THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 2 Approved
OMB No. 1902-0028
(Expires 6/30/2011)
Form 3-Q: Approved
OMB No.1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Northern Natural Gas Company	**End of** 2011/Q1

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information form natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

(a) Submit Forms 2, 2-A and 3-Q electronically through the submission software at http://www.ferc.gov/docs-filing/eforms/form-2/elec-subm-soft.asp .

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

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

(d) For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

(i) Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 158.10-158.12 for specific qualifications.)

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

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

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

(f) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: http://www.ferc.gov/docs-filing/eforms/form-2/form-2.pdf and http://www.ferc.gov/docs-filing/eforms/form-2a/form-2a.pdf, respectively. Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202).502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

(a) FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)

(b) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting quarter (18 C.F.R.§ 260.300), and

(c) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,623 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the Form 2A collection of information is estimated to average 250 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 165 hours per response.

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

GENERAL INSTRUCTIONS

I. Prepare all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.

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

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

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

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

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

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

VIII. Footnote and further explain accounts or pages as necessary.

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

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

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.

DEFINITIONS	
I.	Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).
II.	Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
III.	Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.
IV	Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW
(Natural Gas Act, 15 U.S.C. 717-717w)

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this act; and may prescribe the form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. § 717t-1(a).

QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Northern Natural Gas Company	Year/Period of Report End of 2011/Q1
03 Previous Name and Date of Change (If name changed during year)	
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 1111 South 103rd Street, Omaha, NE 68124	
05 Name of Contact Person Thomas P. Tosoni	06 Title of Contact Person Director - Accounting and Reporting
07 Address of Contact Person (Street, City, State, Zip Code) 1111 South 103rd Street, Omaha, NE 68124	

08 Telephone of Contact Person, Including Area Code 402-398-7993	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)*

QUARTERLY CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

11 Name Joseph M. Lillo	12 Title Vice President - Finance
13 Signature /s/ Joseph M. Lillo	14 Date Signed 05/26/2011

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

List of Schedules (Natural Gas Company)

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 responses are "none," "not applicable," or "NA."

Name of Respondent Northern Natural Gas Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2011/Q1

Important Changes During the Quarter/Year

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were 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: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by 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 authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and cite 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 or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None.

2. None.

3. Pursuant to Section 311(a) of the Natural Gas Policy Act (NGPA)

Milbank, South Dakota - On March 31, 2011, Respondent sold to Northwestern Energy Corporation, D/B/A Northwestern Energy, the following pipeline facilities.

(SDB96401) a 4-inch and 6-inch pipeline from Northern Border Pipeline valve 41 in the SE 1/4 of Section 22, Township 114N, Range 50, Deuel County northeast to the Ortonville meter station in the SW 1/4 of Section 17, Township 121N, Range 46W, Grant County all in the state of South Dakota.

(SDB96501) the Ortonville measuring station and a 4-Inch lateral from the tie in to SDB 96401 in the SW 1/4 of Section 17, Township 21N, Range 46W, Grant County, east to delivery point in the SE 1/4 of Section 17, Township 121N, Range 46W, Grant County terminating at the South Dakota/Minnesota State line all in the state of South Dakota.

(SDB96801) a 2-inch pipeline from take-off valve in the NW 1/4 of Section 25, Township 114N, Range 51W, Hamlin County, south to final delivery point in the NW 1/4 of Section 24, Township 113N, Range 51W, Hamlin County, serving the town of Estelline, all in the state of South Dakota.

(SDB96901) a 2-inch line from the side valve on SDB96401 in the SE 1/4 of Section 22, Township 114N, Range 50W, Deuel County, northwest to final delivery point in the NW 1/4 of Section 1, Township T114N, Range 52W, Hamlin County, serving the town of Castlewood, all in the state of South Dakota.

(SDB97401) the Milbank measuring station and a 4-Inch lateral from 6" x 6" x 4" tee on Milbank/Ortonville Branch Line (SDB96401) in the NW 1/4 of Section 19, Township 120N, Range 48W, Grant County, north to Milbank delivery point in the SW 1/4 of Section 18, Township 120N, Range 48W, Grant County all in the state of South Dakota.

In compliance with CFR 18, Paragraph B of Account 102, Gas Plant Purchased or Sold, Respondent will file with the Federal Energy Regulatory Commission by September 30, 2011, proposed journal entries to clear all amounts recorded to this account related to the abandonment by sale of the Milbank pipeline and measurement facilities.

4. None.

5. No important extensions or reductions of the Respondent's transmission system occurred pursuant to Section 7 of the Natural Gas Act and Part 157 of the regulations of the Federal Energy Regulatory Commission from January 1 through March 31, 2011.

BLANKET CERTIFICATE ACTIVITIES

No important extensions or reductions of the Respondent's transmission system occurred pursuant to its blanket certificate granted on September 1, 1982, in Docket No. CP82-401-000 from January 1 through March 31, 2011.

§311 FACILITIES

No important extensions or reductions of the Respondent's transmission system occurred pursuant to §311(a) of the Natural Gas Policy Act of 1978 from January 1 through March 31, 2011.

6. None.

7. None.

8. None.

9. See footnote 7 on page 122.

10. None.

11. None.

12. None.

13. Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Comparative Balance Sheet (Assets and Other Debits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	3,329,951,056	3,332,876,290
3	Construction Work in Progress (107)	200-201	20,727,914	16,956,918
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	3,350,678,970	3,349,833,208
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		1,244,779,060	1,231,104,888
6	Net Utility Plant (Total of line 4 less 5)		2,105,899,910	2,118,728,320
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)		0	0
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)		0	0
9	Nuclear Fuel (Total of line 7 less 8)		0	0
10	Net Utility Plant (Total of lines 6 and 9)		2,105,899,910	2,118,728,320
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored-Base Gas (117.1)	220	27,903,863	27,903,863
13	System Balancing Gas (117.2)	220	41,211,532	41,211,532
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	0
15	Gas Owed to System Gas (117.4)	220	23,823,934	(3,741,134)
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		0	0
18	(Less) Accum. Provision for Depreciation and Amortization (122)		0	0
19	Investments in Associated Companies (123)	222-223	0	0
20	Investments in Subsidiary Companies (123.1)	224-225	0	0
21	(For Cost of Account 123.1 See Footnote Page 224, line 40)			
22	Noncurrent Portion of Allowances		0	0
23	Other Investments (124)	222-223	0	0
24	Sinking Funds (125)		0	0
25	Depreciation Fund (126)		0	0
26	Amortization Fund - Federal (127)		0	0
27	Other Special Funds (128)		19,834,044	22,161,688
28	Long-Term Portion of Derivative Assets (175)		0	0
29	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		19,834,044	22,161,688
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		20,096,220	(2,748,858)
33	Special Deposits (132-134)		1,848,699	2,433,653
34	Working Funds (135)		24,650	24,650
35	Temporary Cash Investments (136)	222-223	77,912,489	73,363,294
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		77,049,268	66,293,962
38	Other Accounts Receivable (143)		176,322	320,639
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		0	0
40	Notes Receivable from Associated Companies (145)		230,000,000	150,000,000
41	Accounts Receivable from Associated Companies (146)		7,390,645	7,472,725
42	Fuel Stock (151)		0	0
43	Fuel Stock Expenses Undistributed (152)		0	0

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Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Comparative Balance Sheet (Assets and Other Debits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)		0	0
45	Plant Materials and Operating Supplies (154)		23,142,434	22,357,868
46	Merchandise (155)		0	0
47	Other Materials and Supplies (156)		0	0
48	Nuclear Materials Held for Sale (157)		0	0
49	Allowances (158.1 and 158.2)		0	0
50	(Less) Noncurrent Portion of Allowances		0	0
51	Stores Expense Undistributed (163)		0	0
52	Gas Stored Underground-Current (164.1)	220	336,276	1,561,916
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	0	0
54	Prepayments (165)	230	2,071,529	14,239,619
55	Advances for Gas (166 thru 167)		0	0
56	Interest and Dividends Receivable (171)		105,970	100,274
57	Rents Receivable (172)		0	0
58	Accrued Utility Revenues (173)		0	0
59	Miscellaneous Current and Accrued Assets (174)		44,879,438	53,995,959
60	Derivative Instrument Assets (175)		215,484	48,409
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
62	Derivative Instrument Assets - Hedges (176)		3,048,422	0
63	(Less) Long-Term Portion of Derivative Instrument Assests - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		488,297,846	389,464,110
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		3,669,009	3,922,496
67	Extraordinary Property Losses (182.1)	230	0	0
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
69	Other Regulatory Assets (182.3)	232	140,157,446	146,576,050
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	0
72	Clearing Accounts (184)		0	0
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	6,364,317	6,538,465
75	Deferred Losses from Disposition of Utility Plant (187)		0	0
76	Research, Development, and Demonstration Expend. (188)		0	0
77	Unamortized Loss on Reacquired Debt (189)		0	0
78	Accumulated Deferred Income Taxes (190)	234-235	278,479,853	291,492,595
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		428,670,625	448,529,606
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		3,135,641,754	3,044,257,985

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	1,002	1,002
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	981,867,972	981,867,972
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	303,006,813	232,978,353
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	117	(603,669)	(742,993)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		1,284,272,118	1,214,104,334
16	**LONG TERM DEBT**			
17	Bonds (221)	256-257	150,000,000	150,000,000
18	(Less) Reacquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	0	0
20	Other Long-Term Debt (224)	256-257	850,000,000	850,000,000
21	Unamortized Premium on Long-Term Debt (225)	258-259	0	0
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	282,531	299,841
23	(Less) Current Portion of Long-Term Debt		250,000,000	250,000,000
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		749,717,469	749,700,159
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases-Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		15,824	19,669
29	Accumulated Provision for Pensions and Benefits (228.3)		2,692,212	2,585,795
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Comparative Balance Sheet (Liabilities and Other Credits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		61,826,066	60,966,274
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		64,534,102	63,571,738
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		250,000,000	250,000,000
38	Notes Payable (231)		0	0
39	Accounts Payable (232)		21,397,558	18,112,978
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		666,584	1,231,518
42	Customer Deposits (235)		6,554,678	9,494,971
43	Taxes Accrued (236)	262-263	59,073,242	44,960,823
44	Interest Accrued (237)		18,179,483	13,541,446
45	Dividends Declared (238)		0	0
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		603,029	796,468
49	Miscellaneous Current and Accrued Liabilities (242)	268	72,104,215	60,768,890
50	Obligations Under Capital Leases-Current (243)		0	0
51	Derivative Instrument Liabilities (244)		5,548,883	3,480,632
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
53	Derivative Instrument Liabilities - Hedges (245)		37,720,892	63,894,503
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		471,848,564	466,282,229
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		1,420,801	600,579
58	Accumulated Deferred Investment Tax Credits (255)		0	0
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	1,378,184	1,385,731
61	Other Regulatory Liabilities (254)	278	23,407,692	23,277,783
62	Unamortized Gain on Reacquired Debt (257)	260	0	0
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)		0	0
64	Accumulated Deferred Income Taxes - Other Property (282)		473,932,125	468,072,290
65	Accumulated Deferred Income Taxes - Other (283)		65,130,699	57,263,142
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		565,269,501	550,599,525
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		3,135,641,754	3,044,257,985

