RECs and ZECs Prepayments	29,610,141
5	NYPSC General	3,272,709
6	Information System Prepayments	737,455
7	Energy Efficiency Invoices	2,451
8		
9		
10		
11		
12		
13		
14	TOTAL (Account 165)	$36,953,969

OTHER CURRENT AND ACCRUED ASSETS (Accounts 172, 173, and 174)

1. Give a description and the amount of the principal items carried at the end of the year in each of the accounts listed below.
2. Minor items may be grouped by classes, showing the number of items in each group.

Line No.	Description (a)	End Of Year Balance (b)
15	Rents Receivable (Account 172)	12,782,749
16		
17		
18		
19		
20		
21	TOTAL (Account 172)	12,782,749
22	Accrued Utility Revenues (Account 173)	
23	Accrued Utility Revenues - Electric	112,652,798
24	Accrued Utility Revenues - Gas	19,179,769
25		
26		
27	TOTAL (Account 173)	131,832,567
28	Miscellaneous Current and Accrued Assets (Account 174)	
29	Puerto Rico's Aid	23,485,990
30	Misc Current and Accrued Assets	5,925,241
31		
32		
33		
34		
35	TOTAL (Account 174)	$29,411,231

Energy Conservation and Renewables Projects

A. Show in column (a) the programs initiated, continued or concluded during the year, separately for electric operations and gas operations, for the following types of programs:
- T&MD - Technology and Market Development (formerly SBC)
- EEPS - Energy Efficiency Portfolio Standard
- RPS - Renewable Portfolio Standard
- Other Internal Company Programs

B. Show in column (b) all revenue collected during the current year and the account number the revenue was recorded to.
C. Show in column (c) all expense charged during the current year and the account number the expense was recorded to.
D. Show in column (d) any amounts transferred out to third parties and the account number recorded to, and identify the third party.
E. Show on line 42 the amount of any incentives earned by the Company and approved by the Commission during the year related to energy conservation or renewables projects. Provide a description of the incentive.

Line No.	(a) Project Title	(b) Revenue Collected In Current Year		(c) Expense Charged In Current Year		(d) Funds Transferred Out To Third Parties		(e) Cumulative Unencumbered	
		Acct No.	Amount	Acct No.	Amount	Acct No.	Amount	Acct No.	Amount
1	Self-Direct-Gas		$0		$0				
2	ETIPS-Gas		$1,578,784		$6,048,339				
3	EES-Gas		5,567,218		3,068,581				
4	SBC/EEPS-Gas		0		3,684				
5	CEF/NYSERDA-Gas		4,293,219		769,330				
6									
7	Self-Direct-Electric		416,758		200,201				
8	ETIPS-Electric		39,793,500		35,514,258				
9	EES-Electric		17,767,749		262,140				
10	SBC/EEPS-Electric		0		145,256				
11	CEF/NYSERDA-Electric		183,561,132		152,939,910				
12									
13									
14									
15									
16									
17									
18									
19									
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31									
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33									
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35									
36									
37									
38									
39									
40	GRAND TOTAL								
41									
42	Incentives Earned by Company/								
43	Approved by the Commission								
44									

NOTES PAYABLE (Account 231)

1. Report the particulars indicated concerning notes payable at end of year.
2. Give particulars of collateral pledged, if any.
3. Furnish particulars for any formal or informal compensating balance agreements covering open lines of credit.
4. Any demand notes should be designated as such in Column (c).
5. Minor amounts may be grouped by classes, showing the number of such amounts.
6. Report in total, all other interest accrued and paid on notes discharged during the year.

Line No.	PAYEE AND INTEREST RATE (a)	DATE OF NOTE (b)	DATE OF MATURITY (c)	Outstanding at End of Year (d)	INTEREST DURING YEAR ACCRUED (e)	INTEREST DURING YEAR PAID (f)
1						
2	None					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTALS			$0	$0	$0

PAYABLES TO ASSOCIATED COMPANIES (ACCOUNT 233)

1. Report particulars of notes and accounts payable to associated companies to end of year.
2. Provide separate totals for Accounts 233, Notes Payable to Associated Companies.
3. List each note separately and state the purpose for which issued. Show also in Column (a) date of note, maturity and interest rate.
4. Include in Column (f) the amount of any interest expense during the year on notes that were paid before the end of the year.
5. If collateral has been pledged as security to the payment of any note, describe such collateral.

Line No.	PARTICULARS (a)	BALANCE BEGINNING OF YEAR (b)	TOTAL FOR YEAR DEBITS (c)	TOTAL FOR YEAR CREDITS (d)	BALANCE END OF YEAR (e)	INTEREST FOR YEAR (f)
1						
2	Niagara Mohawk Holdings, Inc.	$0	$0	$0		$0
3						
4						
5	TOTALS (ACCOUNT 233)	$0	$0	$0	$0	$0
6						
7	NG USA Parent	50,657,295	185,750,154	139,328,313	4,235,454	
8	NGUSA Service Company	117,066,008	1,891,536,447	1,891,572,971	117,102,532	
9	NG Engineering Services, LLC	466,329	748,719	730,663	448,273	
10	Other	773,942	1,052,548,697	1,054,578,528	2,803,773	
11						
12						
13						
14						
15	TOTALS (ACCOUNT 234)	$168,963,574	$3,130,584,017	$3,086,210,475	$124,590,032	$0

OPERATING RESERVES (ACCOUNTS 228.1, 228.2, 228.3, 228.4)

1. Report below an analysis of the changes during the year for each of the above-named reserves.
2. Show title of reserve, account number, description of the general nature of the entry and the contra account debited or credited. Combine the amounts of monthly accounting entries of the same general nature. If respondent has one utility department, contra accounts debited or credited should indicate the utility department affected.
3. For Accounts 228.1, Accumulated Provision for Property Insurance and 228.2, Accumulated Provision for Injuries and Damages, explain the nature of the risks covered by the reserves.
4. For Account 228.4, Accumulated Miscellaneous Operating Provisions, report separately each reserve comprising the account and explain briefly its purpose.

LINE NO.	ITEM (a)	BALANCE BEGINNING OF YEAR (b)	DEBITS CONTRA ACCOUNT (c)	DEBITS AMOUNT (d)	CREDITS CONTRA ACCOUNT (e)	CREDITS AMOUNT (f)	BALANCE END OF YEAR (g)
1							
2							
3							
4							
5							
6							
7	TOTAL ACCOUNT 228.1	0		0		0	0
8	Injuries & Damages Reserve -	25,554,080	925	46,111,413	925	45,736,098	25,178,765
9	Account covers the probable liability, not covered						
10	by insurance, for deaths or injuries to employees						
11	and others, and for damages to property not						
12	owned or held under lease by the utility.						
13							
14	TOTAL ACCOUNT 228.2	25,554,080		46,111,413		45,736,098	25,178,765
15	Pensions & Benefits Reserve -						
16	Pension Reserve	1,434,446	128/426	6,147,638	128/426	5,945,950	1,232,758
17	Health Reserve	357,643,483	184/232/234	894,849,165	184/232/234	808,219,515	271,013,833
18							
19							
20							
21	TOTAL ACCOUNT 228.3	359,077,929		900,996,803		814,165,465	272,246,591
22	Environmental Reserve	359,631,704	182/254	256,632,846	182/254	236,791,040	339,789,898
23							
24							
25							
26							
27							
28							
29	TOTAL ACCOUNT 228.4	359,631,704		$256,632,846		$236,791,040	$339,789,898

MISCELLANEOUS TAX REFUNDS

1. Report below particulars concerning all tax refunds received or used as a reduction of taxes payable during the year which are not more than $1.5 million or do not exceed $1,000 and 0.2% of the utility's operating revenues. This information is requested in compliance with Section 89.3, Notification Concerning Tax Refunds, of 16NYCRR. This report shall be inapplicable to ordinary operating refunds that are not attributable to negotiation or to new legislation, adjudication, or rulemaking (such as refunds for overpayment of estimated taxes, and carrybacks of net operating losses and investment tax credits).
2. In determining whether a refund exceeds 0.2% of operating revenues for purposes of this report, in the case of a gas, electric, steam, or combination utility, operating revenues shall be reduced by the amounts properly chargeable to the functional group of Production Operation and Maintenance expense accounts; in the case of a combination utility the refund shall be deemed to exceed 0.2% of operating revenues if, after the refund is allocated among the gas, electric and steam departments in a manner reflecting insofar as possible the extent to which the refund is related to each department's activities, one or more of the portions thus allocated exceeds 0.2% of the operating revenues of the department to which it is allocated.
3. In determining whether a refund meets the criteria stated in Instruction 1 above, multiple refunds shall be treated as a single refund if they share a common cause such as a common act of negotiation legislation, adjudication or rulemaking.
4. In this report, the utility also shall either propose a method of distributing to its customers the entire amount refunded, or show why it should not make such a distribution.

LINE NO.	Description of Item (a)	Amount (b)
1		
2	None	
3		
4		
5		
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11		
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22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34	Total	$0

TEMPORARY INCOME TAX DIFFERENCES - SFAS 109

1. Report below the accumulated deferred Federal income tax assets/liabilities, as of December 31 of the reporting year, that result purely from the implementation of SFAS - 109, "Accounting for Income Taxes", and in accordance with the Commission's associated Policy Statement (issued January 15, 1993) in Case 92-M-1005.

Line No.	Item (a)	Debits Account 190 (b)	Credits Account 281 (c)	Account 282 (d)	Account 283 (e)	Total (f)
	AFUDC					
1	AFUDC - Net of Tax - Plant					$0
2	AFUDC - Equity Component - Plant					0
3	Other Net of Tax Items (specify)					0
4						0
	Prior Flow-Through Items					
5	Depreciation			(77,512,473)		(77,512,473)
6	Asset Base Difference (non - ITC)					0
7	Other (specify)					0
8						0
	ITC					
9	Section 46(f)(1) ITC	3,717,576				3,717,576
10	Section 46(f)(2) ITC					0
11						0
	Other Items					
12	Other Deferred Credits				41,006,128	41,006,128
13	Accrued Utility Revenues					0
14	Tax Cuts and Jobs Act (Tax Reform)	(252,694,014)		814,248,035	78,646,420	640,200,441
15	Other	(1,338,457)				(1,338,457)
16	Total	($250,314,895)	$0	$736,735,562	$119,652,548	$606,073,215
17	Gross-up of above amounts for income tax effects; etc.	1,250,068		198,459,356	14,732,104	214,441,528

EXTRAORDINARY ITEMS (Accounts 434 and 435)

1. Give below a brief description of each item included in accounts 434, Extraordinary Income and 435, Extraordinary Deductions.
2. Give reference to Commission approval, including date of approval, for extraordinary treatment of any item which amounts to less than 5% of income. (See General Instruction section 166.7 and 311.7 of the applicable Uniform System of Accounts.
3. Income tax effects relating to each extraordinary item should be listed in Column (c).

LINE NO.	DESCRIPTION OF ITEMS (a)	GROSS AMOUNT (b)	RELATED FEDERAL TAXES (c)
1	Extraordinary Income (Account 434):		
2			
3	None		
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21	Total Extraordinary Income	$0	$0
22	Extraordinary Deductions (Account 435):		
23			
24	None		
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
40			
41			
42			
43			
44			
45			
46	Total Extraordinary Deductions	$0	$0
47	Net Extraordinary Items	$0	$0

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4, Expenditures for Certain Civic, Political and Related Activities.
   (a) Name of person or organization rendering services in alphabetical order,
   (b) description of services received during year and project or case to which services relate,
   (c) total charges for the year.

2. Designate with an asterisk associated companies.

Line No.	Person or Organization	Description of Services	Basis of Charges	Utility Dept	Total Charges
1	TRC ENVIRONMENTAL CORP.	Environmental Services			6,646,295
2	IBM CORP.	Information Technology			4,432,657
3	HARRIS CORPORATION	Information Technology			3,585,938
4	ACCENTURE LLP	Technical & Management Consulting			3,222,455
5	ALIXPARTNERS LLP	Business Consulting			3,188,119
6	BENHAM ARCHITECTS AND ENGINEERS PA	Engineering Consulting			2,948,350
7	WIPRO LTD.	Information Technology			2,767,231
8	BLACK & VEATCH NEW YORK LLP	Engineering Consulting			2,433,150
9	ARCADIS OF NEW YORK INC.	Environmental Services			2,326,091
10	CHA CONSULTING INC	Engineering Consulting			2,272,537
11	BURNS & MCDONNELL CONSULTANTS INC	Engineering Consulting			1,972,688
12	PRICEWATERHOUSECOOPERS LLP	Accounting Services			1,567,664
13	T-SYSTEMS NORTH AMERICA INC.	Information Technology			1,222,286
14	BROWN AND CALDWELL	Environmental Services			1,221,680
15	O'BRIEN & GERE ENGINEERS INC.	Environmental Services			1,079,940
16	OPUS ONE SOLUTIONS ENERGY CORPORATI	Technical & Management Consulting			1,073,391
17	KPMG LLP	Accounting Services			1,052,383
18	GROUNDWATER AND ENVIRONMENTAL SERVI	Environmental Services			988,760
19	DXC TECHNOLOGY SERVICES LLC	Information Technology			838,110
20	BURNS AND MCDONNELL INC.	Engineering Consulting			769,649
21	ENVIRONMENTAL DESIGN & RESEARCH PC	Environmental Services			697,691
22	KLEINFELDER ENGINEERING PC	Engineering Consulting			683,338
23	PADILLA AND COMPANY LLP	Accounting Services			655,101
24	GEI CONSULTANTS INC.	Environmental Services			653,252
25	COMPUTER SCIENCES CORP.	Information Technology			652,541
26	NETWORK MAPPING LTD.	Information Technology			650,306
27	VERIZON NETWORK INTEGRATION CORP	Information Technology			628,352
28	POWER ENGINEERS CONSULTING INC.	Engineering Consulting			624,847
29	KOTTER INTERNATIONAL INC	Technical & Management Consulting			554,859
30	GENERAL ELECTRIC INTERNATIONAL INC	Utility Services			515,907
31	THEW ASSOCIATES PE-LS PLLC	Land Survey			496,984
32	TMG CONSULTING INC	Business Consulting			492,769
33	CULVER CO.	Public Relation Services			472,689
34	FISHER ASSOCIATES	Engineering Consulting			436,088
35	NELSON ASSOC ARCHITECTURAL ENG PC	Engineering Consulting			411,254
36	GPC TECHNICAL & CONSTRUCTION SVC LL	Construction Contractor			409,535
37	COMMONWEALTH ASSOCIATES INC.	Engineering Consulting			380,041
38	HALEY & ALDRICH INC.	Engineering Consulting			370,229
39	AON CONSULTING INC	Technical & Management Consulting			365,316
40	VIP ENGINEERING AND ARCHITECTURE PL	Engineering Consulting			360,693
41	RG VANDERWEIL ENGINEERS PC	Engineering Consulting			345,743
42	Total on page				56,466,909

If applicable, see insert Tab 24A

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

Line No.	Person or Organization	Description of Services	Basis of Charges	Utility Dept	Total Charges
1	OP-TECH ENVIRONMENTAL SERVICES INC	Environmental Services			338,551
2	STANTEC CONSULTING SERVICES INC.	Engineering Consulting			336,499
3	DELOITTE & TOUCHE LLP	Accounting Services			314,276
4	ANCHOR QEA ENGINEERING PLLC	Engineering Consulting			312,518
5	TRC ENGINEERS INC	Environmental Services			296,697
6	GZA GEOENVIRONMENTAL INC.	Environmental Services			281,759
7	CJ BROWN ENERGY PC	Engineering Consulting			265,251
8	ITRON INC.	Utility Services			263,137
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56					
57	Total on page				2,408,688

Employee Protective Plans

Report a summary of each employee program in effect at any time during the year. This schedule is intended to cover pension, profit sharing, group life insurance, accident and sickness, medical, hospital, prescription drugs, guaranteed annual wage, severance pay, and any other plan maintained for employees (or retirees), but it is not intended to cover such a plan required by law, (e.g. social security).