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q1

Statement of Income

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly, if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting mehods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	**UTILITY OPERATING INCOME**					
2	Gas Operating Revenues (400)	300-301	207,252,991	210,662,055	207,252,991	210,662,055
3	Operating Expenses					
4	Operation Expenses (401)	317-325	38,096,741	46,925,626	38,096,741	46,925,626
5	Maintenance Expenses (402)	317-325	7,978,997	7,091,302	7,978,997	7,091,302
6	Depreciation Expense (403)	336-338	13,863,482	13,167,562	13,863,482	13,167,562
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	0	0	0	0
8	Amortization and Depletion of Utility Plant (404-405)	336-338	1,728,546	1,652,076	1,728,546	1,652,076
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	0	0	0	0
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0	0	0	0
11	Amortization of Conversion Expenses (407.2)		0	0	0	0
12	Regulatory Debits (407.3)		2,359,091	2,348,454	2,359,091	2,348,454
13	(Less) Regulatory Credits (407.4)		0	0	0	0
14	Taxes Other than Income Taxes (408.1)	262-263	13,525,779	13,920,280	13,525,779	13,920,280
15	Income Taxes-Federal (409.1)	262-263	22,428,335	36,504,929	22,428,335	36,504,929
16	Income Taxes-Other (409.1)	262-263	4,274,085	8,069,380	4,274,085	8,069,380
17	Provision of Deferred Income Taxes (410.1)	234-235	21,189,404	9,226,820	21,189,404	9,226,820
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	2,183,088	9,655,457	2,183,088	9,655,457
19	Investment Tax Credit Adjustment-Net (411.4)		0	0	0	0
20	(Less) Gains from Disposition of Utility Plant (411.6)		0	0	0	0
21	Losses from Disposition of Utility Plant (411.7)		0	0	0	0
22	(Less) Gains from Disposition of Allowances (411.8)		0	0	0	0
23	Losses from Disposition of Allowances (411.9)		0	0	0	0
24	Accretion Expense (411.10)		0	0	0	0
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		123,261,372	129,250,972	123,261,372	129,250,972
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		83,991,619	81,411,083	83,991,619	81,411,083

Statement of Income(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		83,991,619	81,411,083	83,991,619	81,411,083
28	**OTHER INCOME AND DEDUCTIONS**					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues form Merchandising, Jobbing and Contract Work (415)		0	0	0	0
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		0	0	0	0
33	Revenues from Nonutility Operations (417)		0	0	0	0
34	(Less) Expenses of Nonutility Operations (417.1)		(1,475)	0	(1,475)	0
35	Nonoperating Rental Income (418)		0	0	0	0
36	Equity in Earnings of Subsidiary Companies (418.1)	119	0	0	0	0
37	Interest and Dividend Income (419)		507,955	853,383	507,955	853,383
38	Allowance for Other Funds Used During Construction (419.1)		169,651	555,572	169,651	555,572
39	Miscellaneous Nonoperating Income (421)		49,898	3,779,458	49,898	3,779,458
40	Gain on Disposition of Property (421.1)		1,217,092	0	1,217,092	0
41	TOTAL Other Income (Total of lines 31 thru 40)		1,946,071	5,188,413	1,946,071	5,188,413
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		1,330	(150)	1,330	(150)
44	Miscellaneous Amortization (425)		0	0	0	0
45	Donations (426.1)	340	205,367	195,162	205,367	195,162
46	Life Insurance (426.2)		0	0	0	0
47	Penalties (426.3)		0	0	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		61,012	137,765	61,012	137,765
49	Other Deductions (426.5)		119,516	1,771,790	119,516	1,771,790
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	387,225	2,104,567	387,225	2,104,567
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	0	0	0	0
53	Income Taxes-Federal (409.2)	262-263	(5,724,859)	(4,626,321)	(5,724,859)	(4,626,321)
54	Income Taxes-Other (409.2)	262-263	(1,304,859)	(1,054,470)	(1,304,859)	(1,054,470)
55	Provision for Deferred Income Taxes (410.2)	234-235	7,641,694	6,922,247	7,641,694	6,922,247
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	0	195	0	195
57	Investment Tax Credit Adjustments-Net (411.5)		0	0	0	0
58	(Less) Investment Tax Credits (420)		0	0	0	0
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		611,976	1,241,261	611,976	1,241,261
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		946,870	1,842,585	946,870	1,842,585
61	**INTEREST CHARGES**					
62	Interest on Long-Term Debt (427)		14,737,500	14,737,500	14,737,500	14,737,500
63	Amortization of Debt Disc. and Expense (428)	258-259	225,676	212,542	225,676	212,542
64	Amortization of Loss on Reacquired Debt (428.1)		0	0	0	0
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	0	0	0	0
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		0	0	0	0
67	Interest on Debt to Associated Companies (430)	340	0	0	0	0
68	Other Interest Expense (431)	340	15,237	11,556	15,237	11,556
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		68,384	258,282	68,384	258,282
70	Net Interest Charges (Total of lines 62 thru 69)		14,910,029	14,703,316	14,910,029	14,703,316
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		70,028,460	68,550,352	70,028,460	68,550,352
72	**EXTRAORDINARY ITEMS**					
73	Extraordinary Income (434)		0	0	0	0
74	(Less) Extraordinary Deductions (435)		0	0	0	0
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0	0	0
76	Income Taxes-Federal and Other (409.3)	262-263	0	0	0	0
77	Extraordinary Items after Taxes (Total of line 75 less line 76)		0	0	0	0
78	Net Income (Total of lines 71 and 77)		70,028,460	68,550,352	70,028,460	68,550,352

Statement of Income

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	0	0	207,252,991	210,662,055	0	0
3						
4	0	0	38,096,741	46,925,626	0	0
5	0	0	7,978,997	7,091,302	0	0
6	0	0	13,863,482	13,167,562	0	0
7	0	0	0	0	0	0
8	0	0	1,728,546	1,652,076	0	0
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	2,359,091	2,348,454	0	0
13	0	0	0	0	0	0
14	0	0	13,525,779	13,920,280	0	0
15	0	0	22,428,335	36,504,929	0	0
16	0	0	4,274,085	8,069,380	0	0
17	0	0	21,189,404	9,226,820	0	0
18	0	0	2,183,088	9,655,457	0	0
19	0	0	0	0	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	0	0	0
25	0	0	123,261,372	129,250,972	0	0
26	0	0	83,991,619	81,411,083	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report in columns (b) (c) 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.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Statement of Accumulated Comprehensive Income and Hedging Activities(continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges (Insert Category) (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1		(8,013,921)	(8,013,921)		
2		529,208	529,208		
3		(8,844,037)	(8,844,037)		
4		(8,314,829)	(8,314,829)	68,550,352	60,235,523
5		(16,328,750)	(16,328,750)		
6		(742,993)	(742,993)		
7		167,178	167,178		
8		(27,854)	(27,854)		
9		139,324	139,324	70,028,460	70,167,784
10		(603,669)	(603,669)		

Schedule Page: 117 Line No.: 10 Column: g

The ($603,669) pertains to natural gas commodity swaps.

Fair Value Hedges

The Respondent has entered into natural gas commodity swaps accounted for as fair value hedges with the following objectives: 1) hedge the change in fair value of firm fixed-price gas sale and purchase contracts required for operational storage balancing purposes, and 2) hedge the change in fair value of firm fixed-price storage revenue contracts.

For the three-month period ending March 31, 2010, the Respondent recognized a pre-tax loss of $16,749 in account 483 for gas sales contracts; a pre-tax gain of $131,541 in account 803 for gas purchase contracts and a pre-tax gain of $237,794 in account 489.4 for storage revenue contracts due to fair value hedge ineffectiveness.

As of March 31, 2010, the fair value of the hedged items was $3,166,098 reported in account 174, ($44,496) reported in account 242, and ($2,594,143) reported in account 253. The fair value of the hedging instruments was ($498,918) reported in account 245.

For the three-month period ending March 31, 2011, the Respondent recognized a pre-tax gain of $1,500,713 in account 489.4 for storage revenue contracts due to fair value hedge ineffectiveness.

As of March 31, 2011, the fair value of the hedged items was ($3,676,589) reported in account 242. The fair value of the hedging instruments was ($288,055) reported in account 245 and $4,317,956 was reported in account 176. Ineffectiveness gains of $353,312 were reported in account 182.3.

Statement of Retained Earnings

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 for 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.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter Year to Date Balance (c)	Previous Quarter Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		232,978,353	103,682,734
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	TOTAL Credits to Retained Earnings (Account 439) (footnote details)			
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		70,028,460	68,550,352
7	Appropriations of Retained Earnings (Account 436)			
8	TOTAL Appropriations of Retained Earnings (Account 436) (footnote details)			
9	Dividends Declared-Preferred Stock (Account 437)			
10	TOTAL Dividends Declared-Preferred Stock (Account 437) (footnote details)			
11	Dividends Declared-Common Stock (Account 438)			
12	TOTAL Dividends Declared-Common Stock (Account 438) (footnote details)			
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings			
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		303,006,813	172,233,086
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)			
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account			
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines			
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 1		303,006,813	172,233,086
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)			
23	Equity in Earnings for Year (Credit) (Account 418.1)			
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)			
26	Balance-End of Year			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Statement of Cash Flows

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 25) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 116)	70,028,460	68,550,352
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	15,592,028	14,819,638
5	Amortization of (Specify)	6,014,414	5,254,883
6	Deferred Income Taxes (Net)	26,648,010	6,493,415
7	Investment Tax Credit Adjustments (Net)		
8	Net (Increase) Decrease in Receivables	5,745,770	(5,646,615)
9	Net (Increase) Decrease in Inventory	441,074	(384,277)
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	19,122,736	67,950,016
12	Net (Increase) Decrease in Other Regulatory Assets	16,031,165	(14,335,096)
13	Net Increase (Decrease) in Other Regulatory Liabilities	1,494,578	6,600,749
14	(Less) Allowance for Other Funds Used During Construction	169,651	555,572
15	(Less) Undistributed Earnings from Subsidiary Companies		
16	Other	(44,293,858)	15,393,378
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	116,654,726	164,140,871
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(6,937,341)	(18,637,028)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant		
25	Gross Additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction	(169,651)	(555,572)
27	Other : Removal Costs	(167,792)	(121,292)
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(6,935,482)	(18,202,748)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	4,500,000	
32			
33	Investments in and Advances to Assoc. and Subsidiary Companies		
34	Contributions and Advances from Assoc. and Subsidiary Companies		
35	Disposition of Investments in (and Advances to)		
36	Associated and Subsidiary Companies		
37			
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Statement of Cash Flows (continued)

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
40	Loans Made or Purchased		
41	Collections on Loans		
42			
43	Net (Increase) Decrease in Receivables		
44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses	(6,824,971)	(2,038,982)
47	Other: Cost of disposal of asset		
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(9,260,453)	(20,241,730)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)		
54	Preferred Stock		
55	Common Stock		
56	Other (footnote details):		
57	Net Increase in Short-term Debt (c)		
58	Other : Loan to MEHC	(80,000,000)	(135,000,000)
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	(80,000,000)	(135,000,000)
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)		
63	Preferred Stock		
64	Common Stock		
65	Other (footnote details):		
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock		
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	(80,000,000)	(135,000,000)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	27,394,273	8,899,141
75			
76	Cash and Cash Equivalents at Beginning of Period	70,639,086	9,127,574
77			
78	Cash and Cash Equivalents at End of Period	98,033,359	18,026,714

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	2011	2010
Regulatory assets	$ 5,788,738	$ 5,042,341
Debt discount and expense	225,676	212,542
Total	$ 6,014,414	$ 5,254,883

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	2011	2010
Gas balancing activities	$ (27,243,300)	$ 13,889,521
Price risk management activities	(17,772,426)	5,039,300
Loss (gain) on the sale of assets	(1,215,761)	(149)
Post retirement benefits other than pension obligation payments	(33,725)	(751,195)
Prepaids and other assets	2,015,954	4,589,598
Customer security deposits and other	(44,600)	(7,373,697)
Total	$ (44,293,858)	$ 15,393,378

Notes to Financial Statements

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.
4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where Account 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 item. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund 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 and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant 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.
13. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
14. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
15. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

(1) General

Northern Natural Gas Company (the "Respondent") is an indirect wholly-owned subsidiary of MidAmerican Energy Holdings Company ("MEHC"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). The Respondent owns the largest interstate natural gas pipeline system in the United States, which reaches from southern Texas to Michigan's Upper Peninsula (the "System"). The System, which is interconnected with many interstate and intrastate pipelines in the national grid system, consists of two distinct, but operationally integrated, markets. Its traditional end-use and distribution market area, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area, referred to as the Field Area, includes Kansas, Texas, Oklahoma and New Mexico. The Respondent primarily transports and stores natural gas for utilities, municipalities, other pipeline companies, gas marketing companies, industrial and commercial users and other end-users. The System consists of 15,000 miles of natural gas pipelines, including 6,400 miles of mainline transmission pipelines and 8,600 miles of branch and lateral pipelines, with a Market Area design capacity of 5.5 billion cubic feet ("bcf") per day and a Field Area delivery capacity of 2.0 bcf per day to the Market Area. Additionally, the Respondent has three underground natural gas storage facilities and two liquefied natural gas storage peaking units that have a total firm service and operational storage cycle capacity of 73 bcf and over 2.0 bcf of peak day delivery capability. Based on a review of relevant 2009 industry data, the System is the largest single pipeline in the United States as measured by pipeline miles.

The financial statements and supporting schedules were prepared in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC"). The FERC-approved tariff establishes rates, terms and conditions under which the Respondent provides services to its customers. The Uniform System of Accounts is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). Financial accounting and reporting differences between FERC and GAAP for the Respondent are principally related to account classifications such as but not limited to: revenues collected for future plant retirement costs are classified as a regulatory liability for GAAP and as accumulated provision for depreciation for FERC; and deferred tax assets and liabilities are presented as gross assets and liabilities for FERC purposes, but are netted for GAAP.

The unaudited Financial Statements do not include all of the information and disclosures required for the Respondent's annual financial statements in its 2010 FERC Form No. 2. Management believes the unaudited Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the Financial Statements as of March 31, 2011 and for the three-month periods ended March 31, 2011 and 2010. The results of operations for the three-month period ended March 31, 2011 are not necessarily indicative of the results to be expected for the full year. The Respondent has evaluated subsequent events through May 26, 2011, which is the date the unaudited Financial Statements were available to be issued.

The preparation of the unaudited Financial Statements in conformity with FERC guidelines requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the Financial Statements and the reported amounts of revenues and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Financial Statements. Note 2 of Notes to Financial Statements included in the Respondent's FERC Form No. 2 for the year ended December 31, 2010 describes the most significant accounting policies used in the preparation of the Financial Statements. There have been no significant changes in the Respondent's assumptions regarding significant accounting estimates and policies during the three-month period ended March 31, 2011.

(2) New Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06 ("ASU No. 2010-06"), which amends FASB Accounting Standards Codification ("ASC") Topic 820, "Fair Value Measurements and Disclosures". ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. The Respondent adopted this guidance as of January 1, 2010 with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which the Respondent adopted as of January 1, 2011. The adoption of this guidance did not have a material impact on the Respondent's disclosures included within Notes to Financial Statements.

(3) Fair Value Measurements

The Respondent has various financial assets and liabilities that are measured at fair value on the Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 – Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Respondent has the ability to access at the measurement date.
- Level 2 – Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other

means (market corroborated inputs).

- Level 3 – Unobservable inputs reflect the Respondent's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Respondent develops these inputs based on the best information available, including its own data.

The following table presents the Respondent's assets and liabilities recognized on the Balance Sheets and measured at fair value on a recurring basis (in thousands):

	Input Levels for Fair Value Measurements				
	Level 1	**Level 2**	**Level 3**	**Other**(1)	**Total**
As of March 31, 2011					
Assets:					
Commodity derivatives	$ -	$ 4,017	$ -	$ (2,088)	$ 1,929
Money market mutual funds(2)	83,772	-	-	-	83,772
	$ 83,772	$ 4,017	$ -	$ (2,088)	$ 85,701
Liabilities - commodity derivatives	$ -	$ (44,022)	$ -	$ 2,088	$ (41,934)
As of December 31, 2010					
Assets:					
Commodity derivatives	$ -	$ 6,712	$ -	$ (6,680)	$ 32
Money market mutual funds(2)	82,275	-	-	-	82,275
	$ 82,275	$ 6,712	$ -	$ (6,680)	$ 82,307
Liabilities - commodity derivatives	$ -	$ (74,038)	$ -	$ 6,680	$ (67,358)

(1) Represents netting under master netting arrangements.

(2) Amounts are included in cash, special deposits and other special funds on the Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Respondent transacts. When quoted prices for identical contracts are not available, the Respondent uses forward price curves. Forward price curves represent the Respondent's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Respondent bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by the Respondent. Market price quotations for certain major natural gas trading hubs are generally readily obtainable for the applicable term of the Respondent's outstanding derivative contracts; therefore, the Respondent's forward price curves for those locations and periods reflect observable market quotes. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 4 for further discussion regarding the Respondent's risk management and hedging activities.

The Respondent's investments in money market mutual funds are accounted for as available-for-sale securities and are stated at fair value. A readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

(4) Risk Management and Hedging Activities

The Respondent is exposed to the impact of market fluctuations in natural gas prices as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, customer usage, storage and transportation constraints. The Respondent does not engage in a material amount of proprietary trading activities.

The Respondent has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its natural gas price risk, the Respondent uses commodity derivative contracts generally at fixed prices to hedge natural gas for operational and preferred deferred delivery (“PDD”) storage, storage losses, fuel requirements and other transactions. The Respondent uses natural gas commodity swaps to hedge the margin on forecasted gas sales and purchases required for operational storage balancing purposes, to hedge the margin on anticipated future PDD storage contracts and to hedge the cost of replacing forecasted storage losses. For certain designated markets, the Respondent provides gas to two customers at a fixed price of $.09 per decatherm (“dth”) of volumes delivered to cover compressor fuel and system use. The Respondent estimates it will be required to purchase an annual average of 2.0 bcf of natural gas through October 2022 to meet these requirements based on an average system requirements factor of 1.7% of volumes delivered. The Respondent’s contracts with these customers provide service through October 2019, with annual renewal options for one customer to continue service through October 2022. As of March 31, 2011, the Respondent had purchased gas and entered into swap agreements covering substantially all of the expected contractual requirements through October 2022.

Interest rate risk exists on future debt issuances. The Respondent manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Respondent may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Respondent’s exposure to interest rate risk. The Respondent does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Respondent’s accounting policies related to derivatives. Refer to Note 3 for additional information on derivative contracts.

The following table, which excludes contracts that qualify for the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of the Respondent's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Balance Sheets (in thousands):

	Derivative Assets(1)		Derivative Liabilities(1)		
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Total**
As of March 31, 2011					
Designated as hedging contracts(2)(3):					
Commodity assets	$ 4,883	$ -	$ -	$ -	$ 4,883
Commodity liabilities	(1,835)	-	(6,057)	(31,663)	(39,555)
Total	3,048	-	(6,057)	(31,663)	(34,672)
Not designated as hedging contracts(2):					
Commodity assets	216	-	135	-	351
Commodity liabilities	-	-	(5,684)	-	(5,684)
Total	216	-	(5,549)	-	(5,333)
Total derivatives - net basis(4)	$ 3,264	$ -	$ (11,606)	$ (31,663)	$ (40,005)
As of December 31, 2010					
Designated as hedging contracts(2)(3):					
Commodity assets	$ -	$ -	$ 6,656	$ -	$ 6,656
Commodity liabilities	-	-	(24,737)	(45,813)	(70,550)
Total	-	-	(18,081)	(45,813)	(63,894)
Not designated as hedging contracts(2):					
Commodity assets	50	-	6	-	56
Commodity liabilities	(2)	-	(3,486)	-	(3,488)
Total	48	-	(3,480)	-	(3,432)
Total derivatives - net basis(4)	$ 48	$ -	$ (21,561)	$ (45,813)	$ (67,326)

(1) Derivative assets are included in other current and accrued assets on the Balance Sheets. Derivative liabilities are included in current and accrued liabilities on the Balance Sheets.

(2) Derivative contracts within these categories subject to master netting arrangements are presented on a net basis on the Balance Sheets.

(3) As of March 31, 2011 and December 31, 2010, a regulatory asset of $34.8 million and $50.1 million, respectively, was recorded related to the net derivative liability of $40.0 million and $67.3 million, respectively, for those commodity derivatives generally included in regulated rates.

(4) The net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values included above is 17 million dth and 27 million dth of natural gas purchases as of March 31, 2011 and December 31, 2010, respectively.

Designated as Hedging Contracts

The following table reconciles the beginning and ending balances of the Respondent's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on commodity derivative contracts designated and qualifying as cash flow hedges recognized in OCI, as well as amounts reclassified to earnings for the three-month periods ended March 31 (in thousands):

	2011	2010
Beginning balance(1)	$ 2,475	$ 17,926
Net losses recognized in OCI	324	22,434
Net gains reclassified to gas operating revenues	-	1,202
Net losses reclassified to operating expenses	(278)	(2,081)
Ending balance(1)	$ 2,521	$ 39,481

(1) Certain derivative contracts have settled and the fair value at the date of settlement remains in accumulated other comprehensive loss and is recognized in earnings when the forecasted transactions impact earnings.