For each plan report:
1. the identity thereof, and the employee group covered (e.g. management, non-management, executive officers, etc.)
2. whether the benefits are provided through an insurance carrier or directly by the company.
3. the total cost for the year.

Note: If any important change is made with respect to any such plan during the year, give brief particulars.

LIFE INSURANCE PLAN - These are various group term life insurance plans covering regular non-union and union employees as well as eligible retirees. Coverage is provided on a non-contributory basis at levels ranging from 1.5 times pay to 2 times pay depending on the plan. Eligible retirees receive continued coverage at a reduced level on a non-contributory basis.	2,747,757
MEDICAL CARE PLAN - Various medical plans available through local health plans and national programs that provide medical, prescription drug, and mental health benefits to eligible union and non-union employees and their eligible dependents, eligible retirees and surviving spouses and their eligible dependents and includes amounts charged to expense for OPEB's. These plans are contributory and are self-insured. Contributions vary by employee group, retiree group, and coverage selected.	57,287,191
NIAGARA MOHAWK PENSION PLAN - This is a non-contributory plan providing retirement allowances for eligible employees. The Plan is being funded through payments to a qualified Pension Trust Fund.	58,859,390
EMPLOYEE WELFARE PROGRAMS AND OTHER- These programs include expenses incurred in conducting employees' educational, recreational and other welfare programs. The programs provide services for both represented and non-represented employees, including transitional services, safety shoes, and eyeglasses. Employee contributions vary depending upon the service.	17,936,360
DENTAL PLAN - This consists of various self-insured dental plans available to regular full and part-time union and non-union employees. Coverage includes preventive, basic restorative, oral surgical benefits, major restorative, and orthodontic care. Non participating dentist fees are subject to reasonable and customary limits while participating dentists agree to accept negotiated charges.	1,461,448
Total	138,292,146

For the year ended December 31, 2018, there were no transfers of employees between the Company and any Unregulated Affiliates or Unregulated Competitive Energy Affiliates (as defined in Appendix 7 and Appendix 16 of the Joint Proposals adopted by the New York State Public Service Commission in Cases 12-E-0201/12-G-0202 (March 15, 2013) and Cases 17-E-0238/17-G-0239 (March 15, 2018), respectively.

ANALYSIS OF PENSION COST

1. On lines 1-21 report the terms of the Pension Plan for the holding company or parent company; on lines 22-32 report details for the reporting company. If the reporting company has more than one pension plan, report each using separate forms.
2. Report on line 1 the actuarial present value of benefits determined as of a specific date during the calendar year according to the terms of a pension plan and based on employees' compensation and service to that date (salary progression is not considered in making this computation).
3. Report on line 2 the actuarial present value of all benefits attributed to employee service up to a specific date, based on the terms of the plan including salary progression factor for final pay and career average pay plans.
4. Report on line 3 the amount the pension plan could expect to receive for investments in a sale between a willing buyer and a willing seller, other than in a forced or liquidation sale.
5. Report on line 8 the discount rate which was used to calculate the obligations reported on Lines 1 and 2.
6. Report on Line 9 the expected long-term return on plan assets.
7. Report on line 14 the net asset gain or loss deferred during the reporting year for later recognition. Do not include in this amount amortization of previously deferred gains or losses as these amounts are to be reported on line 17.
8. Report on lines 19 through 21 and lines 29 through 32 the number of persons covered by the plan at the beginning of the policy year.
9. Report on line lines 21 and 32 the numbers of persons having vested pension rights but who are no longer employed by the company and not yet drawing a pension allowance.
10. On line 22, the term "Minimum Required Contribution" shall mean the payment by the employer to its employees' pension fund necessary to meet the requirement set forth in the Employee Retirement Income Security Act of 1974.
11. On line 24, the term "Maximum Amount Deductible" shall mean the amount of pension expense that is allowable under Section 415 of the Internal Revenue Code.
12. Report on line 26 the dollar amount applicable to the reporting company which has been included in the amount on line 18.
13. Report on line 27 the dollar amount included on line 26 which has been capitalized.

For each plan, specify and explain in the space below any accounting changes or changes in assumptions or elected options made during the reporting year. Quantify the effects of each such revision on each of the amounts reported on Page **. Use a separate insert sheet if more space is required.

ANALYSIS OF PENSION COST (Continued)

Line No.	Item (a)		Current Year (b)
	PLAN		
1	Accumulated Benefit Obligation	$	1,386,306,241
2	Projected Benefit Obligation	$	1,396,282,929
3	Fair Value of Plan Assets	$	1,682,737,121
4	Unrecognized Transition Amount	$	0
5	Unrecognized Prior Service Costs	$	6,915,952
6	Unrecognized Gains or (Losses)	$	134,280,955
7	Date of Valuation Reported on Lines 1 through 6		12/31/2018
8	Discount Rate		(A)
9	Expected Long-Term Rate of Return on Assets		6.00%
10	Salary Progression Rate (if applicable)		3.50%
	Net Periodic Pension Cost:		
11	Service Cost	$	28,520,703
12	Interest Cost		59,539,565
13	Actual Return on Plan Assets [(Gain) or Loss]		(105,312,488)
14	Deferral of Asset Gain or (Loss)		9,229,369
15	Amortization of Transition Amount		0
16	Amortization of Unrecognized Prior Service Cost		3,102,824
17	Amortization of Gains or Losses		58,571,831
18	Total Pension Cost	$	53,651,804
19	Number of Active Employees Covered by Plan		3,768
20	Number of Retired Employees Covered by Plan		4,326
21	Number of Previous Employees Vested but Not Retired		1,126
	REPORTING COMPANY		
22	Minimum Required Contribution	$	30,748,055
23	Actual Contribution*	$	10,303,000
24	Maximum Amount Deductible*	$	680,482,308
25	Benefit Payments	$	(81,545,225)
26	Total Pension Cost	$	69,826,877
27	Pension Cost Capitalized	$	10,846,616
28	Accumulated Pension Asset/(Liability) at Close of Year	$	368,590,465
29	Total Number of Company Employees at Beginning of Policy Year		
30	Number of Active Employees Covered by Plan		3,302
31	Number of Retired Employees Covered by Plan		4,284
32	Number of Previous Employees Vested but Not Retired		880

* Specify in the space below the reason(s) for any difference between the amounts reported on lines 23(b) and 24(b).

(A) The discount rate is 4.50% for qualified plans results and 4.10% for non-qualified plan results.

Note: It is acceptable to provide a specific reference to the information already contained in the notes to the financial statements.

ANALYSIS OF PENSION SETTLEMENTS, CURTAILMENTS AND TERMINATIONS

1. Report the amount of gains or losses arising from employee termination benefits or settlements, partial settlements, curtailments or suspensions of pensions or pension obligations during the year. If none have occurred, state "none" on line 5. If they qualified as "small settlements" under SFAS-88 and the company elected not to recognize the gain or loss, state "none" on line 5 and complete the applicable sections on the bottom of the form. Use separate forms to report the effect of each event and, if the event affected more than one plan, use separate forms for each plan. These events include:
   a. purchases of annuity contracts.
   b. lump-sum cash payments to plan participants.
   c. other irrevocable actions that relieved the company or the plan of primary responsibility for a pension obligation and eliminates significant risks related to the obligation and assets.
   d. an event that significantly reduces the expected of years future service for present employees who are entitled to receive benefits from that plan or that eliminates the accrual of benefits for some or all of the future services of a significant number of those employees.

   If this is the first year the company is subject to the reporting requirements of this schedule, complete separate forms for each reportable event having occurred since the company's adoption of SFAS-87 and include those forms in the current Annual Report.

2. On lines 1-15 report activities for the holding company or parent company; on line 16-18 report details for the reporting company.

3. Report on line 1 the amount of overfunding remaining (excess of plan assets, adjusted for accrued or prepaid pension costs, over the Pension Benefit Obligation), if any, from when the company first complied with SFAS-87. The amount should be adjusted by the year-to-date amortization.

4. Report on line 2 the actuarial gains and losses that occurred in prior fiscal years following compliance with SFAS-87 but have not yet been amortized. The amount should be adjusted by the year-to-date amortization.

5. Report on line 3 the actual return on plan assets (the sum of investment income and appreciation).

6. Report on line 4 the expected return on plan assets (a component of the current-year expense calculation, which should be prorated for the elapsed portion of the current year).

7. Report on line 6 the Pension Benefit Obligation (PBO) updated from the previous year-end figure to the settlement date. This amount should reflect the addition of a pro rata portion of the service cost and interest cost and the subtraction of benefit payments. It should also reflect any plan changes made during the year.

8. Convert the basis points and percentages reported on line 7 and 8 to their decimal equivalents before entering them in the formula on line 9.

9. Report on line 17 the applicable Federal income tax rate. Although no tax is currently payable on the gain and loss, it should be reflected because it represents a reduction of future pretax pension expense.

State separately below for each reportable event having occurred since the company's initial compliance with SFAS-87, and for which amortization of deferred gains or losses was not completed by December 31 of last year, the (1) type of event, e.g. settlement or curtailment, (2) date of occurrence, (3) amount of gain or loss originally deferred, (4) period of amortization specified by beginning and ending dates, and (5) amount of the current year's amortization.

ANALYSIS OF PENSION SETTLEMENTS, CURTAILMENTS AND TERMINATIONS (Continued)

Line No.	ESTIMATE OF SETTLEMENT GAIN OR LOSS (a)	(b)	(c)
	PLAN		
1	Unrecognized net asset		1.
2	Unrecognized net actuarial gain or (loss)		2. (142,377,253)
	Year-to-date asset gain or (loss):		
3	Actual return	3.	
4	Expected return	4.	
5	Gain or (loss): (3)-(4)		5. 0
	Year-to-date liability gain or (loss):		
6	PBO at settlement date	6. (1,490,058,829)	
7	Year-to-date increase (or decrease) in actuarial discount rate	7.	basis points
8	Percentage decrease in PBO for each 100 basis-point increase in the discou	8. 0.0%	
9	Liability gain or (loss): {(6) x (7) x (8)} x 100 -- see instructions		9. 0
	Settlement gain or (loss):		
10	Accounting value of obligation which was settled	10. (96,590,587)	
11	Settlement cost (e.g., price of purchased annuity contract)	11. (96,590,587)	
12	Settlement gain or (loss): (10)-(11)		12. 0
13	Total accumulated gain or (loss): (1)+(2)+(5)+(9)+(12)		13. (142,377,253)
14	Settlement ratio: (10)/(6)		14. 6.48%
15	Pretax gain recognizable in current income: (13) x (14)		15. (9,229,369)
	REPORTING COMPANY		
16	Portion of amount on line 15 allocated to reporting company		16.
	Tax-affected gain:		
17	Tax rate	17.	
18	Gain or (loss) after provision for income tax: 16 x [100% - (17)]		18. 0

Explain the basis of allocation used to derive the amount reported on line 16 from that reported on line 15:

For the amount reported on line 16 specify:

a. the amount recorded as income for the current year

b. the amount deferred on the balance sheet

c. amortization period for the deferred amount (specify beginning and ending dates).

Briefly describe the event (e.g., settlement, curtailment or termination with short description of the change) and the date of its occurrence.

This represents a qualified plan settlement on 12/31/2018 resulting from participant elected lump sum plan distributions.

If the event involves the purchase of an annuity contract(s), state whether they are participating or nonparticipating contracts. If they are participating, explain the terms and state the cost difference between the contract(s) purchased and identical contracts without the participating feature.

If the event qualified as a "small settlement" under SFAS 88, and the company elected not to recognize the gain or loss, state:

a. number of employees affected

b. the cost of the settlement

c. the amount of PBO settled

ANALYSIS OF OPEB COSTS, FUNDING AND DEFERRALS

1. Report on pages ** through **, the requested data concerning Postretirement Benefits Other than Pensions (OPEB). For these schedules, the measurement date, calculation of the data requested, and separate reporting for different types of OPEB plans shall be consistent with the disclosure requirements specified in SFAS-106 (Paragraphs 72-89). If the reporting company's OPEB benefits are provided through a joint plan with its parent company or holding company, report under the columnar heading "Total Company" the data applicable to the total plan (i.e., that of the parent or holding company). The columnar heading "New York State Jurisdiction" refers to the New York State jurisdictional operations of the reporting company, exclusive of amounts applicable to subsidiary companies which are subject to the Commission's jurisdiction but are separately reported.
2. The quantification of amounts reported on Lines 1 - 12 shall be as of the date reported on Line 13.
3. Report on Lines 1 - 3 the actuarial present value of benefits attributed employees' service rendered to the date reported on Line 13.
4. Report on Line 4 the amount the OPEB plan(s) could expect to receive for investments in a sale between a willing buyer and a willing seller, other than in a forced or liquidation sale.
5. Report on Lines 5 and 6 , the amounts applicable to OPEB that are recorded in internal reserves, net of their related deferred income tax effect. For New York State Jurisdictional Operations, creation of an internal reserve was required by the Commission's "Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and OPEB" (issued September 7, 1993).
6. Report on Line 10 the amount of unrecognized net gain or loss (including plan asset gains and losses not yet reflected in the market-related value of the plan assets).
7 Report on Line 11 the amount of unrecognized net asset gain or loss not yet reflected in the market-related value of plan assets.
8. In certain instances, a portion of the New York State Jurisdiction OPEB internal reserve may not be subject to the accrual of interest (e.g. in the company's last rate case a portion of the reserve may have been used to reduce rate base). Report on Line 12 the balance of the reserve, net of its related deferred income tax effect, which is subject to the accrual of interest.
9. Report on Line 14 the discount rate which was used to calculate the obligations reported on Lines 1-3.
10. Report on Line 15 the expected long-term return on plan assets reported on Line 4.
11. Report on Line 21 the net asset gain or loss deferred during the reporting year for later recognition. Do not include in this amount amortization of previously deferred gains or losses as these amounts are to be reported on Line 24.
12. The amount reported on Line 24 is to include the amortization of gains and losses arising from changes in assumptions.