Realized gains and losses on hedges and hedge ineffectiveness are recognized on the Statements of Income as gas operating revenues or operating expenses depending upon the nature of the item being hedged. For the three-month periods ended March 31, 2011 and 2010, the Respondent recognized pre-tax gains of $- million and $1.0 million, respectively, in gas operating revenues resulting from hedge ineffectiveness and pre-tax losses of $- million and $1.2 million, respectively, in operating expenses resulting from hedge ineffectiveness. As of March 31, 2011, the Respondent had cash flow hedges with expiration dates extending through June 2012 and the pre-tax unrealized net gains forecasted to be reclassified from accumulated other comprehensive loss into earnings over the next twelve months are insignificant.

Not Designated as Hedging Contracts

For the Respondent's commodity derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets or liabilities. The following table reconciles the beginning and ending balances of the Respondent's regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in regulatory assets, as well as amounts reclassified to earnings for the three-month periods ended March 31 (in thousands):

	2011	2010
Beginning balance	$ 50,124	$ -
Changes in fair value recognized in regulatory assets	(13,719)	-
Net losses reclassified to operating expenses	(1,625)	-
Ending balance	$ 34,780	$ -

For the Respondent's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as a regulatory asset, unrealized gains and losses are recognized on the Statements of Income as gas operating revenues for sales contracts and as operating expenses for purchase contracts. The Respondent recognized pre-tax losses of $0.1 million and pre-tax gains of $0.6 million for the three-month periods ended March 31, 2011 and 2010, respectively, which are included in operating expenses on the Statements of Income.

Credit Risk

The Respondent extends unsecured credit to energy marketing companies, financial institutions and other market participants in conjunction with its derivative contracts. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of natural gas and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

The Respondent analyzes the financial condition of each counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of counterparties, the Respondent enters into netting arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, the Respondent exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain derivative contracts contain provisions that require the Respondent to maintain specific credit ratings from one or more of the major credit rating agencies on its unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features"). These rights can vary by contract and by counterparty. As of March 31, 2011, the Respondent's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Respondent's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $44.0 million and $74.0 million as of March 31, 2011 and December 31, 2010, respectively, for which the Respondent had not posted collateral. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of March 31, 2011 and December 31, 2010, the Respondent would have been required to post $41.9 million and $67.4 million, respectively, of collateral. The Respondent's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(5) Employee Benefit Plans

The Respondent participates in multi-employer benefit plans sponsored by MidAmerican Energy Company ("MEC"), an indirect wholly-owned subsidiary of MEHC. The Respondent's contributions to the defined benefit pension plan and other postretirement benefit plans totaled $0.4 million and $1.1 million for the three-month periods ended March 31, 2011 and 2010, respectively. The Respondent recorded a regulatory asset of $2.7 million and a regulatory liability of $16.3 million as of March 31, 2011 and a regulatory asset of $2.6 million and a regulatory liability of $16.1 million as of December 31, 2010, related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. An offsetting affiliated company payable and receivable are included in other deferred credits and other property and investments, respectively, on the Balance Sheets. Amounts were allocated from MEC to the Respondent in accordance with the intercompany administrative service agreement.

(6) Commitments and Contingencies

Legal Matters

The Respondent is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Respondent does not believe that such normal and routine litigation will have a material impact on its financial results. The Respondent is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

The Respondent's storage gas has migrated from its certificated storage field boundaries near Cunningham, Kansas and has been produced on leaseholds held by Nash Oil & Gas, Inc. ("Nash"), L.D. Drilling Company ("LD Drilling") and Val Energy, Inc. ("Val Energy"). In order to mitigate its losses, the Respondent has initiated the following actions:

- In September 2009, the Respondent filed an application with the FERC to extend the boundaries of the Cunningham natural gas storage facility by 14,240 acres. In June 2010, FERC issued an order granting the Respondent Certificate Authority to extend the boundaries of the Cunningham natural gas storage facility from a prior order by 12,320 acres. The Respondent extended good faith offers to the interested parties in the extension area, and in July 2010, filed a complaint in District Court to acquire the necessary interests by eminent domain. The Respondent has either acquired leases or purchased the property on 3,580 acres, or 29% of the extension area.

- The Respondent filed a lawsuit in December 2008 against Nash, LD Drilling and Val Energy in the United States District Court for the District of Kansas ("District Court") for conversion, nuisance and unjust enrichment. Shortly after the FERC order granting the Respondent authority to expand the boundaries of the Cunningham natural gas storage facility was issued in June 2010, the Respondent filed a motion to shut-in the production of the third-party wells producing the Respondent's storage gas. In December 2010, the District Court granted the Respondent's motion and ordered all of the wells in the extension area to be shut-in by February 21, 2011. The defendants appealed the injunction order to the Tenth Circuit Court of Appeals and requested a stay. The stay was denied and all of the third party wells were shut-in as of February 25, 2011, pending the appeal.

- In December 2009, the Respondent filed a lawsuit in the 13th Judicial District, District Court, Pratt County, Kansas ("Pratt County State District Court") against ONEOK Field Services Company and Lumen Energy Corporation alleging conversion based on their purchase of the storage gas from the producers. In April 2010, the Pratt County State District Court granted the defendants' motion for summary judgment, finding that the Respondent does not have title to storage gas that has migrated beyond adjoining property. The Respondent appealed the decision to the Kansas Court of Appeals in April 2010, and the appeal was transferred to the Kansas Supreme Court at the Respondent's request. Oral argument was held on March 8, 2011. A decision on the merits is expected in 2011.

The Respondent has recorded Cunningham storage gas losses of 13.8 bcf from 2004 through March 2011. The replacement cost of storage gas losses is $2.8 million and $5.1 million for the three-month periods ended March 31, 2011 and 2010, respectively, which are included in operating expenses on the Statements of Income.

While it is not possible to predict with certainty the outcome of the aforementioned litigation and other contingencies, the Respondent believes that the ultimate resolution of these matters will not have a material adverse effect on the Respondent's financial results.

(7) Other Related Party Transactions

The Respondent provided gas transportation, storage and other services to MEC totaling $22.5 million and $22.3 million for the three-month periods ended March 31, 2011 and 2010, respectively. MEC provides certain administrative and management services, including executive, financial, legal and tax, to the Respondent. Expenses incurred by MEC and billed to the Respondent through MEHC are based on the individual services and expense items provided and were $1.6 million and $2.6 million for the three-month periods ended March 31, 2011 and 2010, respectively. MEC also provided electricity and other services to the Respondent of $0.1 million for each of the three-month periods ended March 31, 2011 and 2010. The Respondent reimbursed MEC $11.0 million and $11.1 million for the three-month periods ended March 31, 2011 and 2010, respectively, for payroll, healthcare benefits and other benefit payments that MEC processed on behalf of the Respondent.

MEHC provides certain administrative and management services, including executive, financial, legal and tax, to the Respondent. Expenses incurred by MEHC and billed to the Respondent are based on the individual services and expense items provided and were $0.6 million and $0.3 million for the three-month periods ended March 31, 2011 and 2010, respectively. Income tax transactions with MEHC resulted in net receipts of $0.9 million and $5.6 million for the three-month periods ended March 31, 2011 and 2010, respectively.

The Respondent provides operating, administrative and management services, including executive, financial, regulatory and legal, to MEHC and certain subsidiaries. Expenses incurred by the Respondent and billed to MEHC are based on the individual services and expense items provided. Intercompany expenses were $0.1 million for each of the three-month periods ended March 31, 2011 and 2010. As of March 31, 2011 and December 31, 2010, the Respondent had net accounts payable to MEHC and certain subsidiaries for intercompany transactions totaling of $0.7 million and $1.1 million, respectively.

The Respondent provides certain administrative and management services, including executive, financial, regulatory and legal, to Kern River Gas Transmission Company ("Kern River"), an indirect wholly-owned subsidiary of MEHC. The Respondent billed Kern River $0.3 million and $0.2 million for the three-month periods ended March 31, 2011 and 2010, respectively, for these services.

For the three-month periods ended March 31, 2011 and 2010, the Respondent received demand promissory notes bearing interest at a 30-day LIBOR plus a fixed per annum rate from MEHC in exchange for cash of $80.0 million and $135.0 million, respectively. The balance of the demand promissory notes as of March 31, 2011 and December 31, 2010 was $230.0 million and $150.0 million, respectively. Interest income of $0.4 million and $0.7 million was recorded for the three- month periods ended March 31, 2011 and 2010, respectively.

(8) Components of Accumulated Other Comprehensive Income

Accumulated other comprehensive income consists of losses from changes in the fair value on cash flow hedges of $0.6 million, net of tax of $0.4 million, and $0.7 million, net of tax of $0.5 million, as of March 31, 2011 and December 31, 2010, respectively.

(9) Subsequent Events

In April 2011, the Respondent issued $200.0 million of 4.25% Senior Notes due June 1, 2021. The net proceeds will be used to partially repay at maturity the Respondent's $250.0 million, 7.0% Senior Notes due June 1, 2011.

In May 2011, the United States Army Corps of Engineers Galveston District ("Galveston District") sent a letter to the Respondent in response to the Respondent's request to abandon in place certain pipelines located in offshore Texas waters. The Galveston District has determined that one of the pipelines, which is located in San Antonio Bay, must be removed. The remaining pipelines, as identified in the Respondent's request, will be allowed to be abandoned in place pending approval of modifications to the existing permits for those pipelines. As a result, the Respondent expects an overall reduction in its asset retirement obligation and future expected cash outflows associated with the removal of the Respondent's offshore Texas facilities; however, the resulting impact is not known at this time. Refer to Notes 2 and 8 of the Notes to the audited Financial Statements for the year ended December 31, 2010 for additional information on asset retirement obligations.

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion

Line No.	Item (a)	Total Company For the Current Quarter/Year
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	3,319,207,701
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	10,157,489
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	3,329,365,190
9	Leased to Others	
10	Held for Future Use	585,866
11	Construction Work in Progress	20,727,914
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	3,350,678,970
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,244,779,060
15	Net Utility Plant (Total of lines 13 and 14)	2,105,899,910
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	1,111,272,029
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	6,377,328
21	Amortization of Other Utility Plant	127,026,522
22	TOTAL In Service (Total of lines 18 thru 21)	1,244,675,879
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	TOTAL Leased to Others (Total of lines 24 and 25)	
27	Held for Future Use	
28	Depreciation	103,181
29	Amortization	
30	TOTAL Held for Future Use (Total of lines 28 and 29)	103,181
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustment	
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	1,244,779,060

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (continued)

Line No.	Electric (c)	Gas (d)	Other (specify) (e)	Common (f)
1				
2				
3		3,319,207,701		
4				
5				
6		10,157,489		
7				
8		3,329,365,190		
9				
10		585,866		
11		20,727,914		
12				
13		3,350,678,970		
14		1,244,779,060		
15		2,105,899,910		
16				
17				
18		1,111,272,029		
19				
20		6,377,328		
21		127,026,522		
22		1,244,675,879		
23				
24				
25				
26				
27				
28		103,181		
29				
30		103,181		
31				
32				
33		1,244,779,060		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Gas Plant in Service and Accumulated Provision for Depreciation by Function

1. Report below the original cost of plant in service by function. In addition to Account 101, include Account 102, and Account 106. Report in column (b) the original cost of plant in service and in column(c) the accumulated provision for depreciation and amortization by function.