For each plan, specify and explain in the space below any accounting changes or changes in assumptions or elected options made during the reporting year. Quantify the effects of each revision on each of the amounts reported on Page **. Use a separate insert sheet if more space is necessary.

ANALYSIS OF OPEB COSTS, FUNDING AND DEFERRALS (Continued)

Line No.	Item (a)	Total Company (b)
	ANALYSIS OF OPEB COSTS	
	Accumulated Benefit Obligation Attributable to:	
1	Retirees Covered by the Plan	$ (A)
2	Other Fully Eligible Plan Participants	$ (A)
3	Other Active Plan Participants	$ (A)
4	Fair Value of Plan Assets Held in an Exterior Fund or Trust	$ 1,319,564,959
	Plan Assets Held in an Internal Reserve (net of tax):	
5	New York State Jurisdiction	$ 0
6	Other	$ 0
7	Other Plan Assets (Specify ....)	$ 0
8	Unrecognized Transition Obligation	$ 0
9	Unrecognized Prior Service Costs	$ (38,461)
10	Unrecognized Gains or (Losses)	$ 44,532,553
11	Gains or (Losses) Unrecognized in Market Related Value of Assets	$ 0
12	NYS Jurisdiction Internal Reserve Balance Subject to Accrual of Interest (net of tax)	$ 0
13	Date of Valuation for Amounts Reported on Lines 1 - 12.	12/31/2018
14	Discount Rate	4.10%
15	Expected Long-Term Rate of Return on Assets (Exterior Fund)	(B)
16	Interest Rate Applied to NYS Jurisdiction Internal Reserve Balance	8.07%
17	Salary Progression Rate (if applicable)	3.50%
	NET PERIODIC OPEB COST	
18	Service Cost	$ 21,003,902
19	Interest Cost	72,689,821
20	Actual Return on Plan Assets [(Gain) or Loss]	(92,971,601)
21	Deferral of Asset Gain or (Loss)	0
22	Amortization of Transition Amount	0
23	Amortization of Unrecognized Prior Service Cost	(343,226)
24	Amortization of (Gains) or Losses from Earlier Periods	17,946,623
25	(Gain) or Loss Due to a Temporary Deviation From a Substantive Plan	0
26	**Net Periodic OPEB Cost**	$ 18,325,519

(A) This information is no longer a required disclosure under SFAS 132. Total APBO as of 12/31/2018 $1,814,299,423

(B) The expected long term rate of return on assets is 6.25% for nonunion plans and 6.75% for union plans.

Note: It is acceptable to provide a specific reference to the information already contained in the notes to the financial statements.

ANALYSIS OF OPEB COSTS, FUNDING AND DEFERRALS (Continued)

1. Report on Line 3 items such as transfers of excess pension funds from the company's pension trust fund to an account set up under Section 401(h) of the Internal Revenue Code.
2. Report on Line 5 items of income (e.g., dividends and interest).
3. The amount reported on Line 9 should be the same amount as that reported on Line 4 on Page 31.

Line No.	Item (a)	Total Company (b)
	EXTERNALLY HELD OPEB DEDICATED FUNDS OR TRUSTS	
1	Fair Value of Plan Assets at Beginning of Period	$1,465,145,954
	Contributions to the Fund:	
2	Deposits of Company Funds	21,066,689
3	Transfers from Pension Related Funds	
4	Other *	
5	Income or (Loss) Earned on Fund Assets	(96,845,341)
6	Capital Appreciation or (Depreciation) of Fund Assets	
7	Cost Benefits Paid from the Fund To or For Plan Participants	(69,802,343)
8	Other Expenses Paid By the Fund **	
9	Fair Value of Plan Assets at End of the Period	$1,319,564,959

* Specify the source of any amount reported on Line 4.

** Specify the type and amount of any expenses reported on Line 8.

ANALYSIS OF OPEB COSTS, FUNDING AND DEFERRALS (Continued)

1. The data requested on Lines 1 through 12 are for the internal reserve, the establishment of which is required by the Commission's "Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions" (Case 91-M-0890, issued and effective September 7, 1993). The amounts reported below are to be consistent with the definitions and intent contained in that Statement.
2. The "rate allowance" to be reported on Line 2 is the amount which was projected to be charged to expense accounts (i.e., not charged to construction, depreciation, nor the rate base allowance related to capitalized OPEB costs) in the company's latest rate proceeding, adjusted to actual applicable sales as per the above Policy Statement.
3. The amount reported on Line 9 less the amount on Line 10 should total the amount reported on Line 5 of Page 33.
4. In certain instances, a portion of the OPEB internal reserve may not be subject to the accrual of interest (e.g., in the company's last rate case, a portion of the reserve may have been used as a rate base reduction). Report on Line 12 the balance of the reserve, net of its related deferred income tax effect, which is subject to the accrual of interest.
5. The Commission's September 7, 1993 Policy Statement on pensions and OPEB stated that, except under certain circumstances, the difference between 1) the rate allowance for OPEB expense, plus any pension related or other funds or credits the company is directed to use for OPEB purposes, and 2) OPEB expense determined as required therein, are to be deferred for future recovery. Report on Lines 13 through 17 the amounts relating to this requirement.

Line No.	Item (a)		New York State Jurisdiction (b)
	OPEB RELATED ASSETS RECORDED IN AN INTERNAL RESERVE		
1	Balance in Internal Reserve at Beginning of the Period - [(Debit) / Credit]		($123,731,127)
2	Amount of the Company's Latest Rate Allowance for OPEB Expense		23,569,400
3	Amount of OPEB costs actually charged to Construction		7,246,721
4	Pension Related or Other Funds or Credits this Commission Directed the Company to Use for OPEB Purposes		35,018,359
5	Interest Accrued on Fund Balance		0
6	Cost Benefits Paid to or for Plan Participants		(3,300,580)
7	Amount Transferred to an External OPEB Dedicated Fund		(17,469,737)
8	Other Debits or Credits to the Internal Reserve *		(15,636,323)
9	Balance in Internal Reserve at End of the Period		(94,303,287)
10	Balance of Deferred Income Tax Applicable to the Internal Reserve		(24,646,164)
11	Interest Rate Applied to Internal Reserve Balances	8.07%	
12	Internal Reserve Balance Subject to Accrual of Interest (net of tax)		0
	ACCUMULATED DEFERRED OPEB EXPENSE		
13	Accumulated Deferred Balance Beginning of Period - [Debit / (Credit)]		(73,413,476)
14	Deferral Applicable to Current Year Variation		(16,535,711)
15	Amortization of Previous Deferrals		36,014,019
16	Accumulated Deferred Balance at End of Period		(53,935,168)
17	Balance of Deferred Income Tax Applicable to Deferred OPEB Expense at the End of Period		

* Briefly explain any amounts reported on Line 8.

* Amortization of Deferral Credit established in connection with the January 2018 Joint Proposal resolving Cases 17-E-0238, 17-G-0239, 14-M-0042 and 12-G-0202.

** Reclassification of OPEB deferral credits from the OPEB deferral account to the consolidated Rate Plan deferral account to facilitate amortization.

SALES OF ELECTRICITY BY COMMUNITIES

1. Report below the information called for concerning sales of electricity in each community with a population of 50,000 or more, or according to operating districts or divisions constituting distinct economic areas if the respondent's records do not readily permit reporting by communities. If reporting is not by communities, the territory embraced within the reported area shall be indicated. Except for state boundaries, community areas need not hold rigidly to political boundaries and may embrace a metropolitan area and immediate environs.

		RESIDENTIAL SALES (Account 440)			COMMERCIAL AND INDUSTRIAL SALES (Account 442)		
LINE NO.	COMMUNITY (a)	OPERATING REVENUES (b)	KILOWATT - HOURS SOLD (c)	AVG. NO. OF CUST. PER MO. (d)	OPERATING REVENUES (e)	KILOWATT - HOURS SOLD (f)	AVG. NO. OF CUST. PER MO. (g)
1							
2	Cities:						
3	Albany	30,318,371	215,026,406	34,825	27,702,701	330,799,499	4,068
4	Buffalo(Note)	72,913,150	523,691,220	93,993	26,445,194	88,248,363	6,060
5	Niagara Falls(Note)	16,785,968	127,192,709	18,744	16,761,263	(988,282,297)	1,207
6	Schenectady	19,365,943	143,708,023	21,902	7,606,529	74,320,100	1,762
7	Syracuse	37,176,050	307,056,103	47,435	23,273,931	263,315,997	4,122
8	Utica	15,469,320	131,731,226	20,368	7,708,778	88,903,153	1,882
9							
10	Towns:						
11	Amherst(Note)	42,567,872	324,344,771	42,989	9,444,981	38,441,385	2,667
12	Cheektowaga(Note)	7,129,630	52,586,950	8,623	3,587,571	37,810,680	369
13	Clay	21,880,690	175,662,887	20,320	5,088,176	59,700,018	941
14	Colonie	28,862,808	209,627,090	25,542	14,662,444	140,532,451	2,815
15	Hamburg(Note)	8,708,207	66,608,458	8,519	1,767,906	20,372,693	349
16	Tonawanda(Note)	20,670,106	154,452,187	23,223	5,895,989	(238,500,964)	1,229
17							
18	Balance of Territory	973,501,806	7,520,830,618	903,298	238,421,211	4,332,403,607	77,826
19							
20							
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44							
45							
46	TOTALS	$1,295,349,921	9,952,518,648	1,269,781	$388,366,674	4,248,064,685	105,297

SALES OF ELECTRICITY BY COMMUNITIES (Continued)

2. The information to be shown below should be on the same basis as provided in Schedule entitled "Electric Operating Revenues", pages 300-301.
3. The totals for Accounts 440, 442, 444, and 445 should agree with the amounts for those accounts shown in Schedule entitled "Electric Operating Revenues".

PUBLIC STREET AND HIGHWAY LIGHTING (Account 444)			OTHER SALES TO PUBLIC AUTHORITIES (Account 445)			TOTAL			
OPERATING REVENUES (h)	KILOWATT - HOURS SOLD (i)	AVG. NO. OF CUST. PER MO. (j)	OPERATING REVENUES (k)	KILOWATT - HOURS SOLD (l)	AVG. NO. OF CUST. PER MO. (m)	OPERATING REVENUES (n)	KILOWATT - HOURS SOLD (o)	AVG. NO. OF CUST. PER MO. (p)	LINE NO.
									1
									2
171,764	485,538	15				58,192,836	546,311,443	38,908	3
422,124	2,451,817	623				99,780,468	614,391,400	100,676	4
3,099	23,709	4				33,550,330	(861,065,879)	19,955	5
48,076	125,378	5				27,020,548	218,153,501	23,669	6
4,695,189	14,949,840	286				65,145,170	585,321,940	51,843	7
111,191	638,969	160				23,289,289	221,273,348	22,410	8
									9
									10
50,875	346,730	57				52,063,728	363,132,886	45,713	11
1,843	13,186	3				10,719,044	90,410,816	8,995	12
1,079,792	2,131,577	16				28,048,658	237,494,482	21,277	13
21,465	35,128	4				43,546,717	350,194,669	28,361	14
991	7,612	2				10,477,104	86,988,763	8,870	15
31,967	271,037	47				26,598,062	(83,777,740)	24,499	16
									17
13,578,438	45,605,765	1,670				1,225,501,455	11,898,839,990	982,794	18
									19
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$20,216,814	67,086,286	2,892	$0	0	0	$1,703,933,409	14,267,669,619	1,377,970	46

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DATA BY TERRITORIAL SUBDIVISIONS-ELECTRIC

Report the indicated breakdown of operating revenue deductions and plant investment applicable respectively to accounting divisions and cost areas. Accounts, or groups of accounts, which may be kept on a company-wide basis on order of the Commission should be shown as separate single items. If the boundaries of a "cost area" are not apparent from entries in column (f), or are not otherwise a matter of record with the Commission, a reasonably complete description should be furnished. No breakdown by primary accounts is required for columns (g) and (h).

Accounting Divisions

Line No.		Operations and Maintenance (Acct. 401 - 402.1) (b)	Depreciation Expense (Acct. 403) (c)	Other Amortization (Acct. 404 - 407) (d)	Taxes Other Than Income Taxes (Acct. 408) (e)
1					
2					
3	One Accounting Division				
4					
5	See pages 114 - 117 of this report.				
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Totals	$0	$0	$0	$0

Cost Areas

Line No.		Types of Segregated Plant (g)	Book Cost (h)
22			
23	One Cost Area		
24			
25	See pages 204 - 207 of this report.		
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43		Total	$0

DISTRIBUTION SYSTEM

1. Report the indicated particulars of the electric distribution system as of the end of the year, including street and highway lighting system.

2. For the purposes of this schedule the interpretation of the term "distribution area" shall be at the discretion of, and the responsibility of, the reporting utility. In general when the territory served covers considerable area these subdivisions should be selected so that, from territorial and rate standpoints, the data reported will be of reasonable significance. Entries in column (a) should reflect the approximate geographical extent of the individual subdivision.

3. Entries in column (b) may be based on estimates and those in column (c) should exclude switching and voltage regulator stations. Entries in columns (d) and (e) should not include services.

Line No.	Distribution Area (a)	Maximum Coincident Demand - kW. (b)	Power Units (See instructions) (c)
1			
2	Company's Entire System	6,865,030	751
3			
4	Item 4		
5	The distribution system may be considered as falling into three		
6	principal categories: (1) overhead, or overhead combined with		
7	underground, primary and secondary circuits providing feed to		
8	residential and small commercial loads in general urban, suburban		
9	and rural areas; (2) overhead, underground or combined, primary		
10	and secondary circuits providing feed to large commercial and		
11	industrial loads in concentrated urban and suburban areas;		
12	(3) primary underground circuits providing feed to underground		
13	secondary network systems to serve commercial loads in heavily		
14	concentrated urban areas.		
15	1. General Urban, Suburban and Rural Residential Radial Systems.		
16	(A) The primary voltages in these systems range from 2,400		
17	volts to 13,200 volts. 13,200 volt grounded wire is		
18	standard for new construction. Secondary voltage is		
19	predominantly 120/240 volts.		
20	(B) Primary wire sizes run from No. 6 AWG COPPER TO 336.4		
21	kcmil aluminum depending on load density,distances in-		
22	volved and year installed.		
23	(C) Secondary conductors are No. 2 AWG copper through		
24	336.4 kcmil aluminum and services are No. 6 AWG copper		
25	through 336.4 kcmil aluminum		
26	2. Large Commercial and Industrial Radial Systems.		
27	(A) Primary voltages range from 2,400 to 13,200 volts. Secon-		
28	dary voltages range from 120/240 to 480 volts.		
29	(B) Primary wire sizes run from No 2 AWG to 750 kcmil or		
30	equivalent. Secondary wire sizes run from No. 2 AWG or		
31	500 kcmil copper or equivalent		
32	3. Secondary Network Systems.		
33	Large industrial customers are fed directly from the transmission		
34	system.		
35	(A) These systems are supplied at primary voltges ranging		
36	from 4,160 volts to 34,500 volts.		
37	(B) The secondary mains operate at 120/208 volts with No.		
38	4/0 Awg to 500 kcmil copper conductors sizes, often with		
39	several conductors in parallel.		
40	(C) Spot networks for larger users are operated at 277/480		
41	volts with secondary mains of 500 kcmil copper conductor		
42	paralleled as required.		
43			
44			
45			
46			
47			
48			
49			
50			
51			
52			
53			
54	TOTALS	6,865,030	751

DISTRIBUTION SYSTEM (Continued)

4. Show hereunder a brief general statement in description of the distribution system. Indicate particularly the range of operating voltages and the sizes of wire generally used for different purposes (primaries, secondaries, services, etc.) and under differing circumstances. Show also the approximate percentages of network system, of rural lines, of direct current facilities, and of alternating current service rendered at other than a 60-cycle frequency. Identify exceptions to customary practices (i.e. the last two items in the preceding sentence) with applicable distribution areas.

Miles of Conductor		Miles of	Number of Services		Number of	Street and Highway Lighting			
					Connected	Miles of Conductor		Number of	
Overhead (d)	Underground (e)	Duct (f)	Overhead (g)	Underground (h)	Meters (i)	Overhead (j)	Underground (k)	Lights (l)	Line No.
									1
85,771	10,346		1,030,929	301,551	1,731,962	796	3,679	268,697	2
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85,771	10,346	0	1,030,929	301,551	1,731,962	796	3,679	268,697	54

GAS PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1 Report below the original cost of gas plant in service according to the prescribed accounts.
2 In addition to Account 101, Gas Plant in Service (Classified), this schedule includes Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified--Gas.
3 Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4 Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5 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) reversals of tentative distributions of prior year's unclassified retirements. Attach supplemental statement showing the account 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 Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.
6 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. In showing the clearance of 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 to primary account classifications.
7 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 requirements of these pages.
8 For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, 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 of such filing.

LINE NO.	ACCOUNT (a)	BALANCE BEGINNING OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE END OF YEAR (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	-					$0
3	(302) Franchises and Consents	3,333	(184)				3,149
4	(303) Miscellaneous Intangible Plant	527,165	460,763				987,928
5	TOTAL Intangible Plant	530,498	460,579	0	0	0	991,077
6	2. PRODUCTION PLANT						
7	Natural Gas Production and Gathering Plant						
8	(325.1) Producing Lands						0
9	(325.2) Producing Leaseholds						0
10	(325.3) Gas Rights						0
11	(325.4) Rights-of-Way						0
12	(325.5) Other Land and Land Rights						0
13	(326) Gas Well Structures						0
14	(327) Field Compressor Station Structures						0
15	(328) Field Meas. and Reg. Station Structures						0
16	(329) Other Structures						0
17	(330) Producing Gas Wells - Well Construction						0
18	(331) Producing Gas Wells - Well Equipment						0
19	(332) Field Lines						0
20	(333) Field Compressor Station Equipment						0
21	(334) Field Meas. and Reg. Station Equipment						0
22	(335) Drilling and Cleaning Equipment						0
23	(336) Purification Equipment						0
24	(337) Other Equipment						0
25	(338) Unsuccessful Explor. & Develop. Costs						0
26	(339) Asset Retirement Costs for Natural Gas Production and Gathering Plant						0
27	TOTAL Production and Gathering Plant	0	0	0	0	0	0
28	Products Extraction Plant						
29	(340) Land and Land Rights						0
30	(341) Structures and Improvements						0
31	(342) Extraction and Refining Equipment						0
32	(343) Pipe Lines						0
33	(344) Extracted Products Storage Equipment						0
34	(345) Compressor Equipment						0
35	(346) Gas Meas. and Reg. Equipment						0
36	(347) Other Equipment						0
37	(348) Asset Retirement Costs for Products Extraction Plant						0
38	TOTAL Products Extraction Plant (Enter Total of lines 29 thru 37)	0	0	0	0	0	0
39	TOTAL Nat. Gas Production Plant (Enter Total of lines 27 and 38)	0	0	0	0	0	0
40	Mfd. Gas Prod. Plant (Submit Suppl. Statement)						
41	TOTAL Production Plant (Enter Total of lines 39 and 40)	$0	$0	$0	$0	$0	$0

GAS PLANT IN SERVICE (Continued)

LINE NO.	ACCOUNT (a)	BALANCE BEGINNING OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE END OF YEAR (g)
42	3. NATURAL GAS STORAGE AND PROCESSING PLANT						
43	Underground Storage Plant						
44	(350.1) Land						0
45	(350.2) Rights-of-Way						0
46	(351) Structures and Improvements						0
47	(352) Wells						0
48	(352.1) Storage Leaseholds and Rights						0
49	(352.2) Reservoirs						0
50	(352.3) Non-recoverable Natural Gas						0
51	(353) Lines						0
52	(354) Compressor Station Equipment						0
53	(355) Measuring and Reg. Equipment						0
54	(356) Purification Equipment						0
55	(357) Other Equipment						0
56	(358) Asset Retirement Costs for Underground Storage Plant						0
57	TOTAL Underground Storage Plant	0	0	0	0	0	0
58	Other Storage Plant						
59	(360) Land and Land Rights						0
60	(361) Structures and Improvements						0
61	(362) Gas Holders						0
62	(363) Purification Equipment	1,605					1,605
63	(363.1) Liquefaction Equipment						0
64	(363.2) Vaporizing Equipment						0
65	(363.3) Compressor Equipment						0
66	(363.4) Measuring and Reg. Equipment						0
67	(363.5) Other Equipment						0
68	(363.6) Asset Retirement Costs for Other Storage Plant						0
69	TOTAL Other Storage Plant	1,605	0	0	0	0	1,605
70	Base Load Liquefied Natural Gas Terminating						
71	and Processing Plant						
72	(364.1) Land and Land Rights						0
73	(364.2) Structures and Improvements						0
74	(364.3) LNG Processing Terminal Equipment						0
75	(364.4) LNG Transportation Equipment						0
76	(364.5) Measuring and Regulating Equipment						0
77	(364.6) Compressor Station Equipment						0
78	(364.7) Communications Equipment						0
79	(364.8) Other Equipment						0
80	(364.9) Asset Retirement Costs for Base Load Liquefied Natural Gas Terminating and Processing Plant						0
81	TOTAL Base Load Liquefied Natural Gas,						
82	Terminating and Processing Plant	0	0	0	0	0	0
83	TOTAL Nat. Gas Storage and Proc. Plant	1,605	0	0	0	0	1,605
84	4. TRANSMISSION PLANT						
85	(365.1) Land and Land Rights	5,750,130					5,750,130
86	(365.2) Rights-of-Way	-					0
87	(366) Structures and Improvements	2,693,909	315,506				3,009,415
88	(367) Mains	153,430,214	18,768,574	(180,537)			172,018,251
89	(368) Compressor Station Equipment	-					0
90	(369) Measuring and Reg. Station Equipment	21,983,396	3,793,436	(325,912)	398,021		25,848,941
91	(370) Communication Equipment						0
92	(371) Other Equipment						0
93	(372) Asset Retirement Costs for Transmission Plant						0
94	TOTAL Transmission Plant	$183,857,649	$22,877,516	($506,449)	$398,021	$0	$206,626,737

GAS PLANT IN SERVICE (Continued)

LINE NO.		ACCOUNT (a)	BALANCE BEGINNING OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE END OF YEAR (g)
95		5. DISTRIBUTION PLANT						
96	(374)	Land and Land Rights	2,431,451	239,573	-			2,671,024
97	(375)	Structures and Improvements	6,680,079	23,282	(3,718)			6,699,643
98	(376)	Mains	1,071,266,283	41,250,965	(1,036,062)	360,119	(3,260)	1,111,838,045
99	(377)	Compressor Station Equipment	-	-	-			0
100	(378)	Meas. and Reg. Sta. Equip. - General	63,085,147	197,554	(310,873)		(398,021)	62,573,807
101	(379)	Meas. and Reg. Sta. Equip. - City Gate	-	-	-			0
102	(380)	Services	748,386,076	40,934,467	(2,463,103)		3,260	786,860,700
103	(381)	Meters	92,128,373	5,289,805	(1,551,271)			95,866,907
104	(382)	Meter Installations	92,714,615	9,891,679	(3,295,857)			99,310,437
105	(383)	House Regulators	7,655,234					7,655,234
106	(384)	House Reg. Installations	6,344,788					6,344,788
107	(385)	Industrial Meas. and Reg. Sta. Equipment	5,101,311					5,101,311
108	(386)	Other Prop. on Customers' Premises	-					0
109	(387)	Other Equipment	-					0
110	(388)	Asset Retirement Costs for Distribution Plant	4,539,250		(354,123)			4,185,127
111		TOTAL Distribution Plant	2,100,332,607	97,827,325	(9,015,007)	360,119	(398,021)	2,189,107,023
112		6. GENERAL PLANT						
113	(389)	Land and Land Rights						0
114	(390)	Structures and Improvements	652,699	-	-			652,699
115	(391)	Office Furniture and Equipment	2,675,635	-	(44,440)			2,631,195
116	(392)	Transportation Equipment		-	-			0
117	(393)	Stores Equipment		-	-			0
118	(394)	Tools, Shop and Garage Equipment	24,427,792	2,100,988	(376,691)			26,152,089
119	(395)	Laboratory Equipment	140,061	-	(28,491)			111,570
120	(396)	Power Operated Equipment		-	-			0
121	(397)	Communication Equipment	51,855,037	1,013,070	(49,069)			52,819,038
122	(398)	Miscellaneous Equipment	3,955,751	19,883	(601,575)			3,374,059
123		Subtotal	83,706,975	3,133,941	(1,100,266)	0	0	85,740,650
124	(399)	Other Tangible Property*	85,568		(13,954)			71,614
125	(399.1)	Asset Retirement Costs for General Plant						0
126		TOTAL General Plant	83,792,543	3,133,941	(1,114,220)	0	0	85,812,264
127		TOTAL (Accounts 101 and 106)	2,368,514,902	124,299,361	(10,635,676)	758,140	(398,021)	2,482,538,706
128		Gas Plant Purchased**						0
129		(Less) Gas Plant Sold**						0
130		Experimental Gas Plant Unclassified						0
131		TOTAL Gas Plant in Service	$2,368,514,902	$124,299,361	($10,635,676)	$758,140	($398,021)	$2,482,538,706

ACCUMULATED PROVISIONS FOR DEPRECIATION OF GAS PLANT IN SERVICE (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 14, column (c) and that reported for gas plant in service, pages 60-62, column (d) exclusive of retirements of nondepreciable property.

3. The provisions of account 108 of 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.

5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

LINE NO.	A. BALANCES AND CHANGES DURING YEAR ITEM (a)	TOTAL (c+d+e) (b)	GAS PLANT IN SERVICE (ACCOUNT 108) (c)	GAS PLANT HELD FOR FUTURE USE (d)	GAS PLANT LEASED TO OTHERS (e)
1	Balance beginning of year	859,076,067	859,076,067		
2	Depreciation provisions for year, charged to:				
3	(403) Depreciation expense	52,084,386	52,084,386		
4	(403.1) Depreciation expense for Asset Retirement Costs	108,406	108,406		
5	(413) Exp. of Gas Plt. Leas. to Others	0			
6	Transportation expenses - clearing	0			
7	Other clearing accounts	0			
8	Other accounts (specify):				
9					
10					
11					
12					
13	Total depreciation provisions for year	52,192,792	52,192,792	0	0
14	Net charges for plant retired:				
15	Book cost of plant retired	10,635,678	10,635,678		
16	Cost of Removal	3,602,358	3,602,358		
17	Salvage (credit)				
18	Net charges for plant retired	14,238,036	14,238,036	0	0
19	Other debit or credit items (describe):				
20	Book Cost of Asset Retirement Costs	0			
21	Common Depr allocation	6,569,622	6,569,622		
22	RWIP 2018 Charges	1,432,145	1,432,145		
23					
24					
25	Balance end of year	889,029,056	889,029,056	0	0
	B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
25	Production - Manufactured Gas	$0			
26	Production and Gathering - Natural Gas	0			
27	Products Extraction - Natural Gas	0			
28	Underground Gas Storage	0			
29	Other Gas Storage	0			
30	Base Load LNG Terminating and Procurement	0			
31	Transmission	53,123,206	53,123,206		
32	Distribution	793,728,257	793,728,257		
33	General	42,177,593	42,177,593		
34	Total	889,029,056	889,029,056	$0	$0

GAS OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (e), (g), (h) and (i). Unbilled revenues and Dth related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below gas operating revenues for the year for each account.
3. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
4. Number of customers, columns (h) and (i), should be reported on the basis of meters, plus 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 so added. The average number of customers means the average of twelve figures at the close of each month. If customer count in the residential and commercial classifications includes customers counted more than once because of special services, such as space heating, etc., indicate in a footnote the number of such duplicate customers included in each of the two service classifications.
5. If increase or decrease from preceding year columns (e), (g) and (i) are not derived from previously reported figures, explain any inconsistencies in a footnote.
6. Quantities of natural gas sold should be reported in Dth. If billings are on a therm basis, the B.t.u. content of the gas sold should be given, and the sales converted to Dth. for the purpose of this report.
7. Disclose amounts of $250,000 or greater in a footnote for accounts 488 and 495.
8. Commercial and Industrial Sales, Account 481, should be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent.
9. For lines 3, 4, 5 and 6, see pages 70 and 71 for amounts relating to unbilled revenue by accounts.
10. Include unmetered sales. Provide details of such sales in a footnote.