Line No.	Item (a)	Plant in Service Balance at End of Quarter (b)	Accumulated Depreciation And Amortization Balance at End of Quarter (c)
1	Intangible Plant	176,550,075	107,728,757
2	Productions-Manufactured Gas		
3	Production and Gathering-Natural Gas	28,770,670	(10,648,804)
4	Products Extraction-Natural Gas		
5	Underground Gas Storage	356,966,316	137,746,673
6	Other Storage Plant	75,909,397	45,369,937
7	Base Load LNG Terminaling and Processing Plant		
8	Transmission	2,565,839,740	896,577,426
9	Distribution		
10	General	125,328,992	67,901,890
11	TOTAL (total of lines 1 thru 10)	3,329,365,190	1,244,675,879

Schedule Page: 210 Line No.: 3 Column: c

The accumulated depreciation reserve for production and gathering is related to Respondent's offshore pipeline facilities located in the Gulf of Mexico off the coasts of Texas and Louisiana. The balance is made up of the following components.

Plant Reserve	
Accumulated Depreciation	$ 32,419,577
Cost of Plant Retired	(29,773,632)
Accumulated Plant Reserve	$ 2,645,945
Negative Salvage	
Accumulated Provision	$ 1,439,045
Cost of Removal	(603,629)
Net Negative Salvage Provision	$ 835,416
Asset Retirement Obligation	
Accumulated Depreciation on ARO Capitalized	$ 10,071,625
Asset Retirement Obligation (ARO) Allowance	
Accumulated Annual ARO Allowance of $1,320,306	$ 8,471,964
Accumulated Cost of ARO Retirements	(32,673,754)
Unrecovered Net ARO Costs	($ 24,201,790)
Accumulated Provision for Depreciation Gas Gathering	($ 10,648,804)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Other Regulatory Assets (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
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 $250,000, 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 Current Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1	Computer systems development costs	3,640,490		407.3	1,092,147		2,548,343
2							
3	Deferred regulatory commission expense	4,693,271	149,915	928	281,186		4,562,000
4							
5	FAS 106 implementation deferral	2,053,148		926	256,643		1,796,505
6							
7	Post Retirement medical plan accrual	3,680,000		926	460,000		3,220,000
8							
9	Asset retirement obligation	32,041,522	1,908,939				33,950,461
10							
11	Deferred FERC annual charge	1,327,681		928	442,560		885,121
12							
13	Deferred income taxes for AFUDC equity	14,601,256	112,172	421	62,093		14,651,335
14							
15	Other IMP related costs	4,223,147		407.3	1,266,944		2,956,203
16							
17	Deferred Migration Costs	2,488,489		921	162,292		2,326,197
18							
19	Deferred System Upgrade Costs	2,071,497		921	135,097		1,936,400
20							
21	Smartpigging/hydrostatic testing	22,758,919	365,081	863	1,629,773		21,494,227
22							
23	Defined benefit pension plan	2,585,795	106,417				2,692,212
24							
25	Fair value hedges and firm commitments for operational storage	254,454		483,803	254,454		
26							
27	Unrealized loss on derivatives, net	50,124,266		803	15,344,759		34,779,507
28							
29	Firm commitments/Encroachment revaluation	338	5,868,191	813	3,226,756		2,641,773
30							
31	Electrical compression	31,777	167,693	855	168,717		30,753
32							
33	Tracked fuel/UAF under-retention/PRA		12,546,292	813	2,859,883		9,686,409
34							
35							
36							
37							
38							
39							
40	**Total**	**146,576,050**	**21,224,700**		**27,643,304**	**0**	**140,157,446**

Schedule Page: 232 Line No.: 1 Column: a

Regulatory Authorization

Line No.	Description	Regulatory Citation	Amortization Period
1	Computer systems development costs	RP92-1	Through 10/11
3	Deferred regulatory commission expense	RP04-155	
5	FAS 106 implementation deferral	RP98-203	170 months starting 10/98
7	Post Retirement medical plan accrual	RP98-203	Through 12/12
9	Asset retirement obligation	RP04-155	
11	Deferred FERC annual charge	18 CFR Sec 154.402	12 months ending September
13	Deferred income taxes associated with AFUDC equity	RP04-155	Based on life of plant
15	Other IMP related costs	RP92-1	Through 10/11
17	Deferred Migration Costs	RP04-155	120 months starting 11/04
19	Deferred System Upgrade Costs	RP04-155	120 months starting 11/04
21	Smart Pigging/Hydrostatic Testing	RP04-155	Over 84 months
23	Defined benefit pension plan	AI07-1-000 & Order 710	
25	Fair value hedges and firm commitments	Orders 552 & 627	
27	Unrealized loss on derivatives, net	Orders 552 & 627	
29	Firm commitments / encroachment revaluation	Orders 552 & 627	
31	Electrical compression	RP97-275	
33	Tracked fuel/UAF under-retention/PRA	RP97-275	

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q1

Other Regulatory Liabilities (Account 254)

1. Report below the 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 $250,000, whichever is less) may be grouped by classes.
4. Provide in a footnote, for each line item, the regulatory citation where the respondent was directed to refund the regulatory liability (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)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	Carlton resolution credits	794,866	131	355,109		1,677,949	2,117,706
2							
3	PBOP Obligation	3,680,000	131,165	751,195		281,871	3,210,676
4							
5	Penalty and Deferred Delivery Variance Charge Revenue Crediting Mechanism	735,142				253,546	988,688
6							
7	Tracked fuel/UAF over-retention (PRA)	1,062,321	182.3	4,733,247		3,670,926	
8							
9	Interest rate lock	868,806	428	45,123			823,683
10	(ref. $100M Sr. Notes due 5-1-2015)						
11							
12	Employee benefits	16,136,648	128	120,435		250,726	16,266,939
13							
14							
15							
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45	**Total**	**23,277,783**		**6,005,109**	**0**	**6,135,018**	**23,407,692**

Schedule Page: 278 Line No.: 1 Column: a

Regulatory Authorization

Line No.	Description	Regulatory Citation
1	Carlton resolution credits	RP01-382
3	PBOP obligation	RP98-203
5	Penalty and deferred delivery variance charge revenue crediting mechanism	Order 637 A
7	Tracked fuel/unaccounted for gas over retention (PRA)	RP97-275
9	Interest rate lock	Not applicable
12	Employee benefits	A107-1-000 & Order 710

Schedule Page: 278 Line No.: 7 Column: c

During the quarter, tracked fuel/UAF changed to an under-retention position. The debit balance was transferred to account 182.3.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Monthly Quantity & Revenue Data by Rate Schedule

1. Reference to account numbers in the USofA is provided in parentheses beside applicable data. Quantities must not be adjusted for discounts.
2. Total Quantities and Revenues in whole numbers
3. Report revenues and quantities of gas by rate schedule. Where transportation services are bundled with storage services, reflect only transportation Dth. When reporting storage, report Dth of gas withdrawn from storage and revenues by rate schedule.
4. Revenues in Column (c) include transition costs from upstream pipelines. Revenue (Other) in Column (e) includes reservation charges received by the pipeline plus usage charges, less revenues reflected in Columns (c) and (d). Include in Column (e), revenue for Accounts 490-495.
5. Enter footnotes as appropriate.

Line No.	Item (a)	Month 1 Quantity (b)	Month 1 Revenue Costs and Take-or-Pay (c)	Month 1 Revenue (GRI & ACA) (d)	Month 1 Revenue (Other) (e)	Month 1 Revenue (Total) (f)
1	Total Sales (480-488)	91,449			1,636,858	1,636,858
2	Transportation of Gas for Others (489.2 and 489..3)					
3	CS-1	2,034,893			32,058	32,058
4	TF	38,223,690		73,011	25,054,279	25,127,290
5	TFX	69,685,539		130,968	37,182,029	37,312,997
6	GS-T	8,770		15	6,462	6,477
7	TI	3,481,871		6,120	841,145	847,265
8	SMS	1,537,995			919,826	919,826
9	Less: CS-1 units	-2,034,893				
10	Less: SMS units in other rate schedules	-1,537,995				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Monthly Quantity & Revenue Data by Rate Schedule (continued)

Line No.	Item (a)	Month 1 Quantity (b)	Month 1 Revenue Costs and Take-or-Pay (c)	Month 1 Revenue (GRI & ACA) (d)	Month 1 Revenue (Other) (e)	Month 1 Revenue (Total) (f)
48						
49						
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61						
62						
63	Total Transportation (Other than Gathering)	111,399,870		210,114	64,035,799	64,245,913
64	Storage (489.4)					
65	FDD-1	11,008,205			2,226,588	2,226,588
66	IDD-1	1,107,469			180,404	180,404
67	PDD-1	18,228,267			1,890,997	1,890,997
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87						
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89						
90	Total Storage	30,343,941			4,297,989	4,297,989
91	Gathering (489.1)					
92	Gathering-Firm	217,103			1,194	1,194
93	Gathering-Interruptible	623,932			21,587	21,587
94	Total Gathering (489.1)	841,035			22,781	22,781
95	Additional Revenues					
96	Products Sales and Extraction (490-492)	454			8,323	8,323
97	Rents (493-494)				7,906	7,906
98	Other Gas Revenues (495)				816,880	816,880
99	(Less) Provision for Rate Refunds					
100	Total Additional Revenues	454			833,109	833,109
101	Total Operating Revenues (Total of Lines 1,63,90,94 & 100)	142,676,749		210,114	70,826,536	71,036,650

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Monthly Quantity & Revenue Data by Rate Schedule

1. Reference to account numbers in the USofA is provided in parentheses beside applicable data. Quantities must not be adjusted for discounts.
2. Total Quantities and Revenues in whole numbers
3. Report revenues and quantities of gas by rate schedule. Where transportation services are bundled with storage services, reflect only transportation Dth. When reporting storage, report Dth of gas withdrawn from storage and revenues by rate schedule.
4. Revenues in Column (c) include transition costs from upstream pipelines. Revenue (Other) in Column (e) includes reservation charges received by the pipeline plus usage charges, less revenues reflected in Columns (c) and (d). Include in Column (e), revenue for Accounts 490-495.
5. Enter footnotes as appropriate.

Line No.	Month 2 Quantity (g)	Month 2 Revenue Costs and Take-or-Pay (h)	Month 2 Revenue (GRI & ACA) (i)	Month 2 Revenue (Other) (j)	Month 2 Revenue (Total) (k)	Month 3 Quantity (l)	Month 3 Revenue Costs and Take-or-Pay (m)	Month 3 Revenue (GRI & ACA) (n)	Month 3 Revenue (Other) (o)	Month 3 Revenue (Total) (p)
1	70,402			1,237,079	1,237,079	54,575			964,237	964,237
2	[redacted]									
3	1,927,688			27,596	27,596	1,691,412			30,347	30,347
4	30,634,826		58,593	24,728,447	24,787,040	28,563,487		53,747	24,714,808	24,768,555
5	55,446,070		107,207	36,615,701	36,722,908	52,921,258		100,133	35,345,038	35,445,171
6	11,679		16	9,101	9,117	380		24	(297)	(273)
7	3,601,385		7,131	962,774	969,905	2,326,811		4,618	505,340	509,958
8	1,795,760			925,187	925,187	1,671,243			922,597	922,597
9	-1,927,688					-1,691,412				
10	-1,795,760					-1,671,243				
11										
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Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q1

Monthly Quantity & Revenue Data by Rate Schedule (continued)

Line No.	Month 2 Quantity (g)	Month 2 Revenue Costs and Take-or-Pay (h)	Month 2 Revenue (GRI & ACA) (i)	Month 2 Revenue (Other) (j)	Month 2 Revenue (Total) (k)	Month 3 Quantity (l)	Month 3 Revenue Costs and Take-or-Pay (m)	Month 3 Revenue (GRI & ACA) (n)	Month 3 Revenue (Other) (o)	Month 3 Revenue (Total) (p)
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53										
54										
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58										
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60										
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62										
63	89,693,960		172,947	63,268,806	63,441,753	83,811,936		158,522	61,517,833	61,676,355
64										
65	16,428,196			2,208,918	2,208,918	13,384,232			2,111,944	2,111,944
66	605,450			165,835	165,835	614,057			263,487	263,487
67	5,799,046			1,275,871	1,275,871	1,966,406			674,955	674,955
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86										
87										
88										
89										
90	22,832,692			3,650,624	3,650,624	15,964,695			3,050,386	3,050,386
91										
92										
93	766,399			26,518	26,518	681,269			23,572	23,572
94	766,399			26,518	26,518	681,269			23,572	23,572
95										
96	5,998			98,968	98,968	6,378			104,808	104,808
97				7,906	7,906				8,506	8,506
98				128,864	128,864				1,796,765	1,796,765
99										
100	5,998			235,738	235,738	6,378			1,910,079	1,910,079
101	113,369,451		172,947	68,418,765	68,591,712	100,518,853		158,522	67,466,107	67,624,629

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Natural Gas Company- Gas Revenues and Dekatherms

1. Report below in columns (b), (d) and (f) natural gas operating revenues for each prescribed account year to date

2. In column (f) report the quantity of Dekatherms sold of natural gas year to date.

Line No.	Title of Account (a)	Total Operating Revenues Year to Date Current Qtr (b)	Dekatherms of Natural Gas Year to Date Current Qtr (c)
1	(480) Residential Sales		
2	(481) Commercial and Industrial Sales	3,838,174	216,426
3	(482) Other Sales to Public Authorities		
4	(483) Sales for Resale		
5	(484) Interdepartmental Sales		
6	Total Sales (Lines 1 to 5)	3,838,174	216,426
7	485 Intracompany Transfers		
8	487 Forfeited Discounts		
9	488 Miscellaneous Service Revenues		
10	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities	72,871	2,288,703
11	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities	189,364,021	284,905,766
12	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities		
13	489.4 Revenues from Storing Gas of Others	10,998,999	69,141,328
14	490 Sales of Prod. Ext. from Natural Gas		
15	491 Revenues from Natural Gas Proc. by Others		
16	492 Incidental Gasoline and Oil Sales	212,099	
17	493 Rent from Gas Property	24,318	
18	494 Interdepartmental Rents		
19	495 Other Gas Revenues	2,742,509	
20	Subtotal:	207,252,991	
21	496 (Less) Provision for Rate Refunds		
22	TOTAL	207,252,991	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Gas Production and Other Gas Supply Expenses

Report the amount of gas production and other gas supply expenses year to date

Line No.	Account (a)	Year to Date (b)	
1	Production Expenses		
2	Manufactured Gas Production		
3	Total Manufactured Gas Production (700-742)		
4	Natural Gas Production and Gathering		
5	(750-760) Operation	21,115	
6	(761-769) Maintenance		
7	Total Natural Gas Production and Gathering (lines 5 and 6)	21,115	
8	Production Extraction		
9	(770-783) Operation		
10	(784-791) Maintenance		
11	Total Production Extraction (lines 9 and 10)		
12	(795-798) Exploration and Development Expenses		
13	Other Gas Supply Expenses		
14	Operation		
15	(800) Natural Gas Well Head Purchases		
16	(800.1) Natural Gas Well Head Purchases, Intra company Transfers		
17	(801) Natural Gas Field Line Purchases		
18	(802) Natural Gasoline Plant Outlet Purchases		
19	(803) Natural Gas Transmission Line Purchases	35,440,604	
20	(804) Natural Gas City Gate Purchases		
21	(804.1) Liquefied Natural Gas Purchases		
22	(805) Other Gas Purchases	(11,204,279)	
23	(805.1) (Less) Purchase Gas Cost Adjustments		
24	Total Purchased Gas (lines 15 through 23)	24,236,325	
25	(806) Exchange Gas	4,666,675	
26	Purchased Gas Expenses		
27	(807.1) Well Expense - Purchased Gas		
28	(807.2) Operation of Purchased Gas Measuring Stations		
29	(807.3) Maintenance of Purchased Gas Measuring Stations		
30	(807.4) Purchased Gas Calculations Expenses		
31	(807.5) Other Purchased Gas Expenses		
32	Total Purchased Gas Expenses (lines 27 thru 31)		
33	(808.1) Gas Withdrawn from Storage-Debit	20,063,367	
34	(808.2) (Less) Gas Delivered to Storage - Credit	44,959,635	
35	(809.1) Withdrawals of Liquefield Natural Gas for Processing - Debit		
36	(809.2) (Less) Deliveries of Natural Gas Processing - Credit		
37	Gas Used in Utility Operation - Credit		
38	(810) Gas Used for Compressor Station Fuel - Credit	14,914,347	
39	(811) Gas Used for Products Extraction - Credit		
40	(812) Gas Used for Other Utility Operations - Credit	6,221,012	
41	Total Gas Used in Utility Operations - Credit (Lines 38 thru 40)	21,135,359	
42	(813) Other Gas Supply Expense	2,773,895	
43	Total Other Gas Supply Expenses (Lines 24, 25, 32, 33, thru 36, 42, less 41)	(14,354,732)	
44	Total Production Expenses (Lines 3,7,11,12, and 43)	(14,333,617)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Natural Gas Storage, Terminaling, Processing Services

Report the amount of natural gas storage, terminaling, processing, transmission and distribution expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)	
1	NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
2	UNDERGROUND STORAGE EXPENSES		
3	(814-826) Operations	4,697,596	
4	(830-837) Maintenance	1,045,869	
5	Total Underground Storage Expenses (Lines 3 and 4)	5,743,465	
6	OTHER STORAGE EXPENSES		
7	(840-842.3) Operations	1,045,356	
8	(843.1-843.9) Maintenance	646,683	
9	Total Other Storage Expenses (lines 7 and 8)	1,692,039	
10	LIQUEFIED NATURAL GAS TERMINALING AND PROCESSING		
11	(844.1-846.2) Operations		
12	(847.1-847.8) Maintenance		
13	Total Liquefied Natural Gas Terminaling and Processing (Lines 11 and 12)		
14	TRANSMISSION EXPENSES		
15	Transmission Operation Expenses		
16	(850) Operation Supervision and Engineering	1,345,451	
17	(851) System Control and Load Dispatching	1,613,160	
18	(852) Communication System Expenses	394,756	
19	(853) Compressor Station Labor and Expenses	2,466,071	
20	(854) Gas for Compressor Station Fuel	13,919,989	
21	(855) Other Fuel and Power for Compressor Stations	867,087	
22	(856) Mains Expenses	6,210,331	
23	(857) Measuring and Regulating Station Expenses	1,039,075	
24	(858) Transmission and Compression of Gas by Others		
25	(859) Other Expenses	339,950	
26	(860) Rents	47,867	
27	Total Transmission Operation Expenses (Lines 16 through 26)	28,243,737	
28	Transmission Maintenance Expenses		
29	(861) Maintenance Supervision and Engineering	253	
30	(862) Maintenance of Structures and Improvements	204,874	
31	(863) Maintenance of Mains	2,991,723	
32	(864) Maintenance of Compressor Station Equipment	2,327,840	
33	(865) Maintenance of Measuring and Regulating Equipment	610,872	
34	(866) Maintenance of Communication Equipment	26,265	
35	(867) Maintenance of Other Equipment	124,618	
36	Total Transmission Maintenance Expenses (Lines 29 through 35)	6,286,445	
37	Total Transmission Expenses (lines 27 and 36)	34,530,182	
38	DISTRIBUTION EXPENSES		
39	(870-881) Operation Expenses		
40	(885-894) Maintenance		
41	Total Distribution Expenses (Lines 39 and 40)		
42	Total (lines 5,9,13,37 and 41)	41,965,686	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Gas Customer Accounts, Service, Sales, Administrative and General Expenses

Report the amount of expenses for customer accounts, service, sales, and administrative and general expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)	
1	(901-905) Customer Accounts Expenses		
2	(907-910) Customer Service and Information Expenses	737	
3	(911-916) Sales Expenses	185,038	
4	8. ADMINISTRATIVE AND GENERAL EXPENSES		
5	Operations		
6	920 Administrative and General Salaries	8,023,219	
7	921 Office Supplies and Expenses	3,599,213	
8	(Less) 922 Administrative Expenses Transferred-Credit	283,929	
9	923 Outside Services Employed	1,460,901	
10	924 Property Insurance	290,635	
11	925 Injuries and Damages	235,313	
12	926 Employee Pensions and Benefits	3,978,549	
13	927 Franchise Requirements		
14	928 Regulatory Commission Expenses	723,746	
15	(Less) 929 Duplicate Charges-Credit		
16	930.1 General Advertising Expenses		
17	930.2 Miscellaneous General Expenses	24,876	
18	931 Rents	205,371	
19	TOTAL Operation (Total of lines 6 through 18)	18,257,894	
20	Maintenance		
21	932 Maintenance of General Plant		
22	TOTAL Administrative and General Expenses (Total of lines 19 and 21)	18,257,894	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 403.1, 404.1, 404.2, 404.3, 405) (Except Amort of Acqusition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Other Gas Plant (Accounts 404.1, 404.2 and 404.3) (d)
1	Intangible Plant	0	0	1,355,965
2	Production Plant, Manufacturing Plant	0	0	0
3	Production and Gathering Plant - Natural Gas	359,093	0	0
4	Products Extraction - Natural Gas	0	0	0
5	Underground Gas Storage Plant	1,458,367	0	73,645
6	Other Storage Plant	235,550	0	0
7	Base Load LNG Terminaling and Processing Plant	0	0	0
8	Processing Plant	0	0	0
9	Transmission Plant	9,050,477	0	298,936
10	Distribution Plant	0	0	0
11	General Plant	2,759,995	0	0
12	Common Plant	0	0	0
13	TOTAL GAS (Lines 1 through 12)	13,863,482	0	1,728,546