				Revenues from Natural Gas		Dth. of Natural Gas		Average Number of Natural Gas Customers Per Month	
Line No.	Account Title (a)	Total Operating Revenues (b)	From Manufactured Gas (c)	Amount for Year (d)	Amount for Previous Year (e)	Amount for Year (f)	Amount for Previous Year (g)	Number for Year (h)	Number for Previous Year (i)
1	SALES OF GAS								
2	Bundled								
3	(480) Residential Sales	$ 413,889,495		$ 413,889,495	$ 351,508,090	45,366,268	40,281,823	486,998	472,309
4	(481) Commercial and Industrial Sales								
5	Small (or Commercial) (See Instr. 8)	88,429,151		88,429,151	73,522,572	12,257,923	10,487,796	29,764	28,830
6	Large (or Industrial) (See Instr. 8)	919,105		919,105	1,040,772	160,958	258,754	85	83
7	(482) Other Sales-Public Authorities								
8	(484) Interdepartmental Sales								
9	TOTAL Sales to Ultimate Consumers	503,237,751	0	503,237,751	426,071,434	57,785,149	51,028,373	516,847	501,222
10	(483) Sales for Resale	5,790,551		5,790,551	4,791,911	1,417,473	1,233,031	7	3
11	Total Sales of Gas	509,028,302	0	509,028,302	430,863,345	59,202,622	52,261,404	516,854	501,225
12	Less (496) Provision for Rate Refunds								
13	TOTAL Revenues Net of Provision for Refunds	509,028,302	0	509,028,302	430,863,345	59,202,622	52,261,404	516,854	501,225
14	OTHER OPERATING REVENUES								
15	(487) Forfeited Discounts	2,639,179		2,639,179	2,519,600				
16	(488) Misc. Service Revenues	49,384		49,384	61,211				
17	(490) Sales of Prod. Ext. from Nat. Gas								
18	(491) Rev. from Nat. Gas Proc. by Others								
19	(492) Incidental Gas & Oil Sales								
20	(493) Rent from Gas Property			0					
21	(494) Interdepartmental Rents								
22	(495) Other Gas Revenues	(2,543,767)		(2,543,767)	8,405,260				
23	Transportation of Gas of Others								
24	(489.1) Gathering Facilities								
25	(489.2) Transmission Facilities								
26	(489.3) Distribution Facilities*								
27	Residential Sales	42,336,511		42,336,511	44,472,626	18,955,305	16,753,599	86,743	95,241
28	Commercial and Industrial Sales								
29	Small (or Commercial) (See Instr. 8)	45,683,095		45,683,095	46,234,333	50,683,039	43,983,708	16,258	16,190
30	Large (or Industrial) (See Instr. 8)	25,950,597		25,950,597	24,893,083	52,970,187	47,154,562	180	152
31	Other Sales to Public Authorities								
32	Sales to Railroads and Railways								
33	Interdepartmental Sales								
34	Other								
35	(489.4) Storing Gas of Others								
36	Total Other Operating Revenues	114,114,999	0	114,114,999	126,586,113	122,608,531	107,891,869	103,181	111,583
37	Total Gas Operating Revenues	623,143,301	0	623,143,301	557,449,458	181,811,153	160,153,273	620,035	612,808

*** Note: Account (489.3) Distribution Facilities should be separately identified by subcategories on lines 27 - 34. Items recorded on Line 34 - Other should be footnoted with a description**

BILLING ROUTINE - GAS

Report the following information in days for Accounts 480 and 481:
1. The period for which bills are rendered.
2. The period between the date meters are read and the date customers are billed.
3. The period between the billing date and the date on which discounts are forfeited.

SALES OF NATURAL GAS BY COMMUNITIES

1. Report below the information called for concerning sales of gas in each community of 50,000 population or more, or according to operating districts or divisions constituting distinct economic areas if the respondent's records do not readily permit reporting by communities. Except for state boundaries, community areas need not hold rigidly to political boundaries and may embrace a metropolitan area and immediate environs. Include in this schedule field and main line sales to commercial and industrial customers.

Line No.	Name of Community (a)	Population (b)	BTU Content per cubic foot (c)	Total Residential, Commercial and Industrial and Other Sales to Public Authorities: Operating Revenues (d)	Dth. (e)	Average Number of Customers (f)	Residential: Operating Revenues (g)
1	New York State:						
2							
3	Cities:						
4	Albany			33,723,344	4,855,549	29,993	28,247,322
5	Schenectady			20,155,294	2,661,848	20,435	18,326,108
6	Syracuse			42,591,224	5,776,310	42,221	39,068,894
7	Utica			20,017,400	2,685,302	19,603	18,148,433
8							
9							
10							
11	Towns:						
12	Clay			13,984,225	1,523,817	15,958	13,204,711
13	Colonie			23,861,293	2,874,352	23,525	21,358,195
14							
15							
16							
17							
18	Other Territories			348,904,971	37,407,971	365,112	275,535,832
19							
20							
21							
22							
23							
24							
25							
26							
27							
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43							
44							
45							
46							
47	TOTAL SALES	0	0	503,237,751	57,785,149	516,847	413,889,495

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SALES OF NATURAL GAS BY COMMUNITIES (CONTINUED)

2. Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas. Designate, however, those communities in which mixed gas is sold. In a footnote state the components of mixed gas, i.e.. whether natural and oil refinery gases, natural and coke oven gases, etc., and specify the approximate percentage of natural gas in the mixture. When gases having substantially different thermal characteristics are regularly distributed separate data should be reported with respect to each.

Residential (Continued)		Commercial and Industrial Sales			Other Sales to Public Authorities			
Dth. (h)	Average Number of Customers (i)	Operating Revenues (j)	Dth. (k)	Average Number of Customers (l)	Operating Revenues (m)	Dth. (n)	Average Number of Customers (o)	Line No.
								1
								2
								3
3,447,598	29,242	5,476,022	1,407,951	751				4
2,192,213	20,043	1,829,186	469,635	392				5
4,829,994	41,471	3,522,330	946,316	750				6
2,304,882	19,241	1,868,967	380,420	362				7
								8
								9
								10
								11
1,396,554	15,797	779,514	127,263	161				12
2,467,754	23,012	2,503,098	406,598	513				13
								14
								15
								16
								17
28,727,273	338,192	73,369,139	8,680,698	26,920				18
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								23
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								46
45,366,268	486,998	89,348,256	12,418,881	29,849	0	0	0	47

SALES FOR RESALE

Report the indicated particulars of sales for redistribution during the year. For other than straight natural gas, entries in column (d) should identify the process (or processes) used in production.

Line No.	Sold To (a)	Contract or Service Classification Number (b)	Point of Delivery (c)	Kind of Gas and Average BTU (d)	Measurement Pressure Base (e)	Dth. (f)	Revenues (g)	Average per Dth. (h)
1	BP CANADA ENERGY MARKETING CORP.					78,000	$ 312,264	4.00
2	BP ENERGY COMPANY					134,100	619,092	4.62
3	COLONIAL ENERGY INC.					500	1,595	3.19
4	CONOCOPHILLIPS COMPANY					15,600	59,903	3.84
5	CONSOLIDATED EDISON ENERGY INC.					2,800	6,720	2.40
6	DIRECT ENERGY BUSINESS MARKETING					130,800	605,602	4.63
7	EMERA ENERGY SERVICES INC					214,771	758,979	3.53
8	ENSTOR ENERGY SERVICES, LLC					10,600	36,656	3.46
9	MACQUARIE ENERGY LLC					37,500	143,499	3.83
10	MERCURIA ENERGY AMERICA, INC.					145,523	549,790	3.78
11	MIECO INC.					55,000	245,542	4.46
12	NEXTERA ENERGY MARKETING, LLC					800	2,958	3.70
13	NJR ENERGY SERVICES COMPANY					250,514	1,064,784	4.25
14	SOUTH JERSEY RESOURCES GROUP LLC					1,000	5,292	5.29
15	VITOL INC.					74,600	381,849	5.12
16	WELLS FARGO COMMODITIES, LLC					56,200	247,971	4.41
17	REPSOL ENERGY NA CORP.					1,800	4,824	2.68
18	SEQUENT ENERGY MANAGEMENT					5,000	26,700	5.34
19	UNITED ENERGY TRADING LLC					39,300	115,952	2.95
20	EDF TRADING NORTH AMERICA LLC					5,000	13,750	2.75
21	ENGIE ENERGY MARKETING NA, INC.					4,000	14,070	3.52
22	J. ARON & COMPANY LLC					30,865	114,506	3.71
23	SPRAGUE OPERATING RESOURCES					1,900	6,175	3.25
24	EQUINOR NATURAL GAS LLC					24,400	99,290	4.07
25	HARTREE PARTNERS, LP					4,300	20,545	4.78
26	CASTLETON COMM. MERCHANT TRADING					9,000	42,210	4.69
27	SHELL ENERGY NA (US)					300	1,436	4.79
28	UNIPER GLOBAL COMMODITIES NA LLC					83,300	288,597	3.46
29								
30								
31								
32								
33								
34								
35								
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42								
43								
44								
45								
46								
47								
48								
49								
50								
51								
52	TOTAL					1,417,473	$ 5,790,551	$ 4.09

REVENUE FROM TRANSPORTATION OF GAS OF OTHERS - NATURAL GAS (Account 489)

1. Report below particulars concerning revenue from transportation or compression by respondent of natural gas of others. Report the indicated particulars of sales for redistribution during the year. For other than straight natural gas,
2. Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas. Designate, however, if gas transported or compressed is other other natural gas.
3. In column (a) give names of companies from which revenues were derived, points of receipt and delivery, and names of companies from which gas was received and to which delivered.
4. Points of receipt and delivery should be so designated that they can be identified on map of the respondent's pipeline system.

Line No.	Name of Company and Description of Service Performed (Designate associated companies) (a)	Distance Transported (b)	Dth. Received (c)	Dth. Delivered (d)	Revenue (e)	Avg. rev. per Dth. of gas delivered (f)
1	SC 1M	N/A		9,559,696	39,789,387	4.16
2	SC 2M	N/A		11,183,267	22,556,088	2.02
3	SC 5F	N/A		7,569,163	6,770,324	0.89
4	SC 6I	N/A		5,746,840	3,104,629	0.54
5	SC 7	N/A		6,322,697	9,118,065	1.44
6	SC 8	N/A		19,251,364	15,206,165	0.79
7	SC 9	N/A		8,236,500	3,665,522	0.45
8	SC 11	N/A		4,729,404	474,793	0.10
9	SC 12	N/A		1,410,716	304,487	0.22
10	SC 14/NYSEG	N/A		48,598,884	12,980,743	0.27
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28	TOTAL		0	122,608,531	$113,970,203	0.93

SALES BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the Dth of gas sold and/or distribution of gas sold to others, revenue, average number of customers, average Dth per customer and average revenue per Dth~~.~~, excluding data for Sales for Resale which is reported on page 67.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in schedule entitled "Gas Operating Revenues" page 64. 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. For each rate schedule, provide the required information specified below.
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 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 an adjustment clause for purchased or other gas, state in a footnote the estimated additional revenue billed pursuant thereto.

Line No.	Number and Title of Rate Schedule (a)	Dth. (b)	Revenue (c)	Average Number of Customers (d)	Dth. of Sales per Customer (e)	Revenue per Dth. Sold (f)
1	Residential Sales of Gas					
2	PSC Schedule 219-1-480	44,960,109	$412,101,631	485,693	92.57	9.17
3	PSC Schedule 219-2-480	406,159	1,787,864	1,305	311.15	4.40
4	PSC Schedule 219-13-480	0	0	0		
5	Other	0	0	0		
6						
7						
8						
9						
10						
11						
12	Subtotal	45,366,268	$413,889,495	486,998	93.15	$9.12
13	Residential Transportation					
14						
15						
16						
17						
18						
19						
20						
21						
22						
23	Subtotal	0	$0	0	0	$0
24	TOTAL (ACCOUNT 480)	45,366,268	$413,889,495	486,998	93.15	$9.12
25	Commercial and Industrial Sales of Gas					
26						
27						
28	PSC Schedule 219-2-481	11,819,696	78,895,322	29,809	396.52	6.67
29	PSC Schedule 219-3-481	599,182	3,098,533	40	15,073.79	5.17
30	PSC Schedule 219-4-481	0	0	0		
31	PSC Schedule 219-8-481	0	7,353,478	0		
32	PSC Schedule 219-9-481	0	0	0		
33	PSC Schedule 219-12-481	3	923	0	7.68	307.67
34	PSC Schedule 219-13-481	0	0	0		
35	Other					
36						
37						
38						
39						
40						
41						
42						
43	Subtotal	12,418,881	$89,348,256	29,849	416.06	$7.19

SALES BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	Dth. Sold (b)	Revenue (c)	Average Number of Customers (d)	Dth. of Sales per Customer (e)	Revenue per Dth. Sold (f)
44	Commercial and Industrial Transportation					
45						
46						
47						
48						
49						
50						
51						
52						
53						
54						
55						
56						
57	Subtotal	0	$0	0	0	0
58	TOTAL (ACCOUNT 481)	12,418,881	$89,348,256	29,849	416.06	$7.19
59	Public Authority Sales of Gas					
60						
61						
62						
63						
64						
65						
66						
67						
68						
69						
70						
71						
72						
73						
74						
75						
76						
77	Subtotal	0	$0	0	0	0
78	Public Authority Transportation					
79						
80						
81						
82						
83	Subtotal	0	$0	0	0	0
84	TOTAL (ACCOUNT 482)	0	$0	0	0	0
85	Sales for Resale - Gas					
86						
87						
88	Subtotal	0	$0	0	0	0
89	Sales for Resale - Transportation	1,417,473	5,790,551	7		4.09
90						
91						
92	Subtotal	1,417,473	5,790,551	7	0	$4.09
93	TOTAL (ACCOUNT 483)	1,417,473	$5,790,551	7	0	$4.09
94	Interdepartment Sales - Gas					
95						
96						
97	Subtotal	0	$0	0	0	0
98	Interdepartment Sales - Transportation					
99						
100	Subtotal	0	0	0	0	0
101	TOTAL (ACCOUNT 484)	0	$0	0	0	$0
102						
103						
104	TOTALS (Other)	0	$0	0	0	0
105	Totals (Account 480 - 484)	59,202,622	$509,028,302	516,854	114.54	$8.60

If required, see insert page below.

SALES BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	Dth. Sold (b)	Revenue (c)	Average Number of Customers (d)	Dth. of Sales per Customer (e)	Revenue per Dth. Sold (f)
1	Forfeited Discounts - Gas					
2				0		
3						
4	Subtotal	0	$2,639,179	0		
5	Forfeited Discounts - Transportation					
6						
7	Subtotal	0	0	0		
8	TOTAL (ACCOUNT 487)	0	$2,639,179	0		
9	Miscellaneous Service Revenues - Gas		49,384			
10				0		
11						
12	Subtotal	0	49,384	0		
13	Miscellaneous Service Revenues - Transportation					
14						
15	Subtotal	0	0	0		
16	TOTAL (ACCOUNT 488)	0	$49,384	0		
17	Rent from Gas Property - Gas					
18				0		
19						
20	Subtotal	0	0	0		
21	Rent from Gas Property - Transportation					
22						
23	Subtotal	0	0	0		
24	TOTAL (ACCOUNT 493)	0	$0	0		
25						
26						
27						
28						
29						
30						
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GAS OPERATION AND MAINTENANCE EXPENSES (Accounts 401 - 402.1)

Enter in the space provided the operation and maintenance expenses for the year and previous year.