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 403.1, 404.1, 404.2, 404.3, 405) (Except Amort of Acqusition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Amortization of Other Gas Plant (Account 405) (e)	Total (b) to (e)				
1	0	1,355,965				
2	0	0				
3	0	359,093				
4	0	0				
5	0	1,532,012				
6	0	235,550				
7	0	0				
8	0	0				
9	0	9,349,413				
10	0	0				
11	0	2,759,995				
12	0	0				
13	0	15,592,028				

Gas Account - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales,transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only
01 Name of System:				
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		8,061,310	8,061,310
4	Gas of Others Received for Gathering (Account 489.1)	303	2,288,703	2,288,703
5	Gas of Others Received for Transmission (Account 489.2)	305	284,905,766	284,905,766
6	Gas of Others Received for Distribution (Account 489.3)	301		
7	Gas of Others Received for Contract Storage (Account 489.4)	307	9,208,947	9,208,947
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328		
10	Gas Received as Imbalances (Account 806)	328	1,133,383	1,133,383
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332		
12	Other Gas Withdrawn from Storage (Explain)		40,314,609	40,314,609
13	Gas Received from Shippers as Compressor Station Fuel		2,862,544	2,862,544
14	Gas Received from Shippers as Lost and Unaccounted for		(677,114)	(677,114)
15	Other Receipts (Specify) (footnote details)			
16	Total Receipts (Total of lines 3 thru 15)		348,098,148	348,098,148
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		216,426	216,426
19	Deliveries of Gas Gathered for Others (Account 489.1)	303	2,288,703	2,288,703
20	Deliveries of Gas Transported for Others (Account 489.2)	305	284,905,766	284,905,766
21	Deliveries of Gas Distributed for Others (Account 489.3)	301		
22	Deliveries of Contract Storage Gas (Account 489.4)	307	49,271,023	49,271,023
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328		
26	Deliveries of Gas to Others for Transportation (Account 858)	332		
27	Other Gas Delivered to Storage (Explain)		6,288,172	6,288,172
28	Gas Used for Compressor Station Fuel	509	3,335,000	3,335,000
29	Other Deliveries and Gas Used for Other Operations		880,326	880,326
30	Total Deliveries (Total of lines 18 thru 29)		347,185,416	347,185,416
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		912,732	912,732
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		348,098,148	348,098,148

Schedule Page: 520 Line No.: 3 Column: c

The 8,061,310 Dth represents gas purchases recorded to FERC account 803.

Schedule Page: 520 Line No.: 12 Column: c

The 40,314,609 Dth represents gas withdrawn from storage (includes third party and company owned gas).

Schedule Page: 520 Line No.: 27 Column: c

The 6,288,172 Dth represents gas injected into storage (includes third party and company owned gas).

Schedule Page: 520 Line No.: 29 Column: c

	Amount in Dth
Drip Shrinkage	12,830
Gas Used in other O&M Operations	867,496
Total	880,326

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (m) and (n).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

Line No.	Item (a)	Month 1 Discounted rate Dth (b)	Month 1 Negotiated Rate Dth (c)	Month 1 Recourse Rate Dth (d)	Month 1 Total Dth (e)
1	**SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)**				
2	Gathering			669,641	669,641
3	Production/Extraction/Processing				
4	Transmission				
5	Distribution				
6	Storage				
7	**Total Shipper Supplied Gas**			669,641	669,641
8	**LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)**				
9	Gathering			1,043,526	1,043,526
10	Production/Extraction/Processing				
11	Transmission				
12	Distribution				
13	Storage				
14	**Total gas used in compressors**			1,043,526	1,043,526
15	**LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)**				
16	Gathering			268,229	268,229
17	Production/Extraction/Processing				
18	Transmission				
19	Distribution				
20	Storage				
21	Other Deliveries (specify) (footnote details)				
22	**Total Gas Used For Other Deliveries And Gas Used For Other Operations**			268,229	268,229
23	**LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)**				
24	Gathering			278,044	278,044
25	Production/Extraction/Processing				
26	Transmission				
27	Distribution				
28	Storage				
29	Other Losses (specify) (footnote details)				
30	**Total Gas Lost And Unaccounted For**			278,044	278,044

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Item (a)	Month 1 Discounted rate Dth (b)	Month 1 Negotiated Rate Dth (c)	Month 1 Recourse Rate Dth (d)	Month 1 Total Dth (e)
31	**NET EXCESS OR (DEFICIENCY)**				
32	Gathering			(920,158)	(920,158)
33	Production/Extraction				
34	Transmission				
35	Distribution				
36	Storage				
37	**Total Net Excess Or (Deficiency)**			(920,158)	(920,158)
38	**DISPOSITION OF EXCESS GAS:**				
39	Gas sold to others				
40	Gas used to meet imbalances				
41	Gas added to system gas				
42	Gas returned to shippers				
43	Other (list)				
44					
45					
46					
47					
48					
49					
50					
51	**Total Disposition Of Excess Gas**				
52	**GAS ACQUIRED TO MEET DEFICIENCY:**				
53	System gas			165,000	165,000
54	Purchased gas				
55	Other (list)				
56	Gas to be recovered from shippers			755,158	755,158
57					
58					
59					
60					
61					
62					
63					
64					
65	**Total Gas Acquired To Meet Deficiency**			920,158	920,158

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q1

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (m) and (n).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

Line No.	Item (a)	Month 2 Discounted rate Dth (p)	Month 2 Negotiated Rate Dth (q)	Month 2 Recourse Rate Dth (r)	Month 2 Total Dth (s)
1	**SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)**				
2	Gathering			803,282	803,282
3	Production/Extraction/Processing				
4	Transmission				
5	Distribution				
6	Storage				
7	**Total Shipper Supplied Gas**			803,282	803,282
8	**LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)**				
9	Gathering			1,233,480	1,233,480
10	Production/Extraction/Processing				
11	Transmission				
12	Distribution				
13	Storage				
14	**Total gas used in compressors**			1,233,480	1,233,480
15	**LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)**				
16	Gathering			282,050	282,050
17	Production/Extraction/Processing				
18	Transmission				
19	Distribution				
20	Storage				
21	Other Deliveries (specify) (footnote details)				
22	**Total Gas Used For Other Deliveries And Gas Used For Other Operations**			282,050	282,050
23	**LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)**				
24	Gathering			464,706	464,706
25	Production/Extraction/Processing				
26	Transmission				
27	Distribution				
28	Storage				
29	Other Losses (specify) (footnote details)				
30	**Total Gas Lost And Unaccounted For**			464,706	464,706

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Item (a)	Month 2 Discounted rate Dth (p)	Month 2 Negotiated Rate Dth (q)	Month 2 Recourse Rate Dth (r)	Month 2 Total Dth (s)
31	**NET EXCESS OR (DEFICIENCY)**				
32	Gathering			(1,176,954)	(1,176,954)
33	Production/Extraction				
34	Transmission				
35	Distribution				
36	Storage				
37	**Total Net Excess Or (Deficiency)**			(1,176,954)	(1,176,954)
38	**DISPOSITION OF EXCESS GAS:**				
39	Gas sold to others				
40	Gas used to meet imbalances				
41	Gas added to system gas				
42	Gas returned to shippers				
43	Other (list)				
44					
45					
46					
47					
48					
49					
50					
51	**Total Disposition Of Excess Gas**				
52	**GAS ACQUIRED TO MEET DEFICIENCY:**				
53	System gas			123,915	123,915
54	Purchased gas			60,000	60,000
55	Other (list)				
56	Gas to recovered from shippers			993,039	993,039
57					
58					
59					
60					
61					
62					
63					
64					
65	**Total Gas Acquired To Meet Deficiency**			1,176,954	1,176,954

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q1

Shipper Supplied Gas for the Current Quarter

1. Report monthly (1) shipper supplied gas for the current quarter and gas consumed in pipeline operations, (2) the disposition of any excess, the accounting recognition given to such disposition and the specific account(s) charged or credited, and (3) the source of gas used to meet any deficiency, the accounting recognition given to the gas used to meet the deficiency, including the accounting basis of the gas and the specific account(s) charged or credited.
2. On lines 7, 14, 22 and 30 report only the dekatherms of gas provided by shippers under tariff terms and conditions for gathering , production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dekatherms must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 24-29. The dekatherms must be reported in column (d) unless the company has discounted or negotiated rates which should be reported in columns (b) and (c).
3. On lines 7, 14, 22 and 30 report only the dollar amounts of gas provided by shippers under tariff terms and conditions for gathering, production/ extraction/processing, transmission, distribution and storage service and the use of that gas for compressor fuel, other operational purposes and lost and unaccounted for. The dollar amounts must be broken out by functional categories on Lines 2-6, 9-13, 16-21 and 23-29. The dollar amounts must be reported in column (h) unless the company has discounted or negotiated rates which should be reported in columns (f) and (g). The accounting should disclose the account(s) debited and credited in columns (m) and (n).
4. Indicate in a footnote the basis for valuing the gas reported in Columns (f), (g) and (h).
5. Report in columns (j), (k) and (l) the amount of fuel waived, discounted or reduced as part of a negotiated rate agreement.
6. On lines 32-37 report the dekatherms and dollar value of the excess or deficiency in shipper supplied gas broken out by functional category and whether recourse rate, discounted or negotiated rate.
7. On lines 39 through 51 report the dekatherms, the dollar amount and the account(s) credited in Column (o) for the dispositions of gas listed in column (a).
8. On lines 53 through 65 report the dekatherms, the dollar amount and the account(s) debited in Column (n) for the sources of gas reported in column (a).
9. On lines 66 and 67, report forwardhaul and backhaul volume in Dths of throughput.
10. Where appropriate, provide a full explanation of the allocation process used in reported numbers in a footnote.

Line No.	Item (a)	Month 3 Discounted rate Dth (dd)	Month 3 Negotiated Rate Dth (ee)	Month 3 Recourse Rate Dth (ff)	Month 3 Total Dth (gg)
1	**SHIPPER SUPPLIED GAS (LINES 13 AND 14 , PAGE 520)**				
2	Gathering			712,507	712,507
3	Production/Extraction/Processing				
4	Transmission				
5	Distribution				
6	Storage				
7	**Total Shipper Supplied Gas**			712,507	712,507
8	**LESS GAS USED FOR COMPRESSOR STATION FUEL (LINE 28, PAGE 520)**				
9	Gathering			1,057,994	1,057,994
10	Production/Extraction/Processing				
11	Transmission				
12	Distribution				
13	Storage				
14	**Total gas used in compressors**			1,057,994	1,057,994
15	**LESS GAS USED FOR OTHER DELIVERIES AND GAS USED FOR OTHER OPERATIONS (LINE 29, PAGE 520) (Footnote)**				
16	Gathering			317,217	317,217
17	Production/Extraction/Processing				
18	Transmission				
19	Distribution				
20	Storage				
21	Other Deliveries (specify) (footnote details)				
22	**Total Gas Used For Other Deliveries And Gas Used For Other Operations**			317,217	317,217
23	**LESS GAS LOST AND UNACCOUNTED FOR (LINE 32, PAGE 520)**				
24	Gathering			169,982	169,982
25	Production/Extraction/Processing				
26	Transmission				
27	Distribution				
28	Storage				
29	Other Losses (specify) (footnote details)				
30	**Total Gas Lost And Unaccounted For**			169,982	169,982

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Item (a)	Month 3 Discounted rate Dth (dd)	Month 3 Negotiated Rate Dth (ee)	Month 3 Recourse Rate Dth (ff)	Month 3 Total Dth (gg)
31	**NET EXCESS OR (DEFICIENCY)**				
32	Gathering			(832,686)	(832,686)
33	Production/Extraction				
34	Transmission				
35	Distribution				
36	Storage				
37	**Total Net Excess Or (Deficiency)**			(832,686)	(832,686)
38	**DISPOSITION OF EXCESS GAS:**				
39	Gas sold to others				
40	Gas used to meet imbalances				
41	Gas added to system gas				
42	Gas returned to shippers				
43	Other (list)				
44					
45					
46					
47					
48					
49					
50					
51	**Total Disposition Of Excess Gas**				
52	**GAS ACQUIRED TO MEET DEFICIENCY:**				
53	System gas			87,519	87,519
54	Purchased gas				
55	Other (list)				
56	Gas to be recovered from shippers			745,167	745,167
57					
58					
59					
60					
61					
62					
63					
64					
65	**Total Gas Acquired To Meet Deficiency**			832,686	832,686

Shipper Supplied Gas for the Current Quarter (continued)

.

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 1 Account(s) Debited (n)	Month 1 Account(s) Credited (o)
	Month 1 Discounted Rate Amount (f)	Month 1 Negotiated Rate Amount (g)	Month 1 Recourse rate Amount (h)	Month 1 Total Amount (i)	Month 1 Waived Dth (j)	Month 1 Discounted Dth (k)	Month 1 Negotiated Dth (l)	Month 1 Total Dth (m)		
1										
2			2,971,598	2,971,598					805	805
3										
4										
5										
6										
7			2,971,598	2,971,598						
8										
9			4,643,899	4,643,899					854, 819	810
10										
11										
12										
13										
14			4,643,899	4,643,899						
15										
16			1,193,556	1,193,556					See footnote	812
17										
18										
19										
20										
21										
22			1,193,556	1,193,556						
23										
24			1,213,675	1,213,675					813, 823	812, 813
25										
26										
27										
28										
29										
30			1,213,675	1,213,675						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 1 Account(s) Debited (n)	Month 1 Account(s) Credited (o)
	Month 1 Discounted Rate Amount (f)	Month 1 Negotiated Rate Amount (g)	Month 1 Recourse rate Amount (h)	Month 1 Total Amount (i)	Month 1 Waived Dth (j)	Month 1 Discounted Dth (k)	Month 1 Negotiated Dth (l)	Month 1 Total Dth (m)		
31										
32			(4,079,532)	(4,079,532)						
33										
34										
35										
36										
37			(4,079,532)	(4,079,532)						
38										
39										
40										
41										
42										
43										
44										
45										
46										
47										
48										
49										
50										
51										
52										
53			856,962	856,962					813, 803	164.1, 219
54										
55										
56			3,368,828	3,368,828					182.3	805
57										
58										
59										
60										
61										
62										
63										
64										
65			4,225,790	4,225,790						

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q1

Shipper Supplied Gas for the Current Quarter (continued)

.

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 2 Account(s) Debited (bb)	Month 2 Account(s) Credited (cc)
	Month 2 Discounted Rate Amount (t)	Month 2 Negotiated Rate Amount (u)	Month 2 Recourse rate Amount (v)	Month 2 Total Amount (w)	Month 2 Waived Dth (x)	Month 2 Discounted Dth (y)	Month 2 Negotiated Dth (z)	Month 2 Total Dth (aa)		
1										
2			3,725,987	3,725,987					805	805
3										
4										
5										
6										
7			3,725,987	3,725,987						
8										
9			5,799,870	5,799,870					854, 819	810
10										
11										
12										
13										
14			5,799,870	5,799,870						
15										
16			1,326,538	1,326,538					See footnote	812
17										
18										
19										
20										
21										
22			1,326,538	1,326,538						
23										
24			2,063,753	2,063,753					813, 823	812, 813
25										
26										
27										
28										
29										
30			2,063,753	2,063,753						

Name of Respondent Northern Natural Gas Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q1

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 2 Account(s) Debited (bb)	Month 2 Account(s) Credited (cc)
	Month 2 Discounted Rate Amount (t)	Month 2 Negotiated Rate Amount (u)	Month 2 Recourse rate Amount (v)	Month 2 Total Amount (w)	Month 2 Waived Dth (x)	Month 2 Discounted Dth (y)	Month 2 Negotiated Dth (z)	Month 2 Total Dth (aa)		
31										
32			(5,464,175)	(5,464,175)						
33										
34										
35										
36										
37			(5,464,175)	(5,464,175)						
38										
39										
40										
41										
42										
43										
44										
45										
46										
47										
48										
49										
50										
51										
52										
53			453,650	453,650					813	See Footnote
54			224,400	224,400					803	232
55										
56			4,701,681	4,701,681					182.3	805
57										
58										
59										
60										
61										
62										
63										
64										
65			5,379,731	5,379,731						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Shipper Supplied Gas for the Current Quarter (continued)

.

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 3 Account(s) Debited (pp)	Month 3 Account(s) Credited (qq)
	Month 3 Discounted Rate Amount (hh)	Month 3 Negotiated Rate Amount (ii)	Month 3 Recourse rate Amount (jj)	Month 3 Total Amount (kk)	Month 3 Waived Dth (ll)	Month 3 Discounted Dth (mm)	Month 3 Negotiated Dth (nn)	Month 3 Total Dth (oo)		
1										
2			3,021,397	3,021,397					805	805
3										
4										
5										
6										
7			3,021,397	3,021,397						
8										
9			4,470,577	4,470,577					854, 819	810
10										
11										
12										
13										
14			4,470,577	4,470,577						
15										
16			1,337,523	1,337,523					See footnote	812
17										
18										
19										
20										
21										
22			1,337,523	1,337,523						
23										
24			681,047	681,047					813, 823	812, 813
25										
26										
27										
28										
29										
30			681,047	681,047						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern Natural Gas Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q1

Shipper Supplied Gas for the Current Quarter (continued)

Line No.	Amount Collected (Dollars)				Volume (in Dth) Not Collected				Month 3 Account(s) Debited (pp)	Month 3 Account(s) Credited (qq)
	Month 3 Discounted Rate Amount (hh)	Month 3 Negotiated Rate Amount (ii)	Month 3 Recourse rate Amount (jj)	Month 3 Total Amount (kk)	Month 3 Waived Dth (ll)	Month 3 Discounted Dth (mm)	Month 3 Negotiated Dth (nn)	Month 3 Total Dth (oo)		
31										
32			(3,467,750)	(3,467,750)						
33										
34										
35										
36										
37			(3,467,750)	(3,467,750)						
38										
39										
40										
41										
42										
43										
44										
45										
46										
47										
48										
49										
50										
51										
52										
53			333,981	333,981					813, 182.3	117.4, 813
54										
55										
56			3,133,769	3,133,769					182.3	805
57										
58										
59										
60										
61										
62										
63										
64										
65			3,467,750	3,467,750						

Schedule Page: 521 Line No.: 9 Column: d

		Month 1 Gas Used (Dth)	Month 1 Amount ($)
Transmission	854	975,450	$4,340,948
Underground Storage	819	68,076	302,952
		1,043,526	$4,643,899

Schedule Page: 521 Line No.: 16 Column: d

Gas used for other operation purposes:

		Month 1 Gas Used (Dth)	Month 1 Amount ($)
LNG Compressor Station Fuel	842.1	1,352	$6,017
Line Operations	856	206,859	920,447
Purification Underground Storage	821	13,575	60,411
Other Underground Storage Operations	817	40,805	181,590
Other Compressor Station Fuel	819	5,638	25,090
		268,229	$1,193,556

Volume of gas used for other deliveries and gas used for other operations does not equal the volume reported on line 29 page 520. The variance is due to the exclusion of drip shrinkage which is not considered shipper supplied gas.

Schedule Page: 521 Line No.: 9 Column: d

		Month 2 Gas Used (Dth)	Month 2 Amount ($)
Transmission	854	1,142,383	$5,371,423
Underground Storage	819	91,097	428,447
		1,233,480	$5,799,870

Schedule Page: 521 Line No.: 16 Column: d

Gas used for other operation purposes:

		Month 2 Gas Used (Dth)	Month 2 Amount ($)
LNG Compressor Station Fuel	842.1	23,606	$111,024
Line Operations	856	216,313	1,017,363
Purification Underground Storage	821	10,036	47,201
Other Underground Storage Operations	817	27,217	128,007
Other Compressor Station Fuel	819	4,878	22,942
		282,050	$1,326,538

Volume of gas used for other deliveries and gas used for other operations does not equal the volume reported on line 29 page 520. The variance is due to the exclusion of drip shrinkage which is not considered shipper supplied gas.

Schedule Page: 521 Line No.: 9 Column: d

		Month 3 Gas Used (Dth)	Month 3 Amount ($)
Transmission	854	995,609	$4,207,618
Underground Storage	819	62,385	262,959
		1,057,994	$4,470,577

Schedule Page: 521 Line No.: 16 Column: d

Gas used for other operation purposes:

		Month 3 Gas Used (Dth)	Month 3 Amount ($)
LNG Compressor Station Fuel	842.1	80,880	$340,917
Line Operations	856	207,838	876,480
Purification Underground Storage	821	7,840	33,046
Other Underground Storage Operations	817	16,621	70,059
Other Compressor Station Fuel	819	4,038	17,021
		317,217	$1,337,523

Volume of gas used for other deliveries and gas used for other operations does not equal the volume reported on line 29 page 520. The variance is due to the exclusion of drip shrinkage which is not considered shipper supplied gas.

Schedule Page: 521 Line No.: 56 Column: a

Deficiency gas to be recovered from shippers is recorded in a volumetric tracker. Deficiency gas caused by storage losses is recorded at current market and replaced with system gas and gas purchases at historical cost.

Schedule Page: 521 Line No.: 64 Column: a

For Balance Sheet accounts carried and resolved volumetrically, the Respondent carries the balance priced at the end of the month Northern Natural Gas Demarcation index as published in Gas Daily.

Schedule Page: 521 Line No.: 53 Column: o

Accounts 164.1, 117.4, and 182.3.

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