LINE NO.		ACCOUNT (a)	AMOUNT FOR CURRENT YEAR (b)	AMOUNT FOR PREVIOUS YEAR (c)
1		1. PRODUCTION EXPENSES		
2		A. MANUFACTURED GAS PRODUCTION		
3		A1. STEAM PRODUCTION (Submit Supplemental Statement)	$0	$0
4		A2. MANUFACTURED GAS PROD (Submit Supplemental Statement)		
5		GAS FUELS (Submit Supplemental Statement)		
6		GAS RAW MATERIALS (Submit Supplemental Statement)		
7		B. NATURAL GAS PRODUCTION		
8		B1. NATURAL GAS PRODUCTION AND GATHERING		
9		OPERATION		
10	(750)	OPERATION SUPERVISION AND ENGINEERING		
11	(751)	PRODUCTION MAPS AND RECORDS		
12	(752)	GAS WELLS EXPENSES		
13	(753)	FIELD LINES EXPENSES		
14	(754)	FIELD COMPRESSOR STATION EXPENSES		
15	(755)	FIELD COMPRESSOR STATION FUEL AND POWER		
16	(756)	FIELD MEASURING AND REGULATING STATION EXPENSES		
17	(757)	PURIFICATION EXPENSES		
18	(758)	GAS WELL ROYALTIES		
19	(759)	OTHER EXPENSES		
20	(760)	RENTS		
21		TOTAL OPERATION	0	0
22		MAINTENANCE		
23	(761)	MAINTENANCE SUPERVISION AND ENGINEERING		
24	(762)	MAINTENANCE OF STRUCTURES AND IMPROVEMENTS		
25	(763)	MAINTENANCE OF PRODUCING GAS WELLS		
26	(764)	MAINTENANCE OF FIELD LINES		
27	(765)	MAINTENANCE OF FIELD COMPRESSOR STATION EQUIPMENT		
28	(766)	MAINTENANCE OF FIELD MEAS. AND REG. STA. EQUIPMENT		
29	(767)	MAINTENANCE OF PURIFICATION EQUIPMENT		
30	(768)	MAINTENANCE OF DRILLING AND CLEANING EQUIPMENT		
31	(769)	MAINTENANCE OF OTHER EQUIPMENT		
32		TOTAL MAINTENANCE	0	0
33		TOTAL NATURAL GAS PRODUCTION AND GATHERING	0	0
34		B2. PRODUCTS EXTRACTION		
35		OPERATION		
36	(770)	OPERATION SUPERVISION AND ENGINEERING		
37	(771)	OPERATION LABOR		
38	(772)	GAS SHRINKAGE		
39	(773)	FUEL		
40	(774)	POWER		
41	(775)	MATERIALS		
42	(776)	OPERATION SUPPLIES AND EXPENSES		
43	(777)	GAS PROCESSED BY OTHERS		
44	(778)	ROYALTIES ON PRODUCTS EXTRACTED		
45	(779)	MARKETING EXPENSES		
46	(780)	PRODUCTS PURCHASED FOR RESALE		
47	(781)	VARIATION IN PRODUCTS INVENTORY		
48	(782)	(LESS) EXTRACTED PRODUCTS USED BY THE UTILITY - (CREDIT)		
49	(783)	RENTS		
50		TOTAL OPERATION	$0	$0

GAS OPERATION AND MAINTENANCE EXPENSES (Accounts 401 - 402.1) (Continued)

LINE NO.	ACCOUNT (a)	AMOUNT FOR CURRENT YEAR (b)	AMOUNT FOR PREVIOUS YEAR (c)
1	B2. PRODUCTS EXTRACTION (Continued)		
2	MAINTENANCE		
3	(784) MAINTENANCE SUPERVISION AND ENGINEERING		
4	(785) MAINTENANCE OF STRUCTURES AND IMPROVEMENTS		
5	(786) MAINTENANCE OF EXTRACTION AND REFINING EQUIPMENT		
6	(787) MAINTENANCE OF PIPE LINES		
7	(788) MAINTENANCE OF EXTRACTED PRODUCTS STORAGE EQUIP.		
8	(789) MAINTENANCE OF COMPRESSOR EQUIPMENT		
9	(790) MAINTENANCE OF GAS MEASURING AND REG. EQUIPMENT		
10	(791) MAINTENANCE OF OTHER EQUIPMENT		
11	TOTAL MAINTENANCE	0	0
12	TOTAL PRODUCTS EXTRACTION	0	0
13	C. EXPLORATION AND DEVELOPMENT		
14	OPERATION		
15	(795) DELAY RENTALS		
16	(796) NONPRODUCTIVE WELL DRILLING		
17	(797) ABANDONED LEASES		
18	(798) OTHER EXPLORATION		
19	TOTAL EXPLORATION AND DEVELOPMENT	0	0
20	D. OTHER GAS SUPPLY EXPENSES		
21	OPERATION		
22	(800) NATURAL GAS WELL HEAD PURCHASES		
23	(800.1) NAT. GAS WELL HEAD PURCH., INTRACOMPANY TRANSFERS		
24	(801) NATURAL GAS FIELD LINE PURCHASES		
25	(802) NATURAL GAS GASOLINE PLANT OUTLET PURCHASES		
26	(803) NATURAL GAS TRANSMISSION LINE PURCHASES		
27	(804) NATURAL GAS CITY GATE PURCHASES	266,777,766	196,575,889
28	(804.1) LIQUEFIED NATURAL GAS PURCHASES		
29	(805) OTHER GAS PURCHASES		
30	(805.1) (LESS) PURCHASED GAS COST ADJUSTMENTS		
31	TOTAL PURCHASED GAS	266,777,766	196,575,889
32	(806) EXCHANGE GAS		
33	PURCHASED GAS EXPENSES		
34	(807.1) WELL EXPENSES -- PURCHASED GAS		
35	(807.2) OPERATION OF PURCHASED GAS MEASURING STATIONS		
36	(807.3) MAINTENANCE OF PURCHASED GAS MEASURING STATIONS		
37	(807.4) PURCHASED GAS CALCULATIONS EXPENSES		
38	(807.5) OTHER PURCHASED GAS EXPENSES		
39	TOTAL PURCHASED GAS EXPENSES	0	0
40	(808.1) GAS WITHDRAWN FROM STORAGE -- DEBIT	28,251,837	25,228,141
41	(808.2) (LESS) GAS DELIVERED TO STORAGE -- CREDIT	(36,651,161)	(31,743,091)
42	(809.1) WITHDRAWALS OF LIQ. NAT. GAS FOR PROCESSING -- DEBIT		
43	(809.2) (LESS) DELIVERIES OF NAT. GAS FOR PROCESSING -- CREDIT		
44	GAS USED IN UTILITY OPERATIONS -- CREDIT	(8,399,324)	(6,514,950)
45	(810) GAS USED FOR COMPRESSOR STATION FUEL -- CREDIT		
46	(811) GAS USED FOR PRODUCTS EXTRACTION -- CREDIT		
47	(812) GAS USED FOR OTHER UTILITY OPERATIONS -- CREDIT		
48	TOTAL GAS USED IN UTILITY OPERATIONS -- CREDIT	0	0
49	(813) OTHER GAS SUPPLY EXPENSES	10,988	0
50	TOTAL OTHER GAS SUPPLY EXPENSE	258,389,430	190,060,939
51	TOTAL PRODUCTION EXPENSES	$258,389,430	$190,060,939

GAS OPERATION AND MAINTENANCE EXPENSES (Accounts 401 - 402.1) (Continued)

LINE NO.	ACCOUNT (a)		AMOUNT FOR CURRENT YEAR (b)	AMOUNT FOR PREVIOUS YEAR (c)
1		2. NAT. GAS STORAGE, TERMINALING AND PROCESSING EXP.		
2		A. UNDERGROUND STORAGE EXPENSES		
3		OPERATION		
4	(814)	OPERATION SUPERVISION AND ENGINEERING		
5	(815)	MAPS AND RECORDS		
6	(816)	WELLS EXPENSES		
7	(817)	LINES EXPENSES		
8	(818)	COMPRESSOR STATION EXPENSES		
9	(819)	COMPRESSOR STATION FUEL AND POWER		
10	(820)	MEASURING AND REGULATING STATION EXPENSES		
11	(821)	PURIFICATION EXPENSES		
12	(822)	EXPLORATION AND DEVELOPMENT		
13	(823)	GAS LOSSES		
14	(824)	OTHER EXPENSES		
15	(825)	STORAGE WELL ROYALTIES		
16	(826)	RENTS		
17		TOTAL OPERATION	0	0
18		MAINTENANCE		
19	(830)	MAINTENANCE SUPERVISION AND ENGINEERING		
20	(831)	MAINTENANCE OF STRUCTURES AND IMPROVEMENTS		
21	(832)	MAINTENANCE OF RESERVOIRS AND WELLS		
22	(833)	MAINTENANCE OF LINES		
23	(834)	MAINTENANCE COMPRESSOR STATION EQUIPMENT		
24	(835)	MAINTENANCE OF MEASURING AND REG. STATION EQUIPMENT		
25	(836)	MAINTENANCE OF PURIFICATION EQUIPMENT		
26	(837)	MAINTENANCE OF OTHER EQUIPMENT		
27		TOTAL MAINTENANCE	0	0
28		TOTAL UNDERGROUND STORAGE EXPENSES	0	0
29		B. OTHER STORAGE EXPENSES		
30		OPERATION		
31	(840)	OPERATION SUPERVISION AND ENGINEERING		
32	(841)	OPERATION LABOR AND EXPENSES	1,553,425	15,578
33	(842)	RENTS		
34	(842.1)	FUEL		
35	(842.2)	POWER		
36	(842.3)	GAS LOSSES		
37		TOTAL OPERATION	1,553,425	15,578
38		MAINTENANCE		
39	(843.1)	MAINTENANCE SUPERVISION AND ENGINEERING		
40	(843.2)	MAINTENANCE OF STRUCTURES AND IMPROVEMENTS		
41	(843.3)	MAINTENANCE OF GAS HOLDERS		
42	(843.4)	MAINTENANCE OF PURIFICATION EQUIPMENT		
43	(843.5)	MAINTENANCE OF LIQUEFACTION EQUIPMENT		
44	(843.6)	MAINTENANCE OF VAPORIZING EQUIPMENT		
45	(843.7)	MAINTENANCE OF COMPRESSOR EQUIPMENT		
46	(843.8)	MAINTENANCE OF MEASURING AND REGULATING EQUIPMENT		
47	(843.9)	MAINTENANCE OF OTHER EQUIPMENT		
48		TOTAL MAINTENANCE	0	0
49		TOTAL OTHER STORAGE EXPENSES	$1,553,425	$15,578

GAS OPERATION AND MAINTENANCE EXPENSES (Accounts 401 - 402.1)
(Continued)

LINE NO.	ACCOUNT (a)	AMOUNT FOR CURRENT YEAR (b)	AMOUNT FOR PREVIOUS YEAR (c)
1	C. LIQUEFIED NAT. GAS TERMINALING AND PROCESSING EXP.		
2	OPERATION		
3	(844.1) OPERATION SUPERVISION AND ENGINEERING		
4	(844.2) LNG PROCESSING TERMINAL LABOR AND EXPENSES		
5	(844.3) LIQUEFACTION PROCESSING LABOR AND EXPENSES		
6	(844.4) LIQUEFACTION TRANSPORTATION LABOR AND EXPENSES		
7	(844.5) MEASURING AND REGULATING LABOR AND EXPENSES		
8	(844.6) COMPRESSOR STATION LABOR AND EXPENSES		
9	(844.7) COMMUNICATION SYSTEM EXPENSES		
10	(844.8) SYSTEM CONTROL AND LOAD DISPATCHING		
11	(845.1) FUEL		
12	(845.2) POWER		
13	(845.3) RENTS		
14	(845.4) DEMURRAGE CHARGES		
15	(845.5) (LESS) WHARFAGE RECEIPTS -- CREDIT		
16	(845.6) PROCESSING LIQUEFIED OR VAPORIZED GAS BY OTHERS		
17	(846.1) GAS LOSSES		
18	(846.2) OTHER EXPENSES		
19	TOTAL OPERATION	0	0
20	MAINTENANCE		
21	(847.1) MAINTENANCE SUPERVISION AND ENGINEERING		
22	(847.2) MAINTENANCE OF STRUCTURES AND IMPROVEMENTS		
23	(847.3) MAINTENANCE OF LNG PROCESSING TERMINAL EQUIPMENT		
24	(847.4) MAINTENANCE OF LNG TRANSPORTATION EQUIPMENT		
25	(847.5) MAINTENANCE OF MEASURING AND REGULATING EQUIPMENT		
26	(847.6) MAINTENANCE OF COMPRESSOR STATION EQUIPMENT		
27	(847.7) MAINTENANCE OF COMMUNICATION EQUIPMENT		
28	(847.8) MAINTENANCE OF OTHER EQUIPMENT		
29	TOTAL MAINTENANCE	0	0
30	TOTAL LIQ. NAT. GAS TERMINALING AND PROCESSING EXP.	0	0
31	TOTAL NATURAL GAS STORAGE	1,553,425	15,578
32	3. TRANSMISSION EXPENSES		
33	OPERATION		
34	(850) OPERATION SUPERVISION AND ENGINEERING		
35	(851) SYSTEM CONTROL AND LOAD DISPATCHING	322,635	
36	(852) COMMUNICATION SYSTEM EXPENSES		
37	(853) COMPRESSOR STATION LABOR AND EXPENSES		
38	(854) GAS FOR COMPRESSOR STATION FUEL		
39	(855) OTHER FUEL AND POWER FOR COMPRESSOR STATIONS		
40	(856) MAINS EXPENSES	3,249,130	(154,217)
41	(857) MEASURING AND REGULATING STATION EXPENSES	475,095	87
42	(858) TRANSMISSION AND COMPRESSION OF GAS BY OTHERS		
43	(859) OTHER EXPENSES		
44	(860) RENTS		0
45	TOTAL OPERATION	$4,046,860	($154,130)

GAS OPERATION AND MAINTENANCE EXPENSES (Accounts 401 - 402.1) (Continued)

LINE NO.	ACCOUNT (a)	AMOUNT FOR CURRENT YEAR (b)	AMOUNT FOR PREVIOUS YEAR (c)
1	3. TRANSMISSION EXPENSES (Continued)		
2	MAINTENANCE		
3	(861) MAINTENANCE SUPERVISION AND ENGINEERING	518,266	
4	(862) MAINTENANCE OF STRUCTURES AND IMPROVEMENTS		
5	(863) MAINTENANCE OF MAINS	2,134,821	
6	(864) MAINTENANCE OF COMPRESSOR STATION EQUIPMENT		
7	(865) MAINTENANCE OF MEASURING AND REG. STATION EQUIP.	570,929	
8	(866) MAINTENANCE OF COMMUNICATION EQUIPMENT		
9	(867) MAINTENANCE OF OTHER EQUIPMENT		
10	TOTAL MAINTENANCE	3,224,016	0
11	TOTAL TRANSMISSION EXPENSES	7,270,876	(154,130)
12	4. DISTRIBUTION EXPENSES		
13	OPERATION		
14	(870) OPERATION SUPERVISION AND ENGINEERING	2,925,638	2,469,460
15	(871) DISTRIBUTION LOAD DISPATCHING	1,954,430	2,125,221
16	(872) COMPRESSOR STATION LABOR AND EXPENSES		
17	(873) COMPRESSOR STATION FUEL AND POWER		
18	(874) MAINS AND SERVICES EXPENSES	10,705,645	14,304,074
19	(875) MEASURING AND REGULATING STATION EXPENSES - GENERAL	717,790	593,217
20	(876) MEASURING AND REGULATING STATION EXPENSES - INDUST.	267,583	326,680
21	(877) MEAS. AND REG. STATION EXP. - CITY GATE CHECK STATION		
22	(878) METER AND HOUSE REGULATOR EXPENSES	3,698,512	5,213,752
23	(879) CUSTOMER INSTALLATIONS EXPENSES	2,028,873	788,156
24	(880) OTHER EXPENSES	13,077,950	8,790,414
25	(881) RENTS	40,372	79,635
26	TOTAL OPERATION	35,416,793	34,690,609
27	MAINTENANCE		
28	(885) MAINTENANCE SUPERVISION AND ENGINEERING	2,220,317	2,513,156
29	(886) MAINTENANCE OF STRUCTURES AND IMPROVEMENTS	111,560	4,443
30	(887) MAINTENANCE OF MAINS	3,334,892	7,141,034
31	(888) MAINTENANCE OF COMPRESSOR STATION EQUIPMENT	6,614	
32	(889) MAINTENANCE OF MEAS. AND REG. STA. EQUIP. - GENERAL	1,075,358	1,353,378
33	(890) MAINTENANCE OF MEAS. AND REG. STA. EQUIP. -INDUST.	1,614,010	2,110,789
34	(891) MAINT. OF MEAS. AND REG. STA. EQUIP. - CITY GATE CHECK STA.	37,611	631
35	(892) MAINTENANCE OF SERVICES	17,695,873	12,635,709
36	(893) MAINTENANCE OF METERS AND HOUSE REGULATORS	749,233	825,274
37	(894) MAINTENANCE OF OTHER EQUIPMENT	24,005	33,122
38	TOTAL MAINTENANCE	26,869,473	26,617,536
39	TOTAL DISTRIBUTION EXPENSES	62,286,266	61,308,145
40	5. CUSTOMER ACCOUNTS EXPENSES		
41	OPERATION		
42	(901) SUPERVISION	813,572	629,484
43	(902) METER READING EXPENSES	1,055,813	955,153
44	(903) CUSTOMER RECORDS AND COLLECTION EXPENSES	10,540,429	11,394,106
45	(904) UNCOLLECTIBLE ACCOUNTS	9,230,628	9,091,426
46	(905) MISCELLANEOUS CUSTOMER ACCOUNTS EXPENSES	955,750	1,016,503
47	TOTAL CUSTOMER ACCOUNTS EXPENSES	22,596,192	23,086,672

GAS OPERATION AND MAINTENANCE EXPENSES (Accounts 401 - 402.1)
(Continued)

LINE NO.		ACCOUNT (a)	AMOUNT FOR CURRENT YEAR (b)	AMOUNT FOR PREVIOUS YEAR (c)
1		6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
2		OPERATION		
3	(907)	SUPERVISION	101,345	31,142
4	(908)	CUSTOMER ASSISTANCE EXPENSES	10,960,366	14,238,657
5	(909)	INFORMATIONAL AND INSTRUCTIONAL EXPENSES	1,703,317	1,683,652
6	(910)	MISCELLANEOUS CUST. SVC. AND INFORMATIONAL EXPENSES	681,910	225,691
7		TOTAL CUSTOMER SERVICE AND INFORMATION EXPENSES	13,446,938	16,179,142
8		7. SALES EXPENSES		
9		OPERATION		
10	(911)	SUPERVISION	61,043	0
11	(912)	DEMONSTRATING AND SELLING EXPENSES	1,150,773	816,134
12	(913)	ADVERTISING EXPENSES	292,792	210,785
13	(916)	MISCELLANEOUS SALES EXPENSES	203	
14		TOTAL SALES EXPENSES	1,504,811	1,026,919
15		8. ADMINISTRATIVE AND GENERAL EXPENSES		
16		OPERATION		
17	(920)	ADMINISTRATIVE AND GENERAL SALARIES	16,756,180	17,165,457
18	(921)	OFFICE SUPPLIES AND EXPENSES	9,423,802	11,439,163
19	(922)	(LESS) ADMINISTRATIVE EXPENSES TRANSFERRED - (CREDIT)	(5,367,654)	
20	(923)	OUTSIDE SERVICES EMPLOYED	3,547,811	7,090,372
21	(924)	PROPERTY INSURANCE	829,306	549,542
22	(925)	INJURIES AND DAMAGES	1,572,855	1,848,680
23	(926)	EMPLOYEE PENSIONS AND BENEFITS	20,231,925	16,200,939
24	(927)	FRANCHISE REQUIREMENTS		
25	(928)	REGULATORY COMMISSION EXPENSES	2,496,415	4,002,246
26	(929)	(LESS) DUPLICATE CHARGES - (CREDIT)		
27	(930.1)	GENERAL ADVERTISING EXPENSES	0	764
28	(930.2)	MISCELLANEOUS GENERAL EXPENSES	7,062,277	8,271,024
29	(931)	RENTS	9,107,170	7,973,567
30		TOTAL OPERATION	65,660,087	74,541,754
31		MAINTENANCE		
32	(932)	MAINTENANCE OF GENERAL PLANT	3,740	113,252
33		TOTAL ADMINISTRATIVE AND GENERAL EXPENSES	65,663,827	74,655,006
34		TOTAL GAS OPERATION AND MAINTENANCE EXPENSES	$432,711,765	$366,178,271

NUMBER OF GAS DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the gas department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the gas department

1.	Payroll Period ended (Date)	12/31/18
2.	Total Regular Full-Time Employees	3,830
3.	Total Part-Time and Temporary Employees	0
4.	Total Employees	3,830

PURCHASED GAS (Account 800 thru 805)

1. Report below particulars of purchases for redistribution during the year.
2. Minor purchases and borderline purchases, appropriately designated, may be grouped and entries in column (b) and (c) may be omitted.
3. For manufactured gas, entries in column (d) should reflect the specific process to the extent such information is available.

Line No.	Purchased From (a)	Contract or Service Cl. No. (b)	Point of Receipt (c)	Kind of gas and Average Btu (d)	Dth. (e)	Cost (f)	Average per Dth. (g)
1							
2	None						
3							
4							
5							
6							
7							
8							
9				Totals (Account 800)	0	0	
10							
11	None						
12							
13							
14							
15							
16							
17							
18				Totals (Account 800.1)	0	0	
19							
20	None						
21							
22							
23							
24							
25							
26							
27				Totals (Account 801)	0	0	
28							
29	None						
30							
31							
32							
33							
34							
35							
36				Totals (Account 802)	0	0	

PURCHASED GAS (Account 800 thru 805) Continued

1. Report below particulars of purchases for redistribution during the year.
2. Minor purchases and borderline purchases, appropriately designated, may be grouped and entries in column (b) and (c) may be omitted.
3. For manufactured gas, entries in column (d) should reflect the specific process to the extent such information is available.

Line No.	Purchased from (a)	Contract or Service Cl. No. (b)	Point of Receipt (c)	Kind of gas and Average Btu (d)	Dth. (e)	Cost (f)	Average per Dth. (g)
37							
38	None						
39							
40							
41							
42							
43							
44				Totals (Account 803)	0	0	
45	Purchases				64,165,484	256,508,706	4.00
46	Net Change in Amount of Gas Adjust.					11,750,695	
47	Monthly Cashout Transportation Cust.					2,554,840	
48	Company NGV Use				16,328	58,980	3.61
49	Electric & Gas Department Use				21,840	146,880	6.73
50	Other Gas Supply Expenses					(4,242,335)	
51				Totals (Account 804)	64,203,652	266,777,766	4.16
52							
53	None						
54							
55							
56							
57							
58				Totals (Account 804.1)	0	0	
59							
60	None						
61							
62							
63							
64							
65				Totals (Account 805)	0	0	
66							
67	None						
68							
69							
70							
71							
72				Totals (Account 805.1)	0	0	

CONTRACTS FOR PURCHASE OF GAS

1. Show a brief summary of the terms of contract in effect during the year with the principal supplier (or suppliers if there were more than one, but in any case limited to the two largest) listed in the preceding schedule.

2. Show particularly the provision covering the determination of charges (including pressure base) the expiration date, delivery pressure and imminent charges.

With the implementation of FERC Order 636, Niagara Mohawk Power Corporation's portfolio of services to match its firm obligations includes the following as of December 31, 2018.

PIPELINE FIRM TRANSPORTATION CONTRACTS:
Tennessee Gas Pipeline (14,000 DT into DTI, through 10/31/19) Contract # 65075.
Tennesee Gas Pipeline (20,000 DT to Niagara Mohawk City Gate, through 10/31/38) Contract # 330545
Tennesee Gas Pipeline (30,000 DT to Niagara Mohawk City Gate, through 10/31/37) Contract # 330539
Iroquois Gas Pipeline (51,596 DT to Niagara Mohawk City Gate, through 10/31/21) Contract # 730-05.
Union (52,247 DT into TransCanada, through 10/31/21) Contract # M12186.
TransCanada (51,596 DT into Iroquois, through 10/31/24) Contract # 42385.

DTI-FTNN (340,122 DT to Niagara Mohawk City Gate, through 3/31/21) Contract # 100001.
DTI-FTNN GSS (434,078 DT to Niagara Mohawk City Gate, through 3/31/21) Contract # 700001.
DTI-FT (10,000 DT to Niagara Mohawk City Gate, through 3/31/21) Contract # 200290.
DTI-FT (17,700 DT to Niagara Mohawk City Gate, through 10/31/25) Contract # 200558.
DTI-FT (30,000 DT to Niagara Mohawk City Gate, through 10/31/32) Contract #200720

GAS STORAGE CONTRACTS:

DTI GSS (438,078 DT Demand / 22,917,225 DT Capacity through 3/31/21) Contract # 300001.
DTI-FT (4,000 DT to Niagara Mohawk City Gate, through 3/31/21) Contract # 200290.

Delivery pressures under the DTI Service Agreement are as follows:

4 @ 100 pslg
1 @ 155 pslg
1 @ 200 pslg
1 @ 242 pslg
2 @ 250 pslg
3 @ 300 pslg
1 @ 350 pslg
1 @ 400 pslg
1 @ 450 pslg
1 @ 465 pslg
2 @ 500 pslg

This affords the Company the opportunity to enhance control over gas costs and provide reasonable cost service to its customers.

The Company maintains firm service under contract to meet all firm requirements under design conditions for peak day, winter season and annual requirements.

CONTRACTS FOR PURCHASE OF GAS

MONTH	Net Purchase-including storage avg. commodity cost per DT (Commodity & Reservation)	Net Purchase-including storage avg. commodity cost per DT (Incl. Pipeline Charges)
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

EXCHANGE GAS TRANSACTIONS

(Account 806, Exchange Gas)

1. Report below particulars concerning the gas volumes of natural gas exchange transactions during the year. Minor transactions may be grouped.
2. Points of receipt and delivery of gas should be so indicated that they may be readily identified on a map of the respondent's pipeline system.

Line No.	Name of Company (Designate associated companies) (a)	Exchange Gas Received		Exchange Gas Delivered		Excess Dth. Received or (Delivered) (f)
		Point of Receipt (b)	Dth. (c)	Point of Delivery (d)	Dth. (e)	
1						0
2	None					0
3						0
4						0
5						0
6						0
7						0
8						0
9						0
10						0
11						0
12						0
13						0
14						0
15						0
16						0
17						0
18						0
19						0
20						0
21						0
22						0
23						0
24						0
25						0
26						0
27						0
28						0
29						0
30						0
31						0
32						0
33	Total		0		0	0

TRANSMISSION AND COMPRESSION OF GAS BY OTHERS (Account 858)

1. Report below particulars concerning gas transported or compressed for respondent by others and amounts of payments for such services during the year.
2. In column (a) give name of companies to which payments were made, points of delivery and receipt of gas, names of companies to which gas was delivered and from which received.
3. Points of delivery and receipt should be so designated that they can be identified readily on map of respondent's pipeline system.
4. If the Dth. of gas received differs from the Dth. delivered, explain reason for difference, i.e., uncompleted deliveries, allowance for transmission loss, etc.

Line No.	Name of Company and Description of Service Performed (Designate associated companies) (a)	Distance Transported (b)	Dth. Received (c)	Dth. Delivered (d)	Amount of Payment (e)	Avg. Rev. per Dth of Gas Received (f)
1						
2	None					
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	TOTALS		0	0	$0	

DEPRECIATION AND AMORTIZATION OF GAS PLANT
(Account 403, 404.1, 404.2, 404.3, 405)
(Except Amortization of Acquisition Adjustments)

1. Report in Section A for the year the amounts of depreciation expense, depletion and amortization for the accounts indicated, classified according to the plant functional groups shown.
2. Report in Section B the bases and rates used by the respondent to determine charges for depletion and amortization of gas plant for the year for accounts 404.1, 404.2, 404.3 and 405 whether any changes have been made in the bases or rates from those used for the preceding year.
3. Complete reporting of all available information called for in columns (a) through (g) of Section C shall be made for report year 1972, thereafter report only annual changes to columns (c) through (g). Complete reporting is again required for report year 1974 and every year thereafter with only annual changes to columns (c) through (g) to be shown in the intervals between complete reporting. List numerically in column (a) each plant subaccount or account as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any subaccounts used. In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of Section C the manner in which column (b) 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 or account listed in column (a). Identify those accrual periods shown in column (c) which are based upon the life of associated gas reserves or gas supply contract. If mortality studies are prepared to assist in estimating service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g) the weighted average age of surviving plant. Where the unit-of-production method is used to determine depreciation charges, show at the bottom of Section C any revisions made to estimated gas reserves.
4. If provision 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, Depletion and Amortization Charges

Line No.	Functional classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)	Amortization of Other Limited -term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total Depreciation Depletion and Amortization (h)
1	Intangible Plant						62,462	$62,462
2	Production Plant, Manufactured Gas							0
3	Production and Gathering Plant, Natural Gas							0
4	Products Extraction Plant							0
5	Underground Gas Storage Plant							0
6	Other Gas Storage Plant							0
7	Base Load LNG Terminating and Processing Plant							0
8	Transmission Plant	2,892,222						2,892,222
9	Distribution Plant	43,546,052						43,546,052
10	General Plant	4,213,967						4,213,967
11	Common Plant - Gas	1,432,145						1,432,145
12	Total	$52,084,386	$0	$0	$0	$0	$62,462	$52,146,848

B. Basis for Depletion and Amortization Charges

302 & 303 Depreciation Rate:

Description		Depreciation Base	Depreciation Rate
	30200	3,149	10.00%
	30300	618,003	14.29%

DEPRECIATION AND AMORTIZATION OF GAS PLANT (CONTINUED)

C. Factors Used in Estimating Depreciation charges (Continued)

Line No.	Account Number (a)	Depreciable Plant Base (thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (percent) (d)	Applied Depr. Rate(s) (percent) (e)	Mortality Curve Type (f)	Average Age Surviving Plant (g)
1	Gas Intangible						
2	302	3					
3	303	988					
4	Subtotal	991					
5							
6	Gas Transmission						
7	363.3	2					
8	365	5,750	100	0.00%	1.00%	SQ	
9	366	3,009	55	-10.00%	2.00%	R2	
10	367	172,018	85	-10.00%	1.29%	R3	
11	369.15	24,115	40	-10.00%	2.75%	R0.5	
12	369.25	93	45	-30.00%	2.89%	LO	
13	369.55	1,641	25	-5.00%	4.20%	H4	
14	Subtotal	206,628					
15							
16	Gas Distribution						
17	374	2,671	100	0.00%	1.00%	SQ	
18	375	6,700	45	-40.00%	3.11%	L0	
19	376.11	228,887	95	-40.00%	1.47%	H4	
20	376.12	862,596	65	-30.00%	2.00%	H4	
21	376.13	6,001	80	-200.00%	3.75%	S0.5	
22	376.14	14,354	90	-20.00%	1.33%	R2	
23	378.1	57,608	36	-30.00%	3.61%	L0.05	
24	378.2	1,289	45	-35.00%	3.00%	L0	
25	378.55	3,677	25	-5.00%	4.20%	H4	
26	380	786,861	60		1.83%	R1.5	
27	381	95,867	33	-5.00%	3.18%	R2.5	
28	382	99,310	50	-50.00%	3.00%	R1	
29	383	7,655	40	0.00%	2.50%	R1	
30	384	6,345	40	0.00%	2.50%	H5	
31	385	5,101	40	0.00%	2.50%	R5	
32	388	4,185					
33	Subtotal	2,189,107					
34							
35	Gas General						
36							
37	390	653	55	0.00%	1.82%	L0.5	
38	391	-	22		4.55%	SQ	
39	391.1	4	22	0.00%	4.55%	SQ	
40	391.11	7					
41	391.15	2,620	5	0.00%	20.00%	SQ	
42	393	-	22	0.00%	4.55%	SQ	
43	394	20	22		4.55%	SQ	
44	394.1	-	22	0.00%	4.55%	SQ	
45	394.2	-	22	0.00%	4.55%	SQ	
46	394.3	22,347	22		4.55%	SQ	
47	394.4	3,785					
48	395	112	22	0.00%	4.55%	SQ	
49	396	-	22	0.00%	4.55%	SQ	
50	397.2	29,459	22	0.00%	4.55%	SQ	
51	397.3	-	8	0.00%	12.50%	SQ	
52	397.5	23,360					
53	397.6	-					
54	398	3,267	22	0.00%	4.55%	SQ	
55	398.1	107	22	0.00%	4.55%	SQ	
56	399	72					
57	Subtotal	85,813					
58							
59	TOTAL	2,482,539					

DATA BY TERRITORIAL SUBDIVISIONS - GAS

Report the indicated breakdown of operating revenue deductions and plant investment applicable respectively to accounting divisions and cost areas. Accounts, or groups of accounts, which may be kept on a company-wide basis on order of the Commission should be shown as separate single items. If the boundaries of a "cost area" are not apparent from entries in column (f), or are not otherwise a matter of record with the commission, a reasonably complete description should be furnished. No breakdown by primary accounts is required for columns (g) and (h).

ACCOUNTING DIVISIONS

Line No.	Designation (a)	Operation and Maintenance (Acct. 401 -402.1) (b)	Depreciation Expense (Acct. 403) (c)	Other Amortization (Acct. 404-407) (d)	Operating Taxes (Acct. 408) (e)
	None				

COST AREAS

	Designation (f)	Types of Segregated Plant (g)	Book Cost (h)
	None		

PRODUCTION PLANT STATISTICS

Report the indicated data relating to the operation of each gas producing plant. Entries on lines 1 to 12 should not include purchased gas which has been directly mixed but should include gas which has been reformed. Entries on lines 8 to 12 should include the principal fuels used, and it may be advisable to use more than one column for lines 1 to 22 when more than one kind of gas is produced at a single plant.

Line No.	Item (a)	Designation of Plant (b)	(c)	(d)	(e)	(f)	(g)	Totals
1	Net gas produced (kind and Btu)	N/A						
2								
3								
4								
5								
6	Maximum 24 - hour make Dth							
7	Date of occurrence							
8	Fuel used, kind							
9	Unit							
10	Quantity							
11	Average cost per unit							
12	Average Btu per ___________							
13	Fuel used, kind							
14	Unit							
15	Quantity							
16	Average cost per unit							
17	Average Btu per ___________							
18	Fuel used, kind							
19	Unit							
20	Quantity							
21	Average cost per unit							
22	Average Btu per ___________							
23	Operation supervision and engineering							
24	Operation labor							
25	Fuel							
26	All other operation expenses							
27	Maintenance							
28	Residuals produced - credit							
29	All other expenses							
30	Total Accounts 700 to 743.2							
31	Reformed gas charged to Account 805							

NATURAL GAS PRODUCTION LAND, WELLS AND STATISTICS

1. Report the indicated particulars of natural gas production land and natural gas wells for the year.

Line No.	Designation of Field (a)	Acreage at end of Year: Owned (b)	Acreage at end of Year: Leased (c)	Number of Wells: Added during Year (d)	Number of Wells: Retired during Year (e)	Number of Wells: At End of Year (f)	Number of Wells: Approx.. Average Depth Ft. (g)	Net Gas Produced Dth. (h)
1								
2	None							
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15	Totals							

2. Show the extent to which the wells included above are owned or leased.

NATURAL GAS GATHERING LINES

1. Report the indicated particulars of pipeline carried in Account 332 at the end of the year and of similar property held under lease, distinguishing between the two by suitable entries in columns (a) and (d). Show lengths in feet in columns (b), (c), (e) and (f).

Line No.	Designation of Field (a)	3" and Less (b)	Over 3" (c)	Designation of Field (d)	3" and Less (e)	Over 3" (f)
16						
17	None					
18						
19						
20						
21						
22						
23						
24						
25				Total		

2. If at the end of the year any gathering line included above (and used for conveying gas) was operated at a pressure in excess of 125 psig, show hereunder the total length of such line segregated on the basis of nominal diameter in inches.

NATURAL GAS PRODUCTION LAND, WELLS AND STATISTICS

NATURAL GAS GATHERING LINES

TRANSMISSION SYSTEM

1. Show a description of the transmission system at the end of the year disregarding comparatively insignificant branches. The latter should be summarized on the basis of size and length and shown hereunder as a separate item. Show particularly points of origin and termination, distances in miles, sizes of pipe, operating pressures, and principal compressing, regulating, and measuring stations. In completing this schedule use of a map is permissible. Leased facilities should be included and designated as such.
2. If any transmission line which is operated at a pressure in excess of 125 p.s.i.g. is summarized in this schedule as permitted by Paragraph 1, or if the total length of such line segregated on the basis of nominal diameter in inches is not indicated in the detail portion of reported data, such information should be set forth in a footnote.

Summary of Mains - Entire Company

Size	Length (feet)
Under 4"	0
Over 4" to 10"	47,763
Over 10" to 20"	939,787
Over 20" to 28"	397,700
Over 28"	49,685
Total	1,434,935

TRANSMISSION SYSTEM (Continued)

DISTRIBUTION SYSTEM

1. Report the indicated particulars of the gas distribution system at the end of the year. Entries in columns (b) to (f) should reflect the number of units installed, but if any substantial number of such units had no prospective use, particulars should be shown. Entries in columns (g) and (h) may be restricted to a summary of mains for the company as a whole. Leased facilities should be included and designated as such.
2. For the purposes of this schedule the interpretation of the term "distribution area" shall be optional with, and the responsibility of, the reporting utility. In general when the territory served covers considerable area these subdivisions should be selected so that, from territorial and rate standpoints, the data reported will be of reasonable significance. Entries in column (a) should reflect the approximate geographical extent of the individual subdivisions.

Line No.	Distribution Area (a)	District Regula-tors or Stations (b)	Services		Meters (e)	House Regulators (f)	Summary of Mains - Entire Company	
			Less than 3" (c)	3" and Over (d)			Size (g)	Length, Feet (h)
1	Natural Gas - Entire System	407	563,143	3,196	644,019	472,774	Up to 2	13,090,630
2							2 to 4	13,455,763
3							4 to 8	15,137,776
4							8 to 12	4,305,891
5							Over 12	577,767
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29	Subtotal	407	563,143	3,196	644,019	472,774		46,567,827

DISTRIBUTION SYSTEM (CONTINUED)

Totals	407	563,143	3,196	644,019	472,774		46,567,827

3. If any mains included above were operated at pressures in excess of 125 p.s.i., show the total footage of such mains segregated on the basis of nominal diameter in inches.

Diameter	Footage	Diameter	Footage
2	4,589	14	90,177
3	4	16	111,072
4	9,048	18	52,479
6	52,906	20	44,749
8	57,733	22	0
10	696,202	24	1,682
12	610,541	36	0
		Total	1,731,182

4. Describe briefly (1) the method employed in odorizing natural gas and (2) the protection provided against explosion due to the escape of gas (natural or manufactured) at pressures in excess of a normal customer consumption pressure.

Odorized by Niagra Mohawk at the point of delivery from suppliers. Pressure is monitored by Niagra Mohawk.

GAS ACCOUNT

1. Report the indicated summarization of gas transactions for the year, excluding gas which was reformed but not gas which was used for direct mixing; the former should be treated as fuel. If mixed gas is distributed, it should be shown as such in columns (d) to (f), but the constituent gases should be identified by production processes in columns (a) to (c) unless mixed gas was purchased. Exclude liquid petroleum in storage. Items representing quantities of gas should agree with the corresponding amounts shown elsewhere in this report.

Line No.	Gas Available (See Instructions) (a)	Btu per cf (b)	Quantity (c)	Disposition (Specify kind when possible) (d)	Btu per cf (e)	Quantity (f)	Line No.
1	In storage-beg. of year (specify kind):			Sold		55,483,863	1
2	Natural Gas		12,012,954				2
3	Liquified Natural Gas						3
4	Other (specify kind)						4
5				Delivered to storage		14,539,297	5
6	Natural Gas purchased:		63,219,294				6
7	Other gas purchased (specify kind):			Used by gas dept. (specify purpose and quantities		102,672	7
8	Liquified Natural Gas			in footnote)			8
9	Other (specify kind)		923,585				9
10							10
11				Used by other depts..: Electric			11
12	Natural gas produced:			Steam			12
13	Other gas produced (specify kind):			Common			13
14				Other disposition or credit adjustments (describe)			14
15				Other - Marketer		1,781,149	15
16							16
17				Lost and Unaccounted for:		2,444,424	17
18	Withdrawn from storage		12,373,912	In storage			18
19	Other receipts or debit adjustments (describe)			Other (describe in foot note)			19
20							20
21				In storage-end of year:			21
22				Natural		14,178,340	22
23	Total		88,529,745	Other (specify kind)			23
24	Equivalent therms, line 23		910,470,620	Total		88,529,745	24

25 2. State briefly the extent, including quantities when available, to which any kind of gas was used directly in the production process (other than for reforming) 25
26 which is not included above. 26
27 27
28 3. To the extent not otherwise indicated in this report show the approximate p.s.i.a. pressures which apply to measurement of the principal quantities listed 28
29 above (for example, 14.7 for gas produced, 14.7 plus 6" for general consumption, etc.) 29
30 30
31 **Please provide the factor to convert Dth to Mcf where Mcf is equal** 31
32 **to 1. Please input the factor here-->** 1.0284 32

COMPRESSOR STATIONS

1. Report below details concerning compressor stations. Use the following subheadings: field compressor stations, products extraction compressor stations, underground storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.

2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned. Designate any station that was not operated during the past year. State in a footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are contemplated. Designate any compressor units in transmission compressor stations installed and put into operation during the year and show in a footnote each unit's size and the date the unit was placed in operation.

3. For column (e), include the type of fuel or power, if other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or power.

Line No.	Name of Station and Location (a)	Number of Units at Station (b)	Certified Horsepower for Each Station (c)	Plant Cost (d)	Expenses (except depreciation and taxes) Fuel (e)	Expenses (except depreciation and taxes) Power (f)	Expenses (except depreciation and taxes) Other (g)	Gas for Compressor Fuel in Dth (h)	Electricity for Compressor Station in kWh (i)	Operational Data Total Compressor Hours of Operation During Year (j)	Operational Data Number of Compressors Operated at Time of Station Peak (k)	Date of Station Peak (l)
1												
2	None											
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VERIFICATION

The Public Service Law requires that "... it shall be the duty of every such person and corporation to file with the Commission an annual report, verified by oath of the president, vice-president, treasurer, secretary, general manager, or receiver, if any, thereof, or by the person required to file the same. The verification shall be made by said official holding office at the time of the filing of said report, and if not made upon the knowledge of the person verifying the same shall set forth the sources of his information and the grounds of his belief as to any matters not stated to be verified upon his knowledge."

State of ....New York..)
) ss.:
County of ......Kings......................................)

..............George Carlin..makes oath and

says: I am the ....VP, New York Controller... of ......Niagara Mohawk Power Corporation...............................
(Here insert the official title of the deponent) (Here insert exact name of the reporting company)

I am familiar with the preparation of the foregoing report know generally the contents thereof. The said report which

consists of ....Annual Report Pages 101-450 & Supplemental Filing, Pages 1-94..
(Here insert exact identification of the sections and pages comprising this report)

is true and correct to the best of my knowledge and belief. As to matters not actually stated upon my knowledge,

the sources of my information and the grounds for my belief are as follows: ....Books of Accounts and Underlying Records....................

George Carlin

Signature

Subscribed and sworn to before me a

.....Notary Public...........

this ...17th... day of APRIL 20 19

[use an impression seal] L.S.

Adam P. Tyszka

(Signature of officer authorized to administer oaths)

ADAM P. TYSZKA
Notary Public, State of New York
Reg. No. 01TY6380602
Qualified in Queens County
Commission Expires September 10, 2022

(This space for use of the Public Service Commission)

Computed ....
Examined ....
Reviewed ....